BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 61
MISO Tariff Attachment Y

ATTACHMENT Y

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

Change of Status,

Including Notification of Rescission

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

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

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

_____

Name of Market Participant:_____

Owner's state of organization or incorporation _____

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

_____

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

_____

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

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

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: _____

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

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

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

_____

Signature

Name: _____ Contact Information

Title: _____ Email: _____

Date: _____ Phone: _____

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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.

---

[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?

---

[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?

---

[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]

---

[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?

V.pdf.

[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

---

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

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

[17] *Id.*

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

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

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

Panelists

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

4:00 pm – 4:15 pm: Closing Remarks

Document Content(s)

AD25-7-000 Tech Conf.docx.....1

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

OPEN ACCESS

palgrave
macmillan

Editors
Manfred Hafner
SciencesPo PSIA
Johns Hopkins University SAIS-Europe
Oberägeri, Zug, Switzerland

Giacomo Luciani
Paris School of International Affairs
SciencesPo
Founex, Vaud, Switzerland



ISBN 978-3-030-86883-3 ISBN 978-3-030-86884-0 (eBook)
https://doi.org/10.1007/978-3-030-86884-0

© The Editor(s) (if applicable) and The Author(s) 2022. This book is an open access publication.
Open Access This book is licensed under the terms of the Creative Commons Attribution 4.0 International License (http://creativecommons.org/licenses/by/4.0/), which permits use, sharing, adaptation, distribution and reproduction in any medium or format, as long as you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons licence and indicate if changes were made.
The images or other third party material in this book are included in the book's Creative Commons licence, unless indicated otherwise in a credit line to the material. If material is not included in the book's Creative Commons licence and your intended use is not permitted by statutory regulation or exceeds the permitted use, you will need to obtain permission directly from the copyright holder. The use of general descriptive names, registered names, trademarks, service marks, etc. in this publication does not imply, even in the absence of a specific statement, that such names are exempt from the relevant protective laws and regulations and therefore free for general use.
The publisher, the authors and the editors are safe to assume that the advice and information in this book are believed to be true and accurate at the date of publication. Neither the publisher nor the authors or the editors give a warranty, expressed or implied, with respect to the material contained herein or for any errors or omissions that may have been made. The publisher remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Cover illustration: ART Collection / Alamy Stock Photo

This Palgrave Macmillan imprint is published by the registered company Springer Nature Switzerland AG.
The registered company address is: Gewerbestrasse 11, 6330 Cham, Switzerland

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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 64
IEA Report



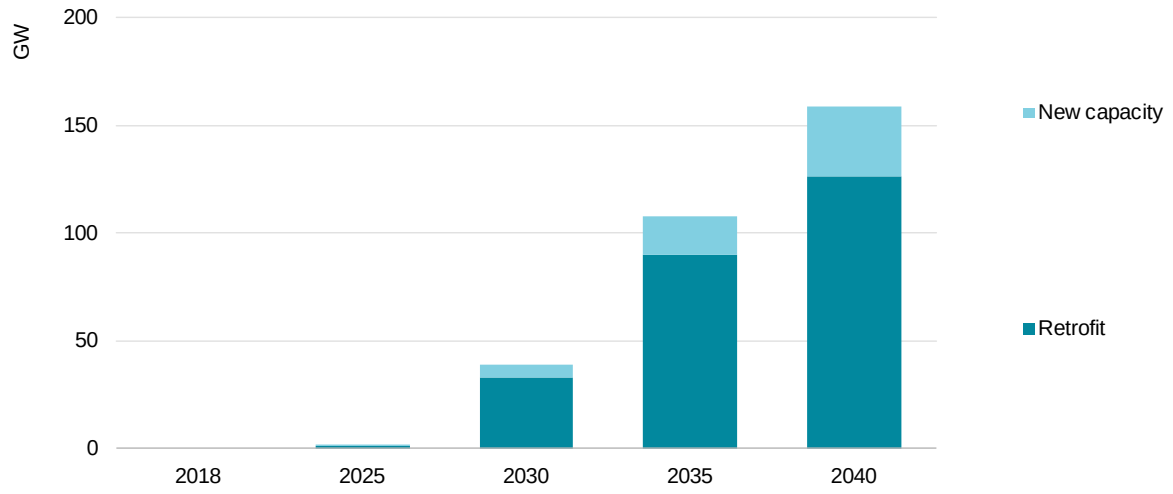
International Energy Agency

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

IEA. All rights reserved.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

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.

Suggested citation
U.S. Department of Energy, Grid Deployment Office. 2024. *The National Transmission Planning Study*. Washington, D.C.: U.S. Department of Energy. https://www.energy.gov/gdo/national-transmission-planning-study.

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.

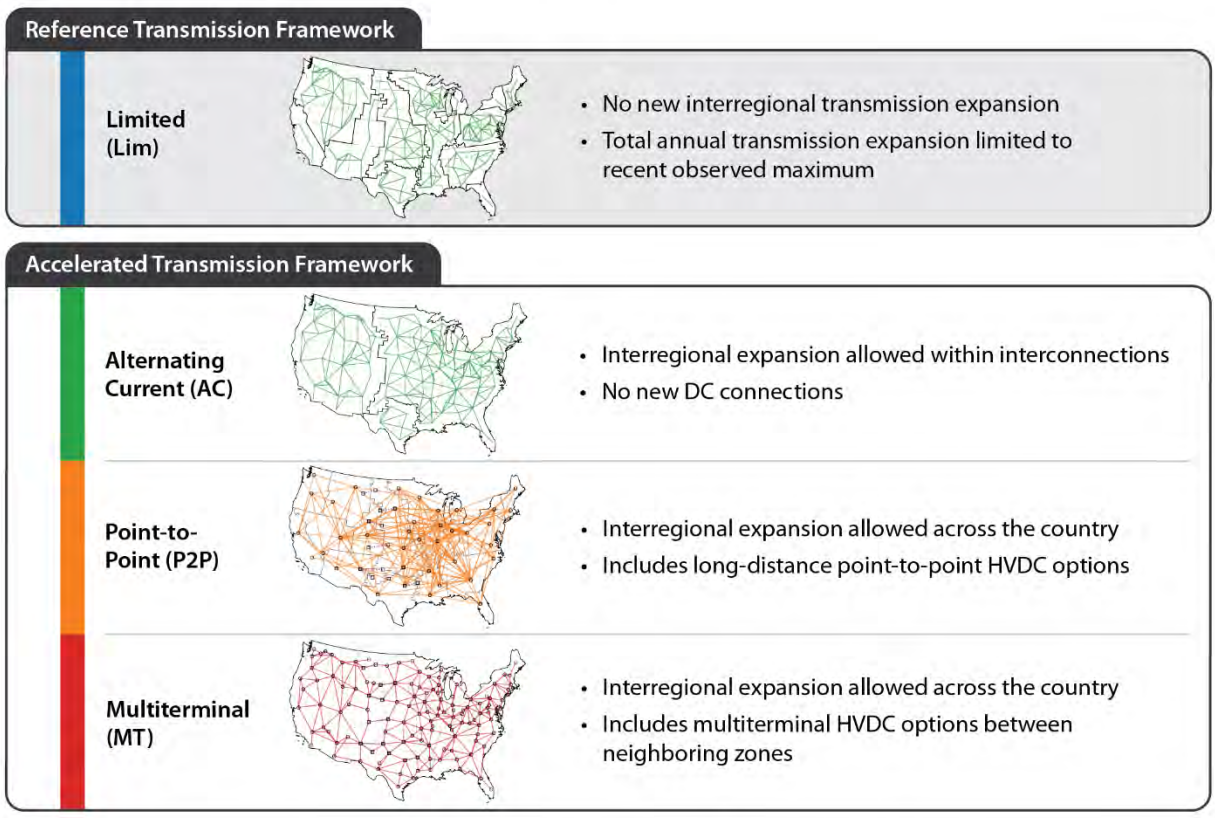


Figure I. NTP Study transmission frameworks

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.

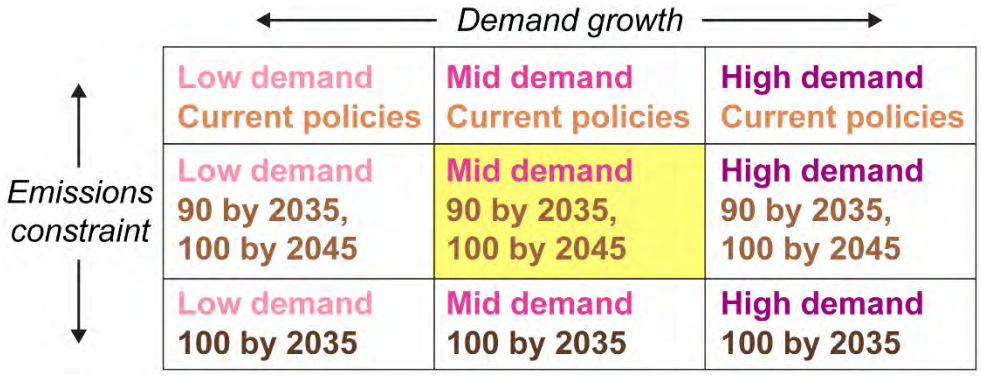


Figure II. Core demand and emissions assumptions.

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.

Table of Contents

1 Introduction 1
2 Methodology 3
2.1 Model Descriptions 3
2.2 Region and Transmission Terminology 4
2.3 Scenario Design 7
2.3.1 Transmission frameworks 8
2.3.2 Policy assumptions and emissions targets 9
2.3.3 Electricity demand growth assumptions 11
2.3.4 Other default assumptions 13
2.3.5 Sensitivity cases 13
2.4 Modeling and Analysis Limitations 15
3 Results 17
3.1 Current Policies 17
3.1.1 Benefits from large-scale transmission expansion include billions of metric tons of avoided CO_2 emissions 17
3.2 Demand Growth and Emissions Constraints 20
3.2.1 Rapid and significant growth in new transmission capacity occurs in scenarios that achieve deep emissions reductions 20
3.2.2 Benefits from large-scale transmission expansion include hundreds of billions of dollars in system cost savings under decarbonization futures 24
3.3 Central Demand and Emissions Assumptions 25
3.3.1 Accelerating transmission deployment consistently reduces system cost across a spectrum of sensitivity cases 26
3.3.2 Transmission expansion enables increased access to wind and solar 35
3.3.3 Significant amounts of transmission are added at all scales (local, regional, and interregional) in decarbonized systems 37
3.3.4 Expansion of interregional transmission is significant in decarbonized systems 39
3.3.5 Zero-carbon power systems dominated by variable renewable energy can meet resource adequacy targets 48
Appendix A. Regional Energy Deployment System (ReEDS) Model 68

A.1 Transmission Modeling 68
A.2 Wind and Solar Supply Curves 71
A.3 Hydrogen Modeling 75
A.4 End-Use Emissions 76
A.5 Climate Change Sensitivity 77
Appendix B. Integrated Capacity Expansion and Resource Adequacy Modeling 81
B.1 What Is PRAS? 81
B.2 Integrated ReEDS-PRAS process 81
B.3 Planning Threshold 82
B.4 Caveats 83
Appendix C. Technology Cost Assumptions 84
C.1 Supply-Side Technologies 84
C.2 Retrofits With CCS 89
C.3 Negative Emissions Technologies 89
C.4 Financing and Retirement Assumptions 90
Appendix D. Additional Results 91
D.1 ReEDS Results for 2035 91
D.2 Additional Capacity Expansion Modeling Results Through 2050 97
D.3 Additional Resource Adequacy Results 104
D.4 Regional Economic Benefits 108
Appendix E. Transmission Value Analysis 111
E.1 Multivalue 111
E.2 System Perspective 112
E.3 Project Scope 112
E.4 Planning Horizon 112
E.5 Uncertainty 112
E.6 Regional Disaggregation: Adjusted Production Cost 112
Appendix F. High Opportunity Transmission Interfaces: Regional Detail 115

List of Figures

Figure I. NTP Study transmission frameworks ix
Figure II. Core demand and emissions assumptions x
Figure 1. Hierarchy of regions used in the ReEDS model 5
Figure 2. Expandable transmission interfaces in the four transmission frameworks considered in this study 7
Figure 3. Core demand and emissions assumptions 8
Figure 4. Emissions constraints under grid decarbonization scenarios 11
Figure 5. Annual demand assumptions for the contiguous United States 12
Figure 6. Daily demand profiles for the contiguous United States in 2020 and 2050 13
Figure 7. Electricity sector CO_2 emissions under current policies across demand assumptions 17
Figure 8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under mid demand and current policies 19
Figure 9. Total transmission capacity as a function of demand (columns) and emissions constraint (rows) 21
Figure 10. Total transmission growth rate in TW-miles/year as a function of demand, emissions constraint, and transmission framework 22
Figure 11. Interregional transmission capacity as a function of demand (columns) and emissions constraint (rows) 23
Figure 12. Generation capacity in 2035 and 2050 as a function of demand, emissions constraint, and transmission framework 24
Figure 13. Net present value of total system cost through 2050 expressed as savings relative to the Limited framework 25
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) 26
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 27
Figure 16. Net present value of total system cost savings relative to the Limited framework under Mid-Demand 90% by 2035 assumptions 28
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 30
Figure 18. Source of cost savings (real $billion per year) compared to the Limited framework under Mid-Demand 90% by 2035 assumptions 31
Figure 19. Transmission costs under Mid-Demand 90% by 2035 assumptions 33
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 34

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 35
Figure 22. VRE share of total generation for the Mid-Demand 90% by 2035 scenarios for each transmission framework 36
Figure 23. National generation mix in 2050 for the Mid-Demand 90% by 2035 scenarios for each transmission framework and sensitivity case 37
Figure 24. Transmission capacity under Mid-Demand 90% by 2035 assumptions for each transmission framework 38
Figure 25. Transmission capacity in 2050 in the Mid-Demand 90% by 2035 scenario for each transmission framework and sensitivity case 38
Figure 26. Average capacity factor of land-based wind (a) and utility-scale PV (b) over 2007–2013 40
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) 41
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 42
Figure 29. New interconnection-seam-crossing transmission capacity in each of the transmission frameworks with Mid-Demand 90% by 2035 assumptions. 43
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 44
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 44
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 45
High Opportunity Transmission interfaces with Mid-Demand 90% by 2035 assumptions under the (top) AC, (middle) MT, and (bottom) P2P transmission frameworks 47
Figure 33. Normalized expected unserved energy (NEUE) in each transmission framework and sensitivity case with Mid-Demand 90% by 2035 assumptions. 48
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. 49
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 50

Figure 36. Single-day wind capacity factor on the least-windy day from 2007 to 2013 weather years in each planning region 51
Figure 37. Single-day PV capacity factor on the least-sunny day from 2007 to 2013 weather years in each planning region 52
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 53
Figure 39. Bidirectional transmission flows between regions for resource adequacy in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS 54
Figure 40. Impact of the allowance of interregional RA sharing on system cost (a) and optimized interregional transmission capacity (b) 55
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. 56
Figure A-1. Interzonal AC transmission cost assumptions 70
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 73
Figure A-3. LCOE supply curves for land-based wind (top) and solar PV (bottom)..... 75
Figure A-4. End-use emissions for the three electricity demand cases 77
Figure A-5. Changes in seasonal all-sector peak load from historical weather (2007–2013) to future weather impacted by climate change (2050–2056) 78
Figure B-1. Integrated capacity expansion and resource adequacy modeling 82
Figure D-1. National generation mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case 91
Figure D-2. Transmission capacity in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case 92
Figure D-3. National capacity mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case 93
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) 94
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 95
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 95
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 96

Figure D-8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Low-Demand Current Policies conditions 97
Figure D-9. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand Current Policies conditions 98
Figure D-10. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Mid-Demand 90% by 2035 conditions 99
Figure D-11. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand 100% by 2035 conditions 100
Figure D-12. National capacity mix in 2050 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case 101
Figure D-13. Annual system cost ($/MWh) for the four transmission frameworks and all sensitivity cases under Mid-Demand 90% by 2035 conditions 102
Figure D-14. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks and all sensitivity cases 103
Figure D-15. National average VRE curtailment rate [$MWh_{curtailed}$ / $MWh_{available}$] with Mid-Demand 90% by 2035 assumptions for all sensitivity cases 104
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 104
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 105
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 106
Figure D-19. Impact of the allowance of interregional RA sharing on system cost for each of the demand and emissions assumptions 107
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 108
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 109
Figure D-22. Net present value of system savings in the MT transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions 109
Figure E-1. System costs included in transmission valuation. Many benefits are correlated and not mutually exclusive. 111
Figure E-2. Production cost adjustment for each transmission planning region and network topology for the core Mid-Demand 90% by 2035 scenarios ($million) 114

List of Tables

Table 1. Sensitivity Cases 14
Table C-1. Technologies Modeled in ReEDS 84
Table C-2. Overnight Capital Costs ($/kW) in the Core Scenarios 86
Table C-3. Fixed Operation and Maintenance Costs in $/(kW-year) in the Core Scenarios 87
Table C-4. Variable Operations and Maintenance Costs in $/MWh in the Core Scenarios 88
Table C-5. Retrofit Assumptions for Technologies in ReEDS 89
Table C-6. Financing and Maximum Age Assumptions for Technologies in ReEDS 90
Table D-1. Wind and Solar Capacity (GW) by State in the Core Mid-Demand 90% by 2035 Scenarios 110

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]

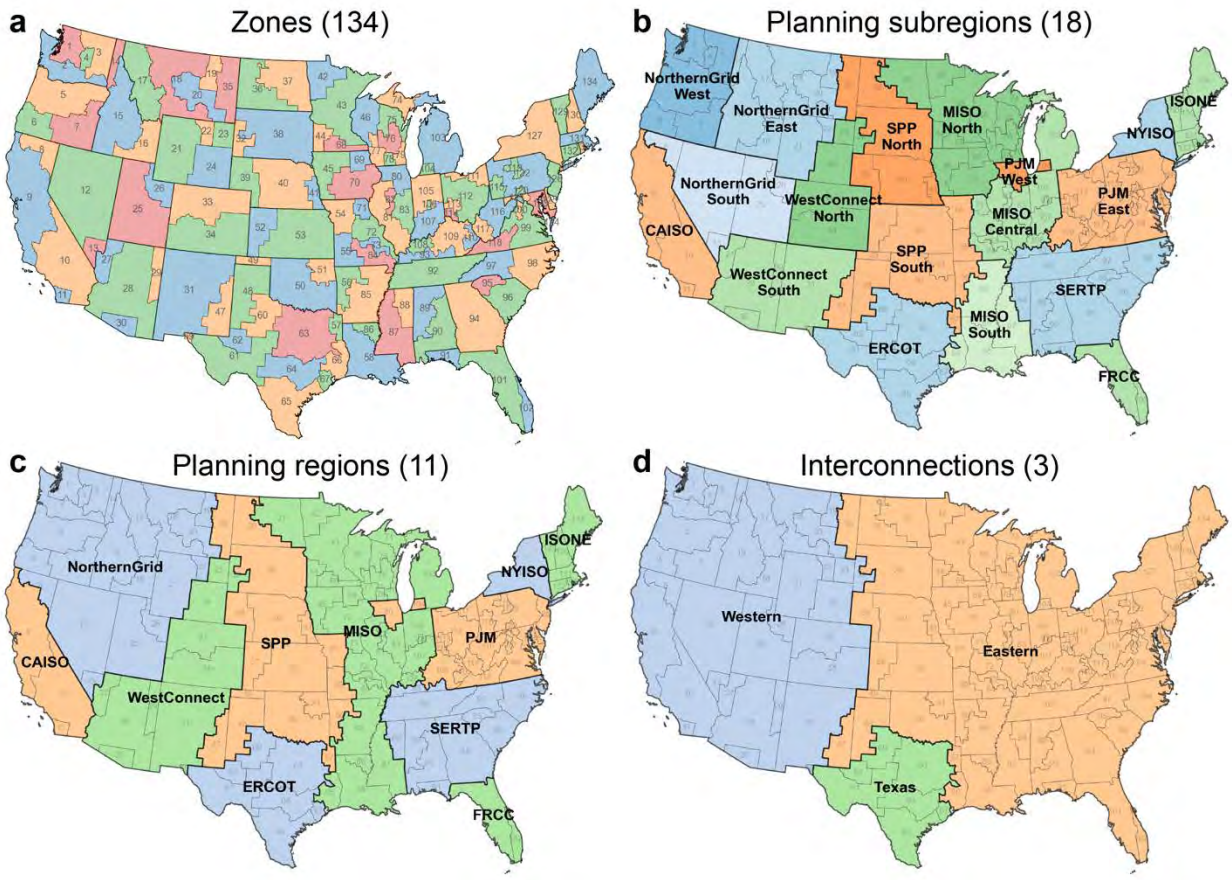


Figure 1. Hierarchy of regions used in the ReEDS model

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.

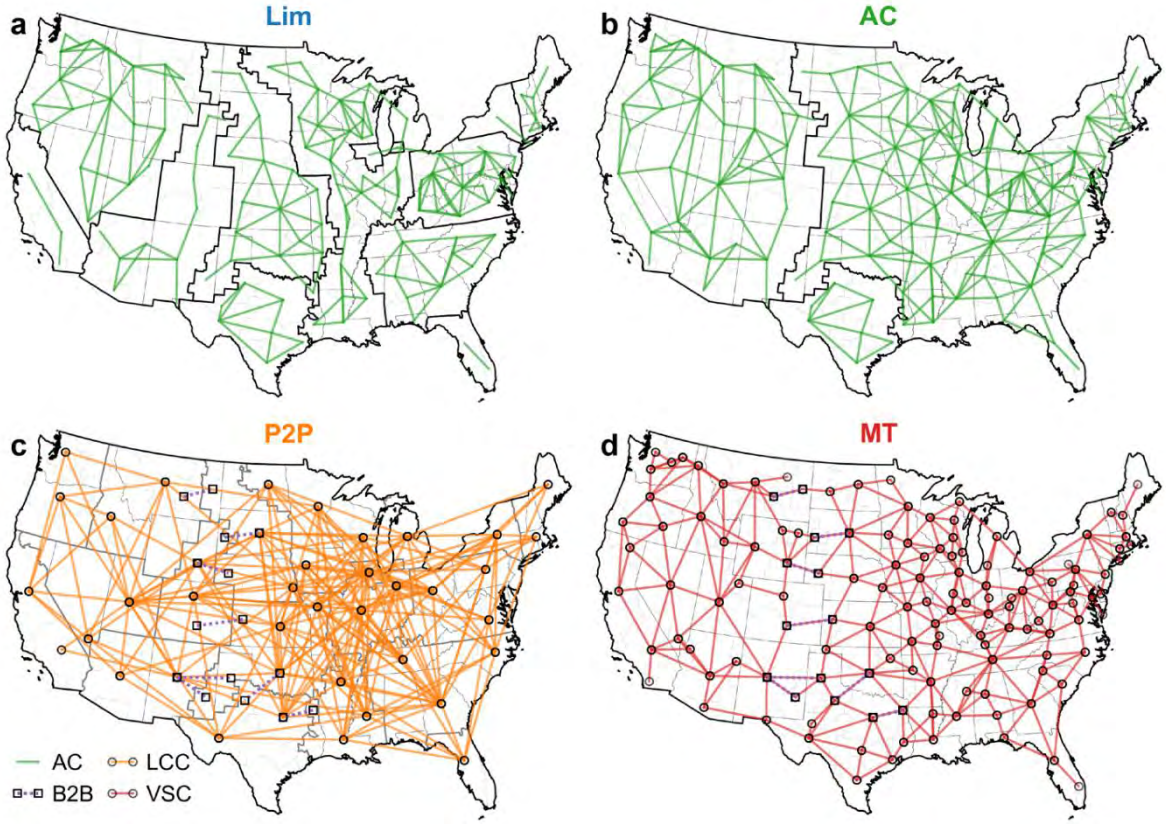


Figure 2. Expandable transmission interfaces in the four transmission frameworks considered in this study

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.

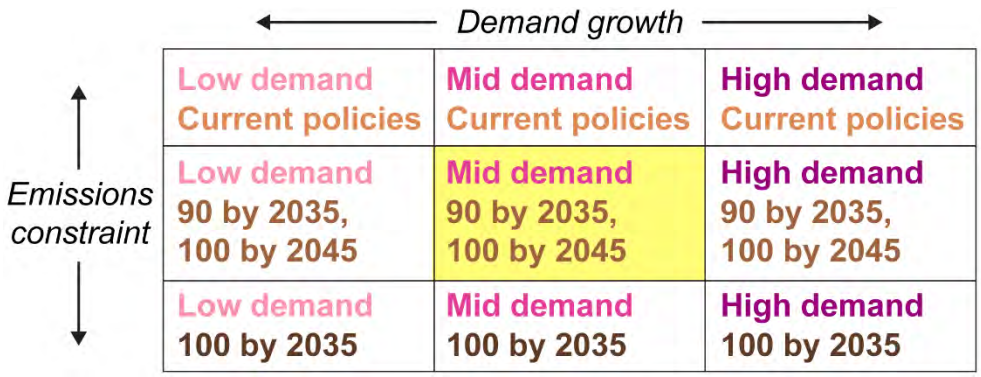


Figure 3. Core demand and emissions assumptions

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).

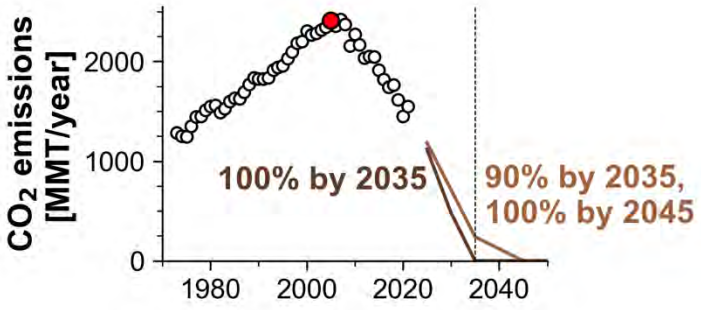


Figure 4. Emissions constraints under grid decarbonization scenarios

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.

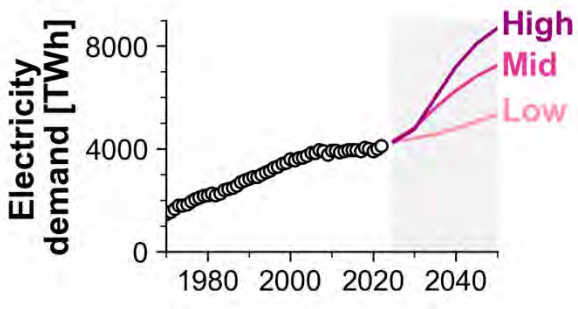


Figure 5. Annual demand assumptions for the contiguous United States

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.

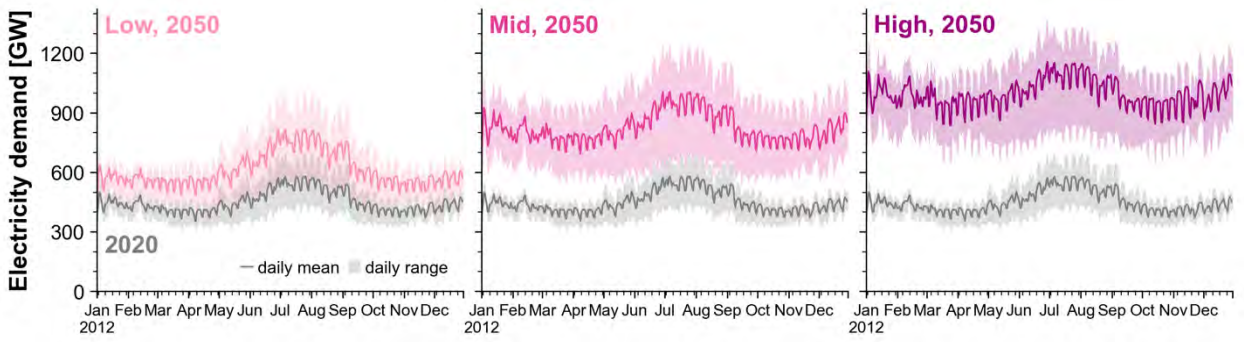


Figure 6. Daily demand profiles for the contiguous United States in 2020 and 2050

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.

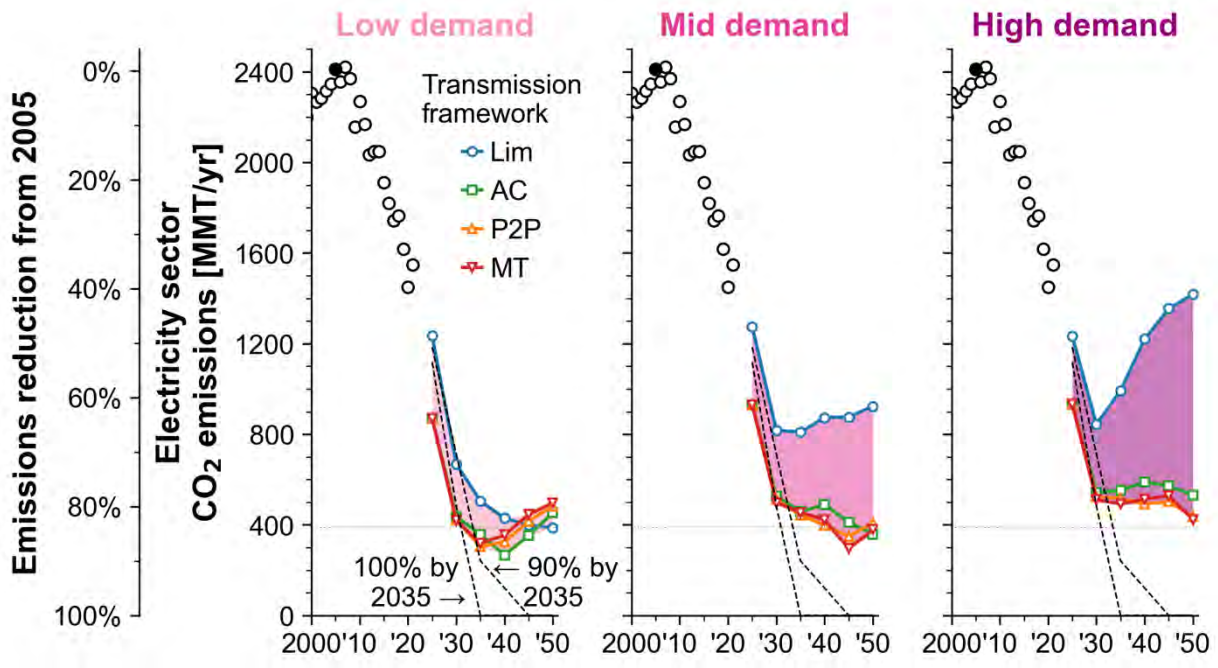


Figure 7. Electricity sector CO_2 emissions under current policies across demand assumptions

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.

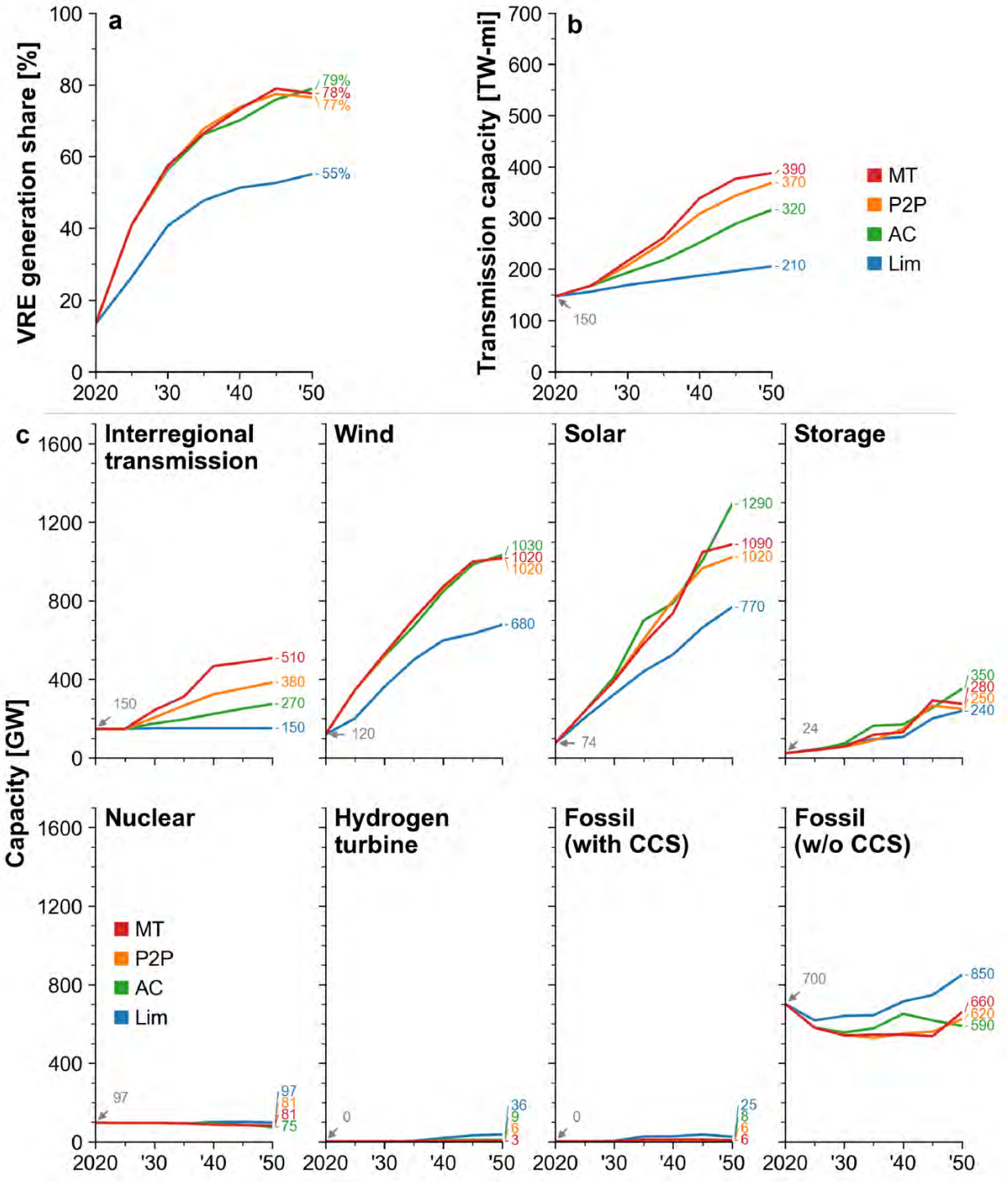


Figure 8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under mid demand and current policies

"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.

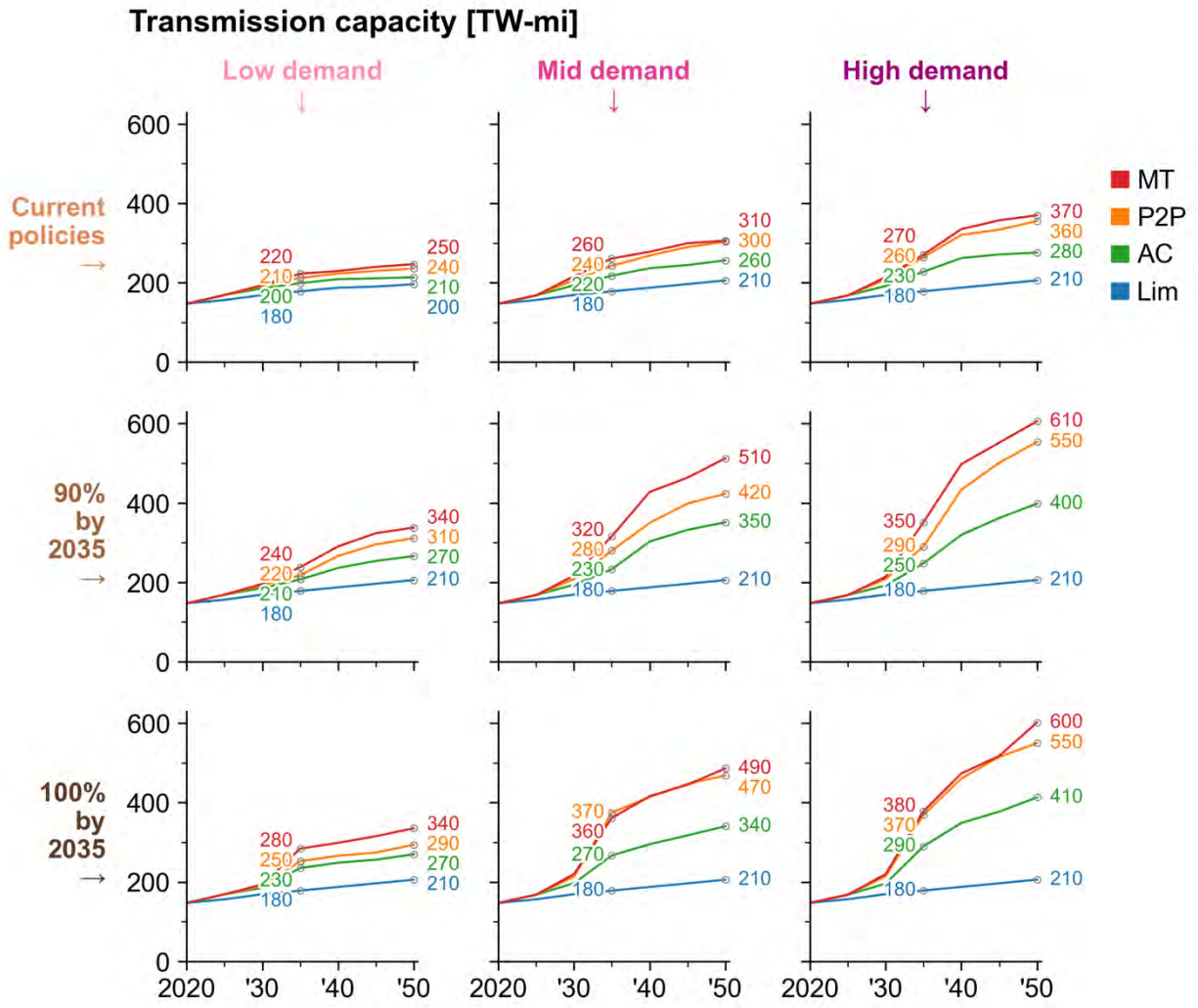


Figure 9. Total transmission capacity as a function of demand (columns) and emissions constraint (rows)

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).

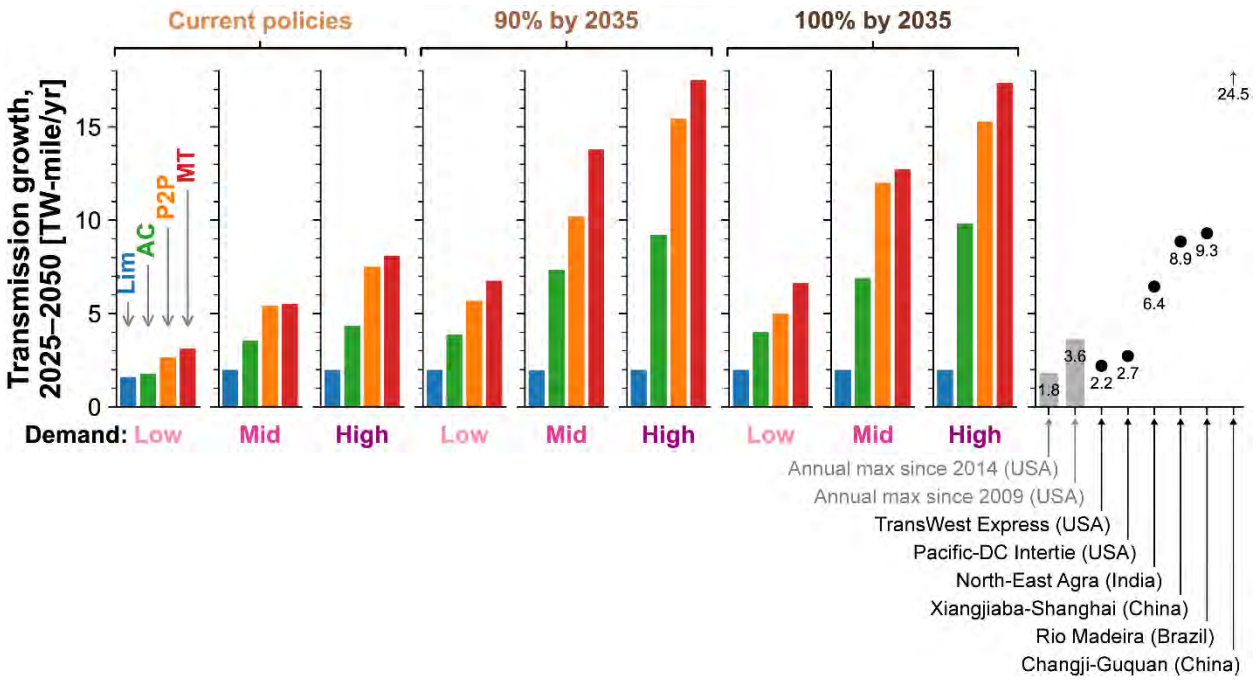


Figure 10. Total transmission growth rate in TW-miles/year as a function of demand, emissions constraint, and transmission framework

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.

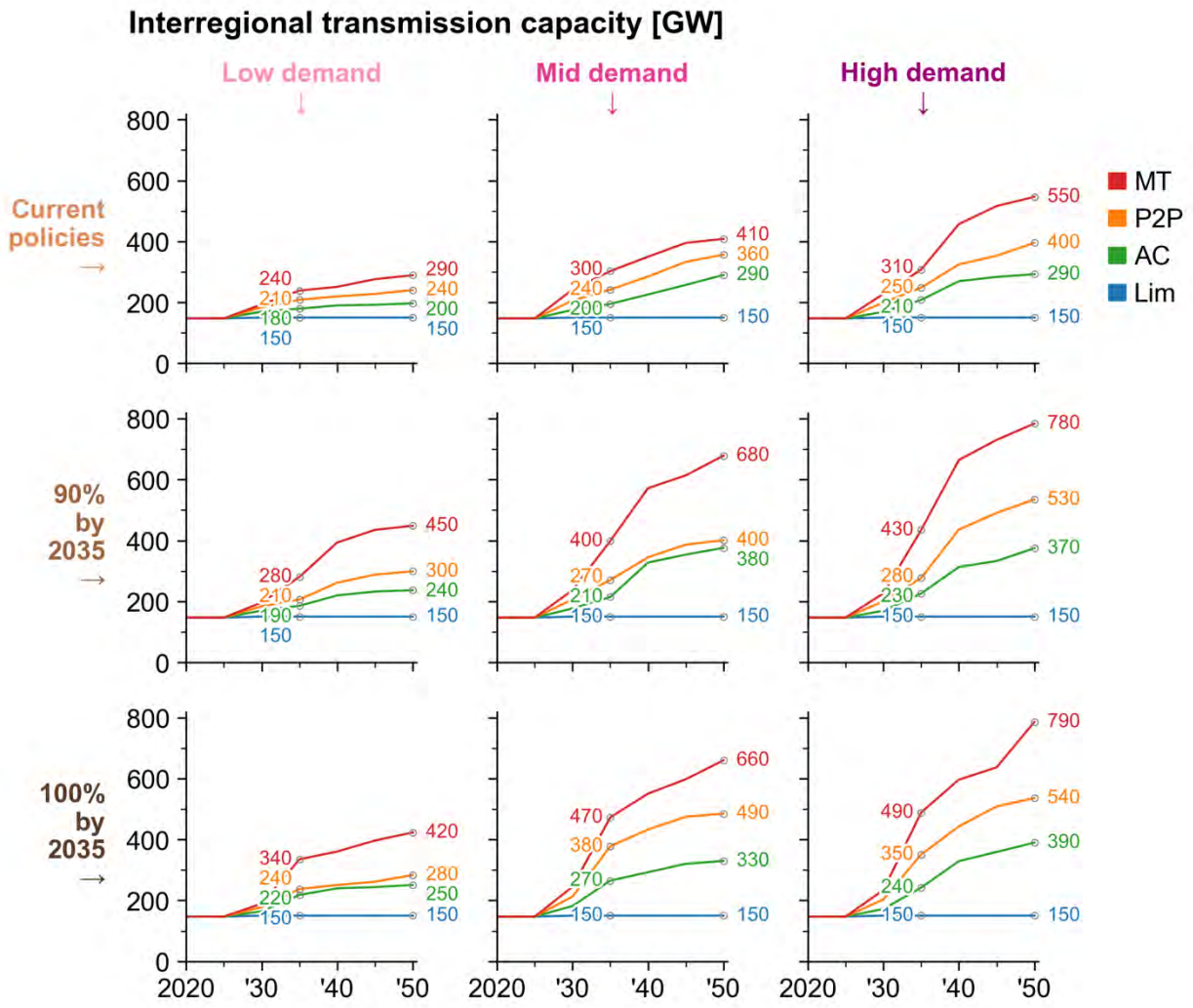


Figure 11. Interregional transmission capacity as a function of demand (columns) and emissions constraint (rows)

"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).

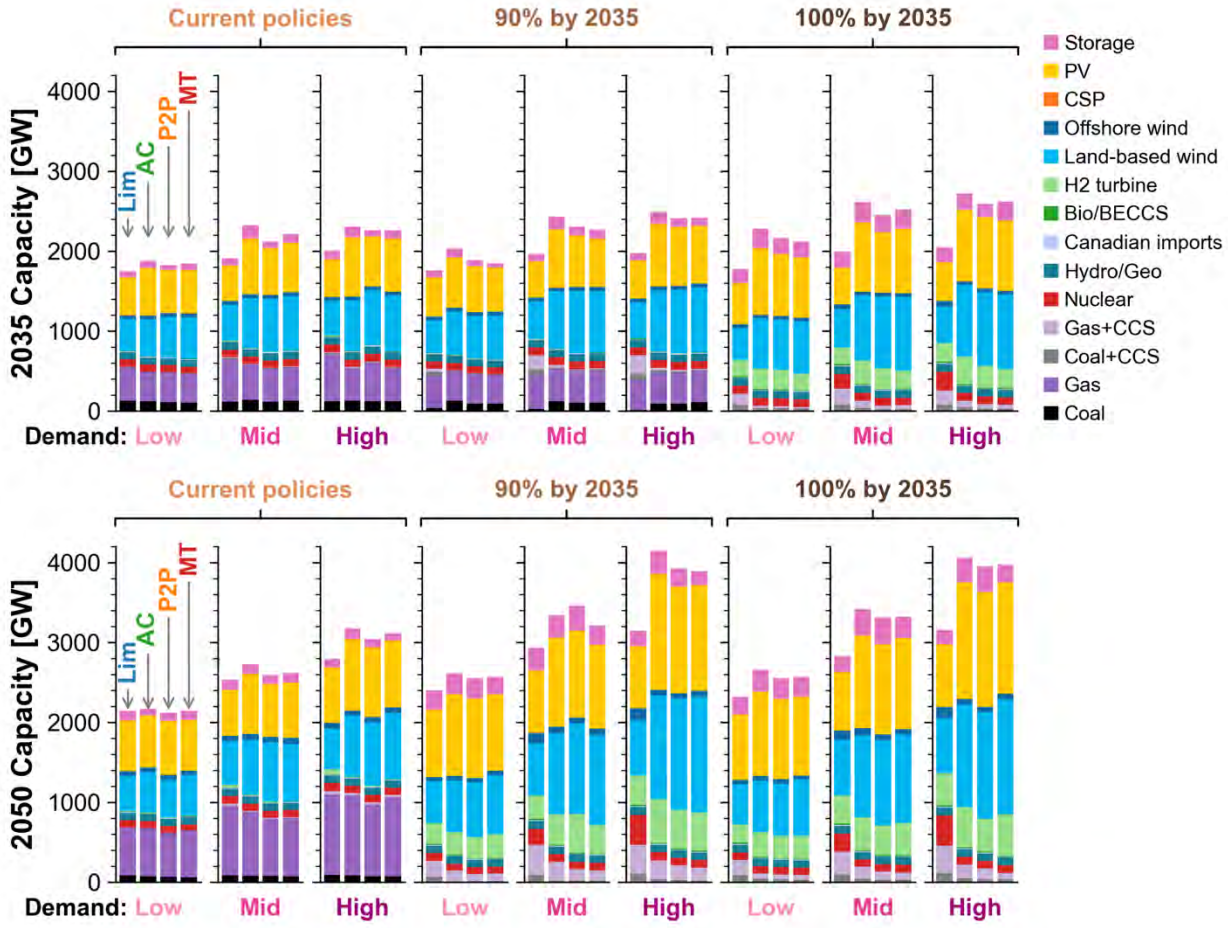


Figure 12. Generation capacity in 2035 and 2050 as a function of demand, emissions constraint, and transmission framework

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).

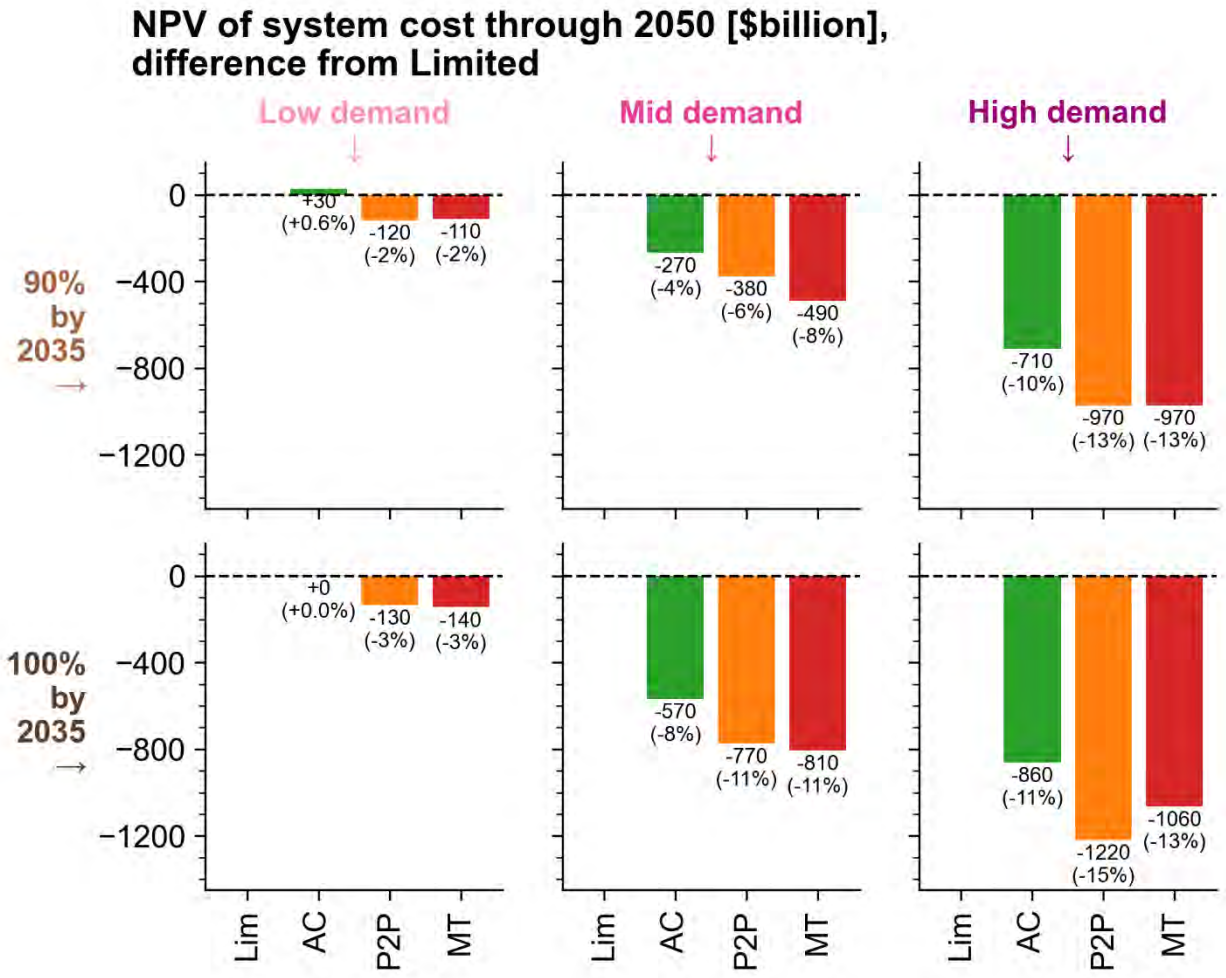


Figure 13. Net present value of total system cost through 2050 expressed as savings relative to the Limited framework

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.

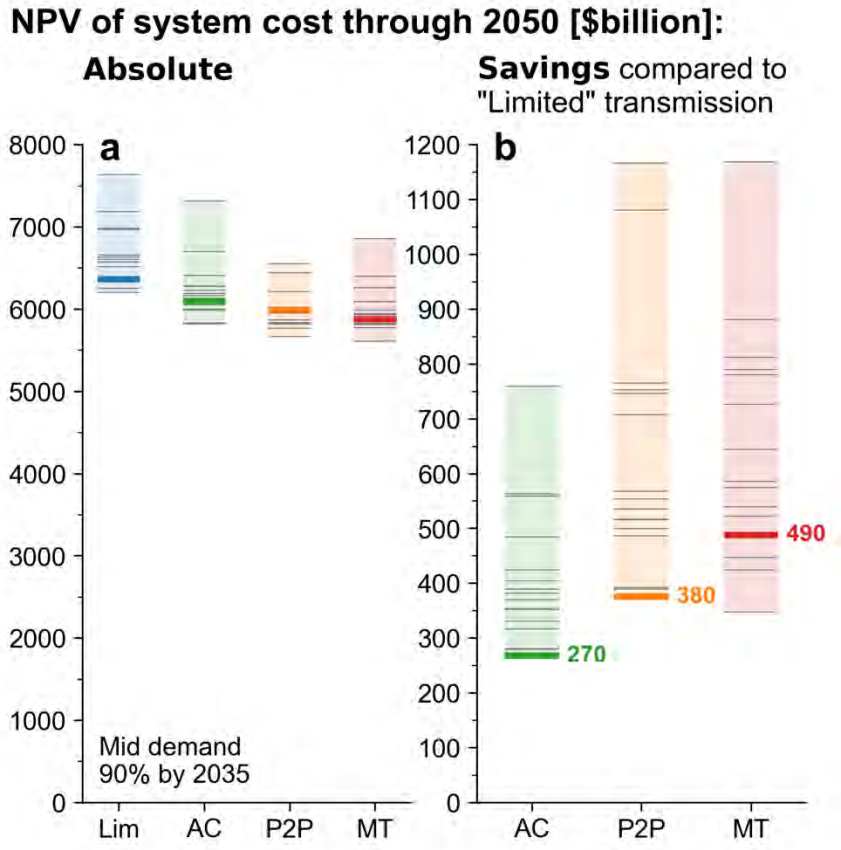


Figure 14. Net present value of total system cost through 2050 under central (Mid-Demand 90% by 2035) assumptions expressed in absolute terms (a) and as savings relative to the Limited framework (b)

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

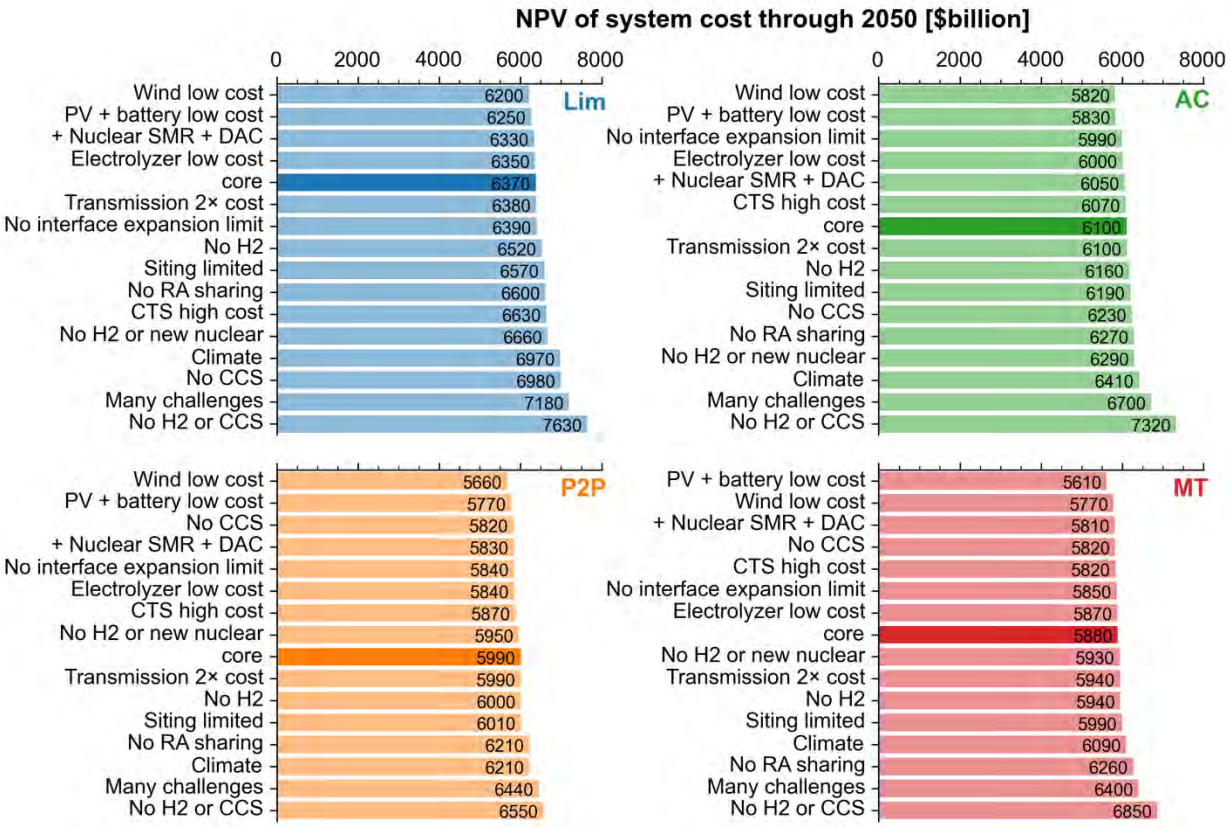


Figure 15. Net present value of total system cost through 2050 for each transmission framework and sensitivity case under Mid-Demand 90% by 2035 assumptions

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.

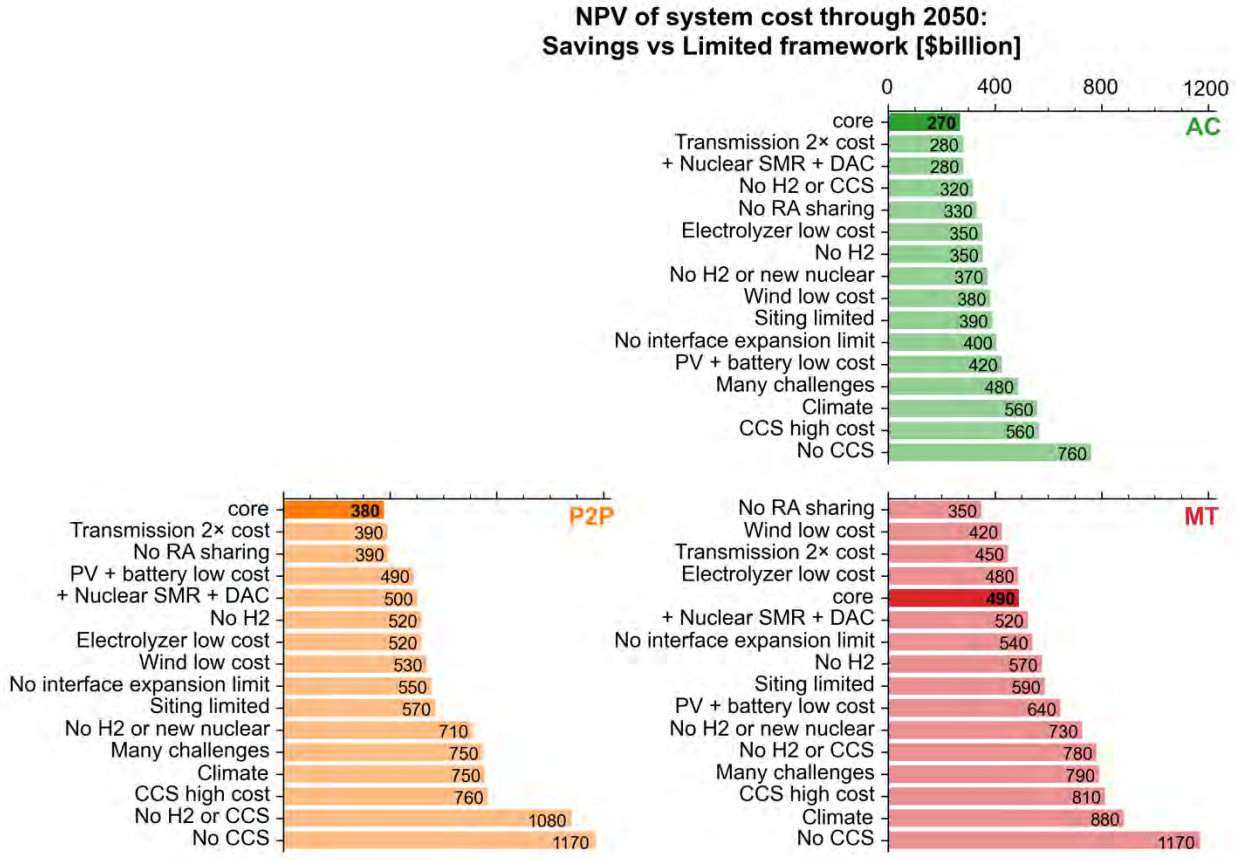


Figure 16. Net present value of total system cost savings relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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.

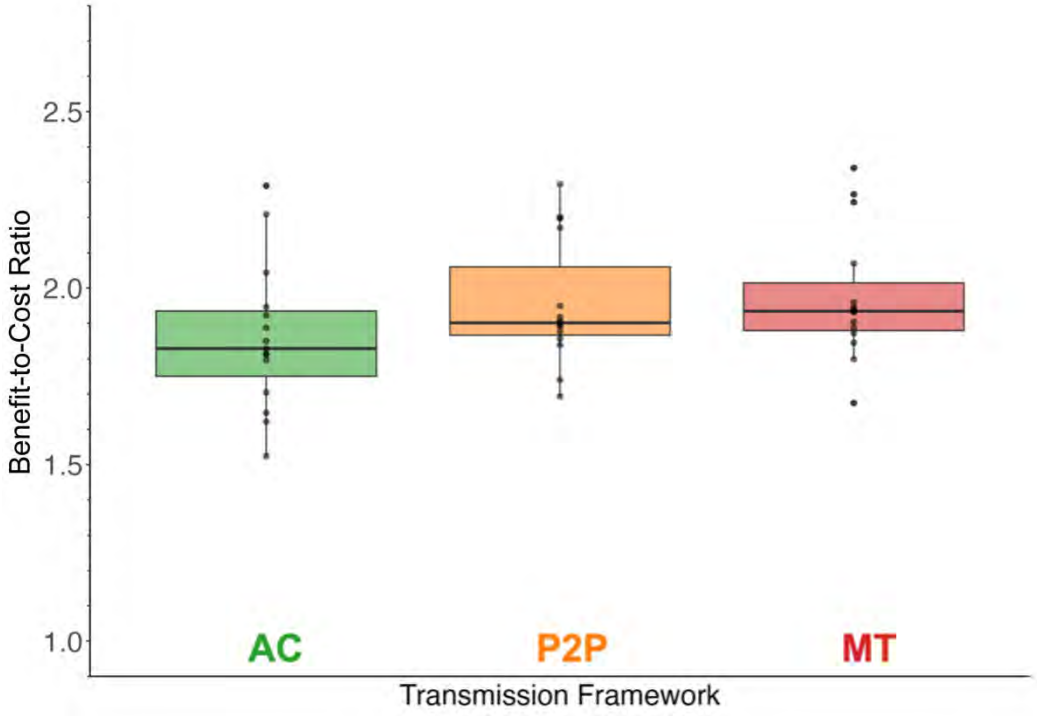


Figure 17. Benefit-to-cost ratio of systemwide savings compared to additional transmission costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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.

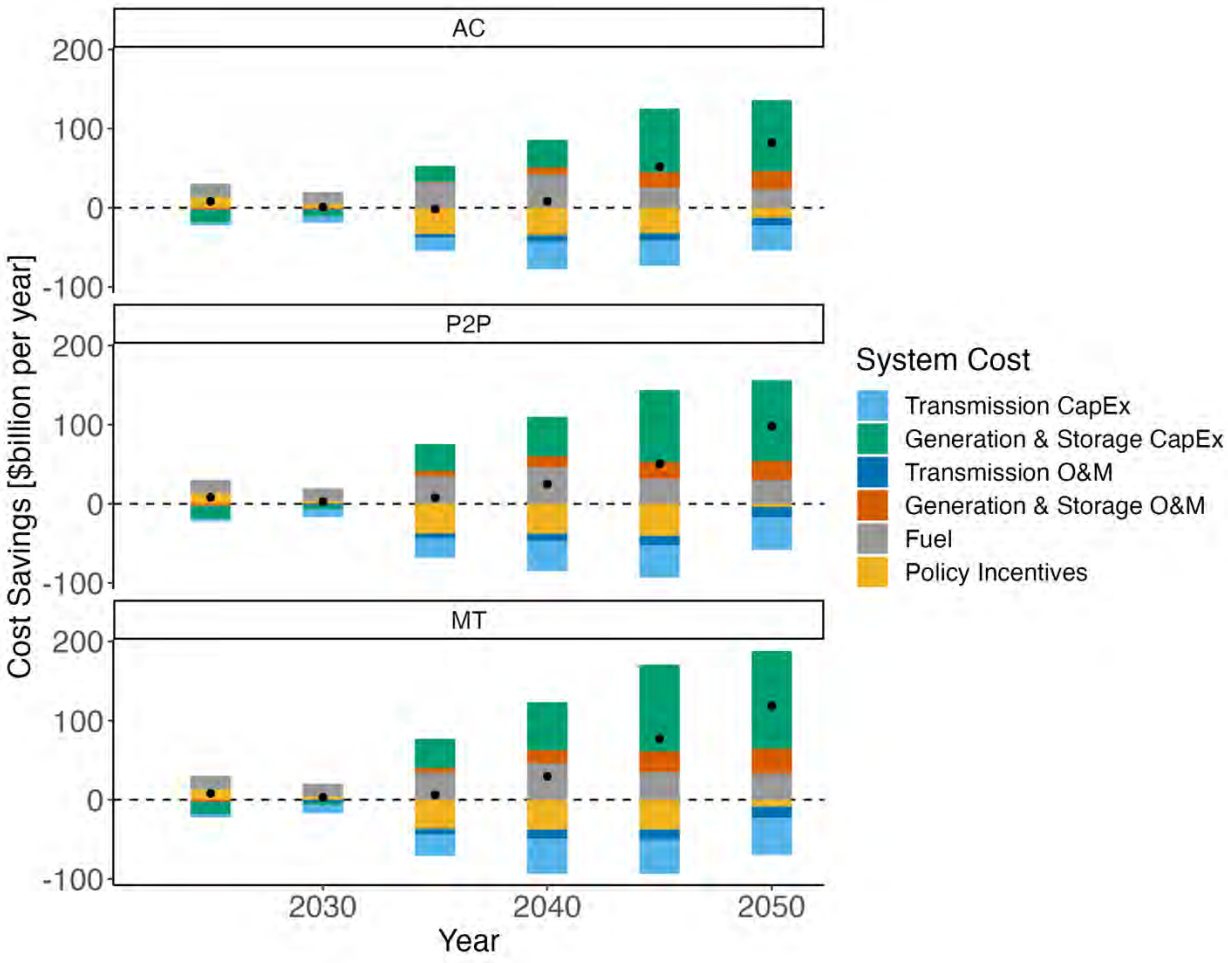


Figure 18. Source of cost savings (real $billion per year) compared to the Limited framework under Mid-Demand 90% by 2035 assumptions

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).

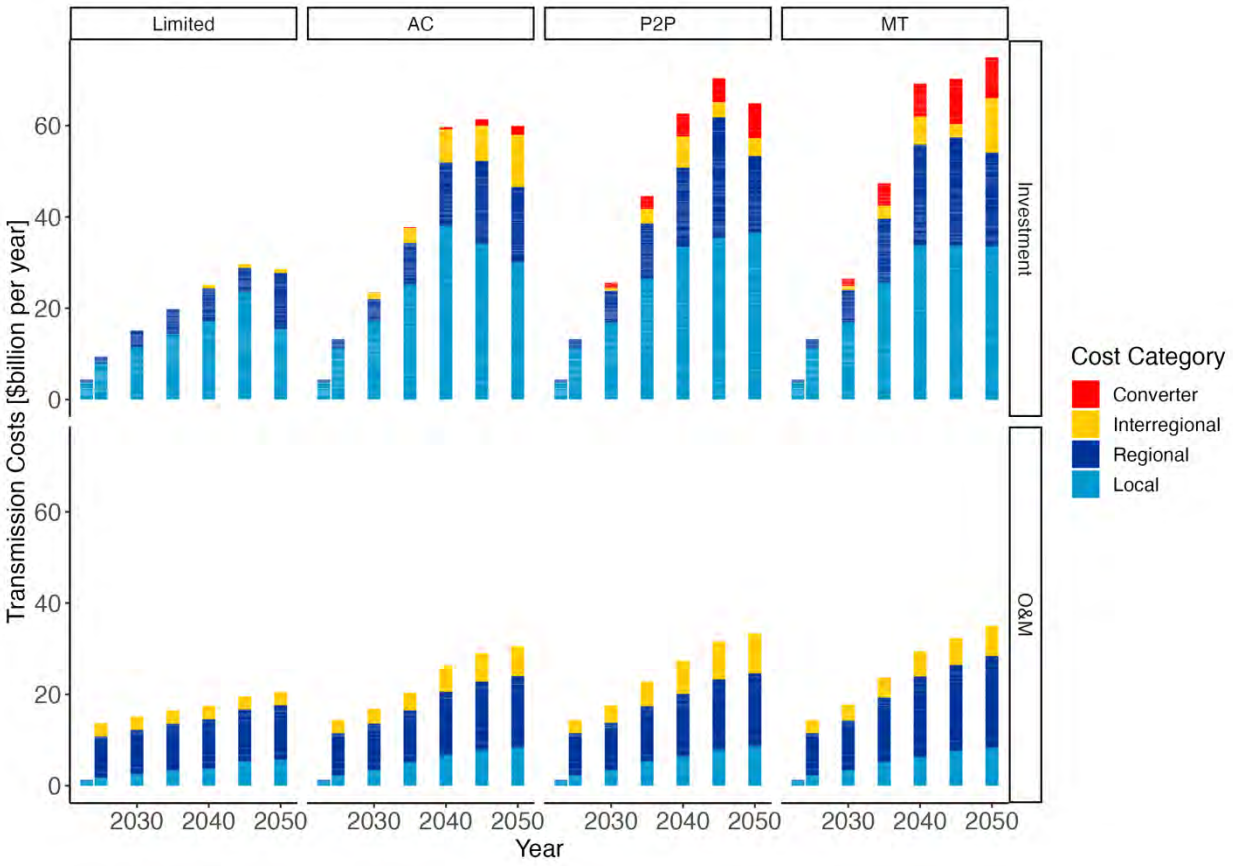


Figure 19. Transmission costs under Mid-Demand 90% by 2035 assumptions

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).

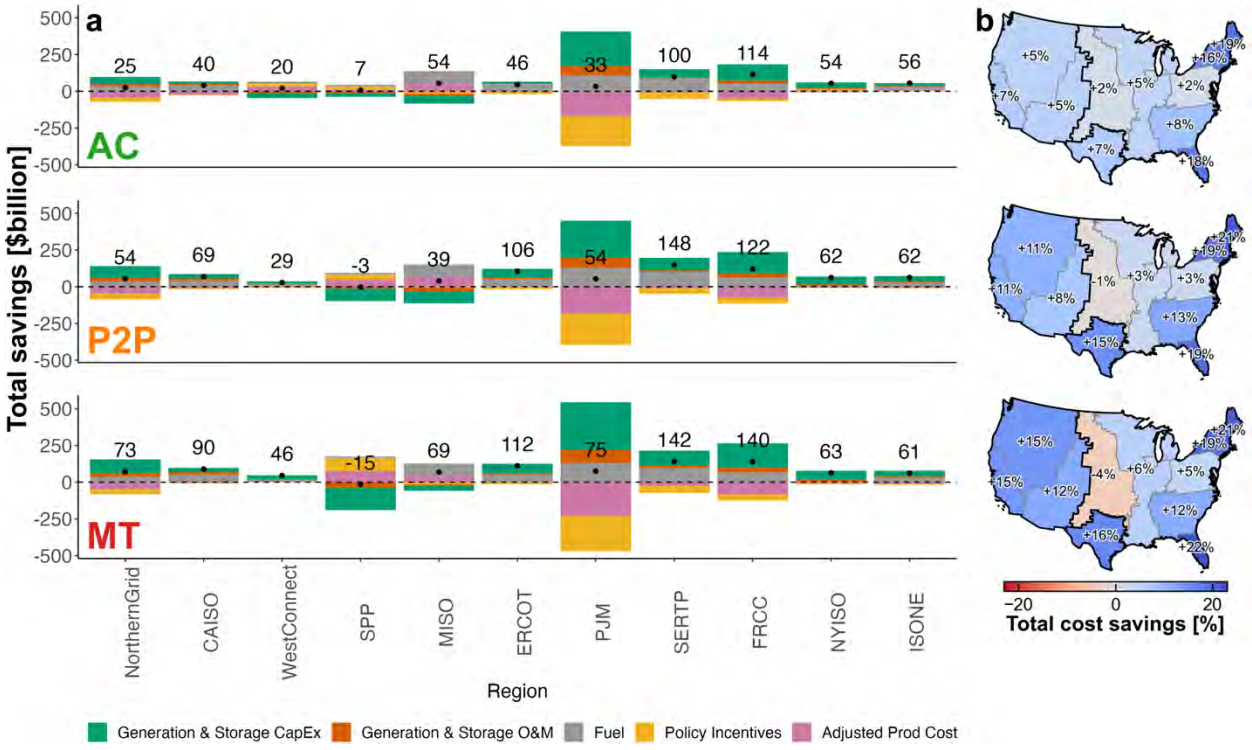


Figure 20. Net present value of system savings by region in absolute $billion (a) and percentage (b) of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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.

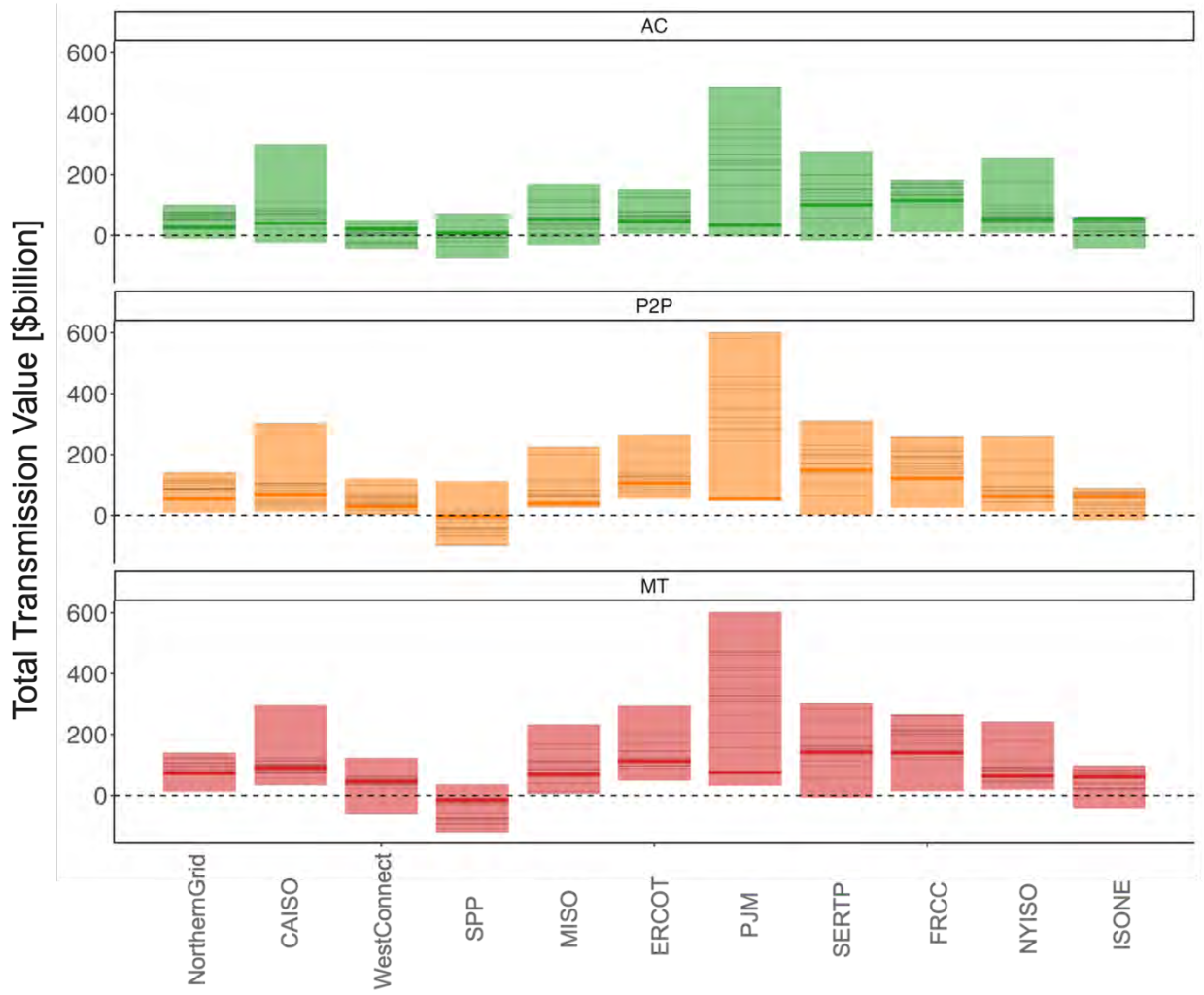


Figure 21. Net present value of total system cost savings to each transmission planning region relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

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).

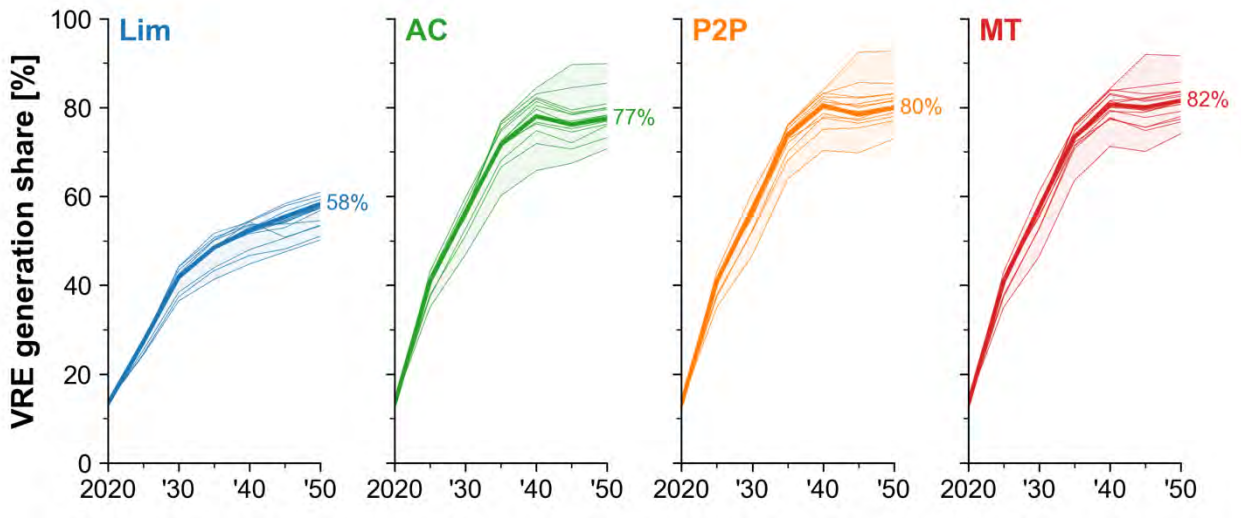


Figure 22. VRE share of total generation for the Mid-Demand 90% by 2035 scenarios for each transmission framework

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.

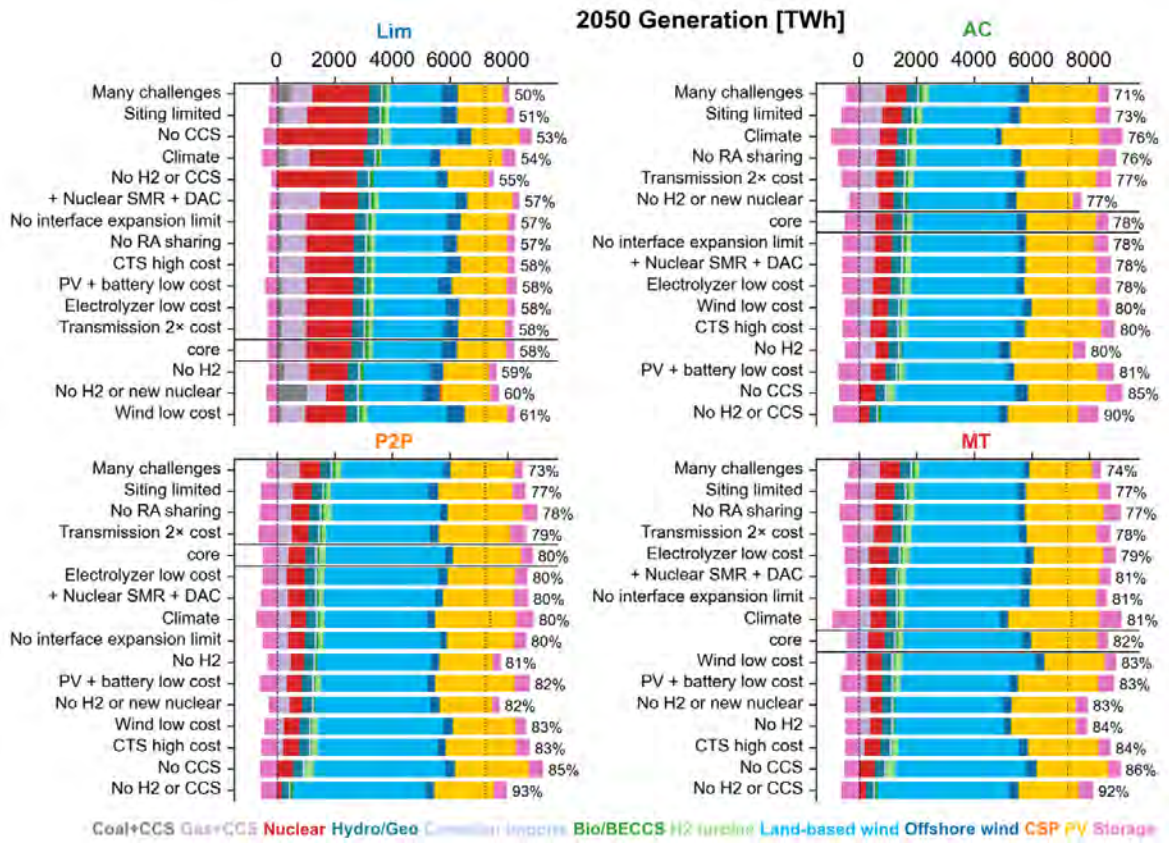


Figure 23. National generation mix in 2050 for the Mid-Demand 90% by 2035 scenarios for each transmission framework and sensitivity case

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.

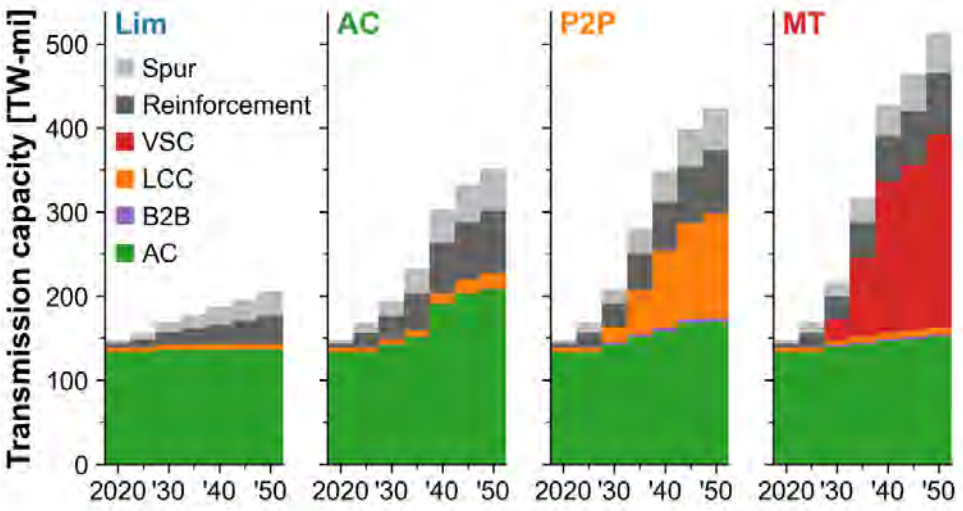


Figure 24. Transmission capacity under Mid-Demand 90% by 2035 assumptions for each transmission framework

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

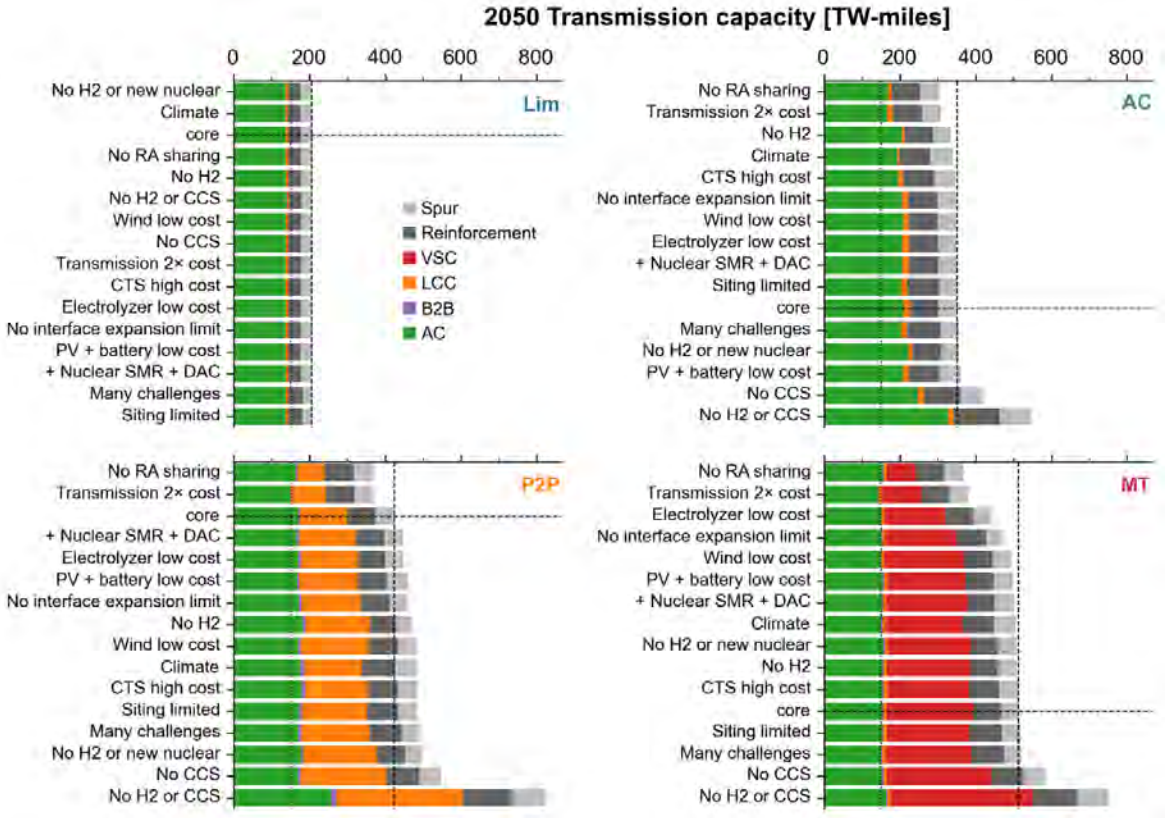


Figure 25. Transmission capacity in 2050 in the Mid-Demand 90% by 2035 scenario for each transmission framework and sensitivity case

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.

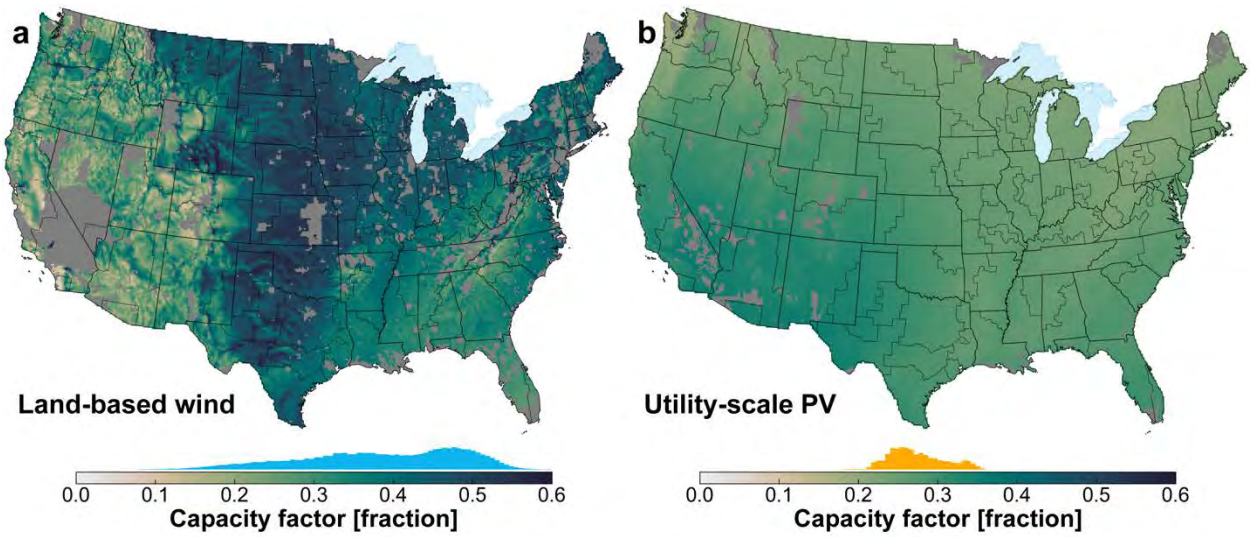


Figure 26. Average capacity factor of land-based wind (a) and utility-scale PV (b) over 2007–2013

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.

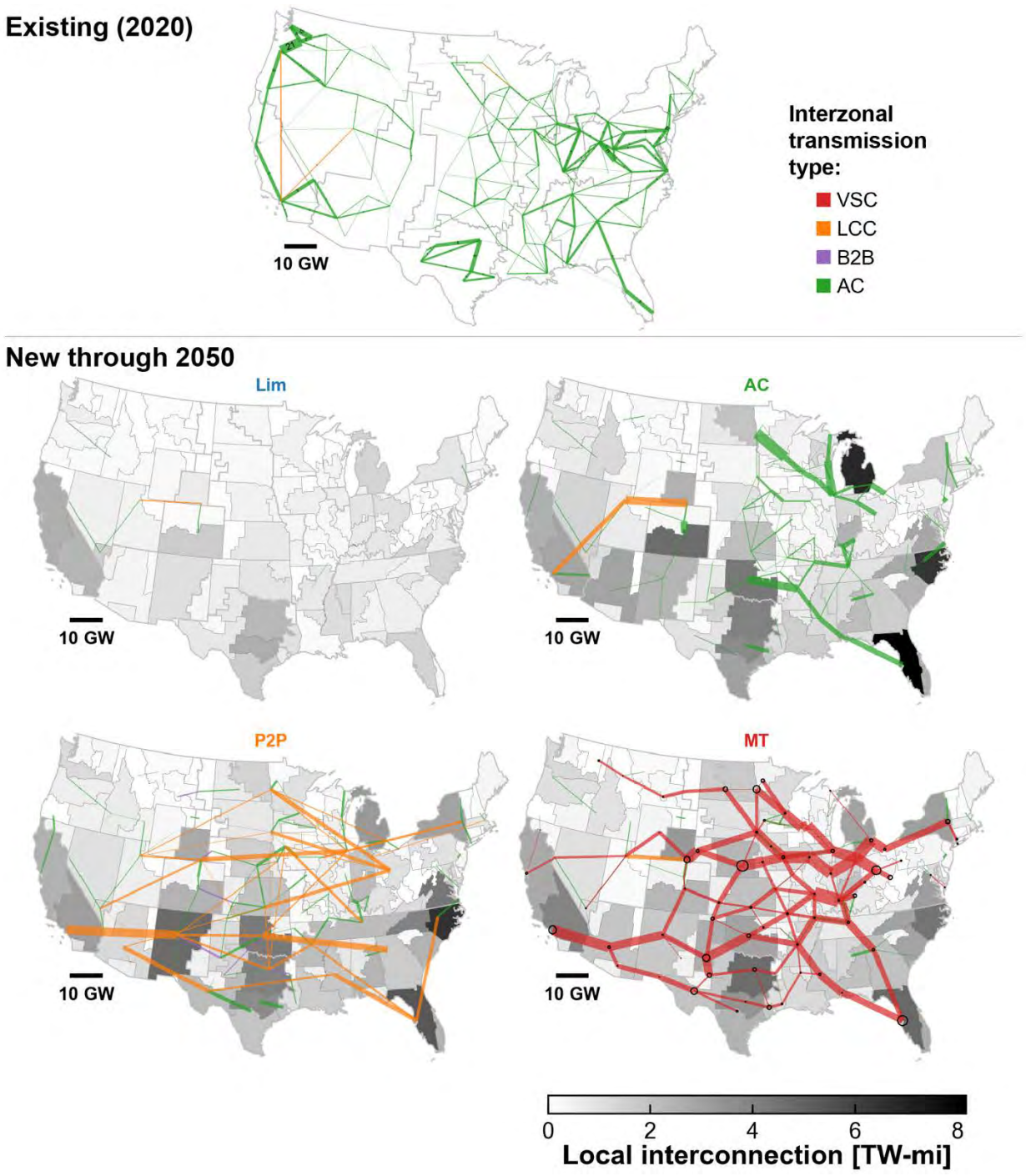


Figure 27. New local and long-distance transmission through 2050 in the Mid-Demand 90% by 2035 scenarios for each transmission framework, with existing 2020 long-distance transmission capacity for context (top)

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.

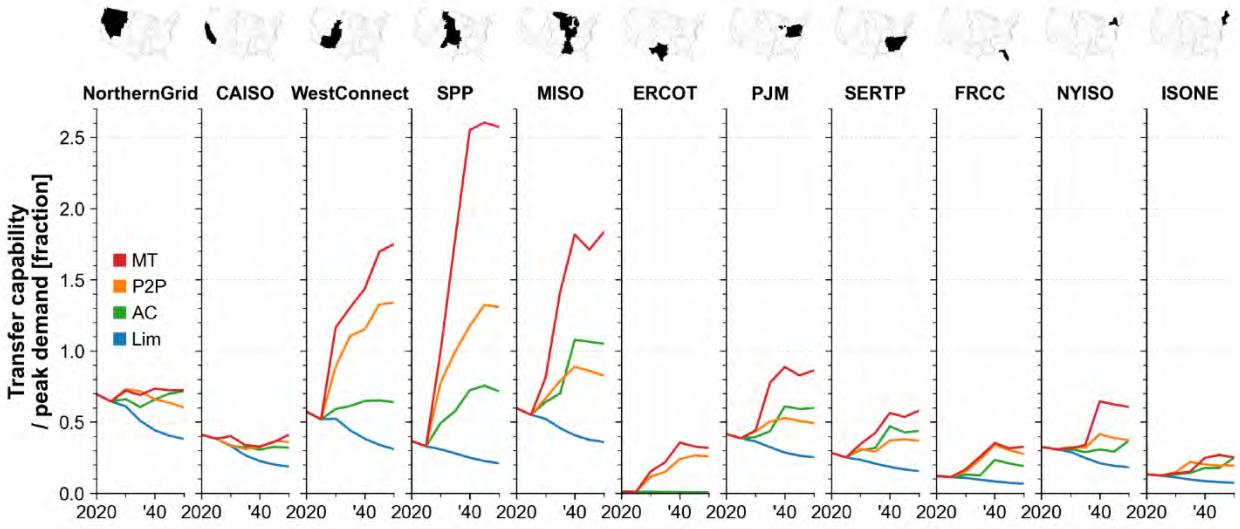


Figure 28. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

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.

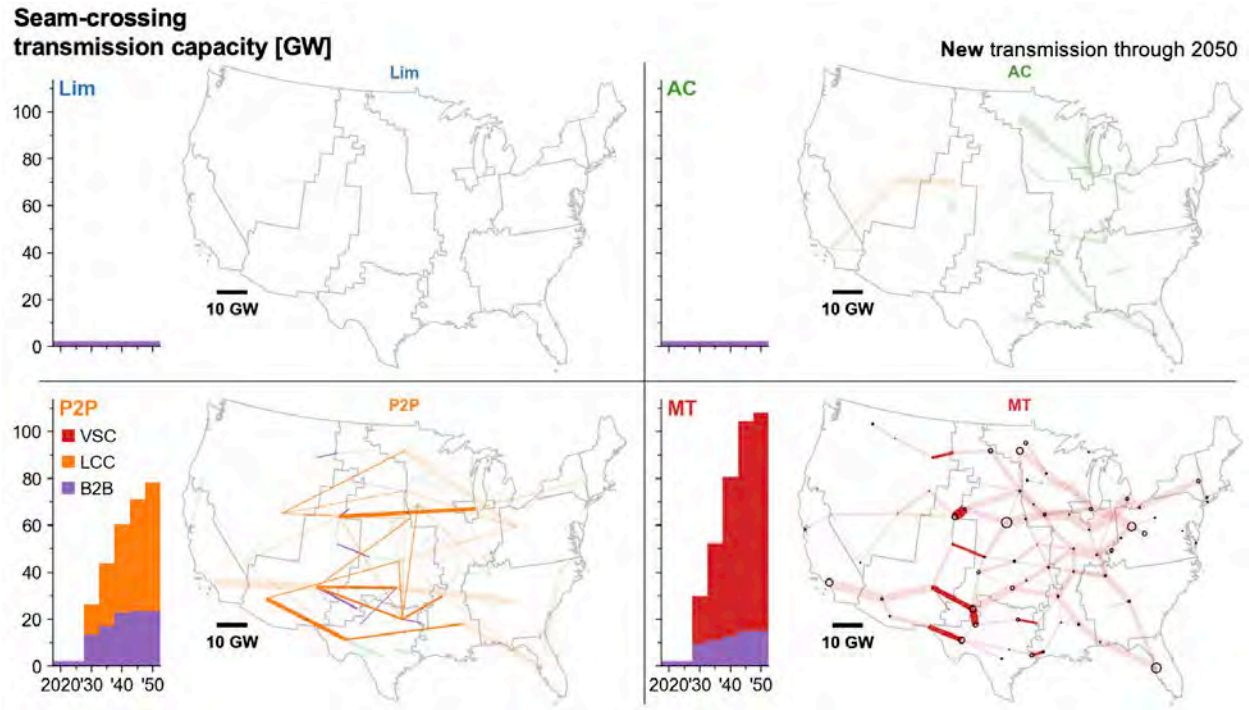


Figure 29. New interconnection-seam-crossing transmission capacity in each of the transmission frameworks with Mid-Demand 90% by 2035 assumptions.

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.

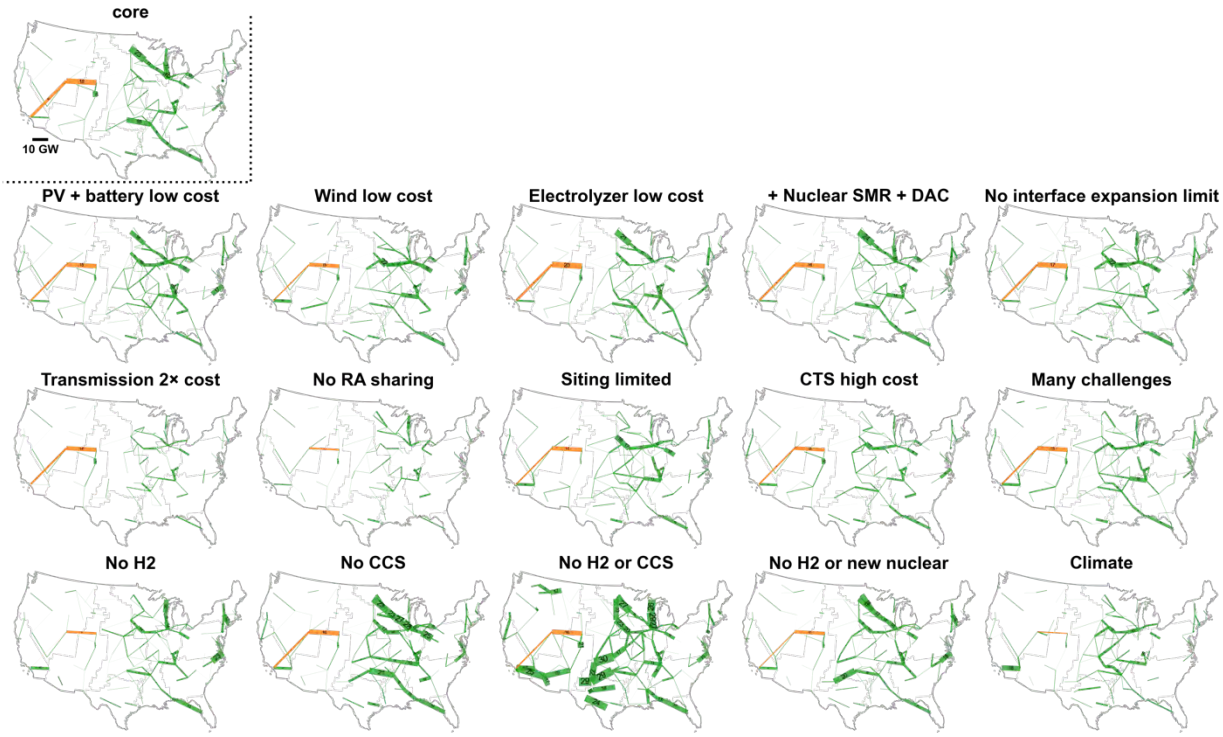


Figure 30. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

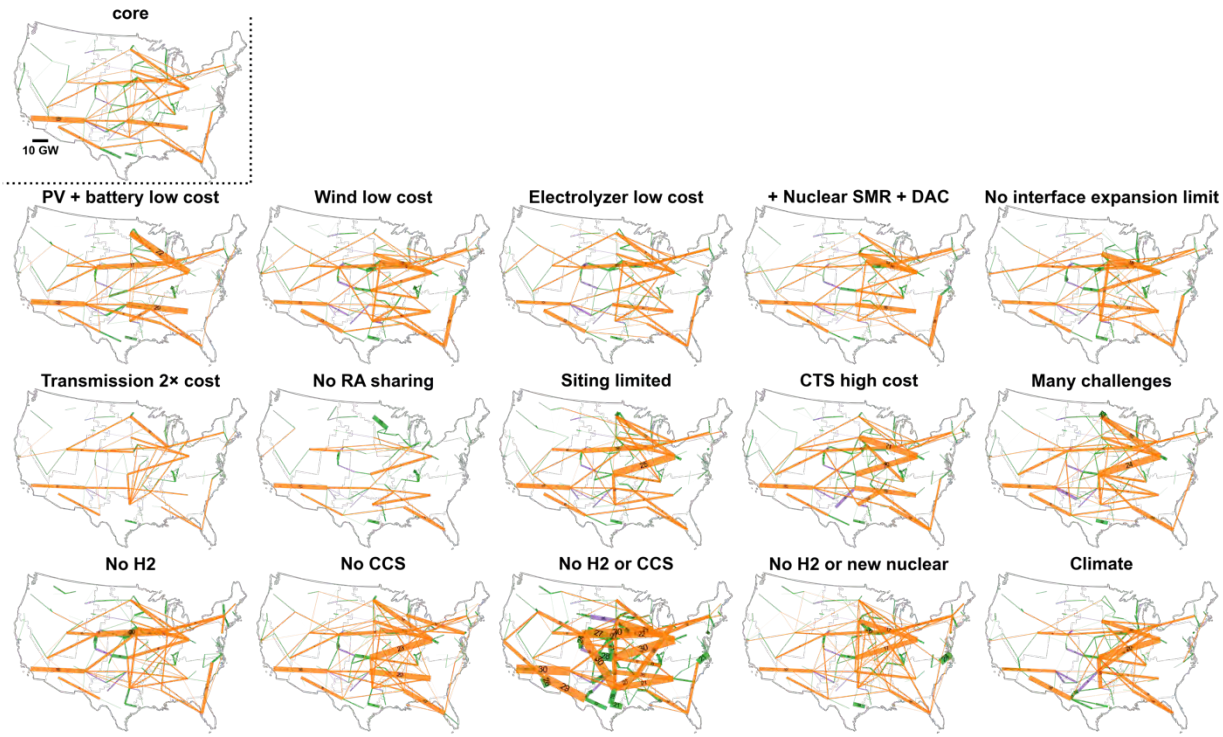


Figure 31. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

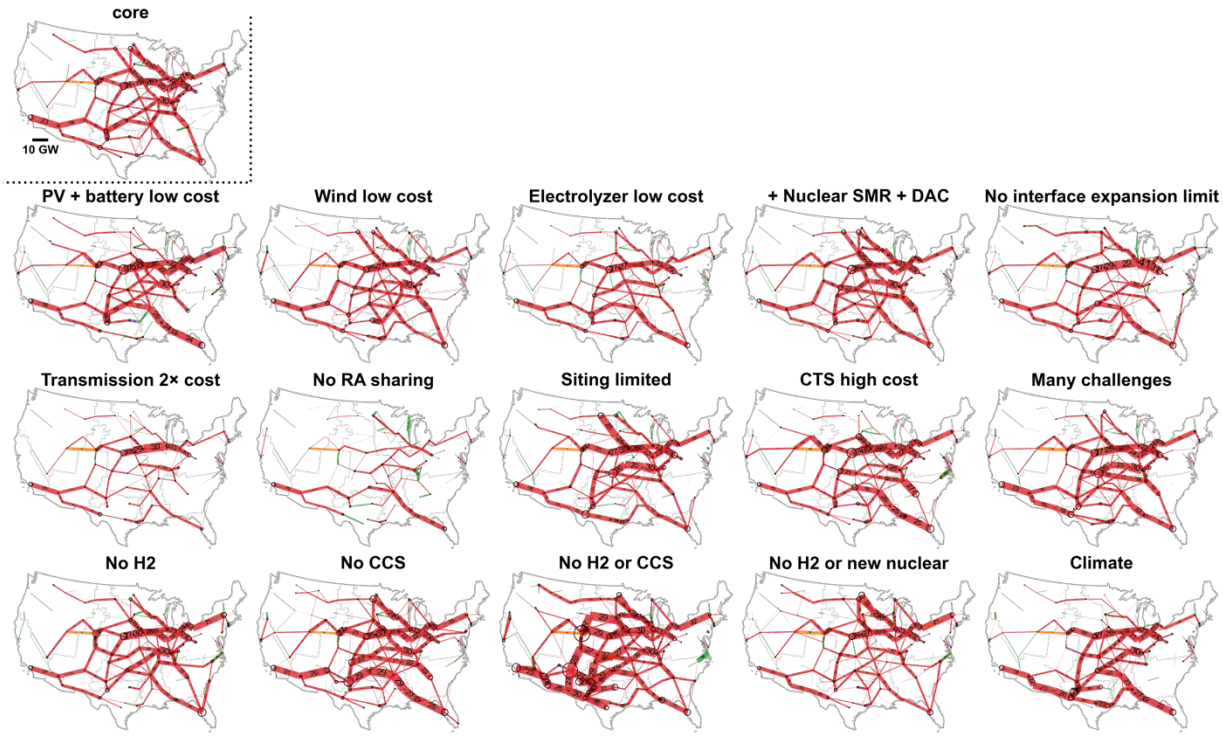


Figure 32. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

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.

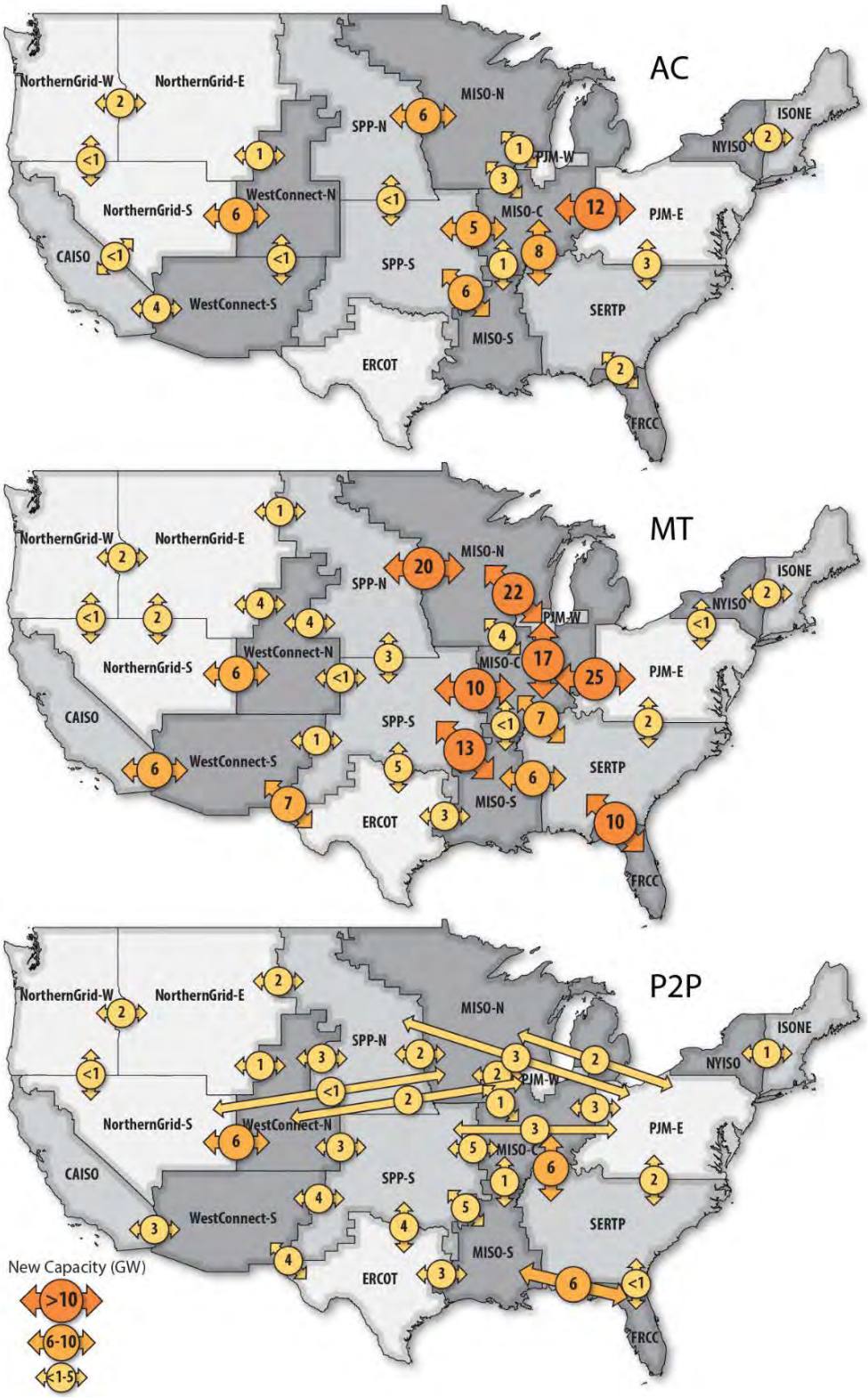
High Opportunity Transmission

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.

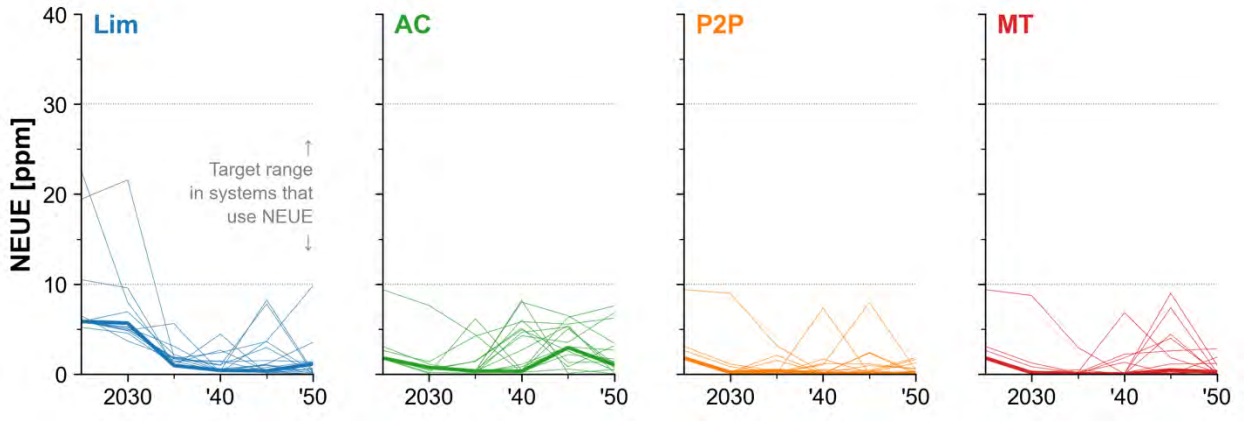


Figure 33. Normalized expected unserved energy (NEUE) in each transmission framework and sensitivity case with Mid-Demand 90% by 2035 assumptions.

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.

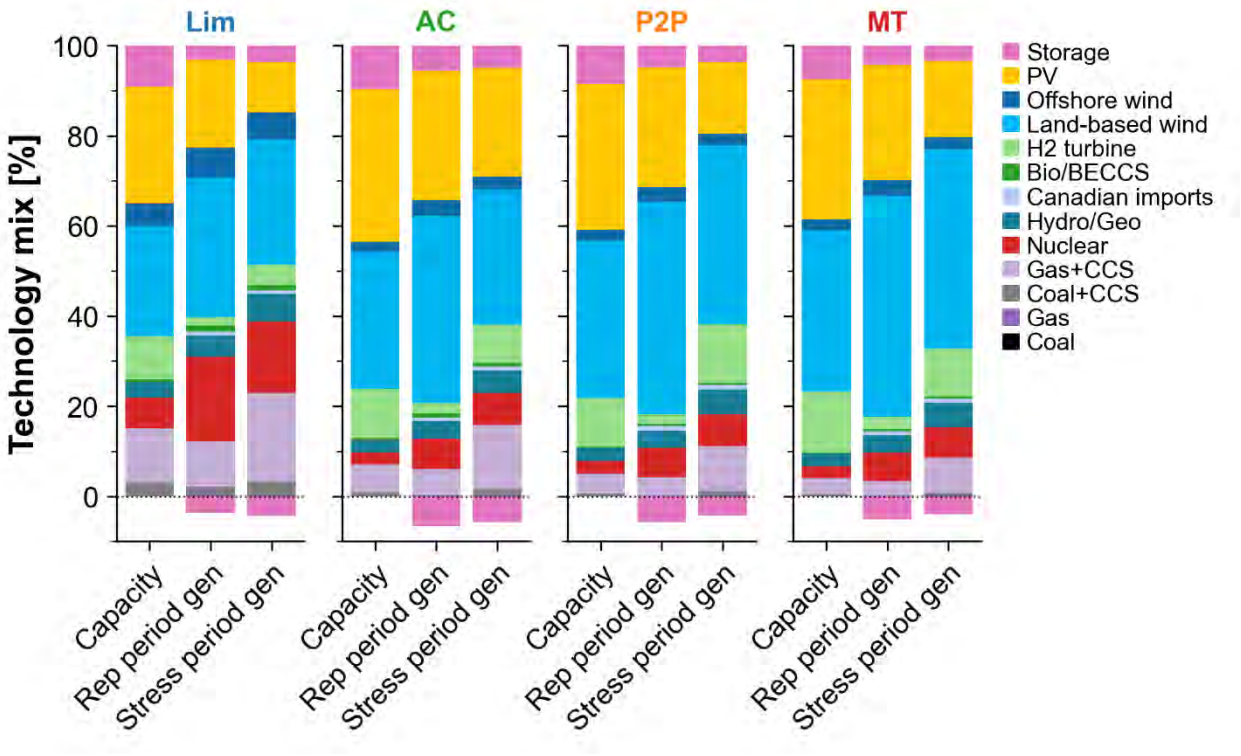


Figure 34. Nameplate capacity mix, representative period generation mix, and stress period generation mix for the core transmission frameworks in 2050 under Mid-Demand 90% by 2035 assumptions.

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).

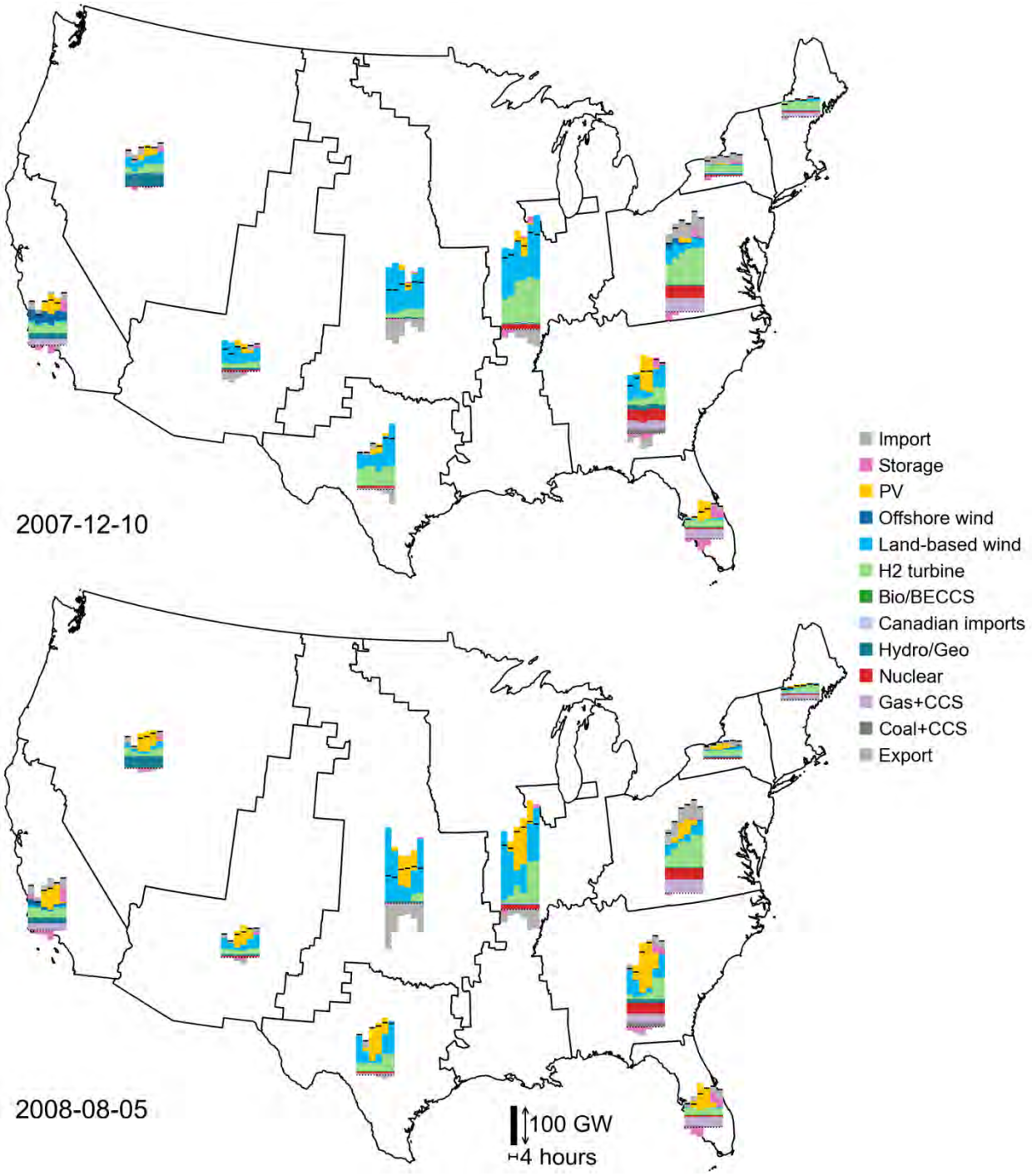


Figure 35. Regional dispatch in the MT framework under Mid-Demand 90% by 2035 assumptions in 2050 modeled in ReEDS during two example stress periods

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]

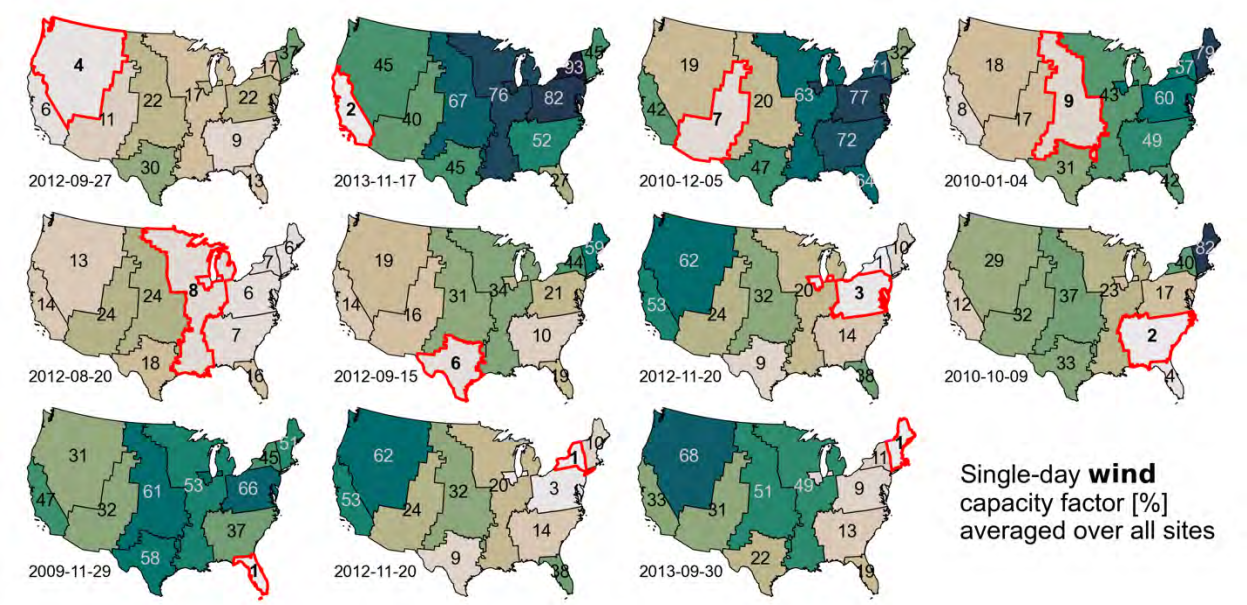


Figure 36. Single-day wind capacity factor on the least-windy day from 2007 to 2013 weather years in each planning region

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.

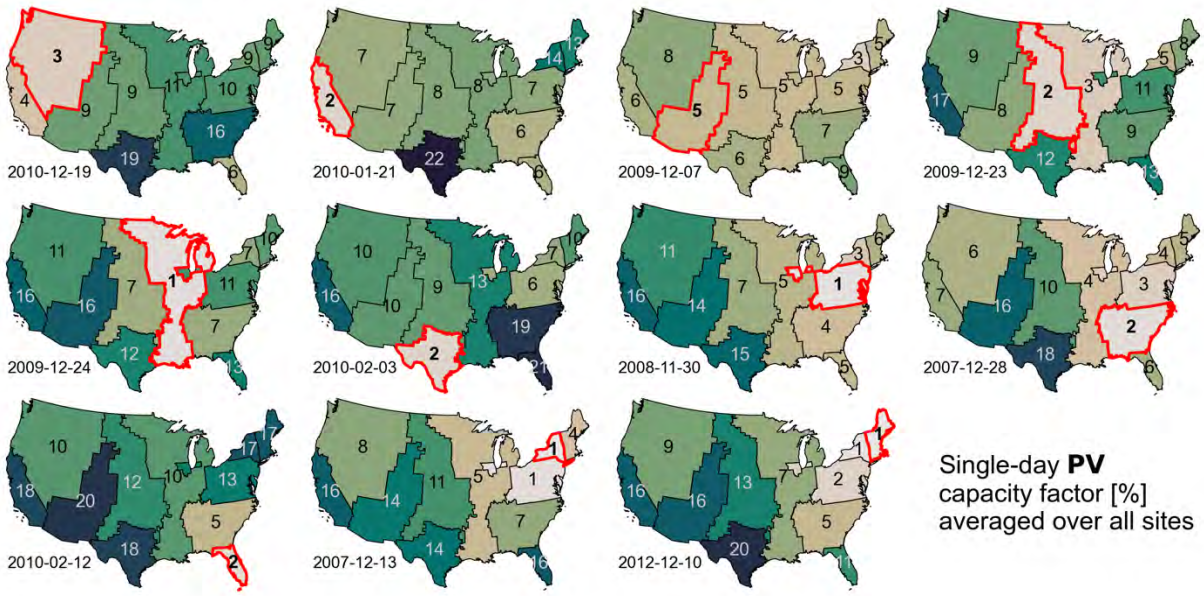


Figure 37. Single-day PV capacity factor on the least-sunny day from 2007 to 2013 weather years in each planning region

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.

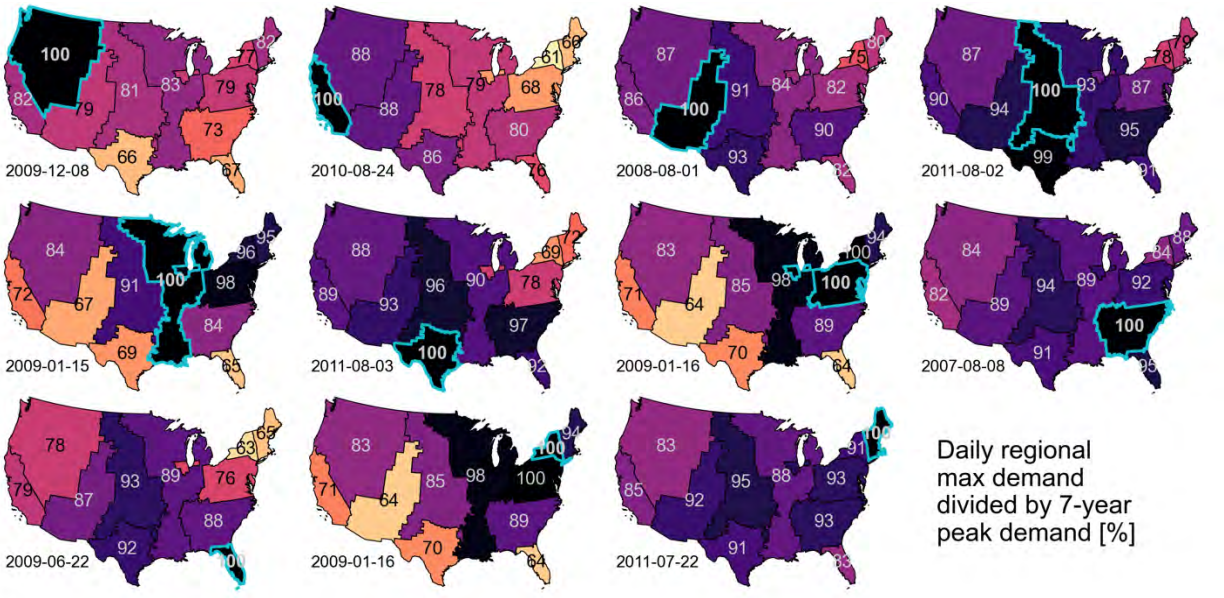


Figure 38. Daily regional maximum demand divided by 7-year peak demand for that region, shown for the regional peak demand day from 2007 to 2013 weather years for each planning region

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.

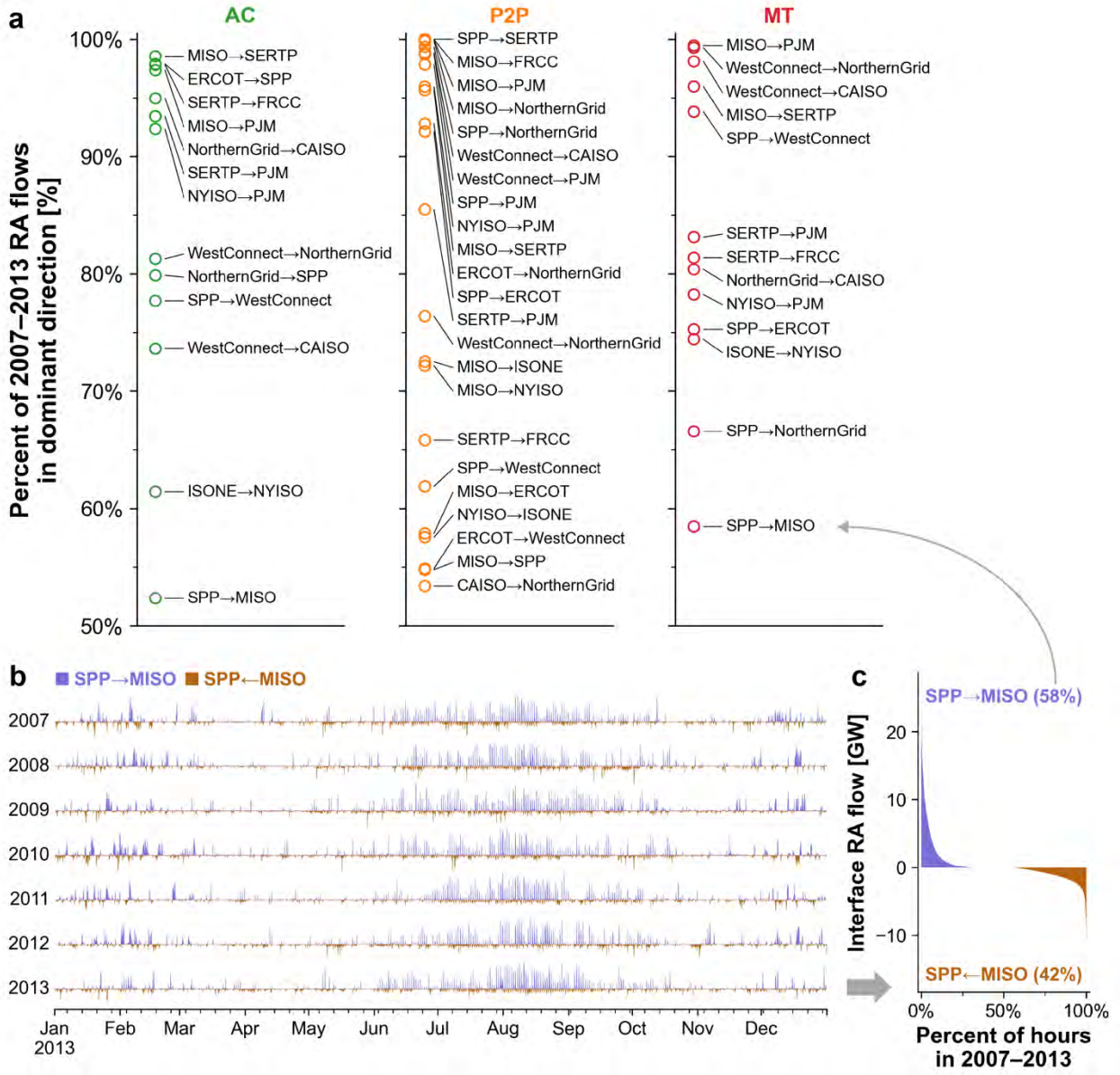


Figure 39. Bidirectional transmission flows between regions for resource adequacy in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

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.

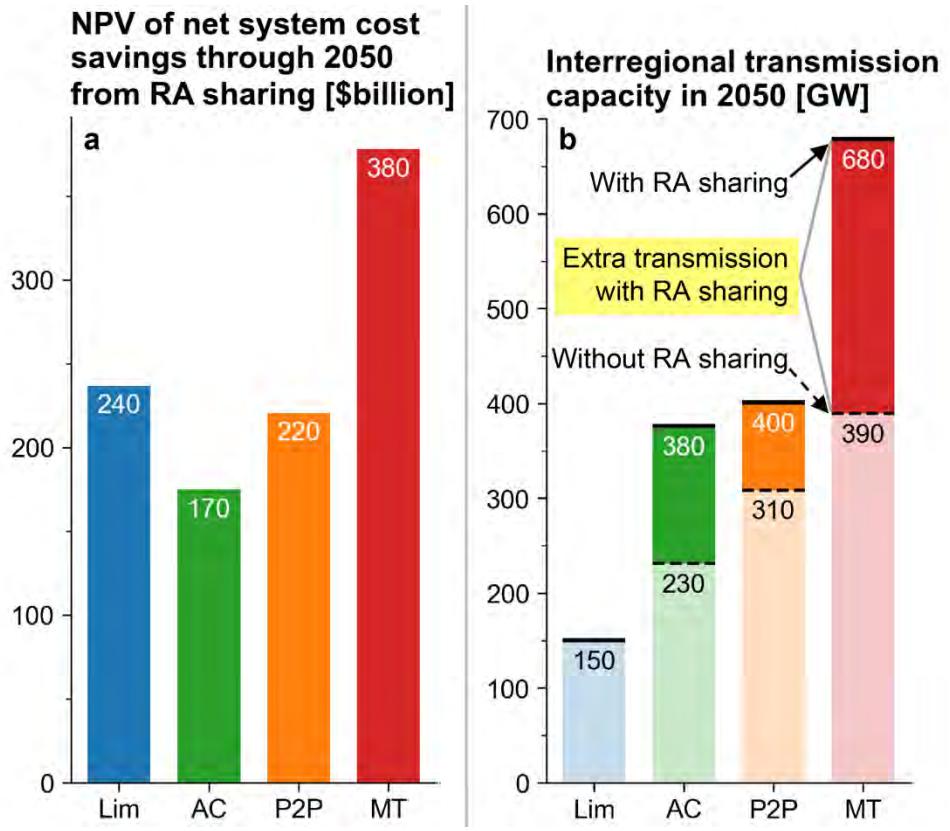


Figure 40. Impact of the allowance of interregional RA sharing on system cost (a) and optimized interregional transmission capacity (b)

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).

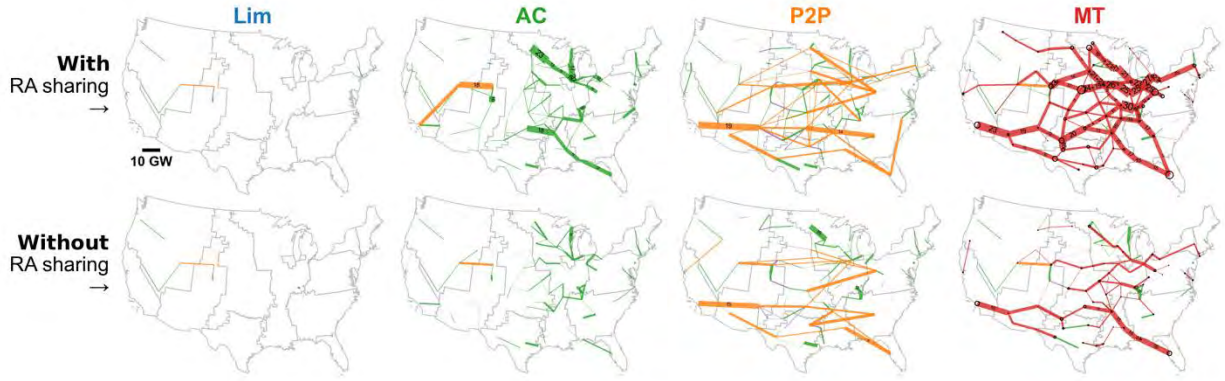


Figure 41. New transmission through 2050 with Mid-Demand 90% by 2035 assumptions for the four transmission frameworks with (top) and without (bottom) RA sharing between planning subregions.

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.

References

Alassi, Abdulrahman, Santiago Bañales, Omar Ellabban, Grain Adam, and Callum MacIver. 2019. “HVDC Transmission: Technology Review, Market Trends and Future Outlook.” *Renewable and Sustainable Energy Reviews* 112 (September): 530–54. https://doi.org/10.1016/j.rser.2019.04.062.

Alberta Electricity system Operator. 2017. “Resource Adequacy, A Comparison of Reliability Metrics.” Alberta Electricity system Operator. https://www.aeso.ca/assets/Uploads/Capital-Power-Reliability-Target-Summary-CM.pdf.

Alvarez, Ramón A., Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, et al. 2018. “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain.” *Science* 361: 186–88. https://doi.org/10.1126/science.aar7204.

Barbose, Galen. 2023. “U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update.” Berkeley, CA: Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf.

Bartos, Matthew, Mikhail Chester, Nathan Johnson, Brandon Gorman, Daniel Eisenberg, Igor Linkov, and Matthew Bates. 2016. “Impacts of Rising Air Temperatures on Electric Transmission Ampacity and Peak Electricity Load in the United States.” *Environmental Research Letters* 11 (11): 114008. https://doi.org/10.1088/1748-9326/11/11/114008.

Blair, Nate, Chad Augustine, Wesley Cole, Paul Denholm, Will Frazier, Madeline Geocaris, Jennie Jorgenson, et al. 2022. *Storage Futures Study: Key Learnings for the Coming Decades*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-81779. https://doi.org/10.2172/1863547.

Brinkman, Gregory, Dominique Bain, Grant Buster, Caroline Draxl, Paritosh Das, Jonathan Ho, Eduardo Ibanez, et al. 2021. “The North American Renewable Integration Study (NARIS): A U.S. Perspective.” NREL. https://www.nrel.gov/docs/fy21osti/79224.pdf.

Brinkman, Gregory, Mike Bannister, Sophie Bredenkamp, Lanaia Carveth, Dave Corbus, Rebecca Green, Luke Lavin, et al. 2024. “Atlantic Offshore Wind Transmission Study.” U.S. Department of Energy. https://www.nrel.gov/wind/atlantic-offshore-wind-transmission-study.html.

Brown, Maxwell, Matthew Irish, Daniel Steinberg, Tamar Moss, Daniel Cherney, Travis Shultz, David Morgan, Alex Zoelle, and Thomas Schmit. forthcoming. “Representing Carbon Dioxide Transport and Storage Network Investments within Power System Planning Models.”

Brown, Patrick R., Clayton P. Barrows, Jarrad G. Wright, Gregory L. Brinkman, Sourabh Dalvi, Jiazi Zhang, and Trieu Mai. 2023. “A General Method for Estimating Zonal

Transmission Interface Limits from Nodal Network Data." arXiv. http://arxiv.org/abs/2308.03612.

Brown, Patrick R., and Audun Botterud. 2021. "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System." *Joule* 5 (1): 115–34. https://doi.org/10.1016/j.joule.2020.11.013.

Brown, Patrick R., Wesley J. Cole, and Trieu Mai. forthcoming. "Selection and weighting of representative time periods to minimize regional distortion in continent-scale electricity system models"

Buster, Grant, Brandon Benton, Andrew Glaws, and Ryan King. 2023. "Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC)." OpenEI. https://doi.org/10.25984/1970814.

CAISO. 2023a. "2022–2023 Transmission Plan." California Independent System Operator. https://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf.

———. 2023b. "Demand Response Issues and Performance 2022." California Independent System Operator. https://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf.

California Public Utilities Commission. 2022. "Proposed Electricity Resource Portfolios for the 2023-2024 Transmission Planning Process." https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/23-24tpp_portfolios_workshopslides.pdf.

Chang, Judy W., Johannes P. Pfeifenberger, and J. Michael Hagerty. 2013. "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments." Brattle Group. https://www.brattle.com/wp-content/uploads/2021/06/The-Benefits-of-Electric-Transmission-Identifying-and-Analyzing-the-Value-of-Investments.pdf.

Denholm, Paul, Patrick Brown, Wesley Cole, Trieu Mai, Brian Sergi, Maxwell Brown, Paige Jadun, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. National Renewable Energy Laboratory. NREL/TP-6A40-81644. https://doi.org/10.2172/1885591.

DOE. 2016. "Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source." Technical Report DOE/GO-102016-4869. Washington, D.C.: U. S. Department of Energy. http://energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source.

———. 2021. "Solar Futures Study." U.S. Department of Energy. https://www.energy.gov/sites/default/files/2021-09/Solar%20Futures%20Study.pdf.

———. 2023a. “National Transmission Needs Study.” U.S. Department of Energy. https://www.energy.gov/gdo/national-transmission-needs-study.

———. 2023b. “Pathways to Commercial Liftoff: Clean Hydrogen.” U.S. Department of Energy. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.

Draxl, Caroline, Andrew Clifton, Bri-Mathias Hodge, and Jim McCaa. 2015. “The Wind Integration National Dataset (WIND) Toolkit.” *Applied Energy* 151 (August): 355–66. https://doi.org/10.1016/j.apenergy.2015.03.121.

Edison Electric Institute. 2024. “Industry Data: Transmission and Distribution.” 2024. https://www.eei.org/en/resources-and-media/industry-data.

EIA. 2021. “State Energy Data System (SEDS).” 2021. https://www.eia.gov/state/seds/sep_update/use_all_btu_update.csv.

———. 2022. “Annual Energy Outlook 2022.” Washington, D.C.: U.S. DOE Energy Information Administration. https://www.eia.gov/outlooks/archive/aeo22/.

———. 2023a. “Annual Energy Outlook 2023.” Washington, D.C.: U.S. Energy Information Administration. https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.

———. 2023b. “National Energy Modeling System (NEMS).” 2023. https://www.eia.gov/outlooks/aeo/info_nems_archive.php.

———. 2024a. “Electric Power Monthly.” 2024. https://www.eia.gov/electricity/monthly/.

———. 2024b. “Monthly Energy Review.” 2024. https://www.eia.gov/totalenergy/data/monthly/.

Electric Power Research Institute. 2024. “Adequacy Standards & Criteria.” 2024. https://gridops.epri.com/Adequacy/standards.

Electric Reliability Council of Texas. 2022. “Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2022.” https://www.ercot.com/files/docs/2022/05/16/SARA_Summer2022.pdf.

European Commission. Joint Research Centre. Institute for Energy and Transport. and SERTIS. 2014. “Energy Technology Reference Indicator (ETRI) Projections for 2010-2050.” LU: Publications Office. https://data.europa.eu/doi/10.2790/057687.

Executive Office of the President. 2021. *Tackling the Climate Crisis at Home and Abroad*. *Executive Order 14008*. https://www.federalregister.gov/documents/2021/02/01/2021-02177/tackling-the-climate-crisis-at-home-and-abroad.

Federal Energy Regulatory Commission. 2011. *Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*. *18 CFR Part 35*. https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf.

———. 2022. *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*. *18 CFR Part 35*. https://www.ferc.gov/media/rm21-17-000.

Frazier, A. Will, Wesley Cole, Paul Denholm, Scott Machen, Nathaniel Gates, and Nate Blair. 2021. “Storage Futures Study: Economic Potential of Diurnal Storage in the US Power Sector.” Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy21osti/77449.pdf.

Gagnon, Pieter, An Pham, Wesley Cole, Sarah Awara, Anne Barlas, Maxwell Brown, Patrick Brown, et al. 2024. 2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook. National Renewable Energy Laboratory. NREL/TP-6A40-87724. https://www.nrel.gov/docs/fy24osti/87724.pdf.

Goggin, Michael. 2021. “Transmission Makes the Power System Resilient to Extreme Weather.” Grid Strategies LLC. https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

Grams, Christian M., Remo Beerli, Stefan Pfenninger, Iain Staffell, and Heini Wernli. 2017. “Balancing Europe’s Wind-Power Output through Spatial Deployment Informed by Weather Regimes.” *Nature Climate Change* 7 (8): 557–62. https://doi.org/10.1038/nclimate3338.

Grant, Tim, Andrea Poe, Jason Valenstein, Allison Guinan, Chung Yan Shih, and ShangMin Lin. 2019. “Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies.” DOE/NETL-2019/2044. National Energy Technology Laboratory. https://doi.org/10.2172/1567735.

Haley, Ben, Ryan Jones, Jim Williams, Gabe Kwok, Jamil Farbes, Darcie Bentz, Greg Schivley, and Jesse Jenkins. 2023. “Annual Decarbonization Perspective: Carbon Neutral Pathways for the United States 2023.” Evolved Energy Research. https://www.evolved.energy/2023-us-adp.

Haley, Ben, Ryan Jones, Jim Williams, Gabe Kwok, Jamil Farbes, Jeremy Hargreaves, Katie Pickrell, Darcie Bentz, Andrew Waddell, and Emily Leslie. 2022. “Annual Decarbonization Perspective.” Evolved Energy Research. https://www.evolved.energy/post/adp2022.

Hitachi. 2020. “The World’s Most Powerful Transmission System Facilitated by Hitachi ABB Power Grids Technologies.” 2020. https://www.hitachienergy.com/us/en/news/features/2020/07/the-world-s-most-powerful-transmis-sion-system-facilitated-by-hi.

———. 2022. “Rio Madeira: One of the Longest and Most Powerful Transmission Links in the World.” Hitachi Energy. https://library.e.abb.com/public/a1df0903c063494690ee4b3a035a5153/Rio%20Madeira%20project%20HVDC0115%20RevA.pdf?x-sign=2/fv6gcA5Mt+EOsyT3U6LP0kINnVStTZXXbf3aOYHAKd9NbpnllCILFxTVPV59gh.

———. 2024. “North-East Agra.” 2024. https://www.hitachienergy.com/us/en/about-us/customer-success-stories/north-east-agra.

Ho, Jonathan, Anne Barlas, Jonathon Becker, Maxwell Brown, Patrick Brown, Vincent Carag, Ilya Chernyakhovskiy, et al. forthcoming. “Regional Energy Deployment System (ReEDS) Model Documentation: Version 2023.”

Kempton, Willett, Felipe M. Pimenta, Dana E. Veron, and Brian A. Colle. 2010. “Electric Power from Offshore Wind via Synoptic-Scale Interconnection.” *Proceedings of the National Academy of Sciences* 107 (16): 7240–45. https://doi.org/10.1073/pnas.0909075107.

Larson, Eric, Chirs Greig, Jesse Jenkins, Erin Mayfield, Andrew Pascale, Chuan Zhang, Joshua Drossman, et al. 2021. “Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report.” Princeton, NJ: Princeton University. https://www.dropbox.com/s/ptp92f65lgds5n2/Princeton%20NZA%20FINAL%20REPORT%20%2829Oct2021%29.pdf?dl=0.

Lopez, Anthony, Wesley Cole, Brian Sergi, Aaron Levine, Jesse Carey, Cailee Mangan, Trieu Mai, Travis Williams, Pavlo Pinchuk, and Jianyu Gu. 2023. “Impact of Siting Ordinances on Land Availability for Wind and Solar Development.” *Nature Energy* 8 (9): 1034–43. https://doi.org/10.1038/s41560-023-01319-3.

Lopez, Anthony, Pavlo Pinchuk, Michael Gleason, Wesley Cole, Trieu Mai, Travis Williams, Owen Roberts, et al. 2024. *Solar Photovoltaics and Land-Based Wind Technical Potential and Supply Curves for the Contiguous United States: 2023 Edition*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-87843. https://doi.org/10.2172/2283517.

Lord, Anna S., Peter H. Kobos, and David J. Borns. 2014. “Geologic Storage of Hydrogen: Scaling up to Meet City Transportation Demands.” *International Journal of Hydrogen Energy* 39 (28): 15570–82. https://doi.org/10.1016/j.ijhydene.2014.07.121.

Maclaurin, Galen, Nick Grue, Anthony Lopez, Dona Heimiller, Michael Rossol, Grant Buster, and Travis Williams. 2021. “The Renewable Energy Potential (reV) Model: A Geospatial Platform for Technical Potential and Supply Curve Modeling.” NREL/TP-6A20-73067. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/73067.pdf.

Mai, Trieu, Patrick R Brown, Luke Lavin, Surya Dhulipala, and Jessica Kuna. forthcoming. “Incorporating Stressful Grid Conditions for Reliable and Cost-Effective Electricity System Planning.”

Martinez, A. and G. Iglesias. 2022. “Climate Change Impacts on Wind Energy Resources in North America Based on the CMIP6 Projections.” *Science of The Total Environment* 806 (February): 150580. https://doi.org/10.1016/j.scitotenv.2021.150580.

Millstein, Dev, Ryan Wiser, Will Gorman, Seongeun Jeong, James Kim, and Amos Ancell. 2022. “Empirical Estimates of Transmission Value Using Locational Marginal Prices.” Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf.

MISO. 2021. “Transmission Cost Estimation Guide for MTEP21.” Midcontinent Independent System Operator. https://cdn.misoenergy.org/20210209%20PSC%20Item%2006a%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP21519525.pdf.

———. 2022. “Reliability Imperative: Long Range Transmission Planning.” Midcontinent Independent System Operator. https://cdn.misoenergy.org/20220725%20Board%20of%20Directors%20Item%2002a%20Reliability%20Imperative%20LRTP625714.pdf.

Murphy, Caitlin, Trieu Mai, Yinong Sun, Paige Jadun, Matteo Muratori, Brent Nelson, and Ryan Jones. 2021. *Electrification Futures Study: Scenarios of Power System Evolution and Infrastructure Development for the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72330. https://www.nrel.gov/docs/fy21osti/72330.pdf.

Murphy, Sinnott, Fallaw Sowell, and Jay Apt. 2019. “A Time-Dependent Model of Generator Failures and Recoveries Captures Correlated Events and Quantifies Temperature Dependence.” *Applied Energy* 253 (November): 113513. https://doi.org/10.1016/j.apenergy.2019.113513.

Musial, Walter, Paul Spitsen, Patrick Duffy, Philipp Beiter, Matt Shields, Daniel Mulas Hernando, Rob Hammond, Melinda Marquis, Jennifer King, and Sathish Sriharan. 2023. “Offshore Wind Market Report: 2023 Edition.” U.S. Department of Energy. https://www.energy.gov/sites/default/files/2023-09/doe-offshore-wind-market-report-2023-edition.pdf.

National Renewable Energy Laboratory. 2023. “Annual Technology Baseline.” 2023. https://atb.nrel.gov/electricity/2023/data.

NERC. 2021. “2021 Long-Term Reliability Assessment.” North American Electric Reliability Corporation. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

———. 2022. “2022 State of Reliability.” North American Electric Reliability Corporation. https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

———. 2023a. “2023 Long-Term Reliability Assessment.” North American Electric Reliability Corporation. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

———. 2023b. “Generating Availability Data System (GADS).” 2023. https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx.

———. 2024. “Evolving Planning Criteria for a Sustainable Power Grid.” North American Electric Reliability Corporation. https://www.nae.edu/File.aspx?id=322052&v=39f1c49a.

OMB. 2023. “Draft Circular A-4.” Office of Management and Budget. https://www.whitehouse.gov/wp-content/uploads/2023/04/DraftCircularA-4.pdf.

Papadias, D. D. and R. K. Ahluwalia. 2021. “Bulk Storage of Hydrogen.” *International Journal of Hydrogen Energy* 46 (70): 34527–41. https://doi.org/10.1016/j.ijhydene.2021.08.028.

Pierre, Brian J., Felipe Wilches-Bernal, David A. Schoenwald, Ryan T. Elliott, Daniel J. Trudnowski, Raymond H. Byrne, and Jason C. Neely. 2019. “Design of the Pacific DC Intertie Wide Area Damping Controller.” *IEEE Transactions on Power Systems* 34 (5): 3594–3604. https://doi.org/10.1109/TPWRS.2019.2903782.

Power Technology. 2020. “The World’s Longest Power Transmission Lines.” 2020. https://www.power-technology.com/features/featurethe-worlds-longest-power-transmission-lines-4167964/?cf-view.

Sathaye, Jayant, Larry Dale, Peter Larsen, Gary Fitts, Kevin Koy, Sarah Lewis, and Andre Lucena. 2011. “Estimating Risk to California Energy Infrastructure from Projected Climate Change.” LBNL-4967E, 1026811. https://doi.org/10.2172/1026811.

Seel, Joachim, Julie Mulvaney Kemp, Joseph Rand, Will Gorman, Dev Millstein, Fritz Kahrl, and Ryan Wiser. 2023. “Generator Interconnection Costs to the Transmission System.” Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/generator-interconnection-costs.

Sengupta, Manajit, Yu Xie, Anthony Lopez, Aron Habte, Galen Maclaurin, and James Shelby. 2018. “The National Solar Radiation Data Base (NSRDB).” *Renewable and Sustainable Energy Reviews* 89 (June): 51–60. https://doi.org/10.1016/j.rser.2018.03.003.

Sigrin, Benjamin, Michael Gleason, Robert Preus, Ian Baring-Gould, and Robert Margolis. 2016. *The Distributed Generation Market Demand Model (dGen): Documentation*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-65231. http://www.nrel.gov/docs/fy16osti/65231.pdf.

Southern California Edison. 2021. “2021 Final SCE Generator Interconnection Unit Cost Guide.” 2021. http://www.caiso.com/Documents/SCE2021FinalPerUnitCostGuide.xlsx.

SPP and MISO. 2022. “SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes.” https://www.spp.org/engineering/spp-miso-jtiq/.

Steinberg, Daniel, Maxwell Brown, Ryan Wiser, Paul Donohoo-Vallett, Pieter Gagnon, Anne Hamilton, Matthew Mowers, Caitlin Murphy, and Ashreeta Prasanna. 2023. *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-85242. https://doi.org/10.2172/1962552.

Stenclik, Derek. 2023. “Ensuring Efficient Reliability - New Design Principles for Capacity Accreditation.” Energy Systems Integration Group. https://www.esig.energy/new-design-principles-for-capacity-accreditation/.

Stenclik, Derek, Aaron Bloom, Wesley Cole, Armando Acevedo, Gord Stephen, and Aidan Tuohy. 2021. *Redefining Resource Adequacy for Modern Power Systems: A Report of the Redefining Resource Adequacy Task Force*. Energy Systems Integration Group. NREL/TP-5C00-80896. https://doi.org/10.2172/1961567.

Stephen, Gord. 2021. *Probabilistic Resource Adequacy Suite (PRAS) v0.6 Model Documentation*. National Renewable Energy Laboratory. NREL/TP-5C00-79698. https://doi.org/10.2172/1785462.

Stephen, Gord, Simon H. Tindemans, John Fazio, Chris Dent, Armando Figueroa Acevedo, Bagen Bagen, Alex Crawford, Andreas Klaube, Douglas Logan, and Daniel Burke. 2022. “Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric.” In *2022 17th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, 1–4. Manchester, United Kingdom: IEEE. https://doi.org/10.1109/PMAPS53380.2022.9810615.

TransWest Express. 2024. “TransWest Express.” 2024. https://www.transwestexpress.net/index.shtml.

Turner, Sean, Nathalie Voisin, Kristian Nelson, and Vincent Tidwell. 2022. “Drought Impacts on Hydroelectric Power Generation in the Western United States.” PNNL-33212, 1887470. Pacific Northwest National Laboratory. https://doi.org/10.2172/1887470.

Voisin, N., M. Kintner-Meyer, D. Wu, R. Skaggs, T. Fu, T. Zhou, T. Nguyen, and I. Kraucunas. 2017. “Opportunities for Joint Water–Energy Management: Sensitivity of the 2010 Western U.S. Electricity Grid Operations to Climate Oscillations.” *Bulletin of the American Meteorological Society* 99 (2): 299–312. https://doi.org/10.1175/BAMS-D-16-0253.1.

Western Electricity Coordinating Council. 2019. “Transmission Cost Calculator.” 2019. https://www.wecc.org/Administrative/TEPPC_TransCapCostCalculator_E3_2019_Update.xlsx.

Wiser, Ryan, Mark Bolinger, Ben Hoen, Dev Millstein, Joe Rand, Galen Barbose, Naïm Darghouth, et al. 2023. “Land-Based Wind Market Report: 2023 Edition.” Department of Energy. https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2023-edition.

Young, D. 2020. “US-REGEN Model Documentation.” Electric Power Research Institute. https://www.epri.com/research/products/000000003002016601.

Yukimoto, Seiji, Tsuyoshi Koshiro, Hideaki Kawai, Naga Oshima, Kohei Yoshida, Shogo Urakawa, Hiroyuki Tsujino, et al. 2019. “MRI MRI-ESM2.0 Model Output Prepared for CMIP6 C4MIP Esm-Ssp585.” Earth System Grid Federation. https://doi.org/10.22033/ESGF/CMIP6.6811.

Appendix A. Regional Energy Deployment System (ReEDS) Model

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

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

A.1 Transmission Modeling

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

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

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

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

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

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

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

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

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

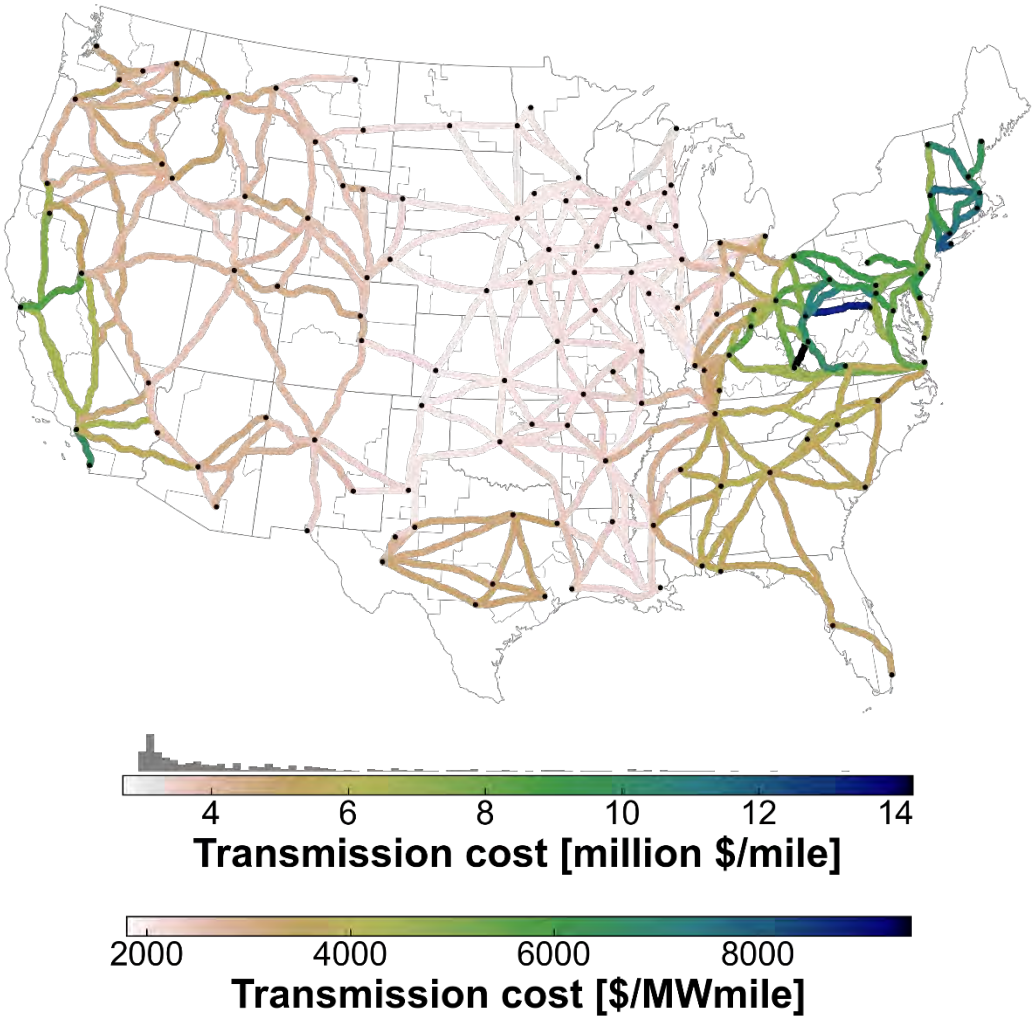


Figure A-1. Interzonal AC transmission cost assumptions

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

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

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

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

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

A.2 Wind and Solar Supply Curves

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

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

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

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

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

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

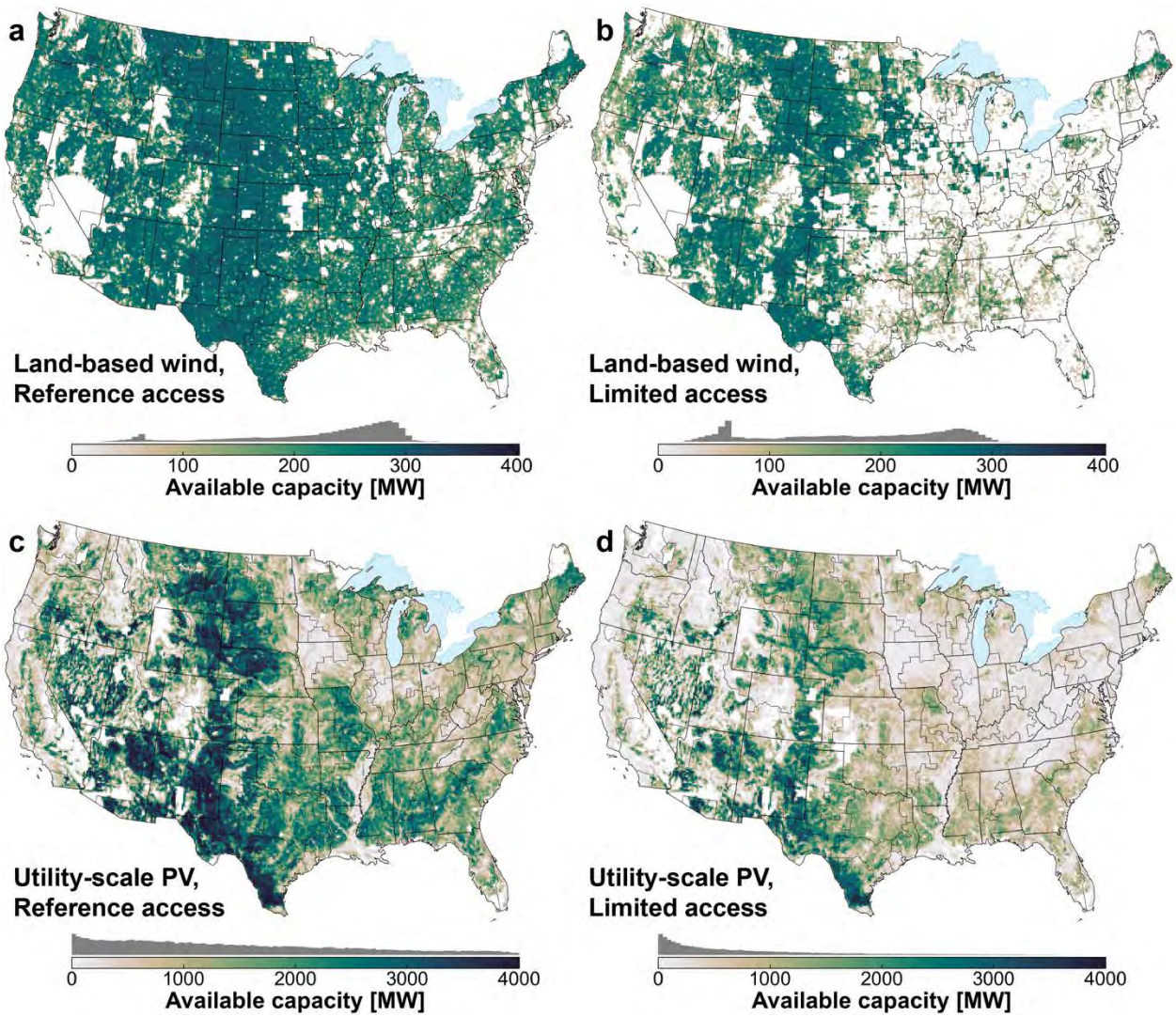


Figure A-2. Available land-based wind (a, b) and utility-scale PV (c, d) capacity under Reference Access (a, c) and Limited Access (b, d) assumptions

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

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

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

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

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

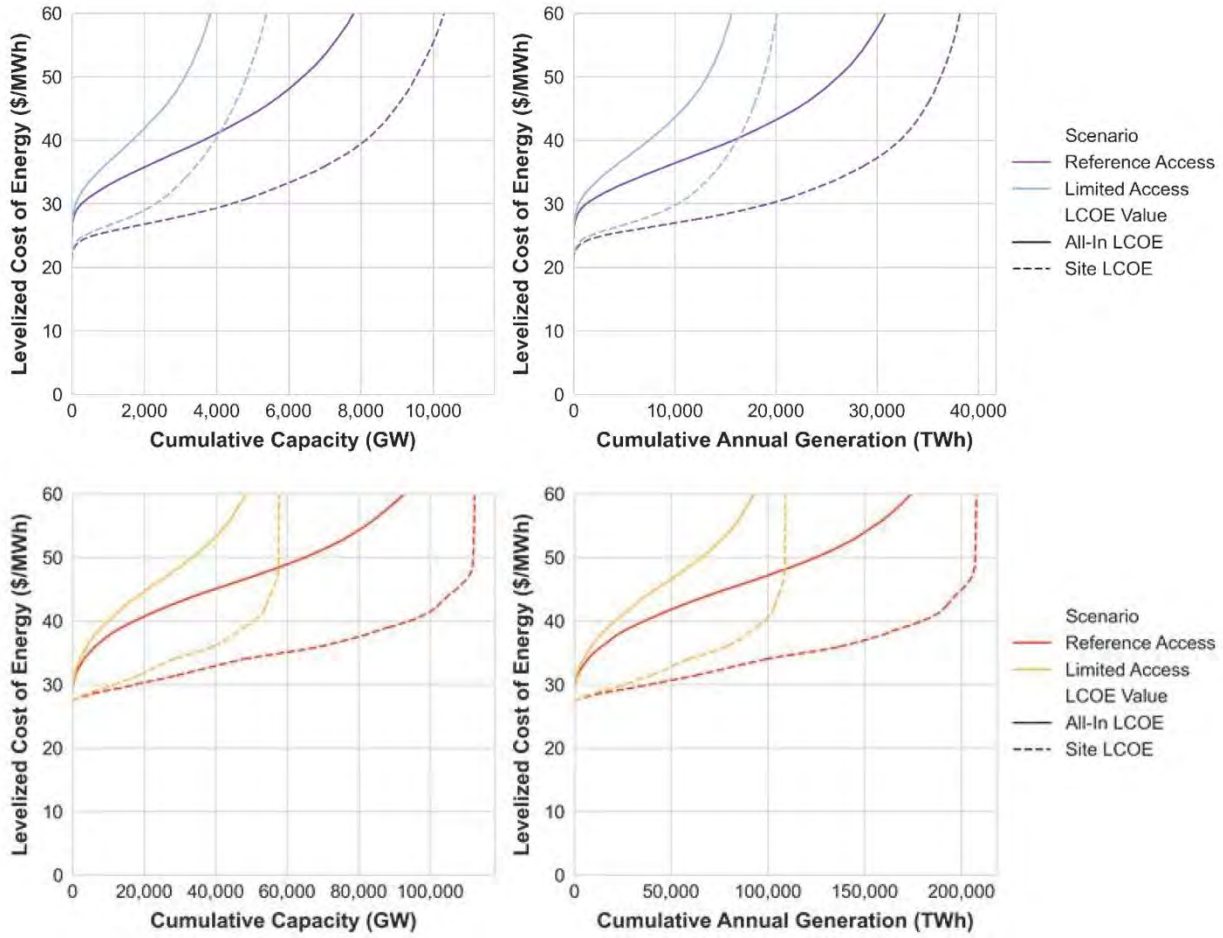


Figure A-3. LCOE supply curves for land-based wind (top) and solar PV (bottom)

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

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

A.3 Hydrogen Modeling

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

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

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

A.4 End-Use Emissions

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

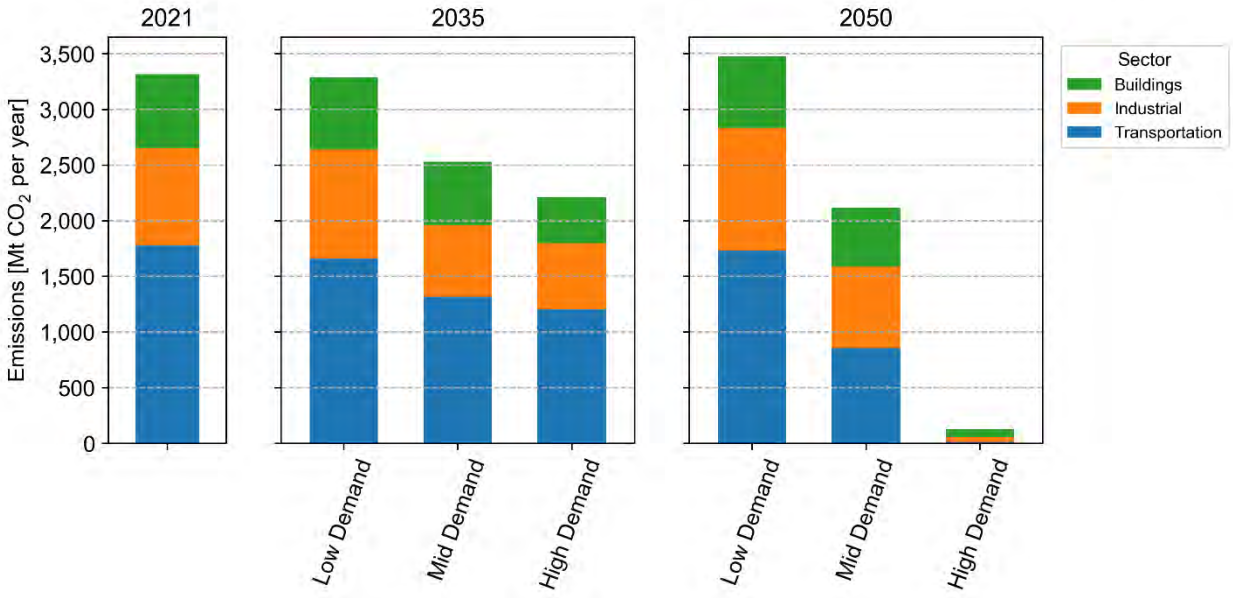


Figure A-4. End-use emissions for the three electricity demand cases

A.5 Climate Change Sensitivity

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

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

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

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

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

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

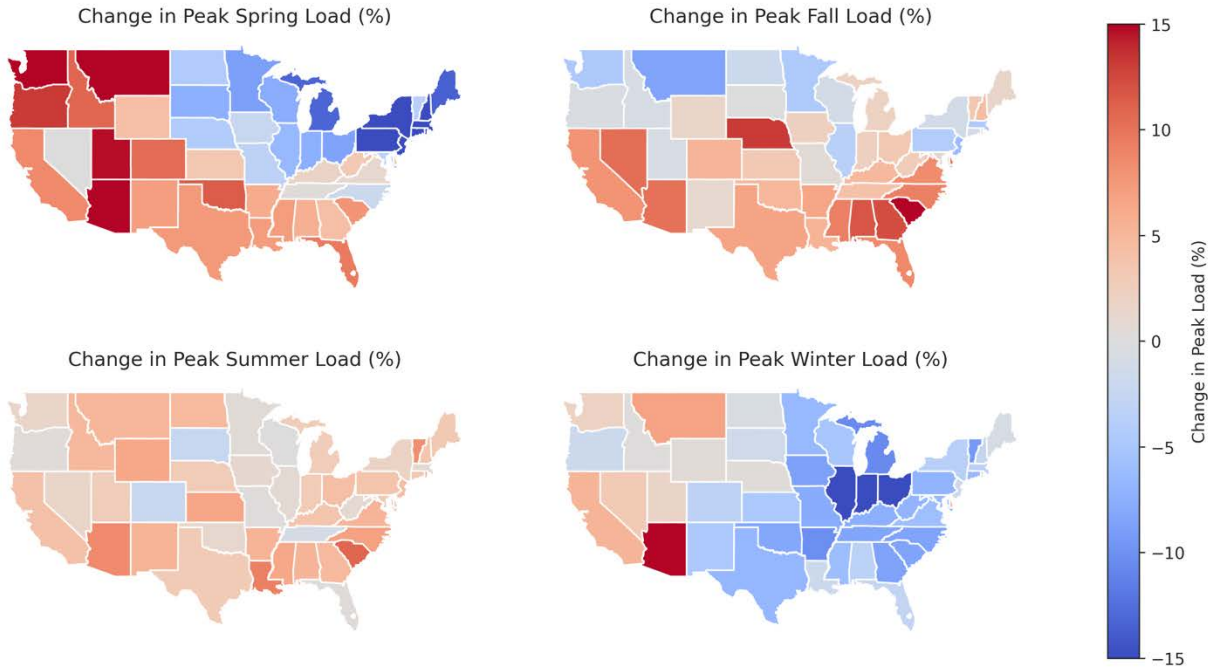


Figure A-5. Changes in seasonal all-sector peak load from historical weather (2007–2013) to future weather impacted by climate change (2050–2056)

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

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

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

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

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

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

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

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

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

Appendix B. Integrated Capacity Expansion and Resource Adequacy Modeling

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

B.1 What Is PRAS?

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

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

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

B.2 Integrated ReEDS-PRAS process

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

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

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

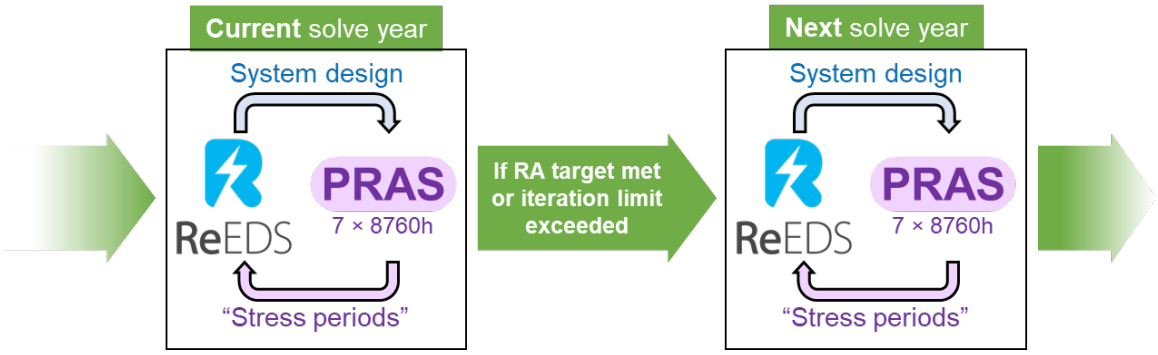


Figure B-1. Integrated capacity expansion and resource adequacy modeling

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

B.3 Planning Threshold

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

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

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

B.4 Caveats

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

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

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

Appendix C. Technology Cost Assumptions

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

C.1 Supply-Side Technologies

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

Table C-1. Technologies Modeled in ReEDS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C.2 Retrofits With CCS

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

Table C-5. Retrofit Assumptions for Technologies in ReEDS

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

C.3 Negative Emissions Technologies

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

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

C.4 Financing and Retirement Assumptions

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

There are multiple ways plants can retire:

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

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

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

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

Appendix D. Additional Results

D.1 ReEDS Results for 2035

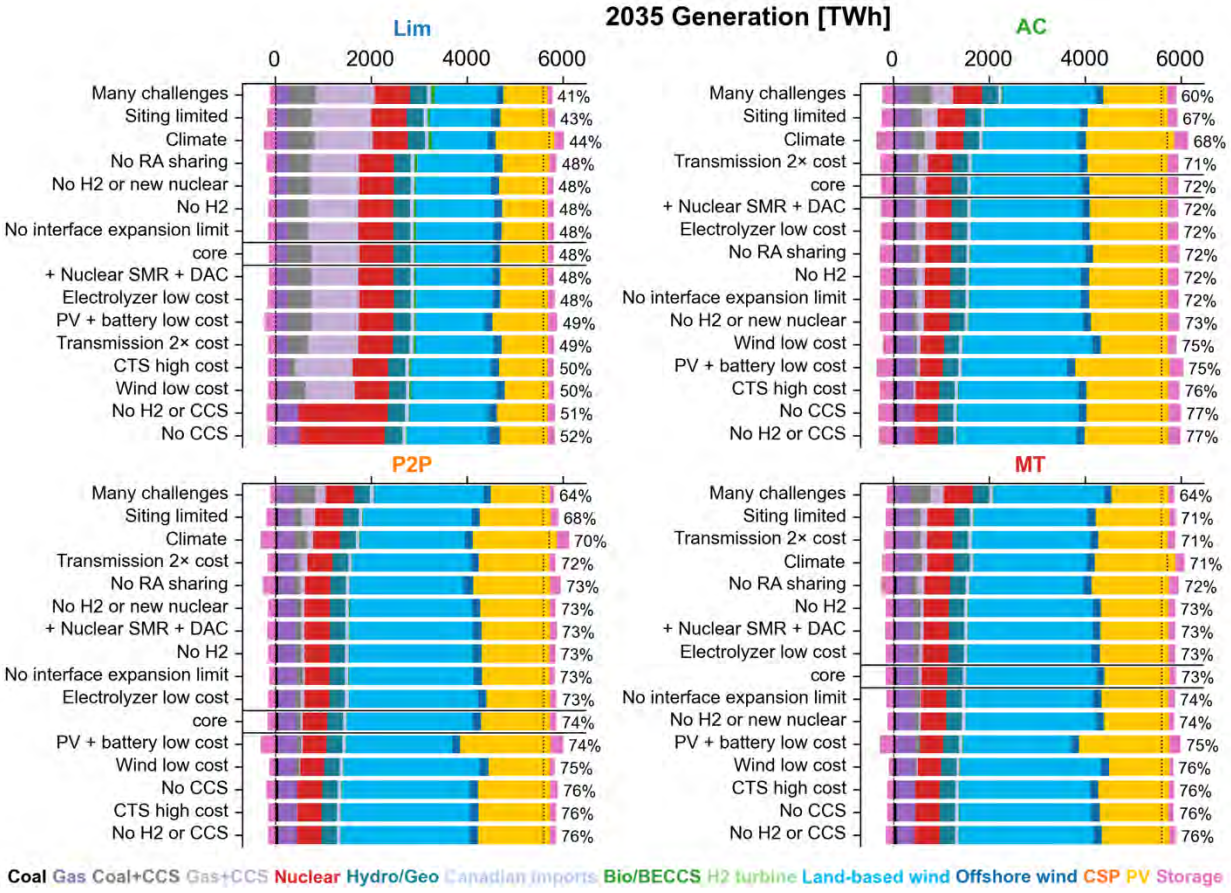


Figure D-1. National generation mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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

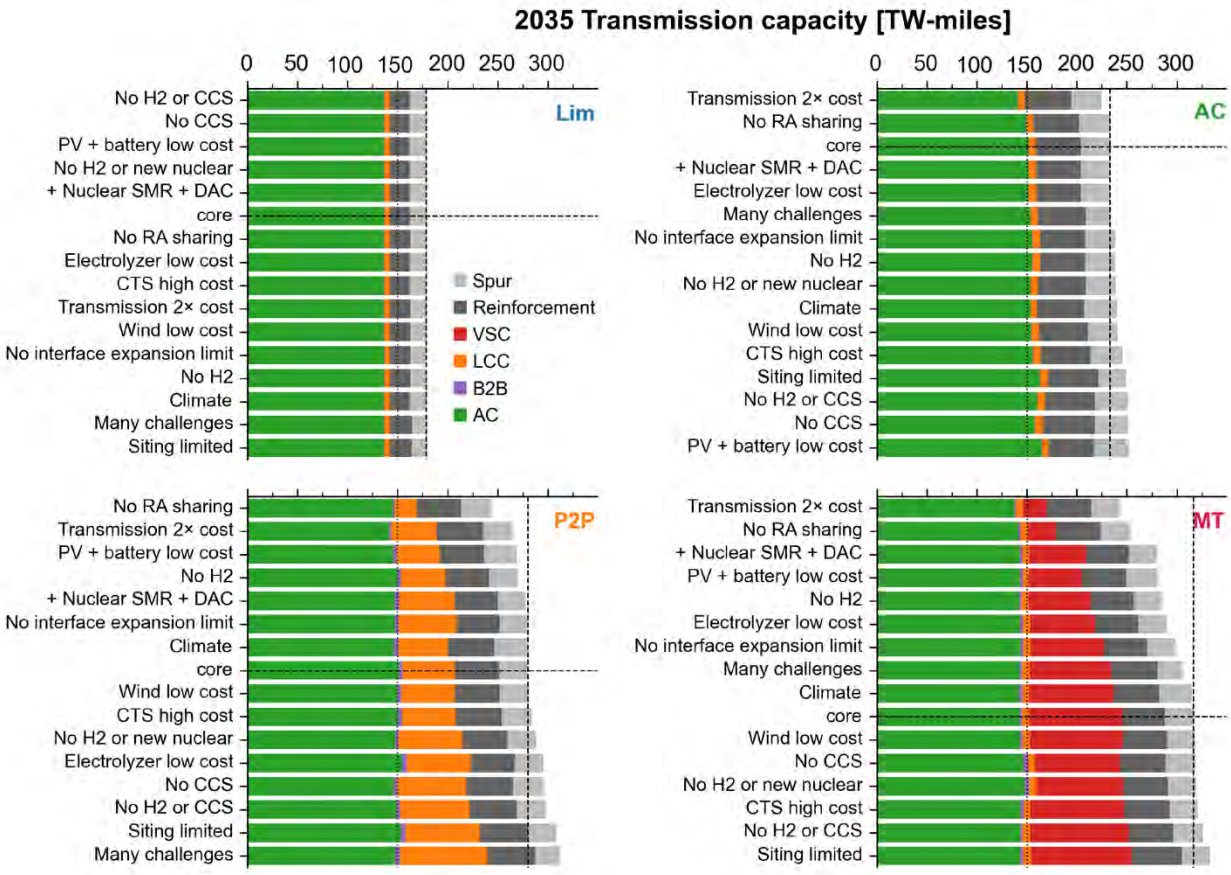


Figure D-2. Transmission capacity in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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

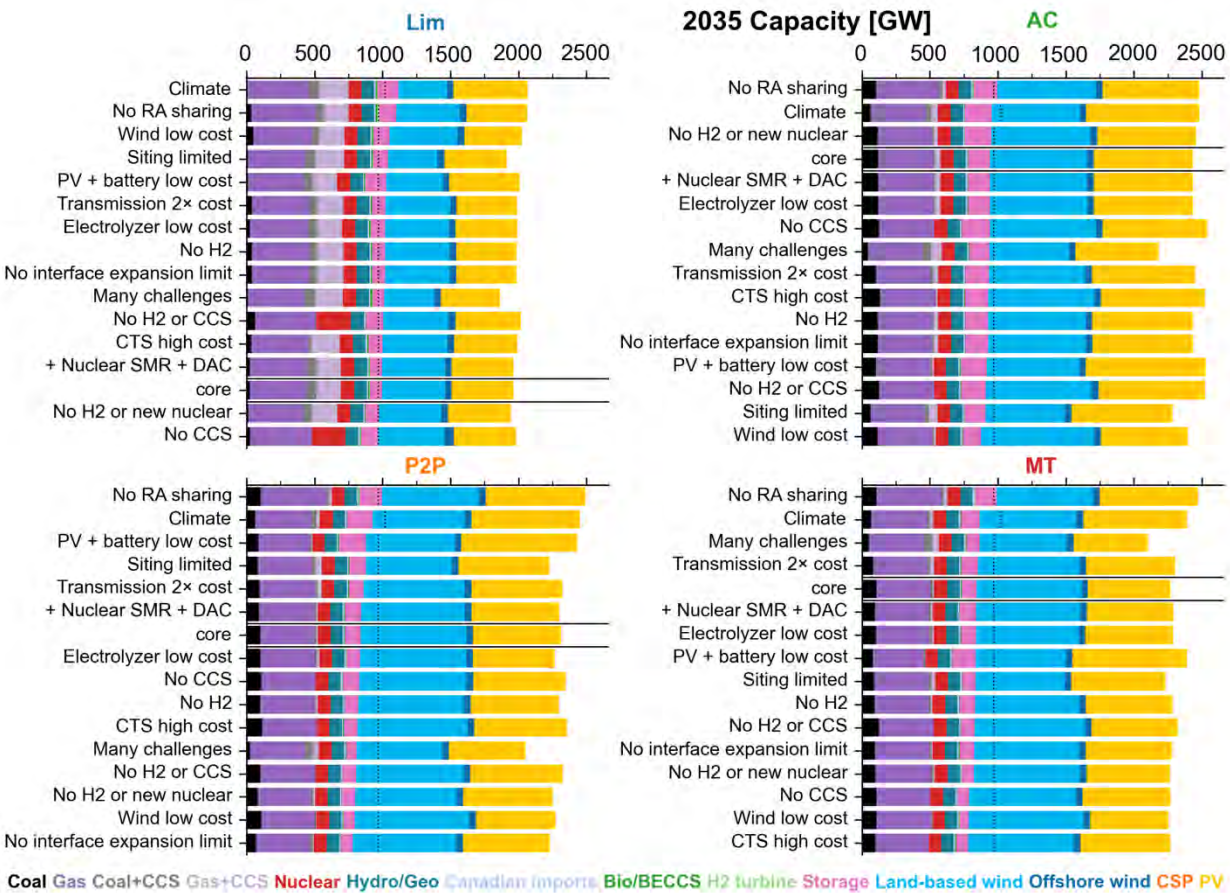


Figure D-3. National capacity mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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

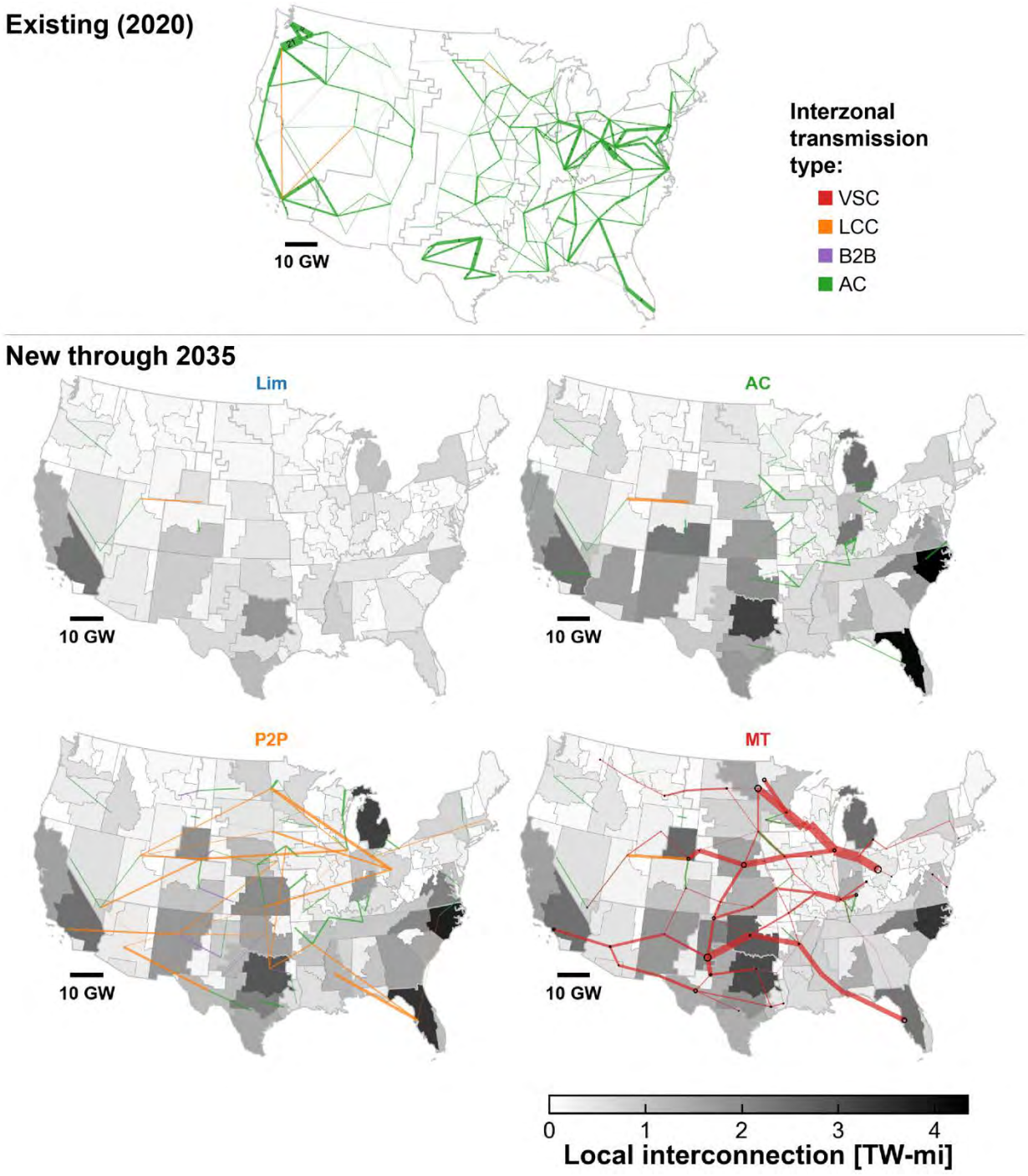


Figure D-4. New local and long-distance transmission through 2035 under Mid-Demand 90% by 2035 assumptions for each of the four transmission frameworks, with existing 2020 long-distance transmission capacity for context (top)

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

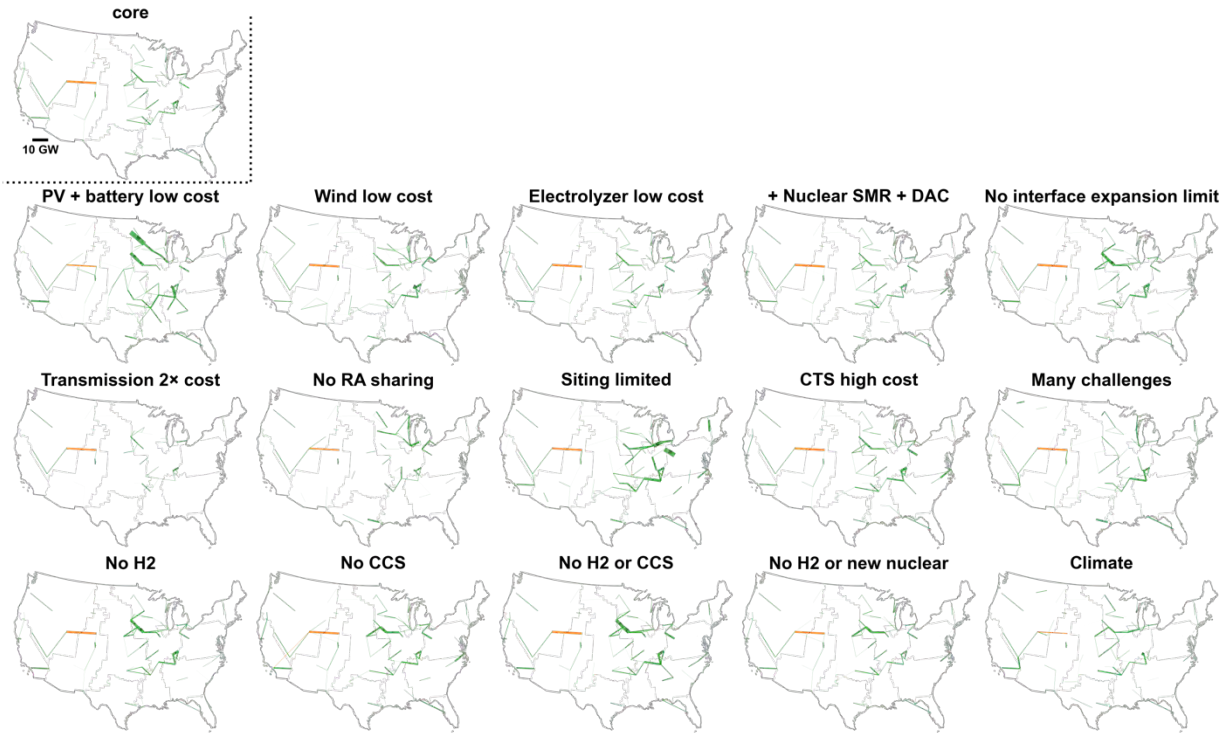


Figure D-5. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

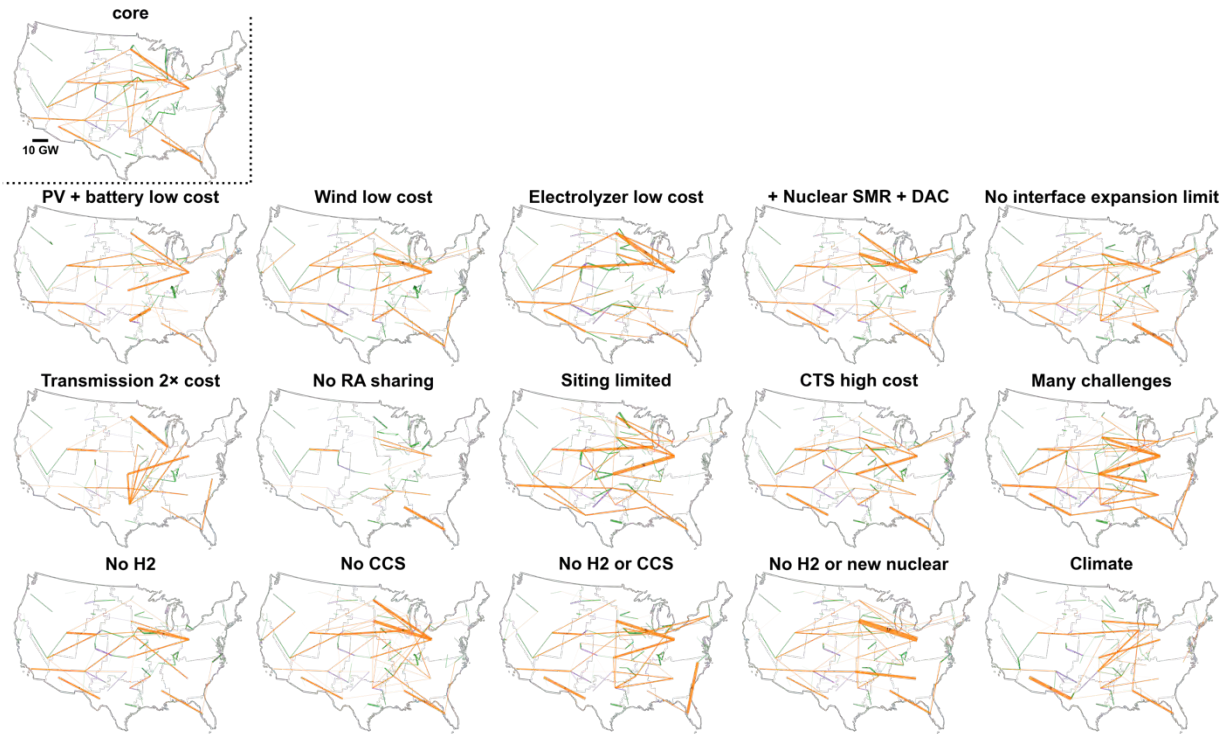


Figure D-6. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

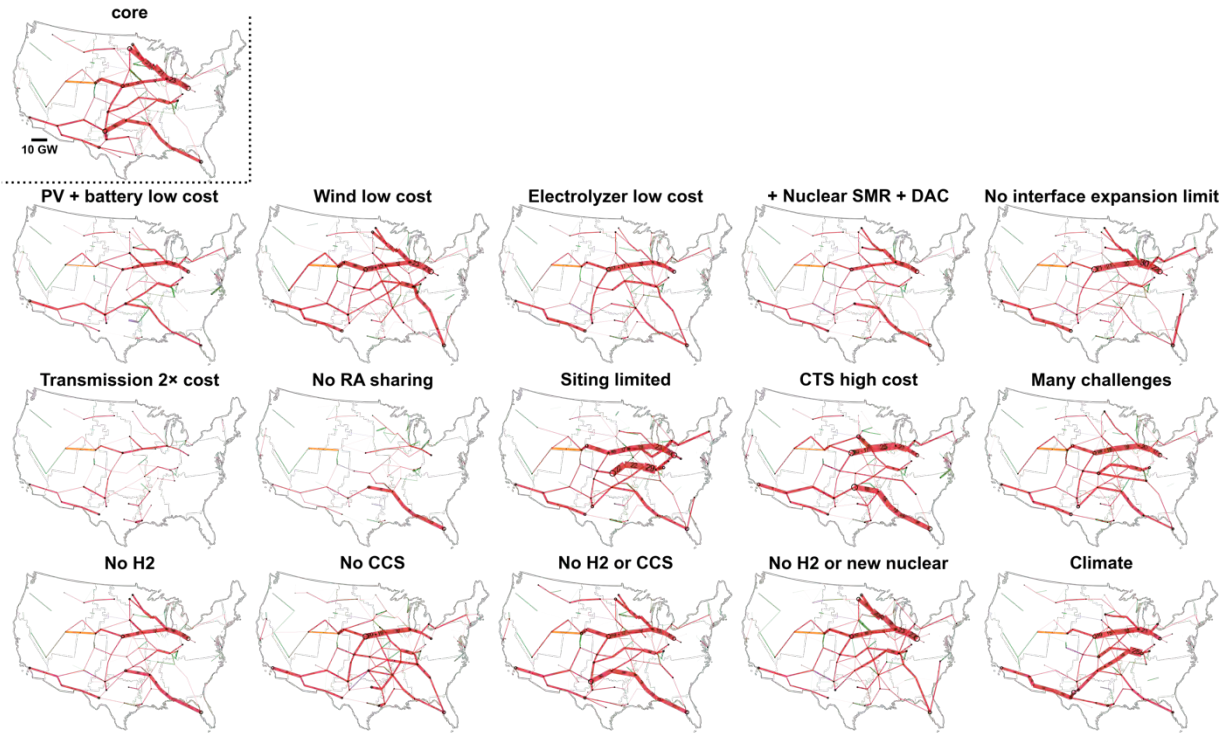


Figure D-7. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

D.2 Additional Capacity Expansion Modeling Results Through 2050

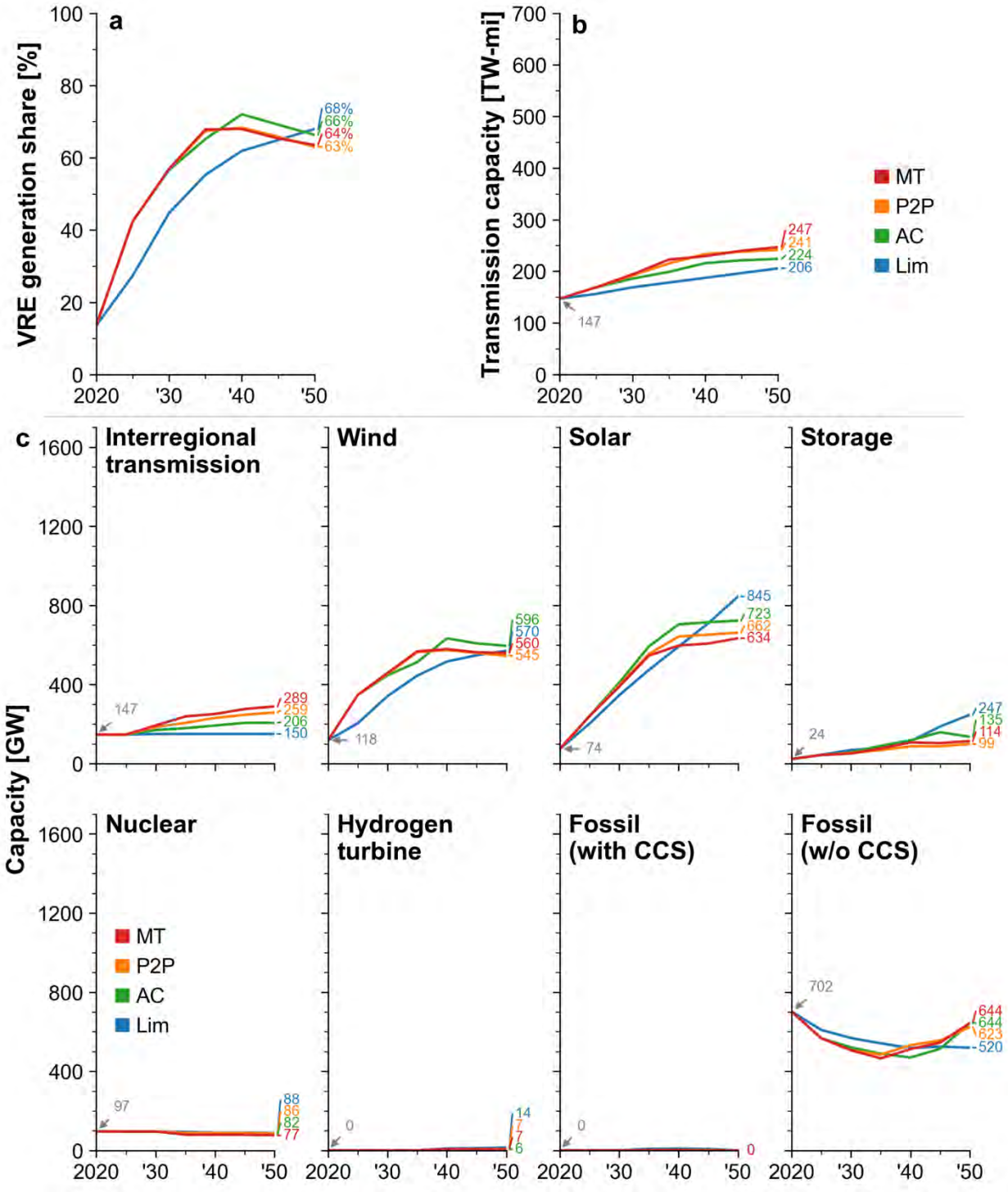


Figure D-8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Low-Demand Current Policies conditions

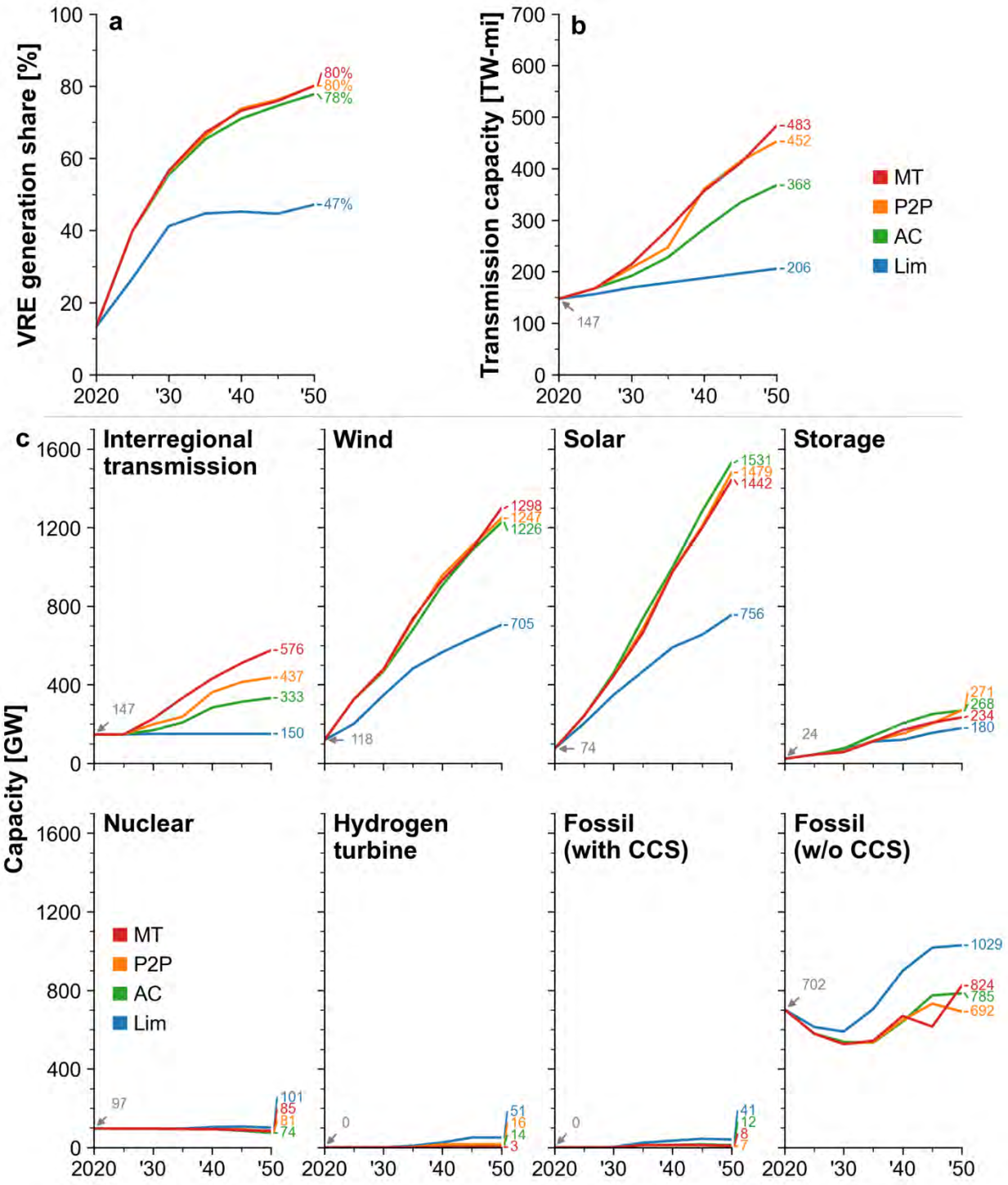


Figure D-9. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand Current Policies conditions

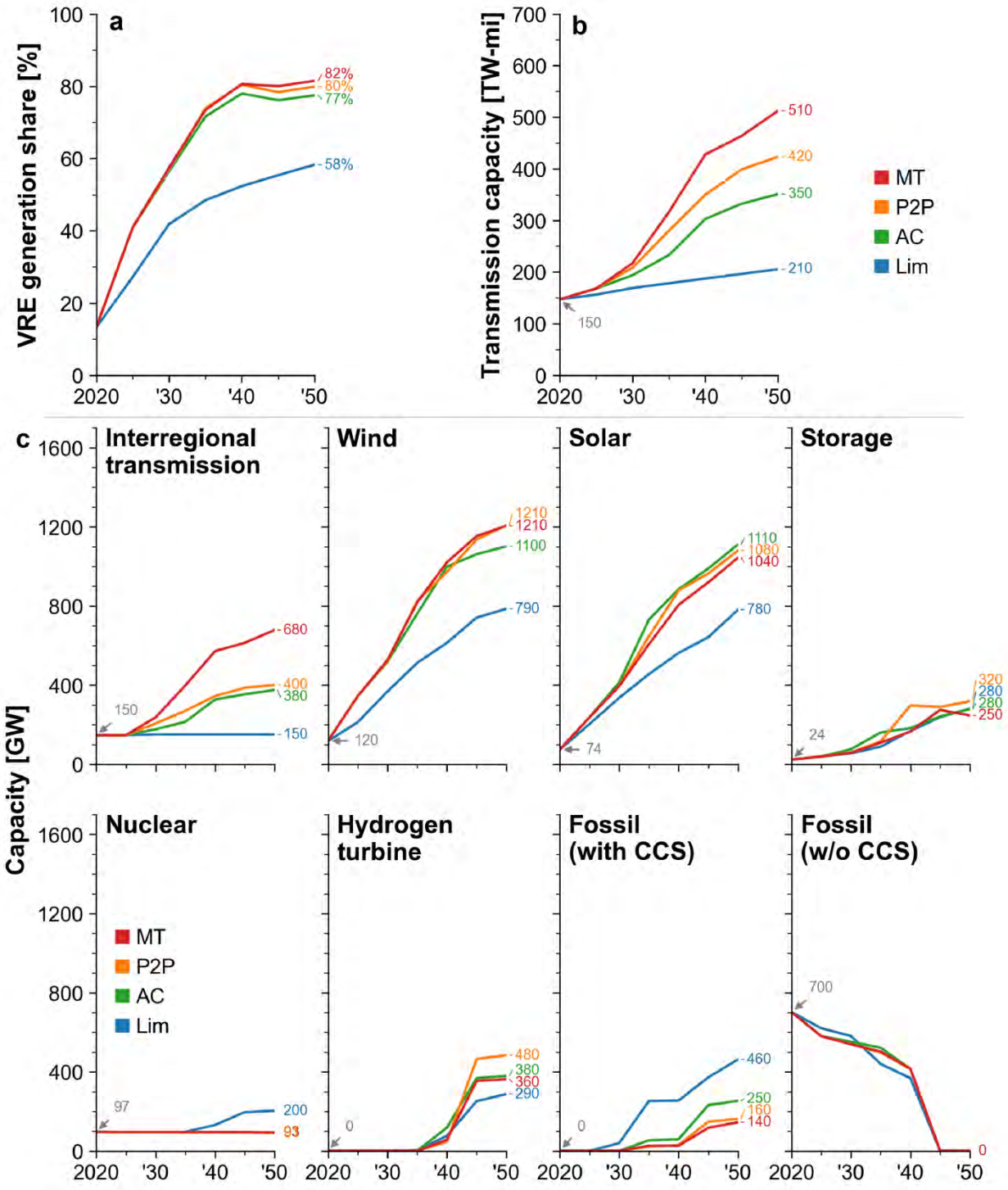


Figure D-10. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Mid-Demand 90% by 2035 conditions

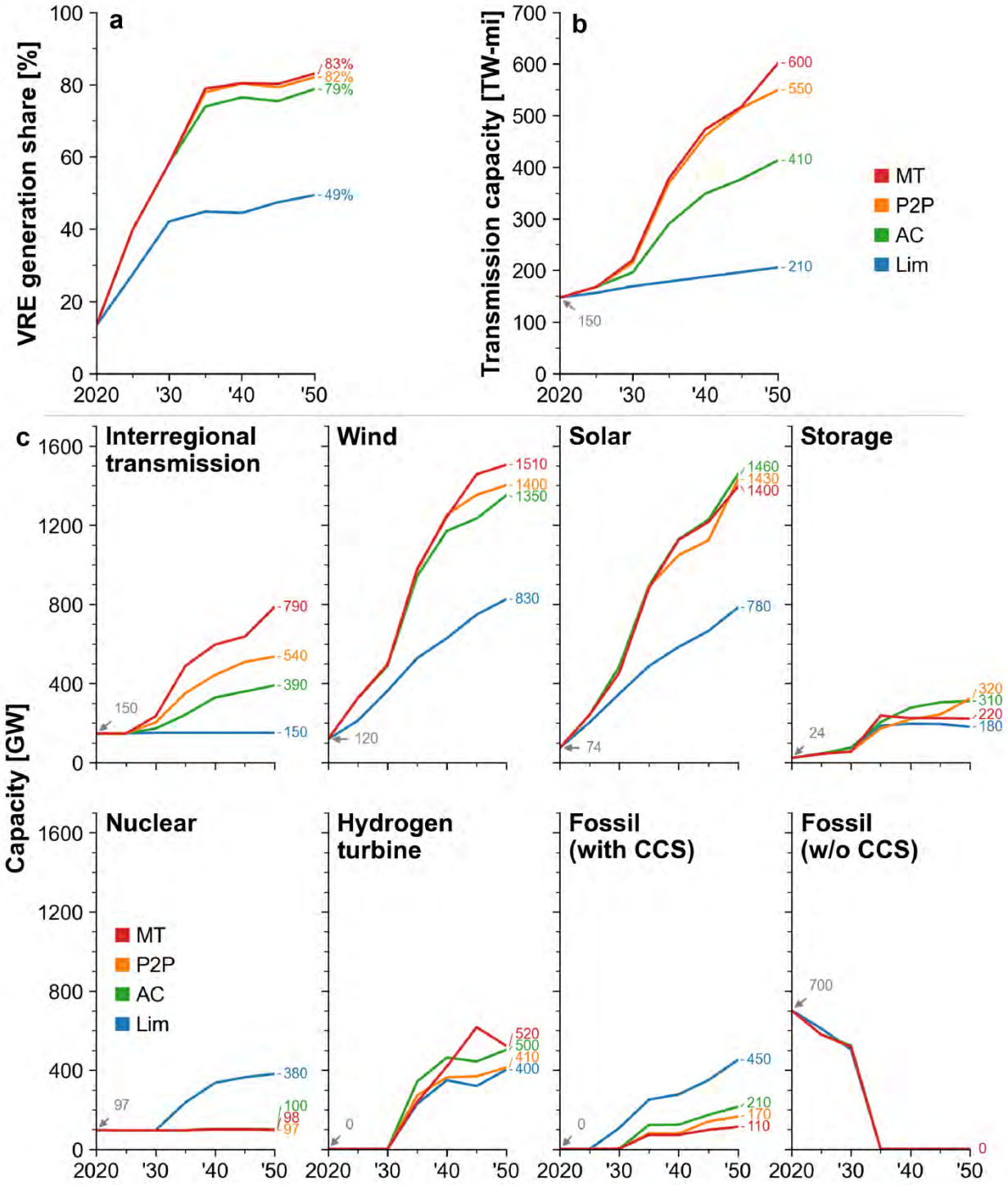


Figure D-11. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand 100% by 2035 conditions

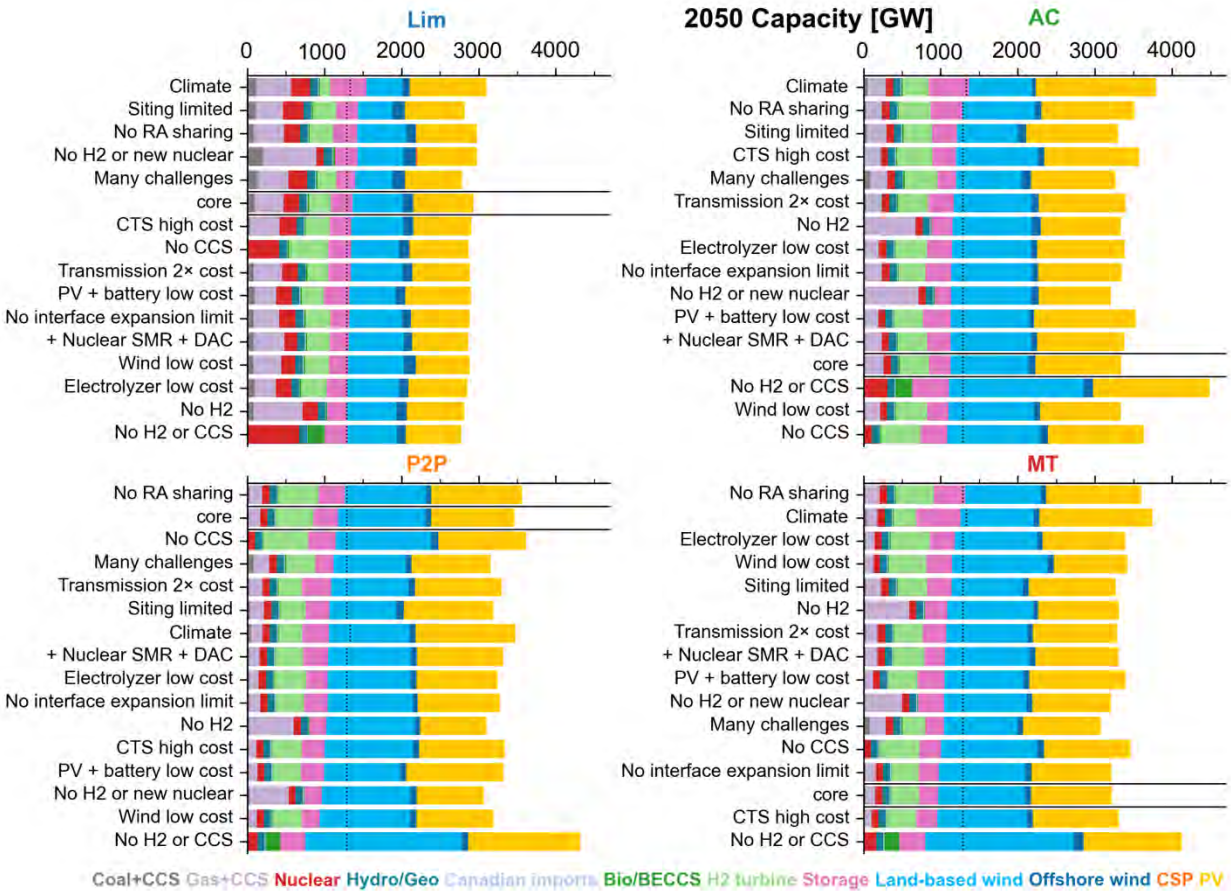


Figure D-12. National capacity mix in 2050 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

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

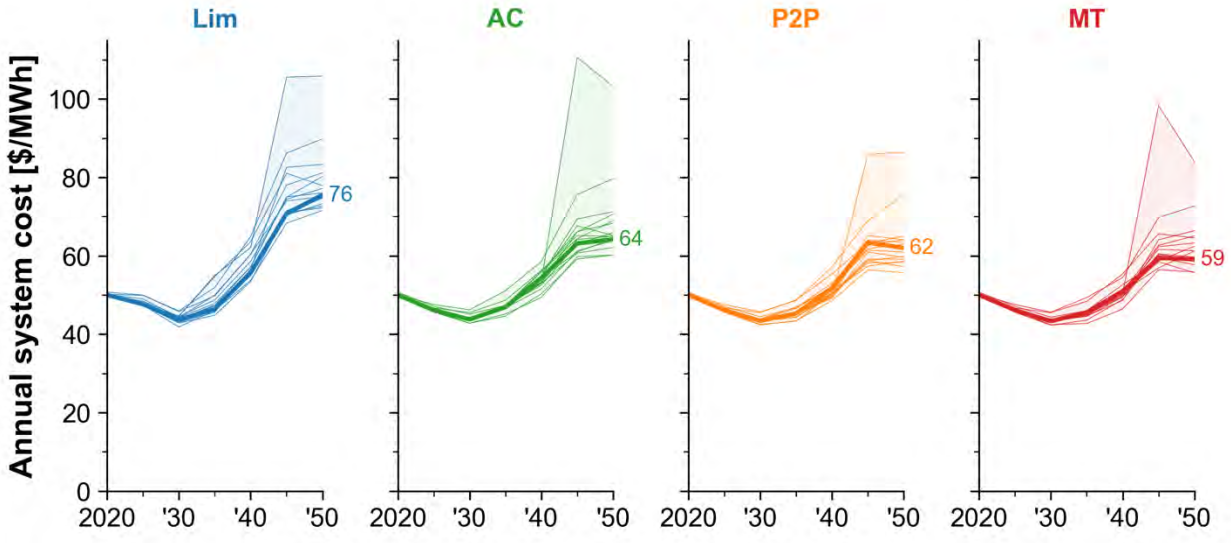


Figure D-13. Annual system cost ($/MWh) for the four transmission frameworks and all sensitivity cases under Mid-Demand 90% by 2035 conditions

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

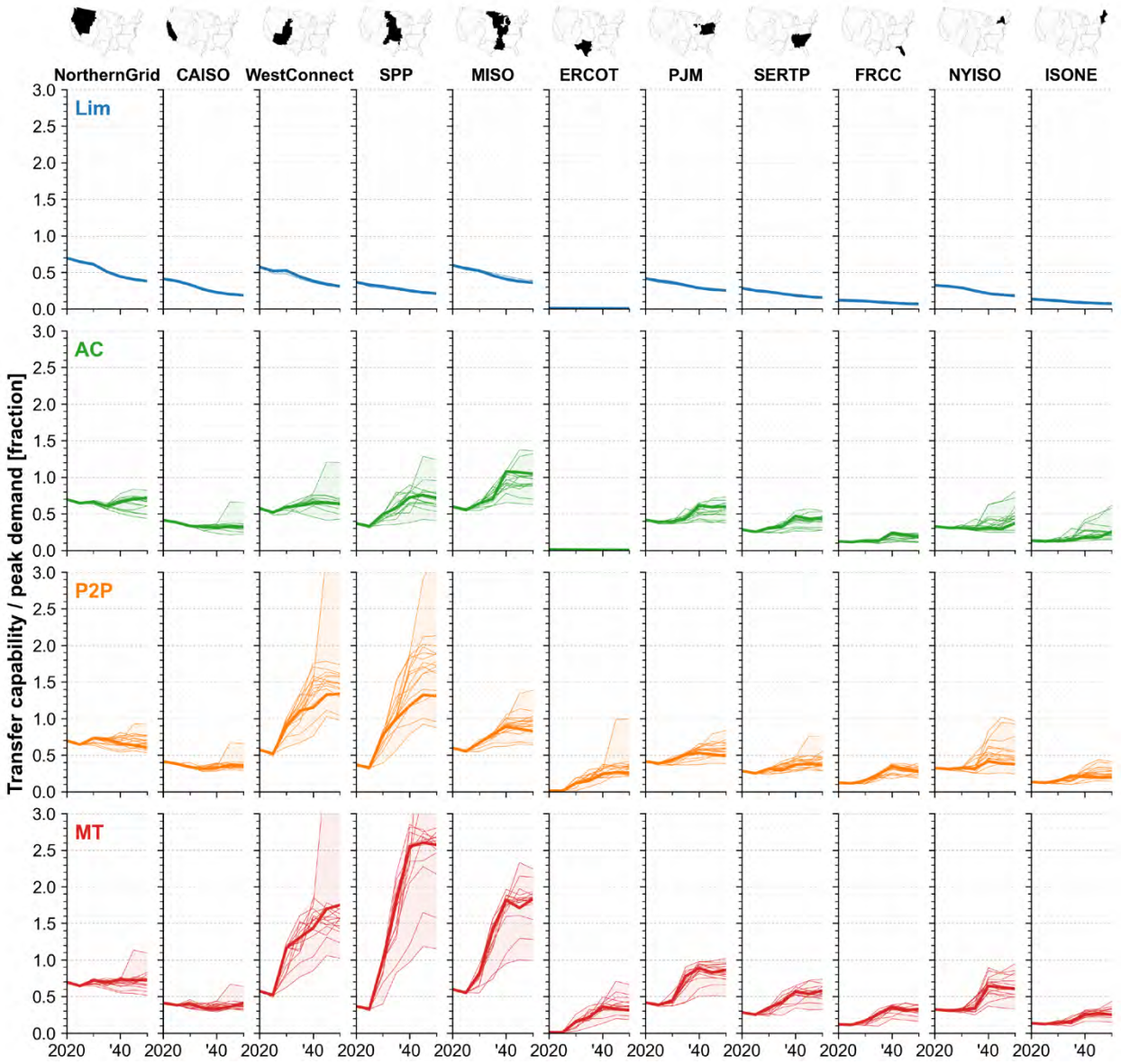


Figure D-14. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks and all sensitivity cases

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

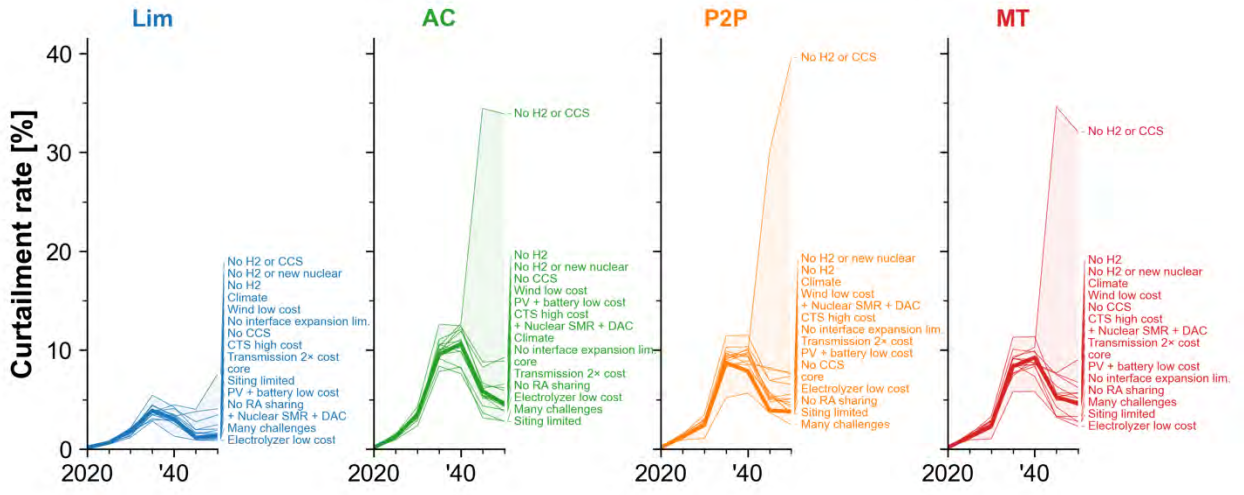


Figure D-15. National average VRE curtailment rate [$MWh_{curtailed}$ / $MWh_{available}$] with Mid-Demand 90% by 2035 assumptions for all sensitivity cases

D.3 Additional Resource Adequacy Results

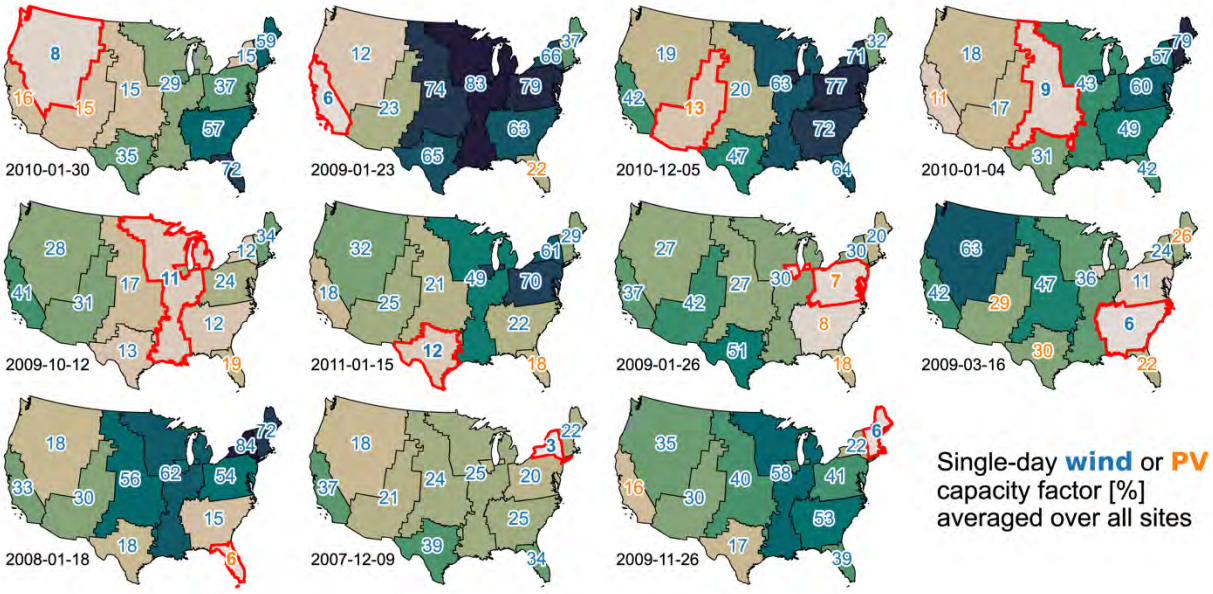


Figure D-16. Single-day wind (blue) or PV (orange) capacity factor on the least-windy/sunny day from 2007 to 2013 weather years in each planning region

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

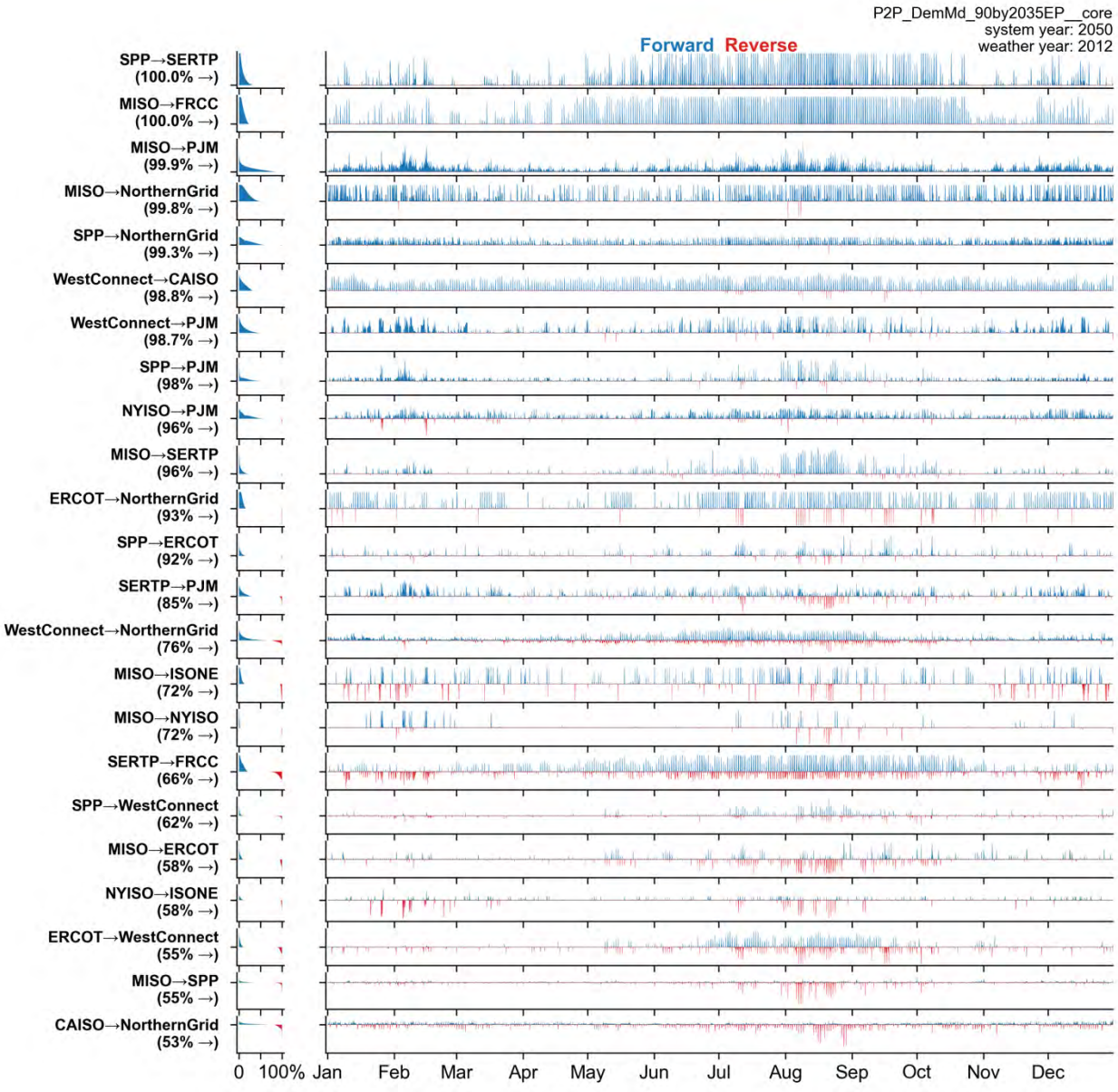


Figure D-17. Hourly interregional transmission flows for the P2P transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

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

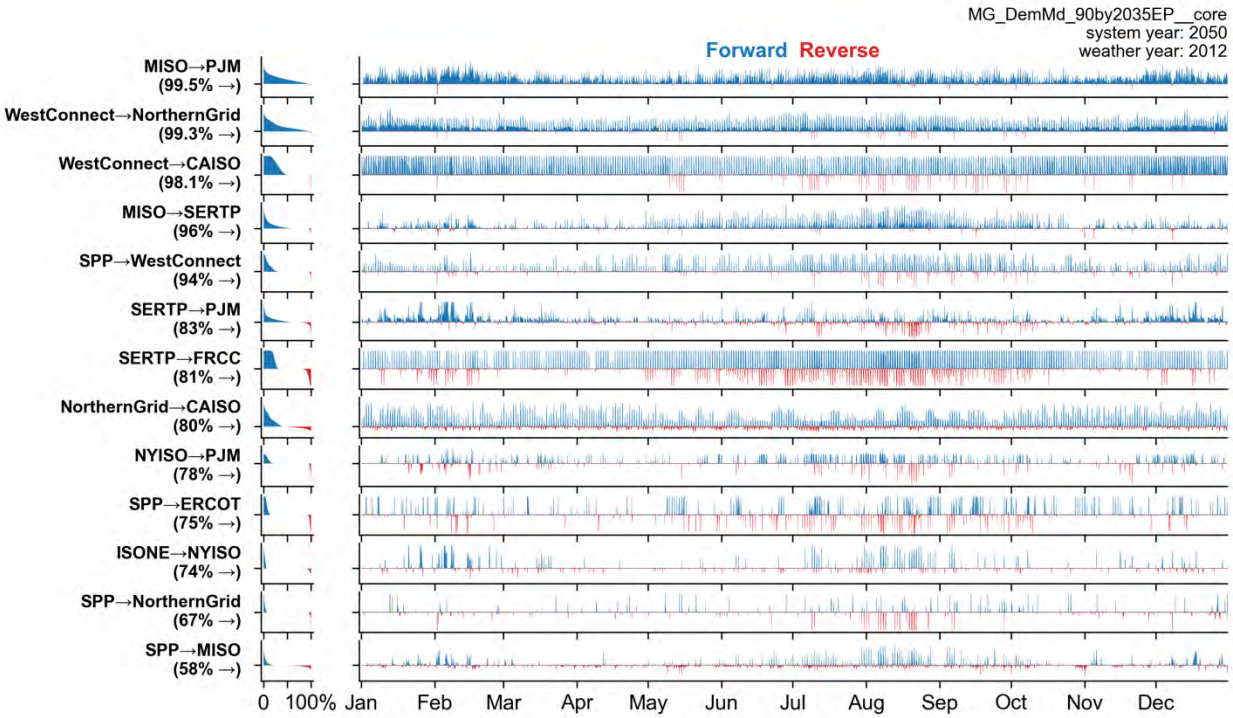


Figure D-18. Hourly interregional transmission flows for the MT transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

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

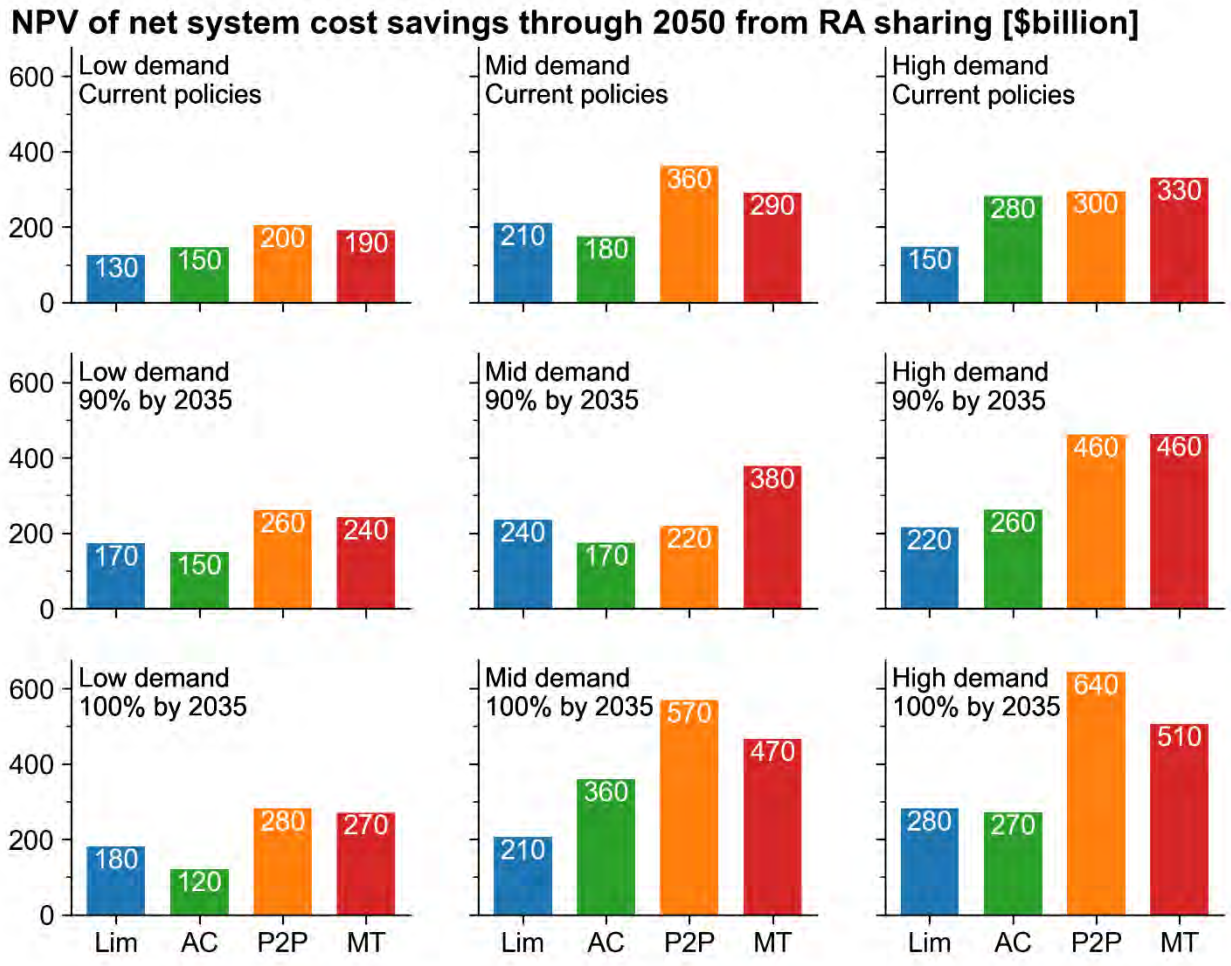


Figure D-19. Impact of the allowance of interregional RA sharing on system cost for each of the demand and emissions assumptions

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

D.4 Regional Economic Benefits

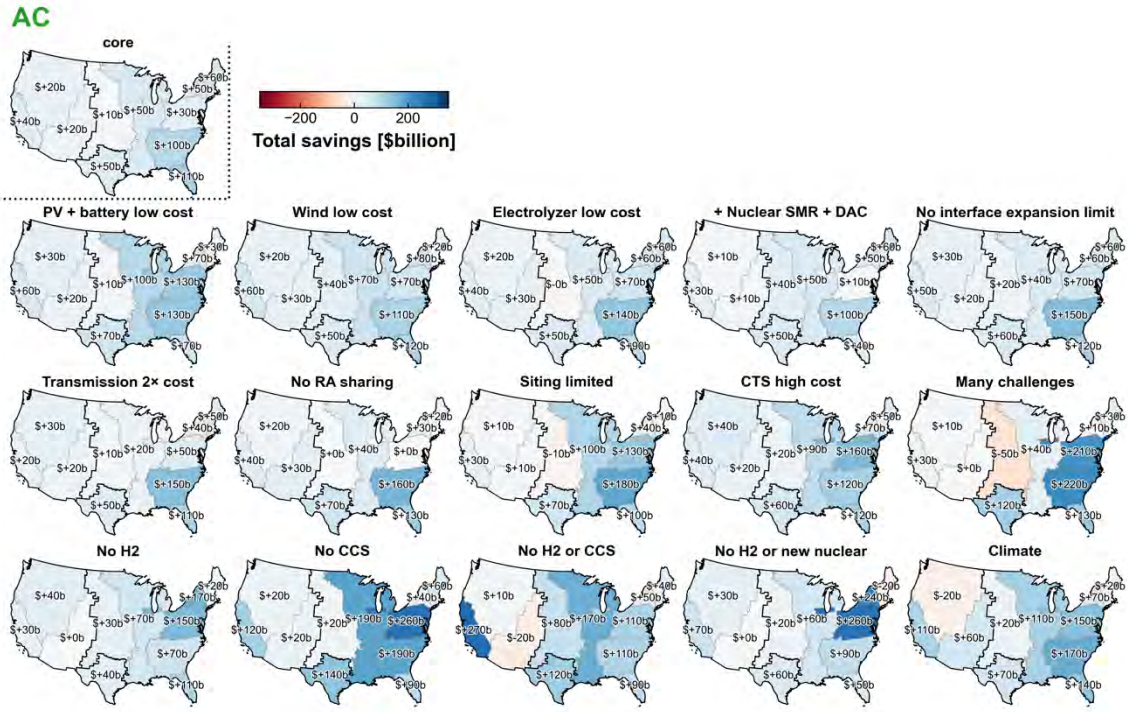


Figure D-20. Net present value of system savings in the AC transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

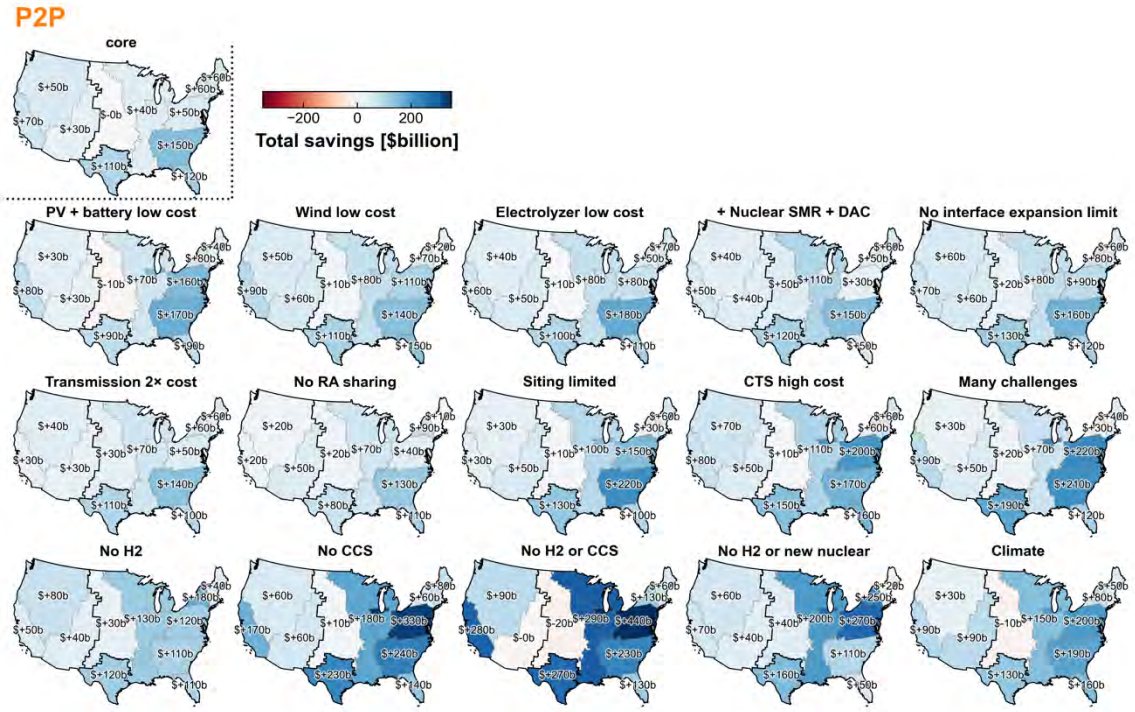


Figure D-21. Net present value of system savings in the P2P transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

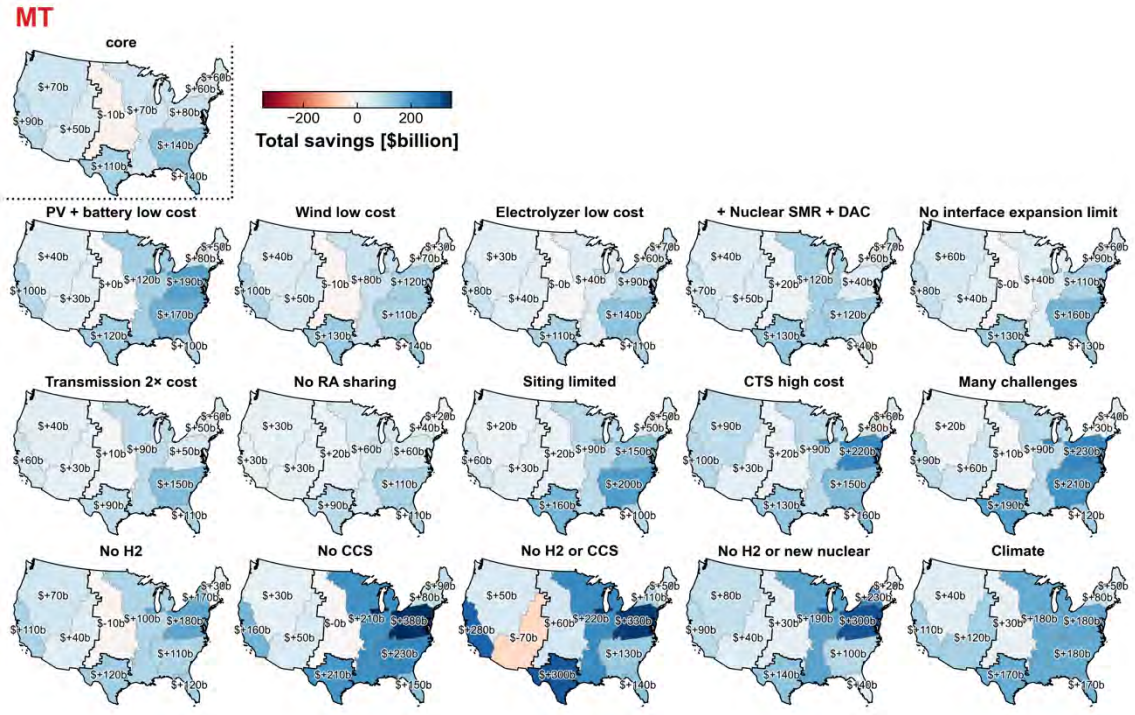


Figure D-22. Net present value of system savings in the MT transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

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

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

Appendix E. Transmission Value Analysis

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

E.1 Multivalue

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

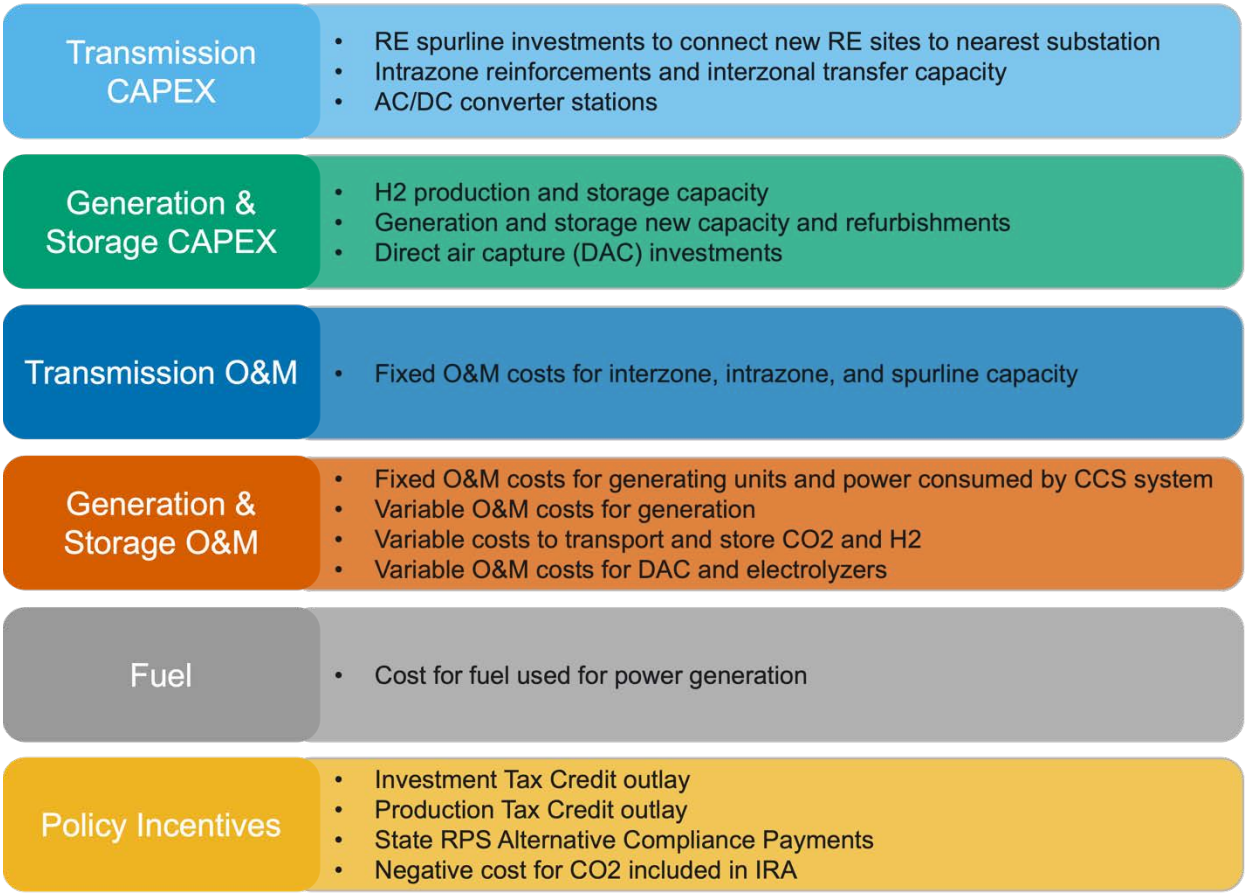


Figure E-1. System costs included in transmission valuation. Many benefits are correlated and not mutually exclusive.

E.2 System Perspective

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

E.3 Project Scope

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

E.4 Planning Horizon

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

E.5 Uncertainty

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

E.6 Regional Disaggregation: Adjusted Production Cost

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

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

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

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

where

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

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

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

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

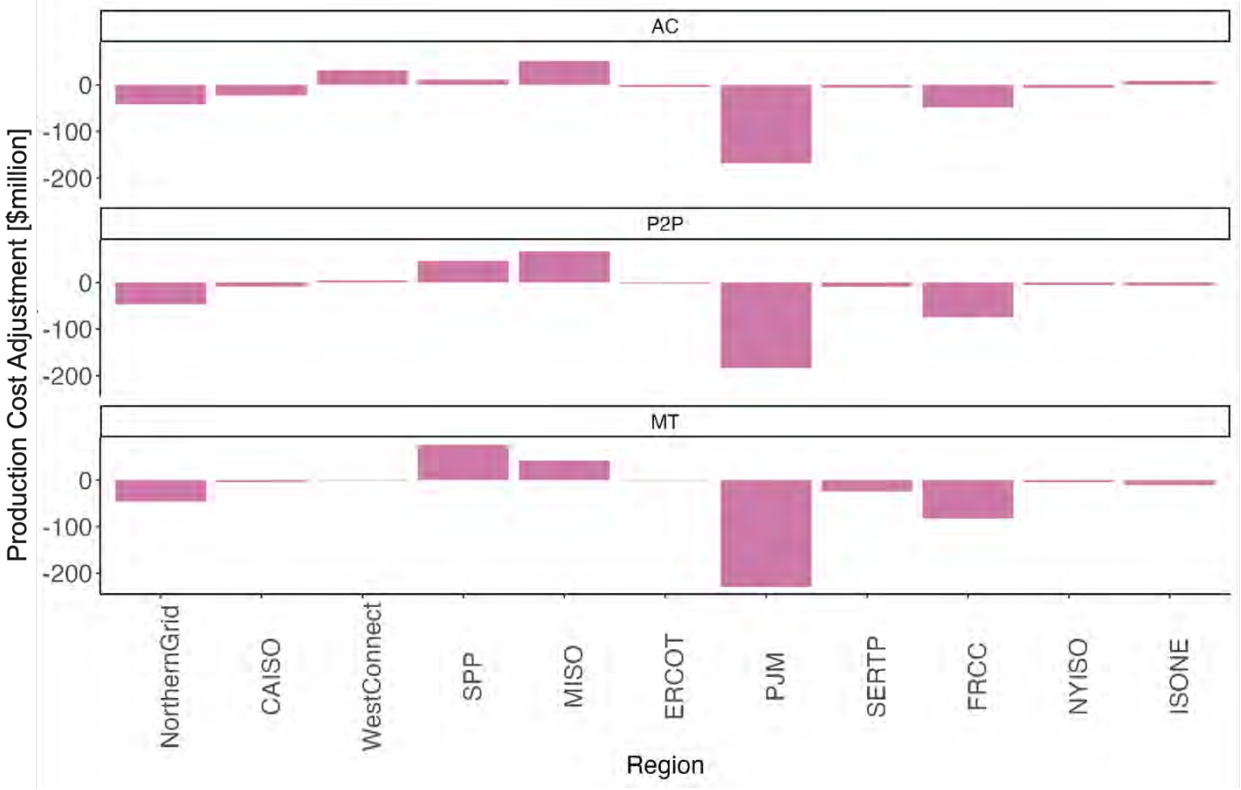


Figure E-2. Production cost adjustment for each transmission planning region and network topology for the core Mid-Demand 90% by 2035 scenarios ($million)

Appendix F. High Opportunity Transmission Interfaces: Regional Detail

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



CAISO

AC Framework

Interface Capacity (GW)

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



P2P Framework

Interface Capacity (GW)

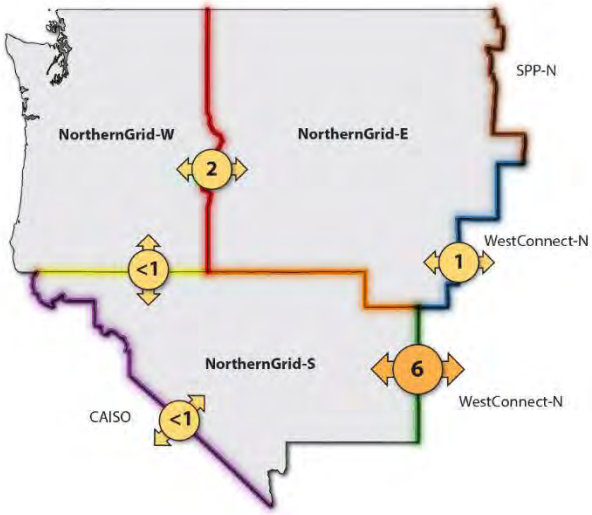
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0	0.1	0.4
West Connect S.	5.3	3.0	4.1	4.9



MT Framework

Interface Capacity (GW)

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

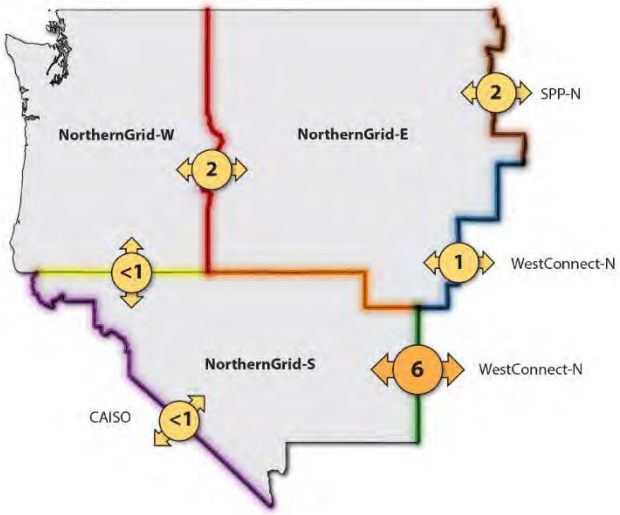


NorthernGrid

AC Framework

Interface Capacity (GW)

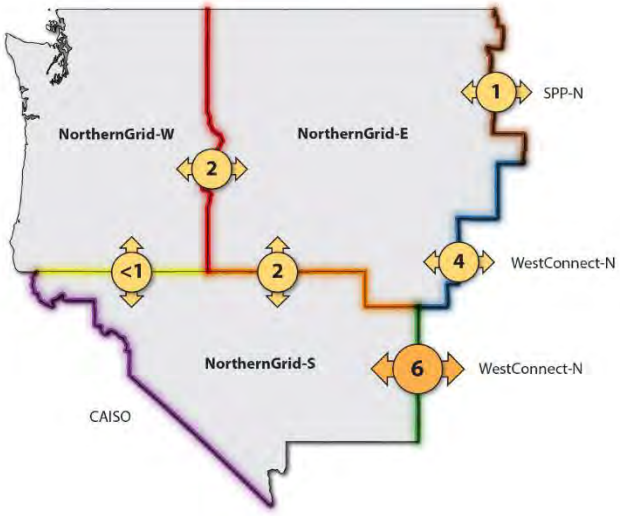
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	0	0	0
NG-E, WC-N	4.0	1.1	1.2	1.8
NG-E, NG-S	3.1	0	0	0.6
NG-W, NG-S	0.5	0.1	0.4	1.2
NG-S, WC-N	2.4	6.3	7.1	7.2
NG-S, CAISO	11	0.1	0.7	1.4



P2P Framework

Interface Capacity (GW)

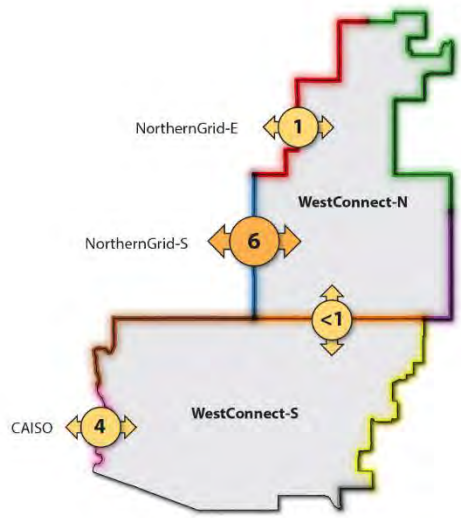
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.8	2.2	2.5
NG-E, WC-N	4.0	1.4	2.1	2.5
NG-E, NG-S	3.1	0	0	0
NG-W, NG-S	0.5	0.1	0.3	0.5
NG-S, WC-N	2.4	5.8	7.0	7.9
NG-S, CAISO	11	0.1	0.4	0.3



MT Framework

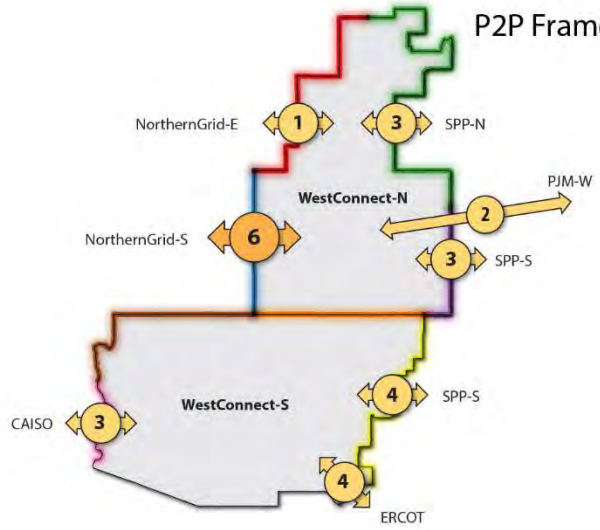
Interface Capacity (GW)

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



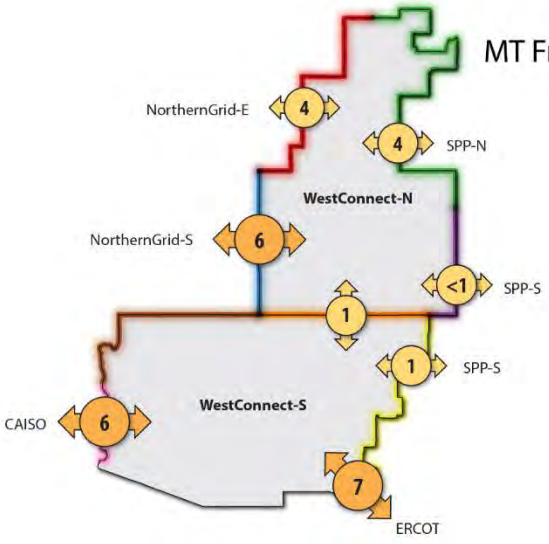
Interface Capacity (GW)

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



Interface Capacity (GW)

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

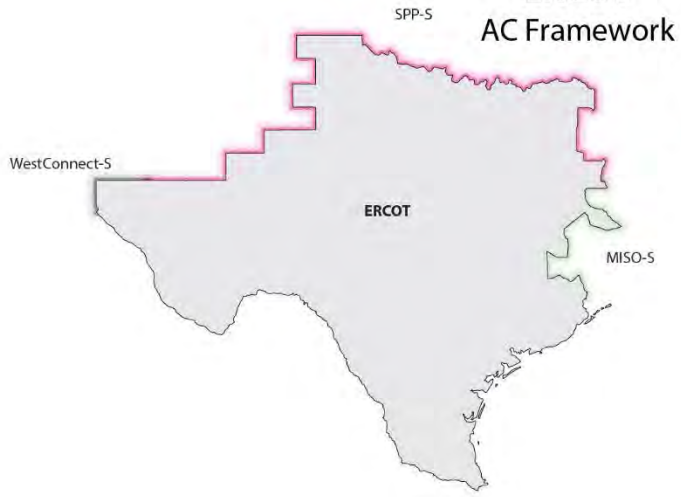


Interface Capacity (GW)

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

ERCOT

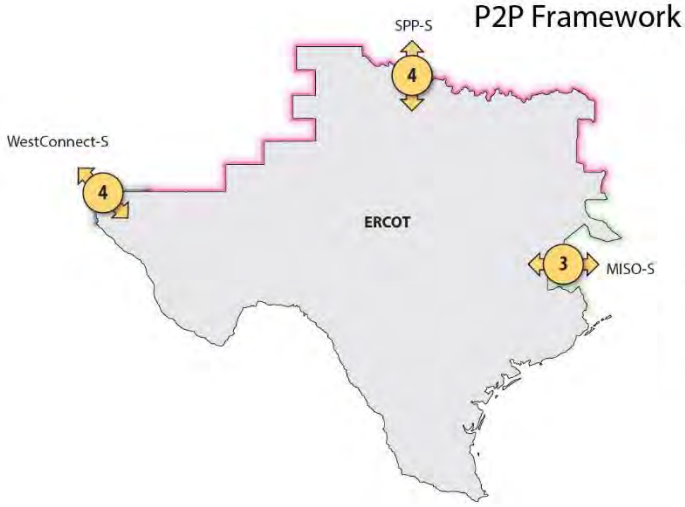
AC Framework



Interface Capacity (GW)

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

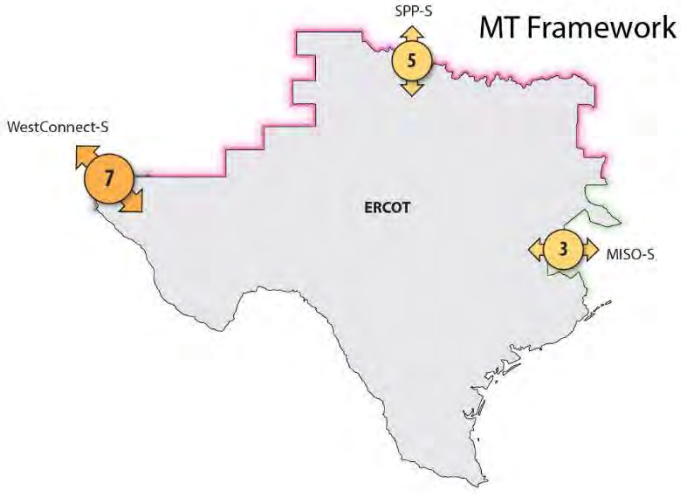
P2P Framework



Interface Capacity (GW)

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

MT Framework

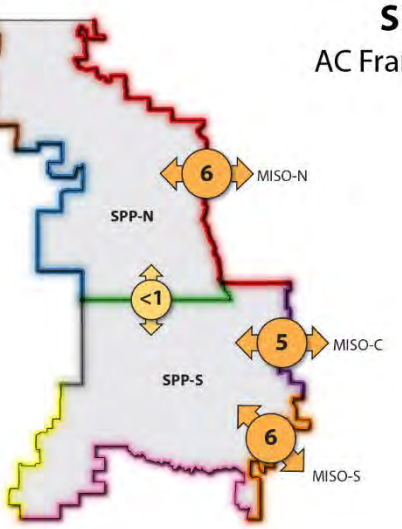


Interface Capacity (GW)

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

SPP

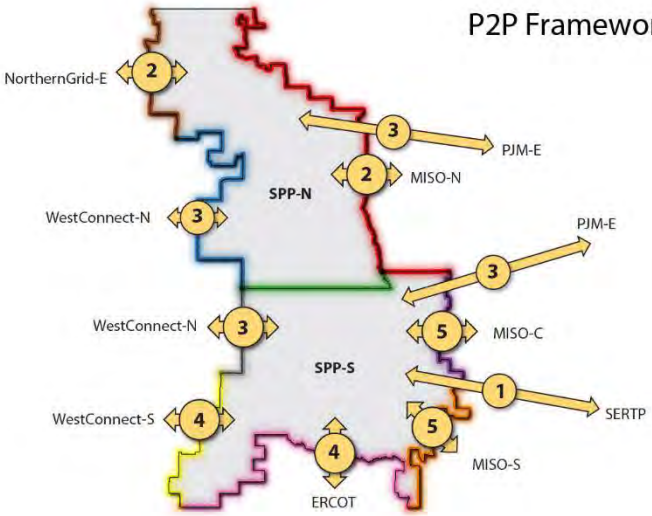
AC Framework



Interface Capacity (GW)

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

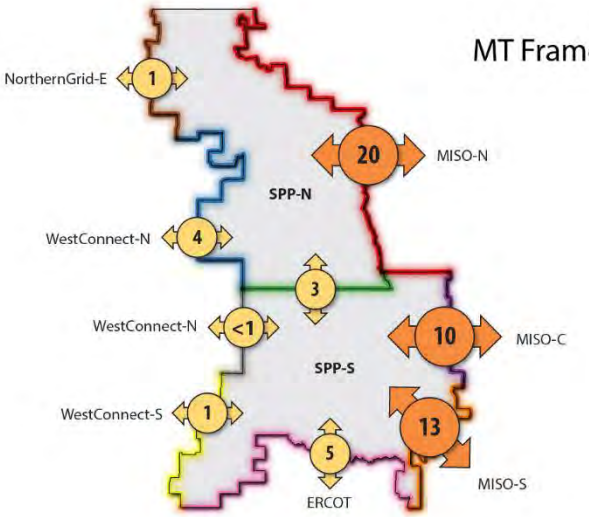
P2P Framework



Interface Capacity (GW)

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

MT Framework

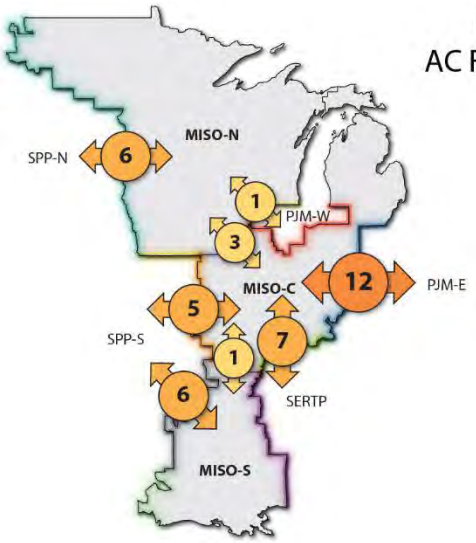


Interface Capacity (GW)

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

MISO

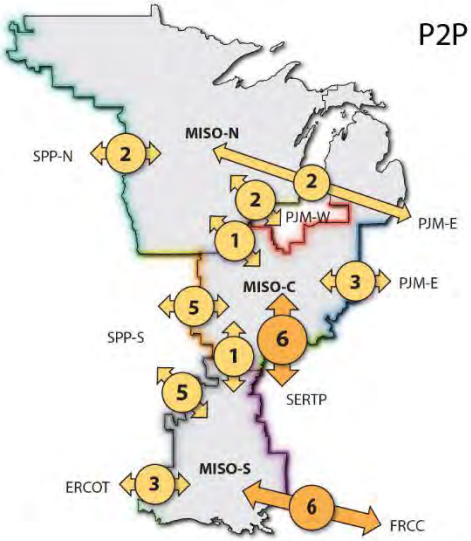
AC Framework



Interface Capacity (GW)

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

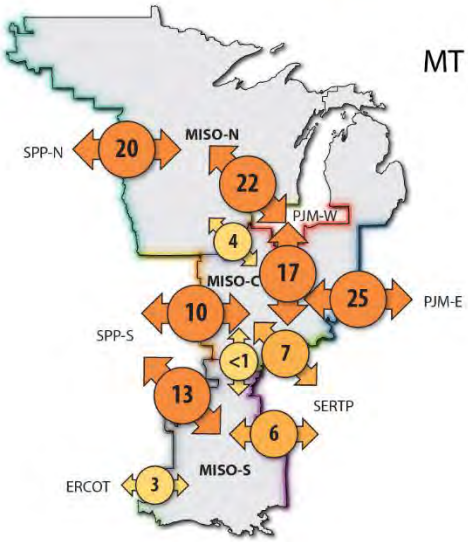
P2P Framework



Interface Capacity (GW)

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

MT Framework

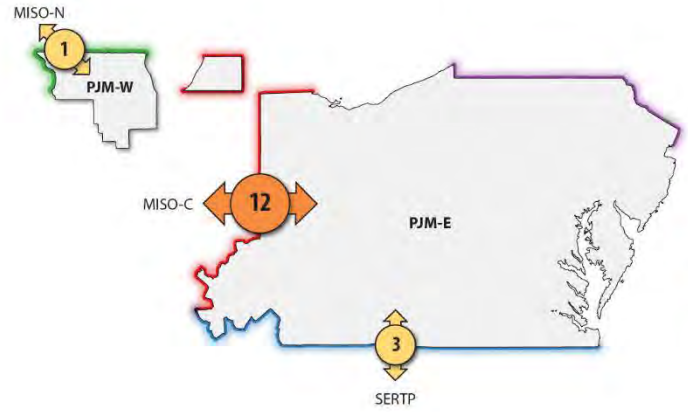


Interface Capacity (GW)

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

PJM

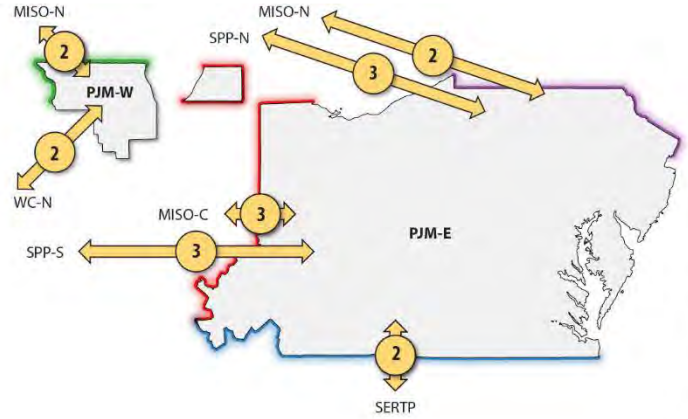
AC Framework



Interface Capacity (GW)

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

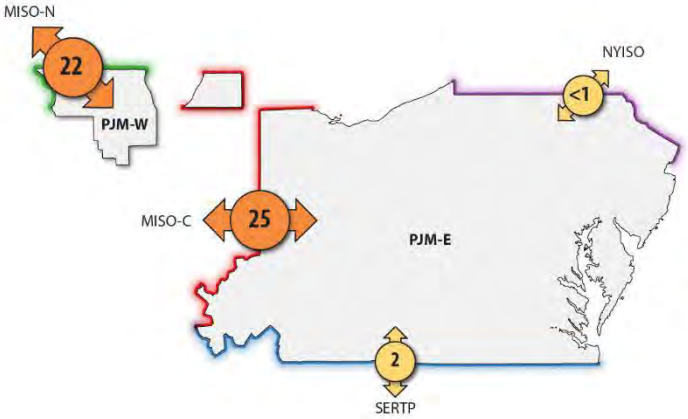
P2P Framework



Interface Capacity (GW)

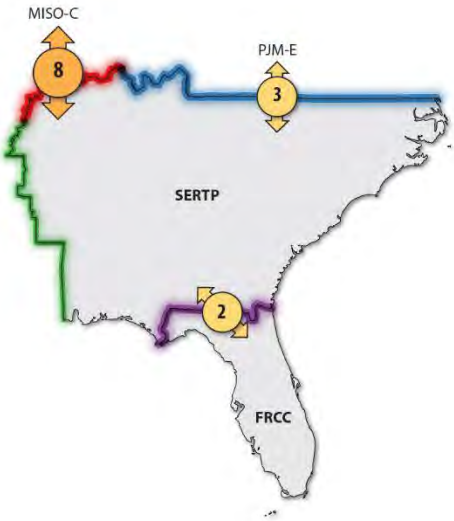
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.5	2.0	3.4
PJM-E, MISO-C	28.3	2.6	4.7	7.9
PJM-E, SERTP	10.9	2.2	5.0	6.3
PJM-E, NYISO	6.6	0	0	0
Nonadjacent Region Interfaces				
PJM-E, MISO-N	0	2.0	4.4	7.1
PJM-E, SPP-N	0	3.4	5.2	10.0
PJM-E, SPP-S	0	3.3	4.7	7.1
PJM-W, WC-N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

MT Framework



Interface Capacity (GW)

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

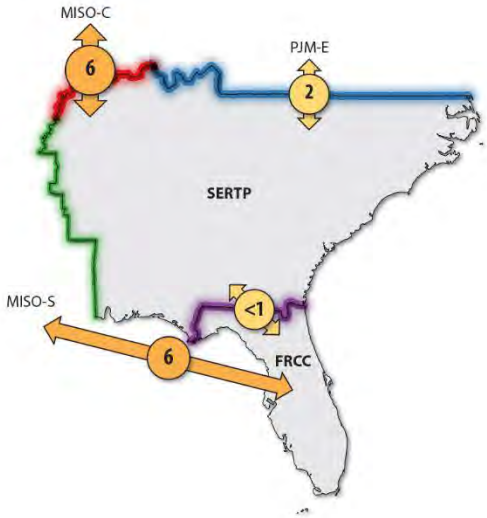


SERTP & FRCC

AC Framework

Interface Capacity (GW)

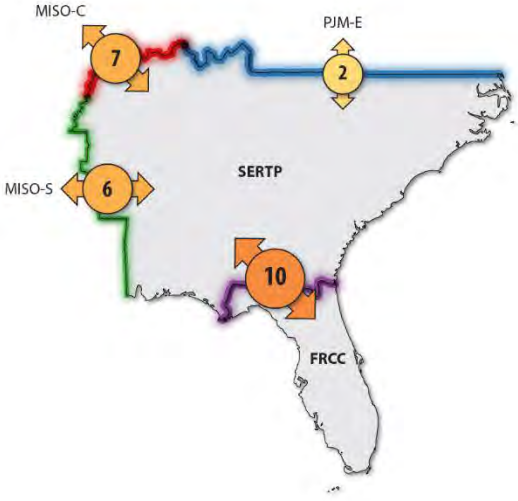
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.5	10.1	12.2
SERTP, PJM-E	10.9	3.2	6.8	7.4
SERTP, MISO-S	11.0	0	0	0.1
SERTP, FRCC	6.6	1.9	2.3	2.6



P2P Framework

Interface Capacity (GW)

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



MT Framework

Interface Capacity (GW)

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

NYISO & ISONE

AC Framework



Interface Capacity (GW)

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

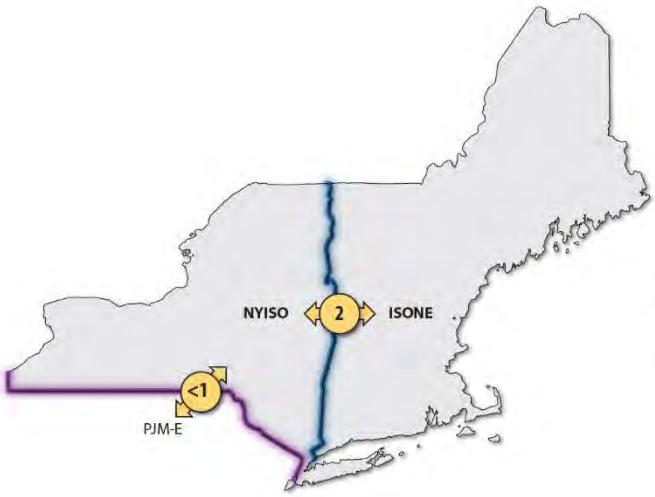
P2P Framework



Interface Capacity (GW)

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

MT Framework



Interface Capacity (GW)

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







GDO
GRID DEPLOYMENT OFFICE

DOE/GO-102024-6258 | October 2024

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 66
NERC 2024 Interregional Transfer Capability Study, Part 1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interregional Transfer Capability Study (ITCS)

Strengthening Reliability Through the Energy Transformation

Transfer Capability Analysis (Part 1)

August 2024

RELIABILITY | RESILIENCE | SECURITY






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

Table of Contents

Preface iii

Statement of Purpose iv

Executive Summary v

- Key Observations v
- A Complex Grid v
- Study Need v
- Significance of Transfer Capability vi
- Holistic Approach to Transfer Capability vi
- Limitations of Transfer Capability vii
- Transfer Capability Analysis (Part 1) Summary viii
- Stakeholder Engagement and Reporting x

Chapter 1: Part 1 Study Process Details 1

- Transmission Planning Regions 1
- Total Transfer Capability 2
- Base Case Development 2
- Contingencies 3
- Monitored Facilities and Thresholds 3
- Modeling of Transfer Participation 4
- Special Interface Considerations 4
- Study Results 4

Chapter 2: Western Interconnection Results 6

Chapter 3: Western – Eastern Interconnection Results 15

Chapter 4: ERCOT – Eastern Interconnection Results 19

Chapter 5: Eastern Interconnection Results 22

Chapter 6: Québec – Eastern Interconnection Results 43

Chapter 7: Supplemental Results Between Order 1000 Areas 46

Chapter 8: Supplemental Total Import Interface Limits 51

Chapter 9: Acknowledgements 65

Appendix A: Key Study Opportunities 66

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.

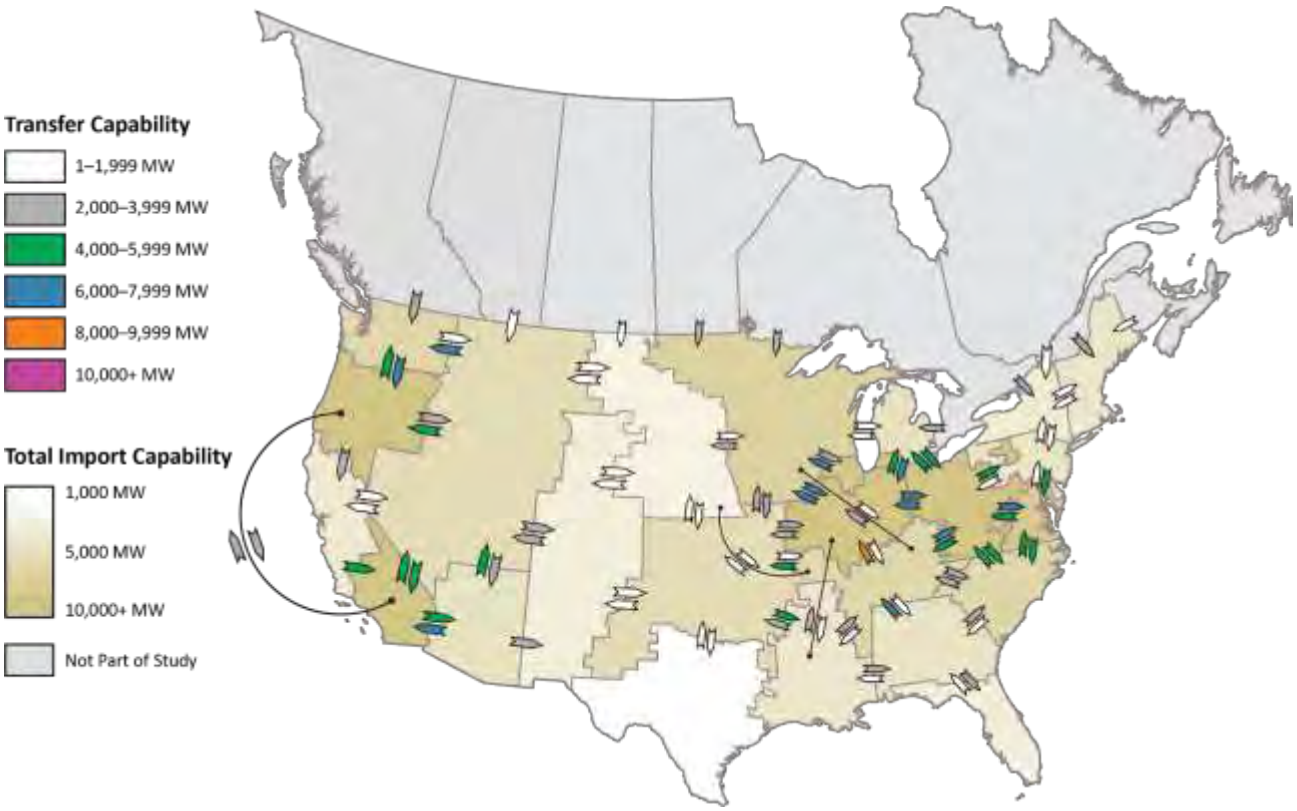


Figure ES.1: Transfer Capabilities (Summer)

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

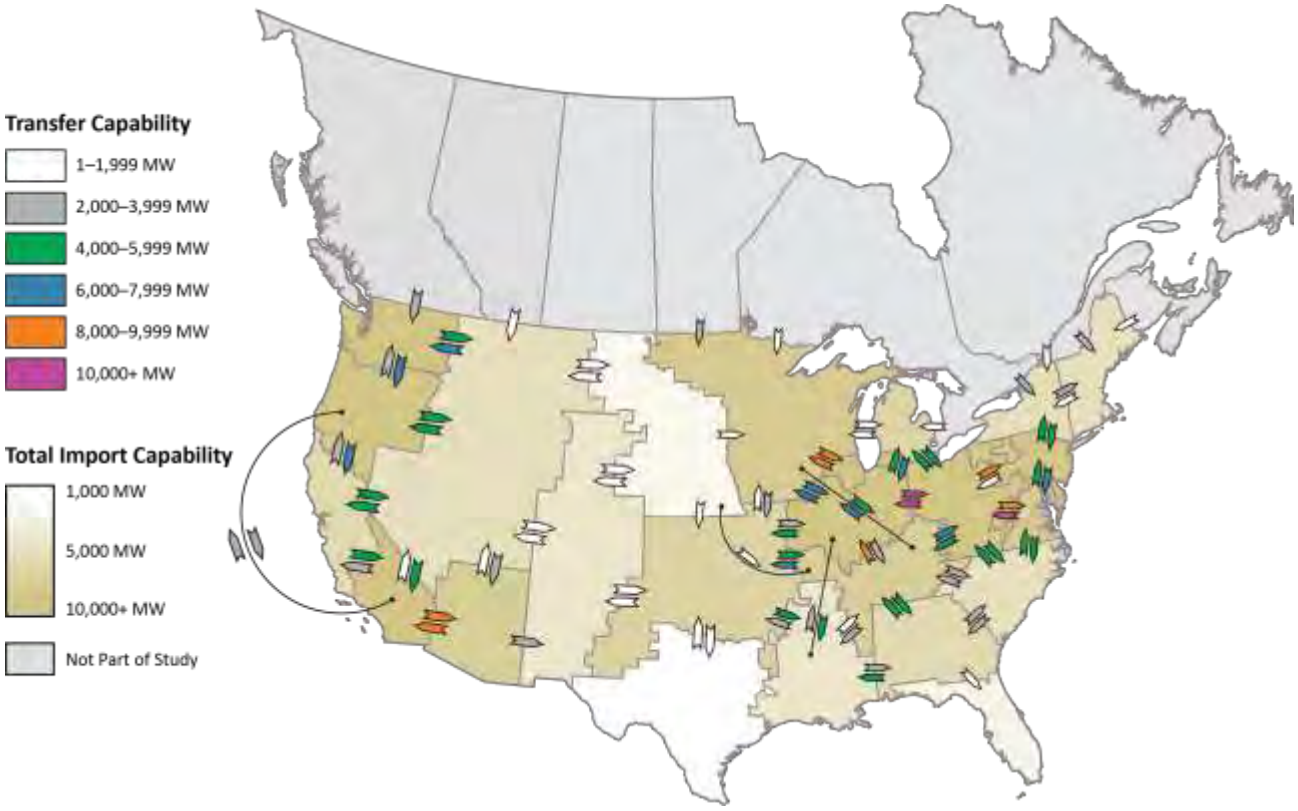


Figure ES.2: Transfer Capabilities (Winter)

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.

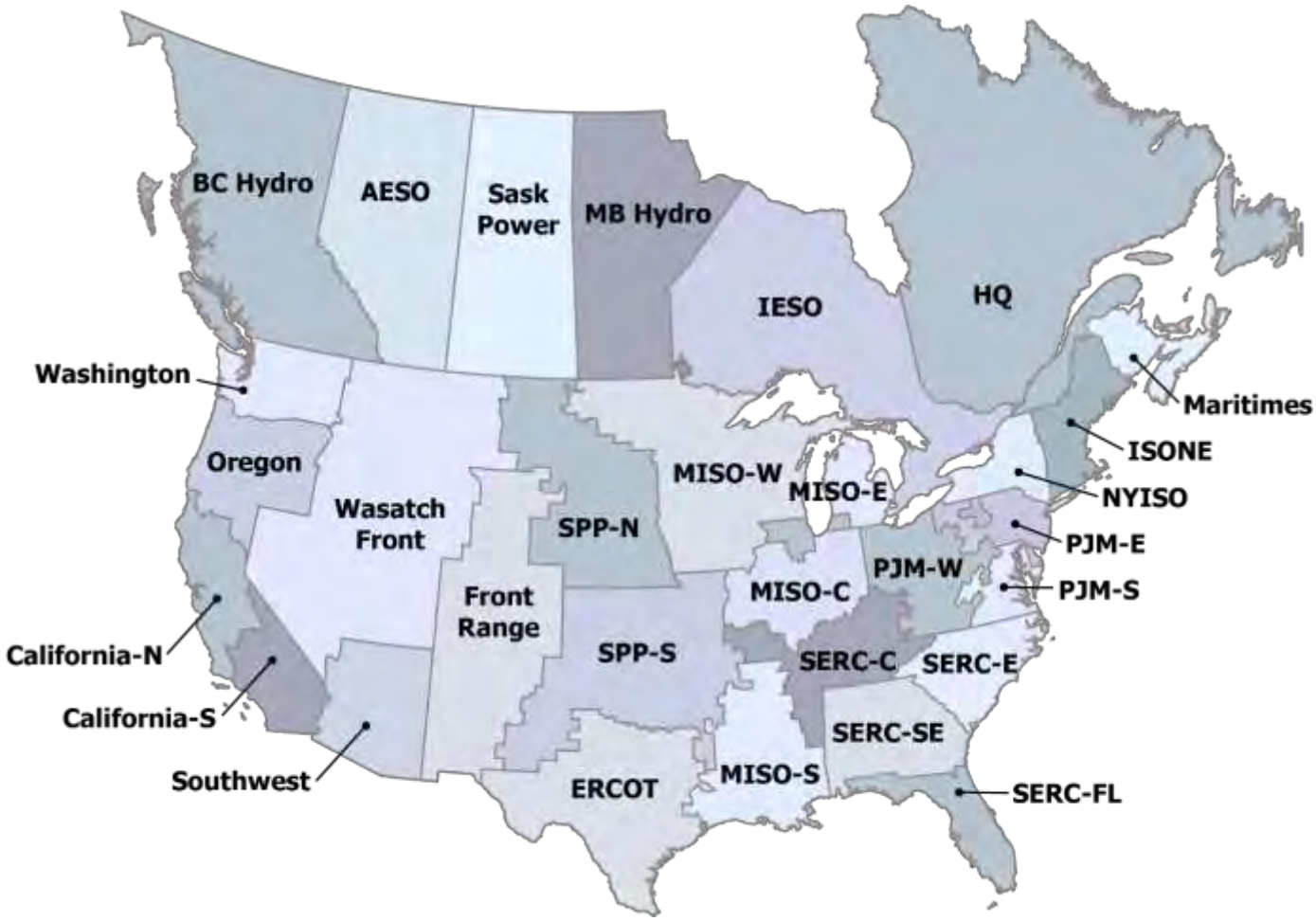


Figure 1.1: Transmission Planning Regions

[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)

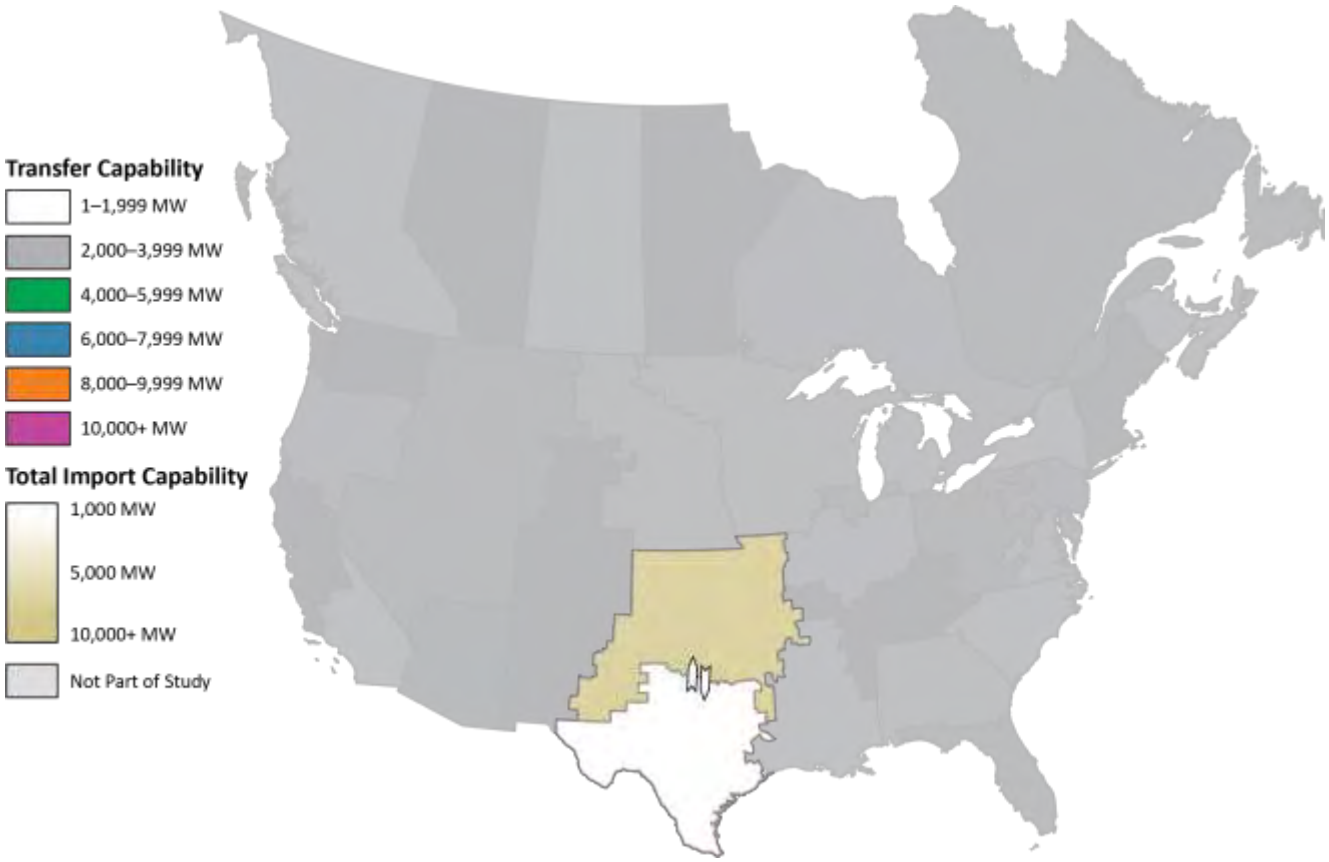


Figure 4.2: Transfer Capability Between ERCOT and Eastern Interconnections (Winter)

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.

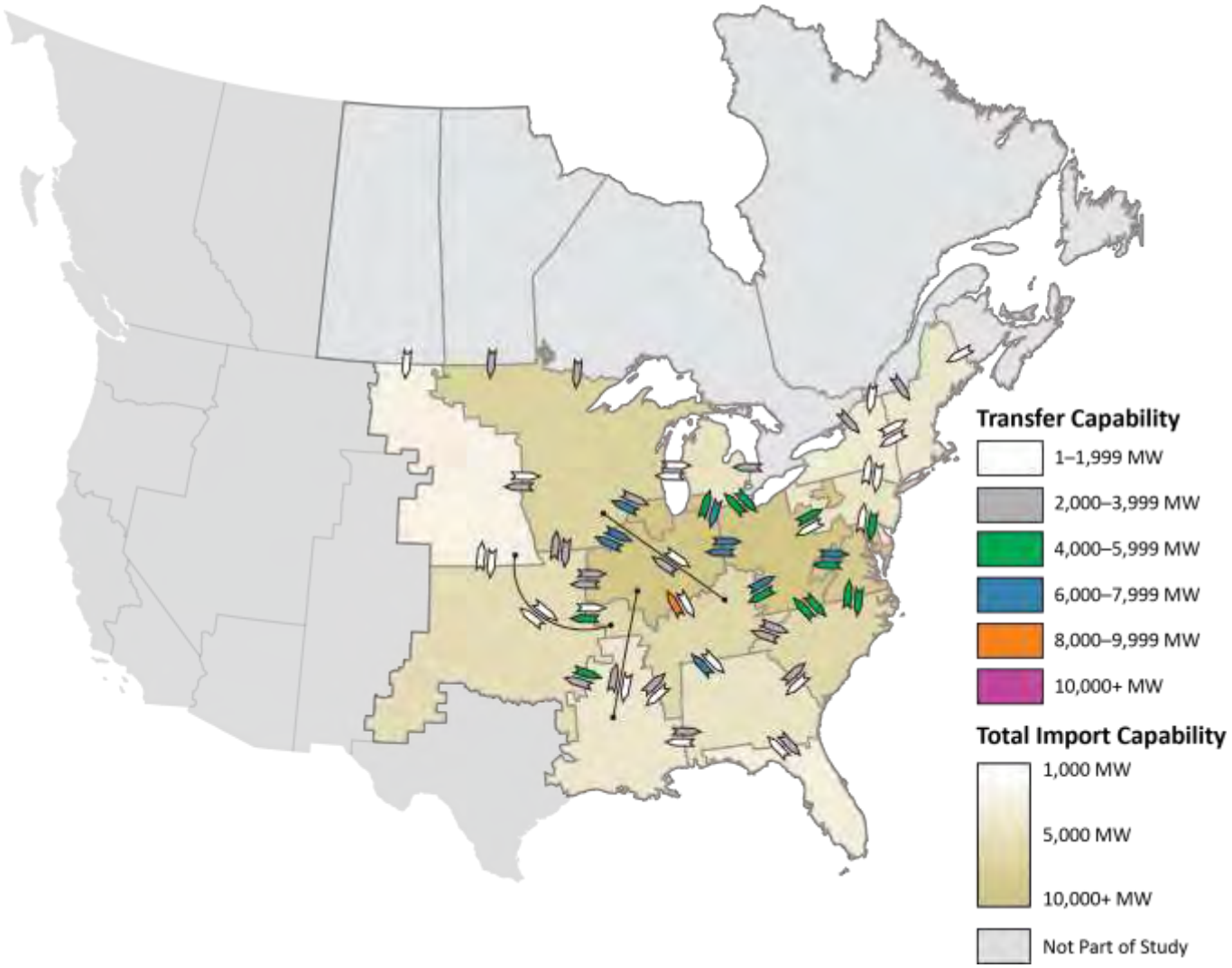


Figure 5.1: Transfer Capabilities of Eastern Interconnection Interfaces (Summer)

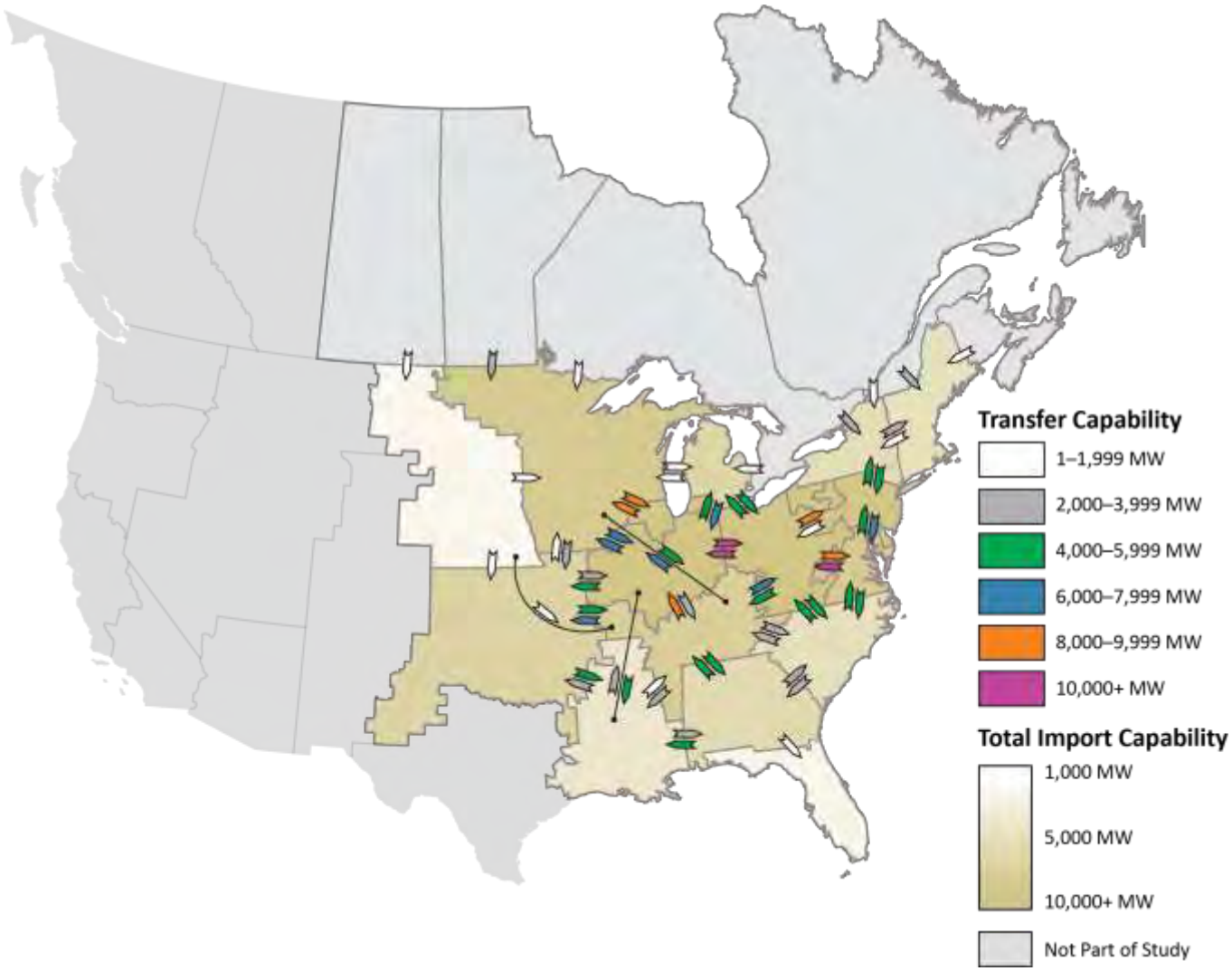


Figure 5.2: Transfer Capabilities of Eastern Interconnection Interfaces (Winter)

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

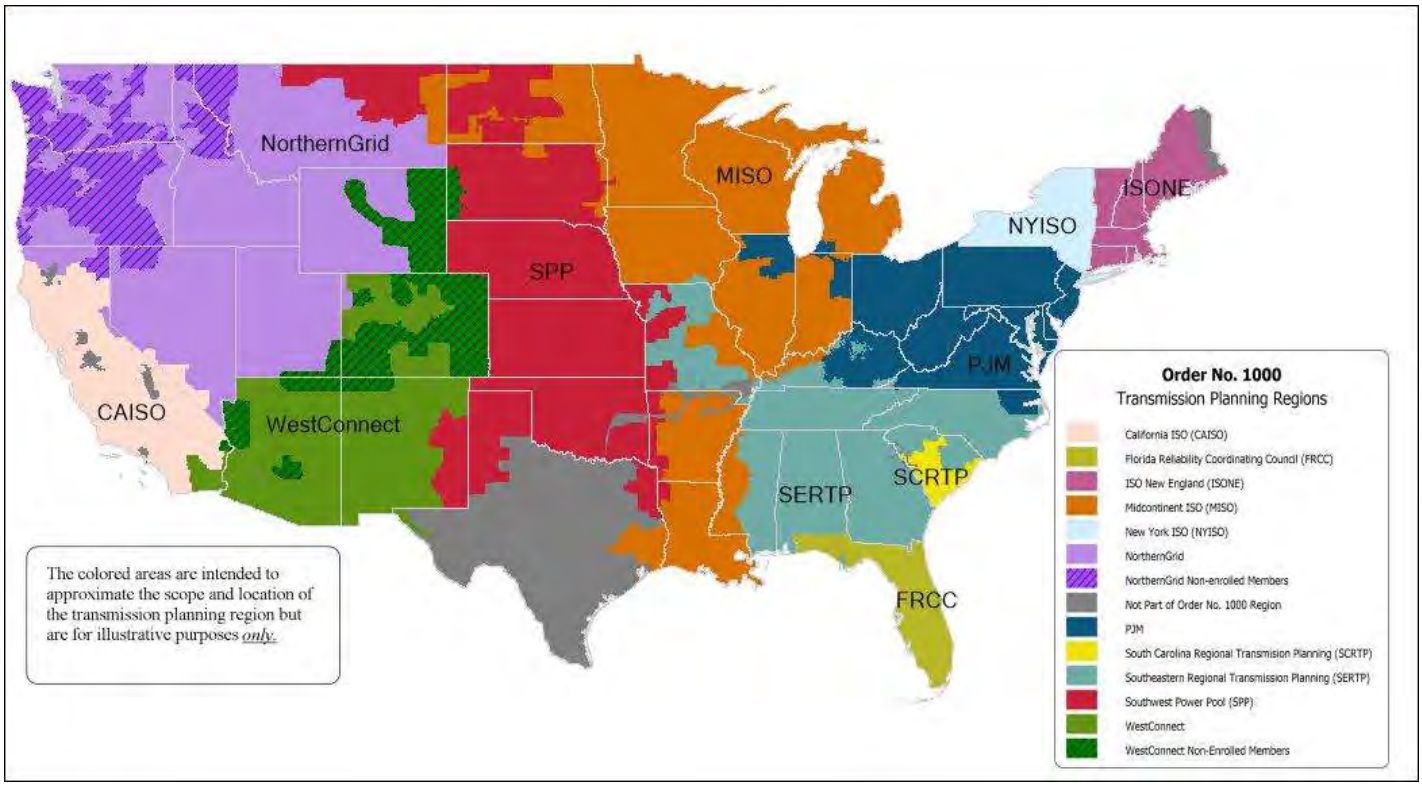


Figure 7.1: Areas Defined in FERC Order 1000

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

NERC appreciates the people across the industry who provided technical support and identified areas for improvement throughout the ongoing ITCS project.

NERC Industry Group Acknowledgements	
Group	**Members**
ITCS Executive Committee	Dave Angell (NERC), Richard Burt (MRO), Charles Dickerson (NPCC), Tim Gallagher (RF), Fritz Hirst (NERC), Robert Kondziolka (NERC), Mark Lauby (NERC), Gary Leidich (NERC), Kimberly Mielcarek (NERC), Tim Ponseti (SERC), Sonia Rocha (NERC), Branden Sudduth (WECC), Joseph Younger (Texas RE)
ITCS Advisory Group	Gabriel Adam (IESO), Aaron Berner (PJM), Adria Brooks (DOE), Daniel Brooks (EPRI), Jessica Cockrell (FERC), Vandan Divatia (Eversource), Edison Elizeh (BPA), Vincent Fihey (Hydro Québec), Greg Ford (Georgia System Operations), Tom Galloway (NATF), Jeffrey Gindling (Duke Energy Midwest), Prabhu Gnanam (ERCOT), Biju Gopi (California ISO), Wayne Guttormson (SaskPower), Hassan Hayat (AEP), Matt Holtz (Invenergy), Larre Hozempa (FirstEnergy), Faheem Ibrahim (ISO New England), David Jacobson (Manitoba Hydro), Aubrey Johnson (MISO), David Kelley (SPP), Brett Kruse (Calpine), Darryl Lawrence (Pennsylvania Office of Consumer Advocate), Charles Long (Entergy), Chelsea Loomis (Northern Grid), Thanh Luong (FERC), Charles Marshall (ITC), Daryl McGee (Southern), Gayle Nansel (WAPA), Heidi Pacini (WestConnect), Colton Pankhurst (Natural Resources Canada), Nate Schweighart (TVA), Zachary Smith (NYISO), Lance Spross (ONCOR), Aidan Tuohy (EPRI), John Twitty (MJMEUC), Miguel Yanes (FP&L)
ITCS Transfer Study Team	Salva Andiappan (MRO), Diana Barsotti (NPCC), Kent Bolton (WECC), Edwin Cano (PowerGem), Bryan Clark (MRO), Vic Howell (WECC), John Idzior (RF), Marilyn Jayachandran (NERC), Gaurav Karandikar (SERC), Neeraj Lal (NPCC), Matthew A. Lewis (NERC), Saad Malik (NERC), Shirley Matthew (Texas RE), Melinda Montgomery (SERC), John Moura (NERC), Manos Obessis (PowerGem), Mohamed Osman (NERC), Shayan Rizvi (NPCC), Kevin Sherd (NERC), Paul Simoneaux (SERC), Doug Tucker (WECC), Dianlong Wang (MRO), Brad Woods (Texas RE)
ITCS SAMA Team (Scenarios, Assumptions, Metrics, and Adequacy)	Salva Andiappan (MRO), Diana Barsotti (NPCC), Richard Becker (SERC), Kent Bolton (WECC), Ryan Deyoe (Telos Energy), Matthew Elkins (WECC), Johnny Gest (RF), Vic Howell (WECC), Marilyn Jayachandran (NERC), Bill Lamanna (NERC), Matthew A Lewis (NERC), Saad Malik (NERC), William Martin (NERC), Shirley Mathew (Texas RE), John Moura (NERC), Jack Norris (NERC), Mark Olson (NERC), Mohamed Osman (NERC), Matt Richwine (Telos Energy), Katie Rogers (WECC), Martin Sas (SERC), Kevin Sherd (NERC), Matthew Shirley (Texas RE), Paul Simoneaux (SERC), Derek Stenclik (Telos Energy), Jim Uhrin (RF), Mike Welch (Telos Energy), Brad Woods (Texas RE)
ITCS Report Writing Team	Diana Barsotti (NPCC), Candice Castaneda (NERC), Bryan Clark (MRO), Mark Henry (Texas RE), Saad Malik (NERC), Stony Martin (SERC), Kevin Sherd (NERC), Robert Tallman (NERC), Jim Uhrin (RF), Brad Woods (Texas RE)

Appendix A: Key Study Opportunities

Observation 1: There is an opportunity to develop guidance for subdividing large areas and standardizing data sources for future studies.
One challenge was selecting appropriately sized and electrically connected TPRs. It is essential to strike the right balance to identify significant limitations of interregional transfers. As the BPS evolves, these TPRs should be reviewed and modified as appropriate. In a few instances where Balancing Authorities are split into multiple TPRs, there are opportunities to enhance available data to more efficiently account for each TPR, improving the data quality in future studies.

Observation 2: There is an opportunity to improve coordination with NERC's Long-Term Reliability Assessment (LTRA) process.
Some differences in load forecasts and resource assumptions were noted when comparing study cases to LTRA data. Standardizing case-building processes and associated content could ensure consistency and improve the efficiency of future studies.

Observation 3: Future studies may need special cases to study additional conditions.
This transfer analysis used cases designed for transmission planning assessments.[48] This study revealed a potential need to develop additional cases, such as to study heavy transfers in both directions of an interface.

Observation 4: Future studies should include stability analysis.
Part 1 studies included power flow analysis, voltage screening, and known stability limits. Future studies should include more expansive stability analysis to identify potentially more restrictive limits, especially because stability limitations can become more prominent when there is increased reliance on heavy transfers across large areas.

Observation 5: A future study evaluation schedule is needed.
The study results are highly dependent on the point-in-time information used to develop the cases. Since generation construction and retirement, transmission expansion plans, and load forecasts are constantly evolving, it would be beneficial to repeat this transfer analysis on a regular basis. Further, given the long lead time required for transmission additions, consideration should be given to future study horizons.[49]

[48] For example, TPL-001-5 (nerc.com)
[49] The study horizon for ITCS Part 2 is 2024 and 2033.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 67
CenterPoint Indiana 2025 Winter Reliability Presentation







2025 Winter Reliability Forum

December 2, 2025

CenterPoint® Energy

Presenters



Mike Roeder
President
Indiana Region



Shane Bradford
Vice President
Indiana Electric



Gregg Maurer
Vice President
Indiana Gas

CenterPoint Executive Summary

- CenterPoint Energy is committed to **Community Affordability Initiatives** for our customers
- CenterPoint Energy is prepared to meet the **energy needs** of our customers this winter
- Natural gas supplies are **affordable** and **reliable**





Indiana Service Territories

Indiana Natural Gas Distribution

More than

778,000

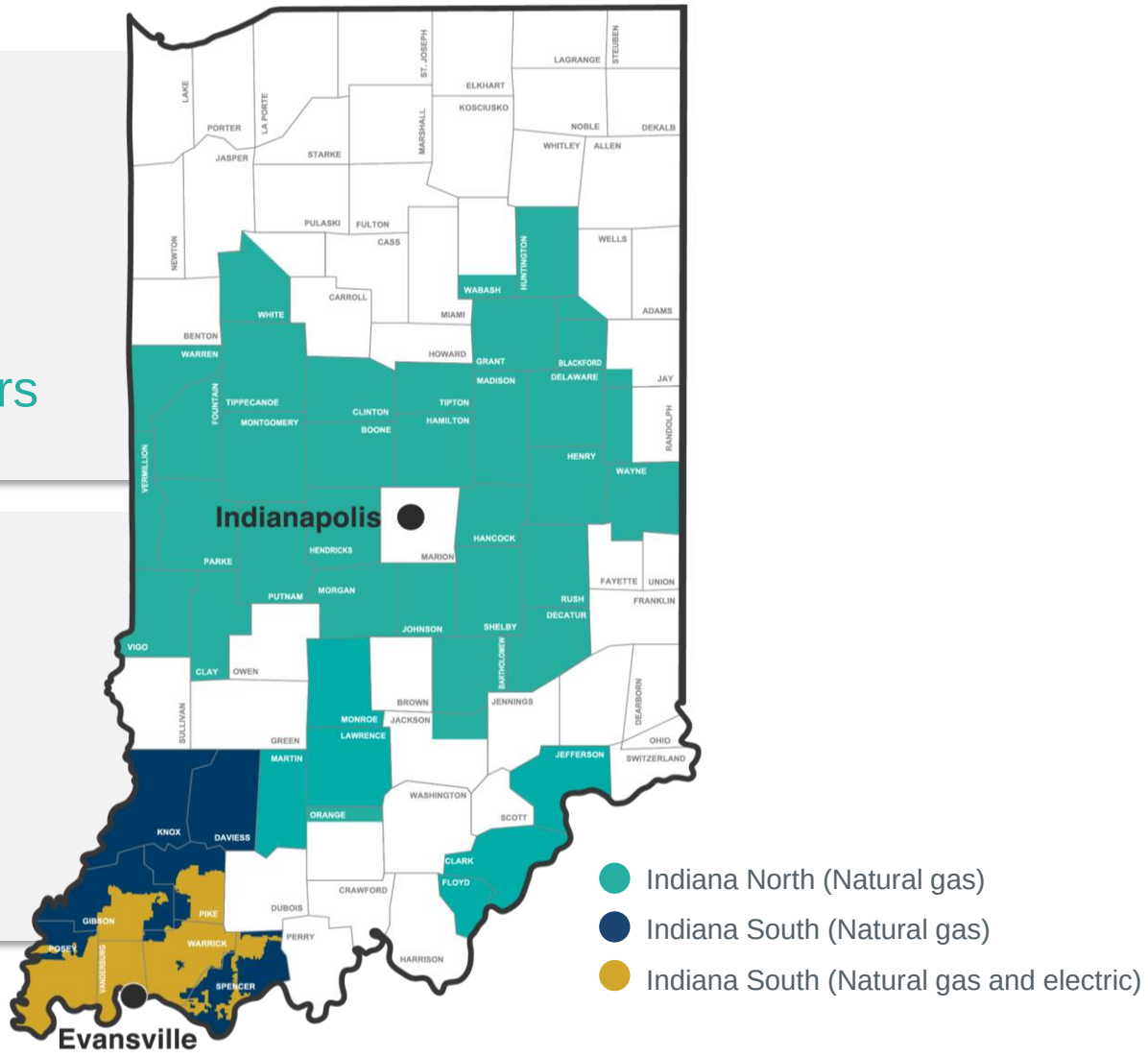
Natural gas metered customers

Indiana Electric Transmission & Distribution and Power Generation

More than

150,000

Electric metered customers

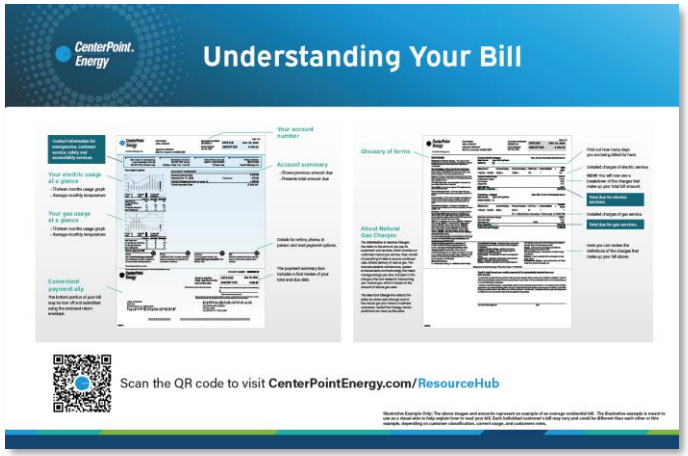


Customer Experience

CenterPoint Energy

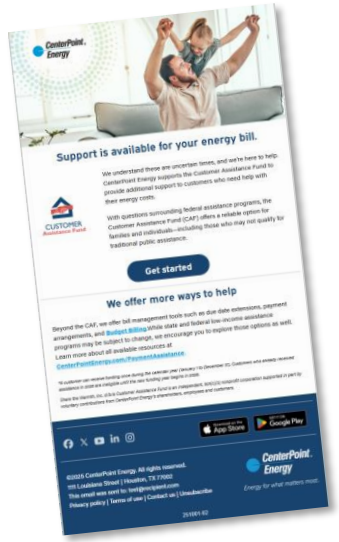
Customer Experience











News Releases

- Energy-saving tips
- Enroll in payment programs
- Prepare for winter

Dedicated Webpage

- Rate details
- Access to assistance programs

Customer Emails

- Manage your usage
- Weather alerts and impacts

Social Media

- Energy-saving rebates
- General safety tips

Bill Messaging

- Budget Bill can help stabilize monthly payments
- Self-service billing and payment options

Community Outreach

- IN South Customer Experience Collaborative Sessions
- Community Connects

Call Agents and IVR

- Community resource connections
- Upfront messaging and guided options

Customer Experience – Latest Initiatives

- **Customer Connect**
  Engaging directly with southwestern Indiana customers for direct feedback.

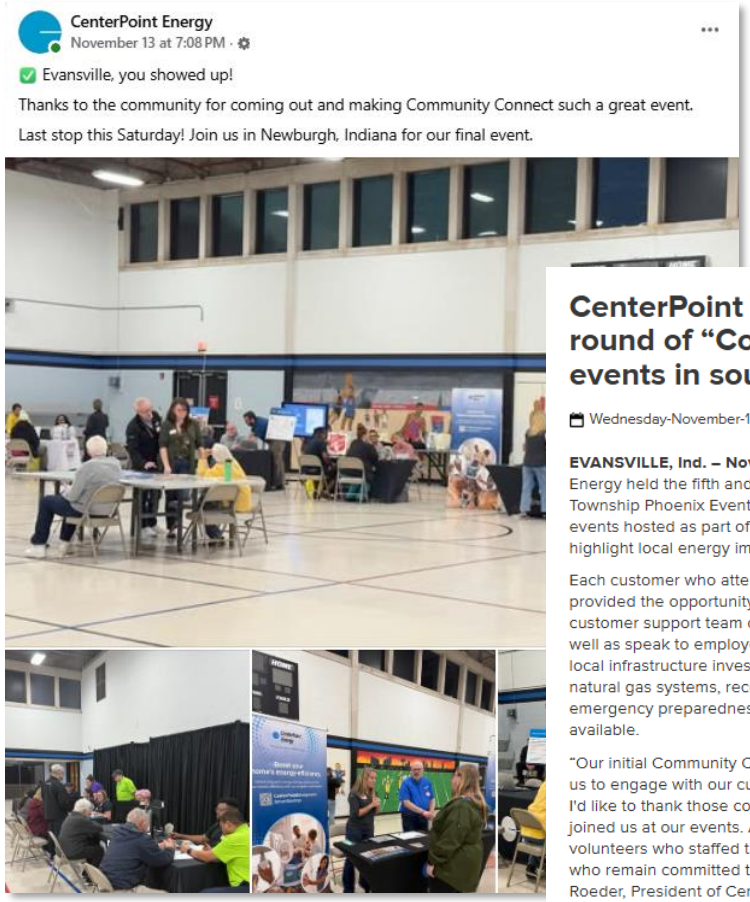
- **Foundation Commitment**
  $5 Million donation to the community focusing on home repair, energy efficiency, and economic development.

- **Customer Experience Collaborative**
  Engaging directly with southwestern Indiana customers for direct feedback.

- **Customer Assistance Fund**
  Financial support to eligible customers in Indiana for bill assistance.

- **Energy Efficiency Block Party**
  Connecting the Evansville community with energy-saving resources and activities.

- **Traveling City Hall**
  Engaging with the City of Evansville to provide customer service solutions at various events.



CenterPoint Energy completes first round of "Community Connect" events in southwestern Indiana

Wednesday-November-19-2025

EVANSVILLE, Ind. – Nov. 19, 2025 – This past Saturday, CenterPoint Energy held the fifth and final Community Connect event at the Ohio Township Phoenix Event Center in Newburgh, Ind., wrapping up a series of events hosted as part of its commitment to listen to local feedback, highlight local energy improvements and address customer priorities.

Each customer who attended the five Community Connect events was provided the opportunity to speak with a member of CenterPoint's customer support team one-on-one to resolve any issues or concerns, as well as speak to employees at a number of informational stations about local infrastructure investments designed to strengthen the electric and natural gas systems, recent affordability actions, the importance of emergency preparedness and financial assistance and other programs available.

"Our initial Community Connect events were an excellent opportunity for us to engage with our customers face-to-face and listen to their feedback . I'd like to thank those community members, as well as local officials, who joined us at our events. And I also want to thank the 100+ employee volunteers who staffed the events and the entire Indiana CenterPoint team who remain committed to serving our customers every day ," said Mike Roeder, President of CenterPoint Energy Indiana.

"We will share more information soon on how we will continue to show up and engage our community on a more consistent and frequent basis going forward as we execute our previously announced affordability actions."

Community Foundation and Engagement

2025 Foundation Giving

- Provided grants to **100 organizations**
- Donated more than **$3 million**

2025 Employee Impact

- More than **40 leaders** serve on non-profit boards
- **9,200 volunteer hours** contributed
- **$177,800** contributed in matching gifts to IN non-profits



Significant Projects

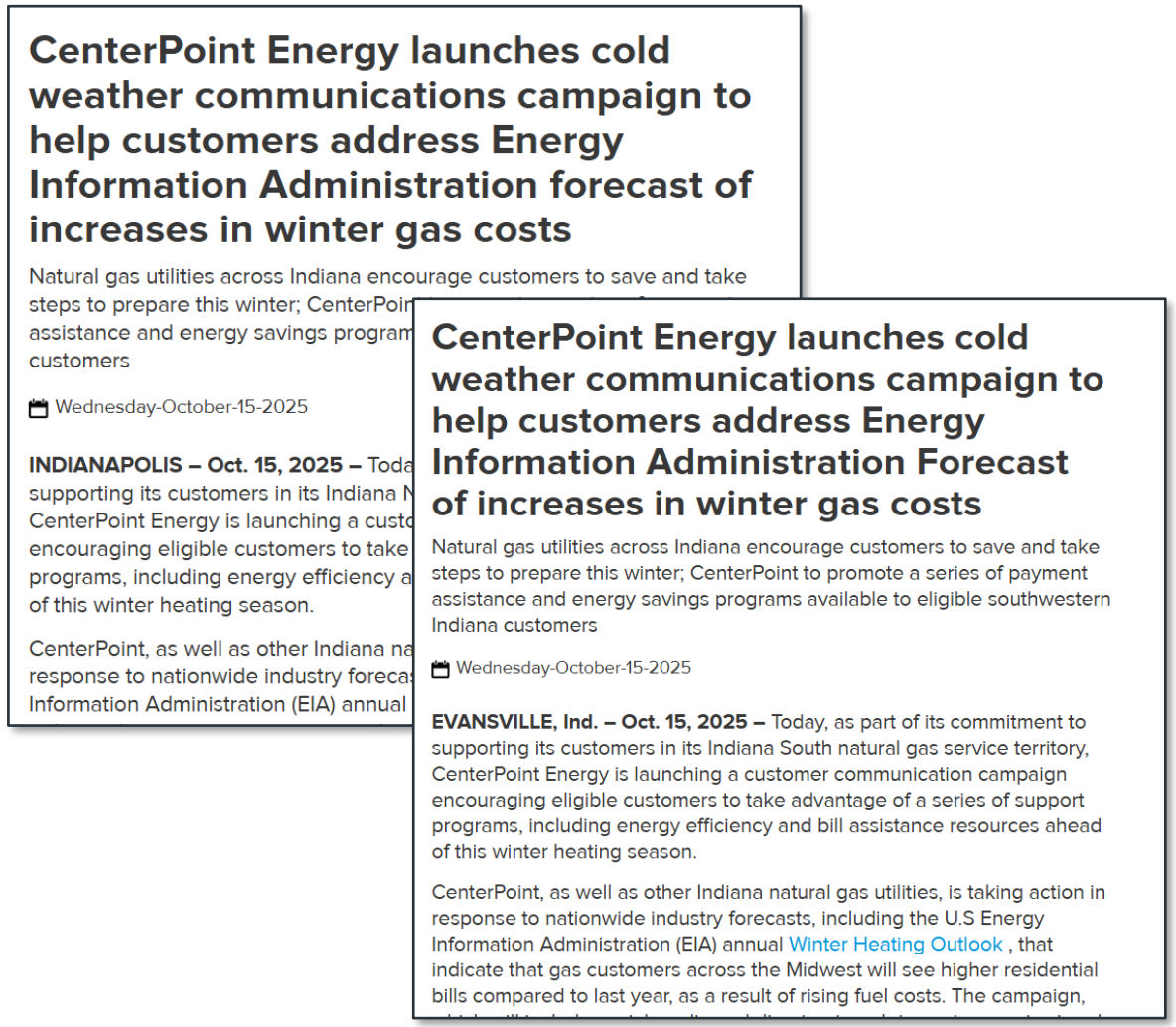
Investment into storefront at new **Junior Achievement** Biztown Campus in Evansville, IN

Continued partnership with **Nextech** to bring 25 students to training center for experiential field trip

Funded new Aviation training center in partnership with **Vincennes University**

Winter Bill Projections Summary

- **Natural gas bill impacts**
  - Commodity cost driven
  - Communicated to customers on October 15
- **Electric bill impacts**
  - Driven largely by recently implemented rate case



CenterPoint Energy launches cold weather communications campaign to help customers address Energy Information Administration forecast of increases in winter gas costs

Natural gas utilities across Indiana encourage customers to save and take steps to prepare this winter; CenterPoint to promote a series of payment assistance and energy savings programs available to eligible southwestern Indiana customers

Wednesday-October-15-2025

EVANSVILLE, Ind. – Oct. 15, 2025 – Today, as part of its commitment to supporting its customers in its Indiana South natural gas service territory, CenterPoint Energy is launching a customer communication campaign encouraging eligible customers to take advantage of a series of support programs, including energy efficiency and bill assistance resources ahead of this winter heating season.

CenterPoint, as well as other Indiana natural gas utilities, is taking action in response to nationwide industry forecasts, including the U.S Energy Information Administration (EIA) annual Winter Heating Outlook , that indicate that gas customers across the Midwest will see higher residential bills compared to last year, as a result of rising fuel costs. The campaign,

2025-26 Winter Bill Projections – Electric, Gas, & Combo

Customers Based on Average Use (South Gas: 108 therms / month; North Gas: 117 therms / month; South Electric Standard Rate 750 kWh / month; South Electric Transitional 1,422 kWh / month)	2024/2025 Heating Season	2025/2026 Heating Season	Difference
CEI South Electric (standard rate)	$146	$181	$35
CEI South Gas	$127	$141	$14
CEI South Combo	$273	$322	$49
CEI South Electric (transitional - electric heat rate)	$214	$277	$63
CEI North Gas	$105	$112	$7

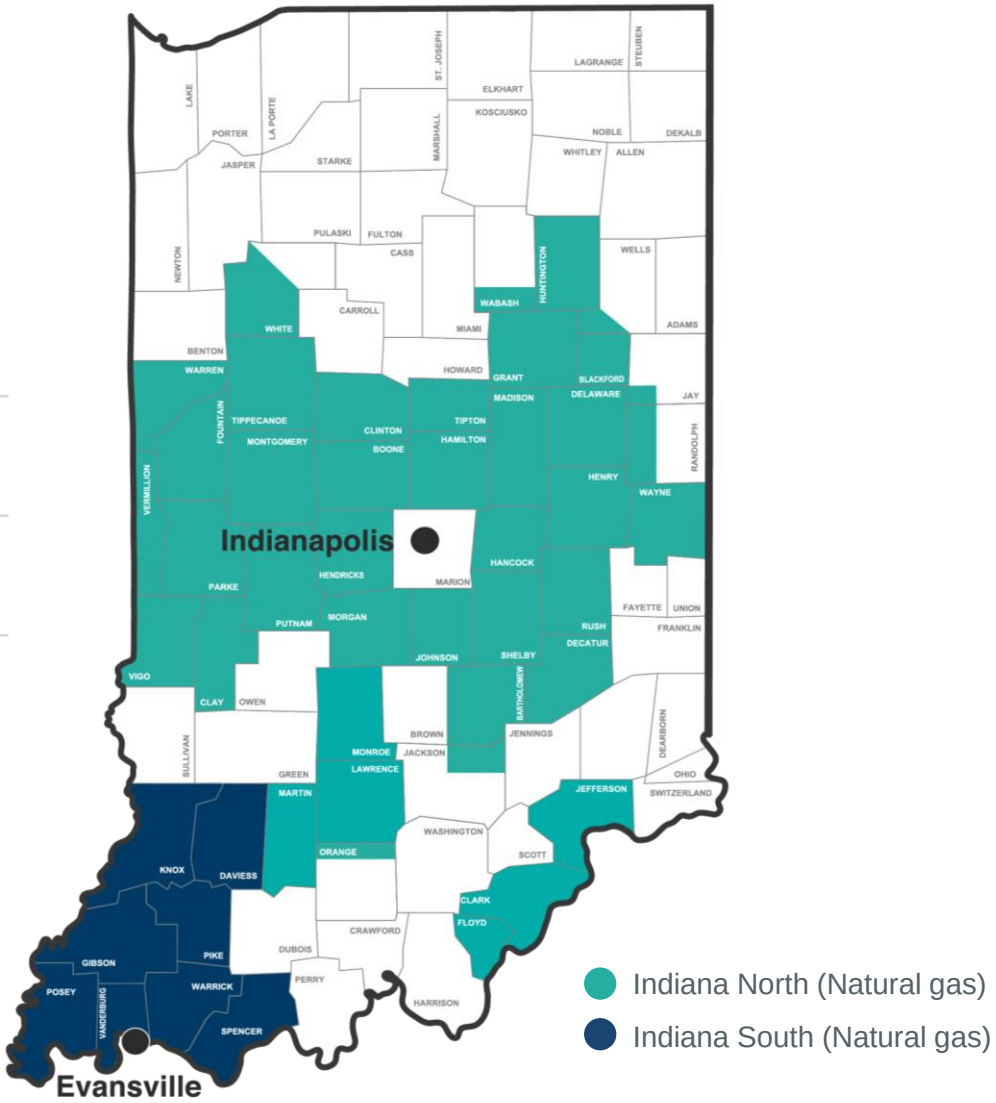
Customers Based on 1,000 kWh and 200 therms / month	2024/2025 Heating Season	2025/2026 Heating Season	Difference
CEI South Electric (standard rate)	$190	$231	$41
CEI South Gas	$216	$242	$26
CEI South Combo	$406	$473	$67
CEI South Electric (transitional - electric heat rate)	$171	$203	$32
CEI North Gas	$166	$177	$11

Natural Gas

CenterPoint Energy®

Gas Footprint

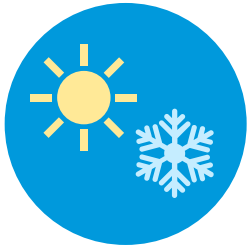
Company	Distribution Lines (Miles)	Transmission Lines (Miles)
Indiana North (IGC)	14,020	631
Indiana South (SIGECO)	3,009	119
Total	17,029	750



Winter 2025-26 Gas Supply Plan - Objectives



Procure natural gas for essential **human needs** for space heating, cooking and water heating



Provide supply to customers with **varying load conditions**

- Extremely warm weather and severely cold weather



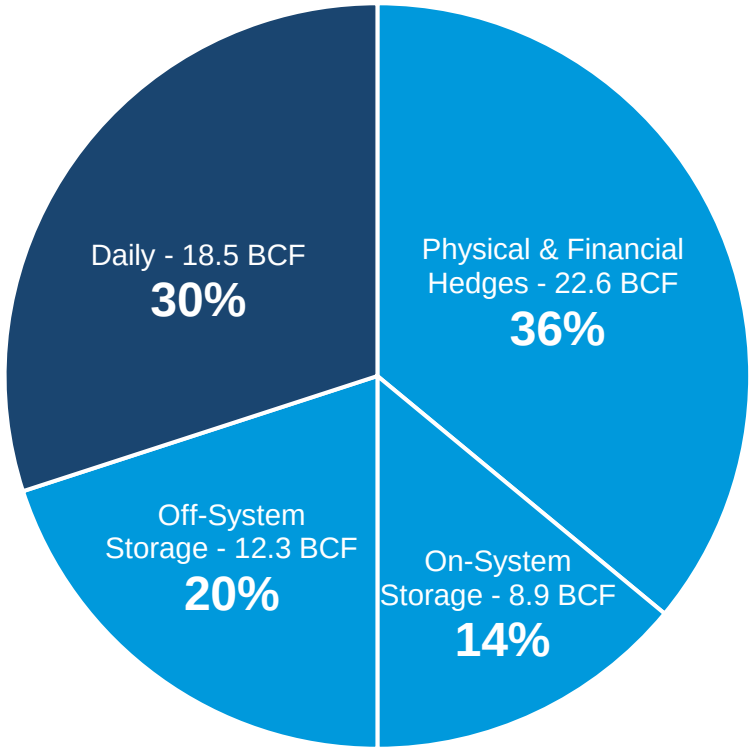
Supply products that provide a balance for weather forecast errors and weekend varying loads such as:

- Off-System Storage & On-System Storage, price protected baseload supply, propane-air peak shaving

2025-26 Gas Supply Plan – Price Stabilization

30%
of forecasted winter sales are **purchased in spot market**

Winter 2025-2026 Price Stabilization (Residential & Commercial)



- Physical & Financial Hedges - 22.6 BCF
- On-System Storage - 8.9 BCF
- Off-System Storage - 12.3 BCF
- Daily - 18.5 BCF

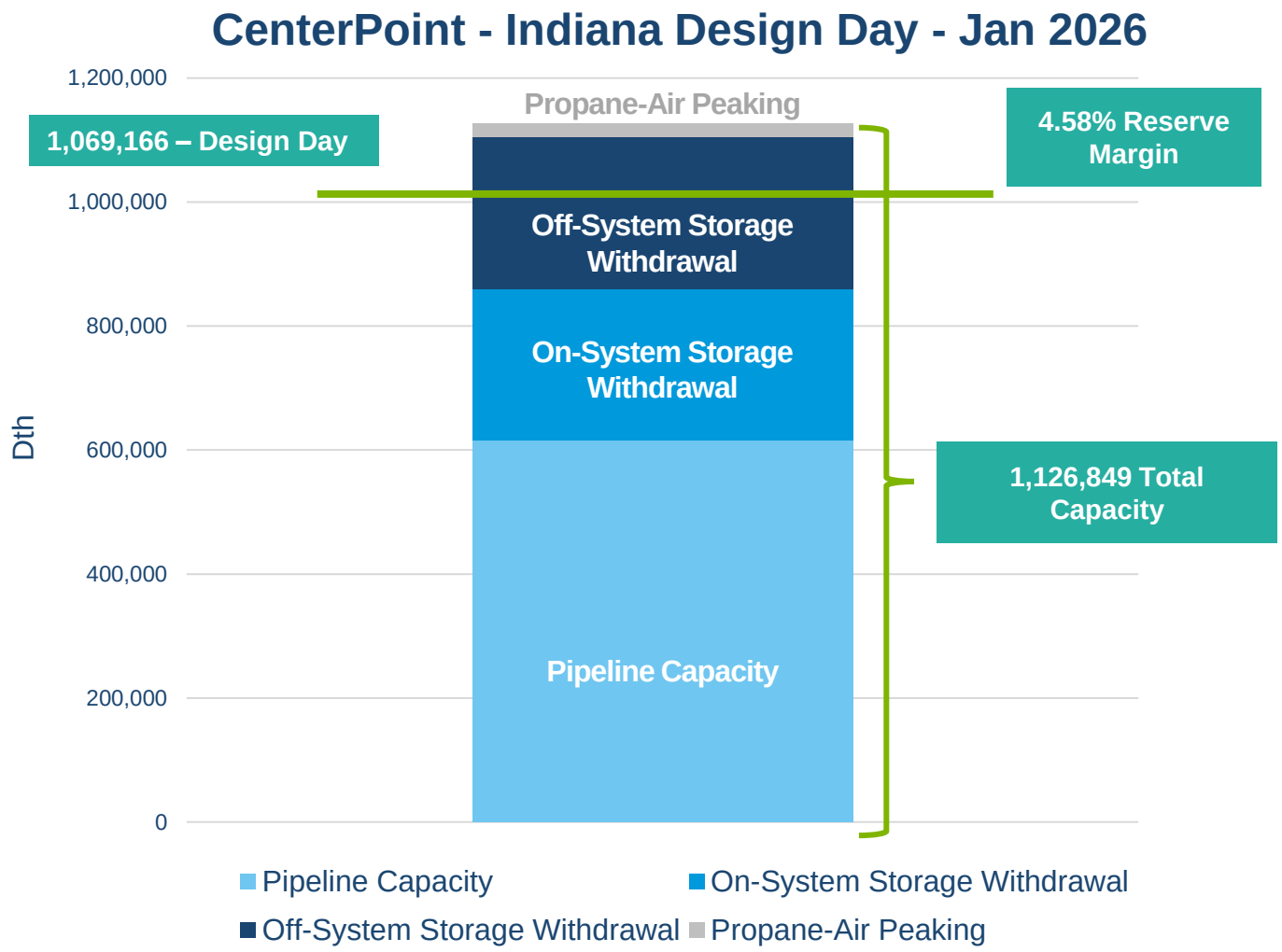
70%
of forecasted winter sales are **stabilized with hedges**

Diverse supply mix
- Multiple pipelines
- Various supply terms & pricing

Asset Manager provides:
- Flexibility & risk mitigation
- Ensures reliability during high demand days

Total Winter Purchases	**62.3 BCF**
Total Hedges	**43.7 BCF**
Price Stabilization %	**70.3%**

2025-26 Gas Supply Plan – Design Day



Pipeline & Storage capacity are under long-term firm contracts.

Total Capacity	**1.12 BCF**
Design Day	**1.07 BCF**
Reserve Margin %	**4.58%**

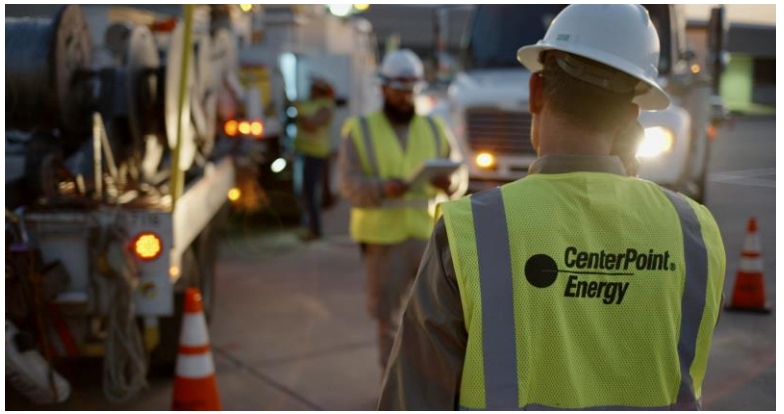
Natural Gas Winterization

To prepare for extreme cold weather events:

- Ensure critical system components are operational
- Modify shifts to staff critical facilities
- Communicate regularly with Gas Control, Gas Supply, Forecasting, Transmission Operations, System Planning, and Storage
  - Review gas supply plan, supplemental gas plan, areas of concern/recent pressure alarms, review of system charts, etc.
  - Monitor weather forecasts daily for updates to the severity and timing
  - Increase the frequency of meetings to daily as needed







Natural Gas Winterization *(Continued)*

- Stop planned work to allow the workforce to monitor the system/equipment
- Construction crews have heightened awareness of the effects of cold weather on polyethylene pipe during construction and make sure steel plates are removed or secured
- Pump drips, as necessary
- Ensure vehicles, technicians, and facilities are staged and equipped appropriately to support operations
- Verify cold weather Personal Protective Equipment (PPE) is distributed and stocked



Natural Gas Winterization *(Continued)*

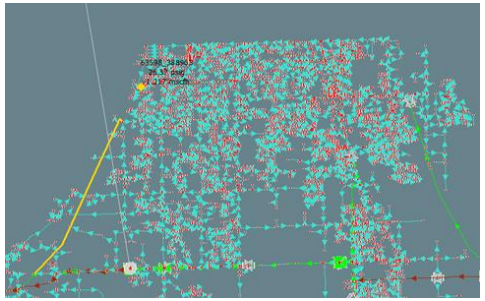
Planning Meetings

- Gas System Planning (GSP) facilitates an annual meeting to review:
  - Known areas of concern, remediation projects planned, and solicit operation's feedback
  - System changes from the past years' Modernization (BSCI and other) projects and load growth
  - Chart systems to provide critical information that will confirm load

Winterization activities that differ by type of facility:

- Regulator stations feeding medium and high-pressure systems will likely remain at **normal** setpoints, low-pressure stations are usually set at a temporary **increased** setting that is closer to MAOP
- Systems considered at an increased risk may be physically staffed 24/7







Electric

CenterPoint Energy

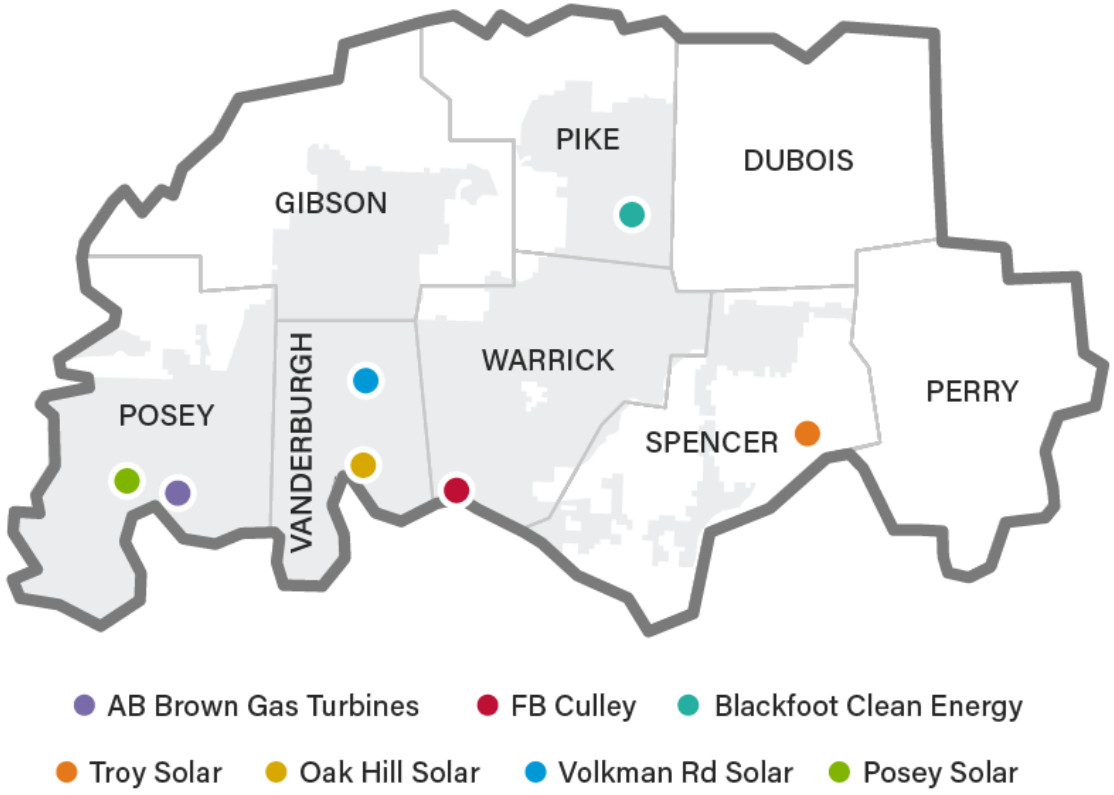
2025 CenterPoint Energy (CEI) South

In Southwestern Indiana, CEI South Electric:

- Serves more than **150,000 customers**
  - **2024 Retail Sales 4,819 (GWh)**
    - Residential 1,4236 GWh
    - Commercial 1,163 GWh
    - Industrial 2,149 GWh
    - Other 13 GWh

- Owns and operates:
  - **1,039** circuit miles of transmission lines
  - **7,318** circuit miles of distribution lines
  - **109** substations

- Has **1,341 MW** of installed generating capacity, including:
  - **246 MW** of solar
  - **80 MW** of wind
  - **623 MW** of gas-fired units
  - **392 MW** of coal-fired units



Notes:
1. Fowler Ridge & Benton County Wind Farms not shown.
2. AB Brown CTs 5&6 now in-service.
3. Posey Solar now in-service.
4. Salt Creek Wind PPA, not shown, expected to be in-service yearend 2025.
5. Wheatland Solar PPA, not shown, expected to be in-service Q1 2026.

Generation Fleet Overview | Installed Capacity

Coal Units – 392 MW *(29%)*

- FB Culley Units 2 and 3 – 360 MW
  - Unit 2 (90 MW) on track to cease operation Dec. 31, 2025
- Ohio Valley Electric Cooperative (OVEC) – 32 MW

Gas Peaking Units – 620 MW *(46%)*

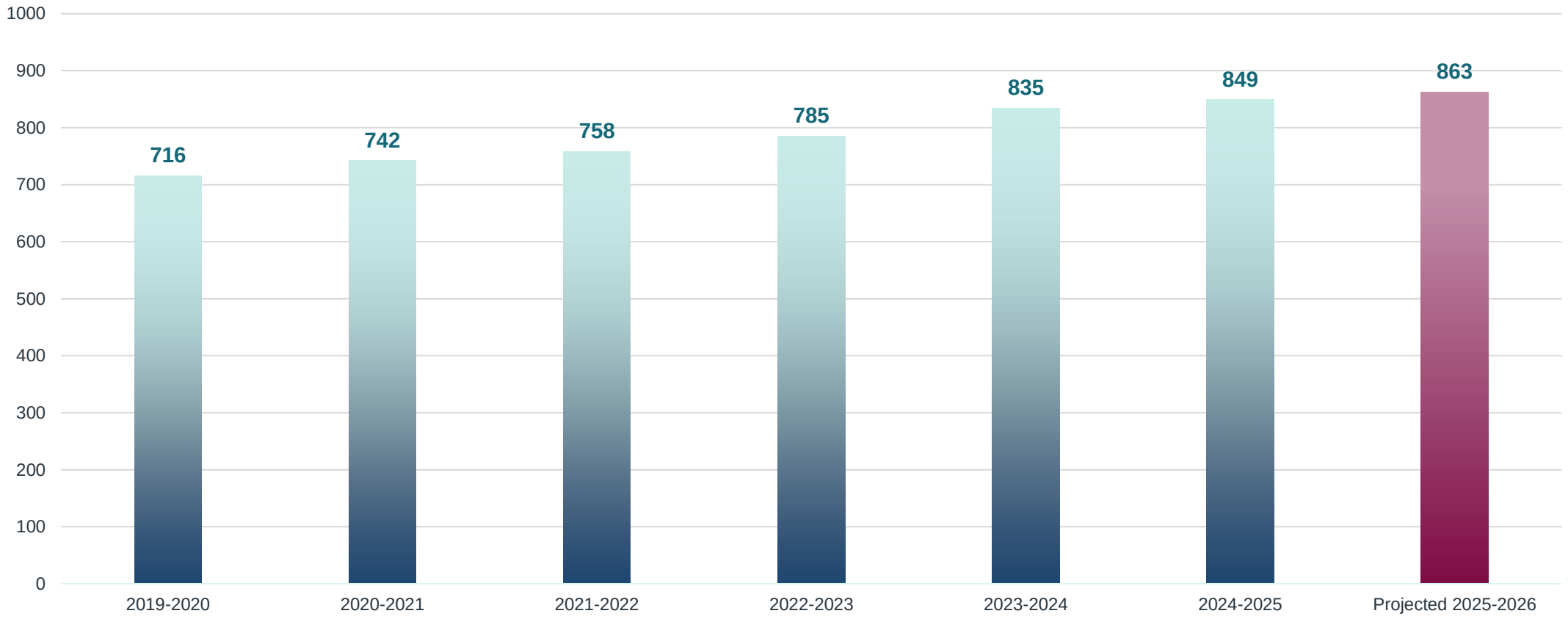
- AB Brown Units 3 and 4 – 160 MW
- AB Brown Units 5 and 6 – 460 MW

Renewables – 329 MW *(25%)*

- Posey Solar – 191 MW
- Troy Solar – 50 MW
- Volkman Road Solar – 2 MW
  - Includes 1 MW/4 MWh Battery
- Evansville Urban Solar – 2 MW
- Blackfoot Landfill Gas – 3 MW
- Fowler Ridge Wind PPA – 50 MW
- Benton County Wind PPA – 30 MW



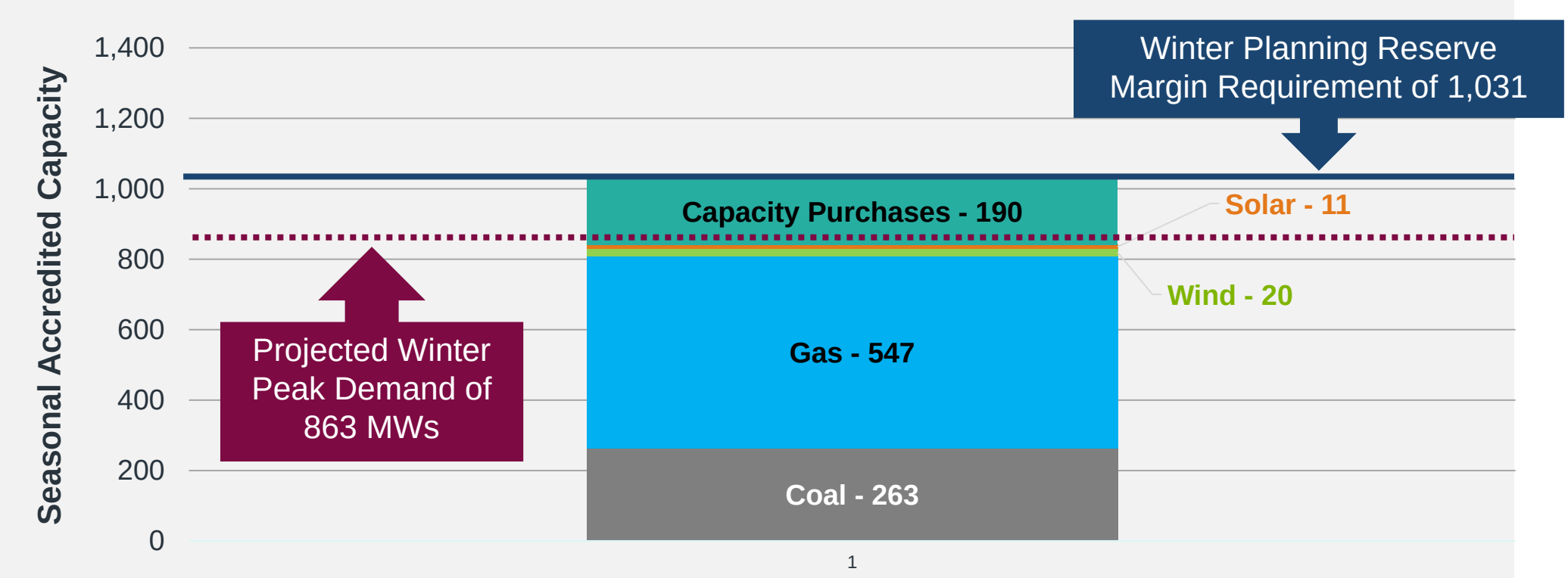
CEI South Historical and Projected Winter Season Peak Load (MW)



[1] December 2025-February 2026, based on load forecast for the 2025-2026 MISO planning year

CEI South Capacity Resources for 2025–2026 Winter Season

- CEI South procured sufficient capacity to meet customer demand and MISO planning reserve margin requirements (PRMR) for the winter season
- **190 MW of capacity purchases** were secured for the 2025-2026 planning year
- **68% of CEI South's generators** have onsite fuel storage or firm capacity for this winter



CEI Electric – Winter Reliability Preparedness

Preparation

- Year-round preventive and predictive maintenance program to support readiness for peak conditions.
  - Perform standard winterization prior to the winter season.
- On staff meteorologists monitor weather and proactively provide daily reports and escalate significant weather events.
  - Prior to an extreme cold weather event, critical equipment areas are inspected for additional preparation consideration.
- MISO emergency conditions – “hands off” approach.
- Culley Unit 3 scheduled major outage in-progress; expected completion is mid-December.

Fuel Supply and Chemical Inventories

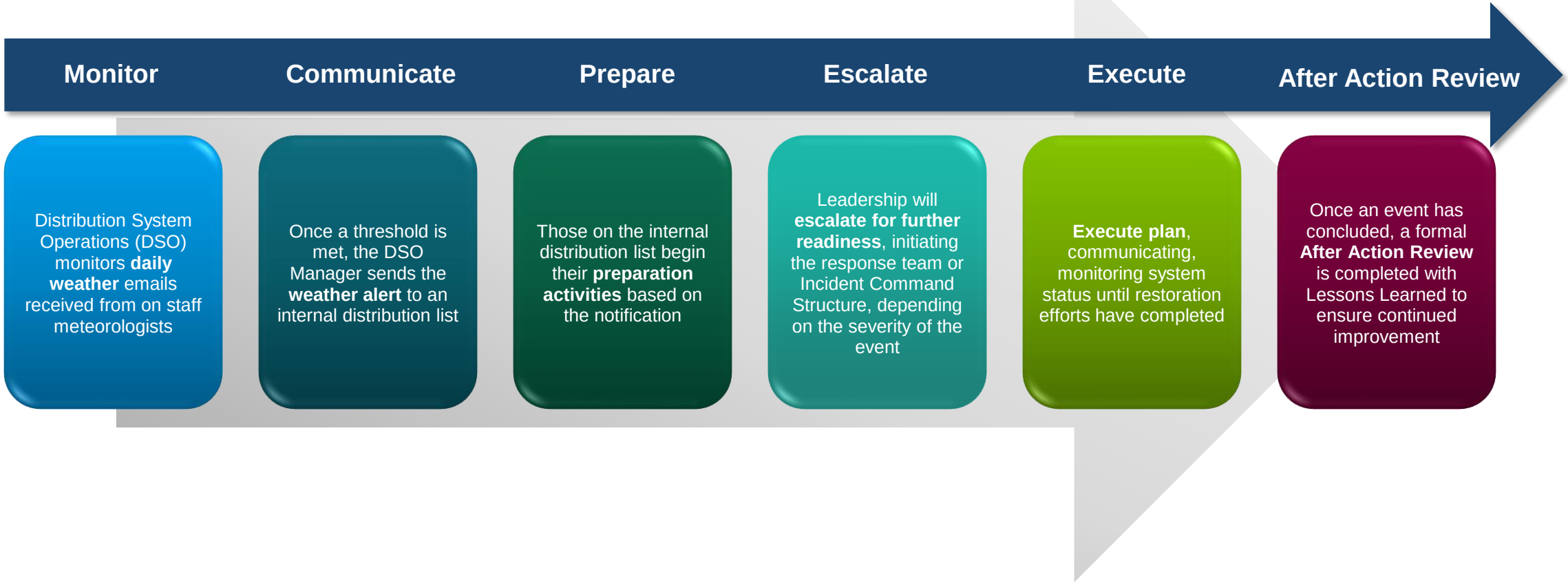
- Coal pile inventory at Culley generating station is approximately 100 days.
  - Preferred inventory is 60 days ± 30 days.
- Coal supplier and transportation are operating with no restrictions.
- Gas supply for existing A.B. Brown GTs Units 3&4 is 76% firm capacity and 24% storage for peak day usage.
  - GT 3 is the only dual fuel unit (gas primary; diesel secondary).
- Gas supply for new A.B. Brown GTs Units 5&6 is 100% firm no-notice storage.
- Ensure chemicals and reagents inventory is adequate and deliveries are scheduled to maintain environmental compliance.





Electric Winterization Activities

When impacted by a severe weather event, we execute our **storm response plan**.



Q&A



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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.

---

[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.

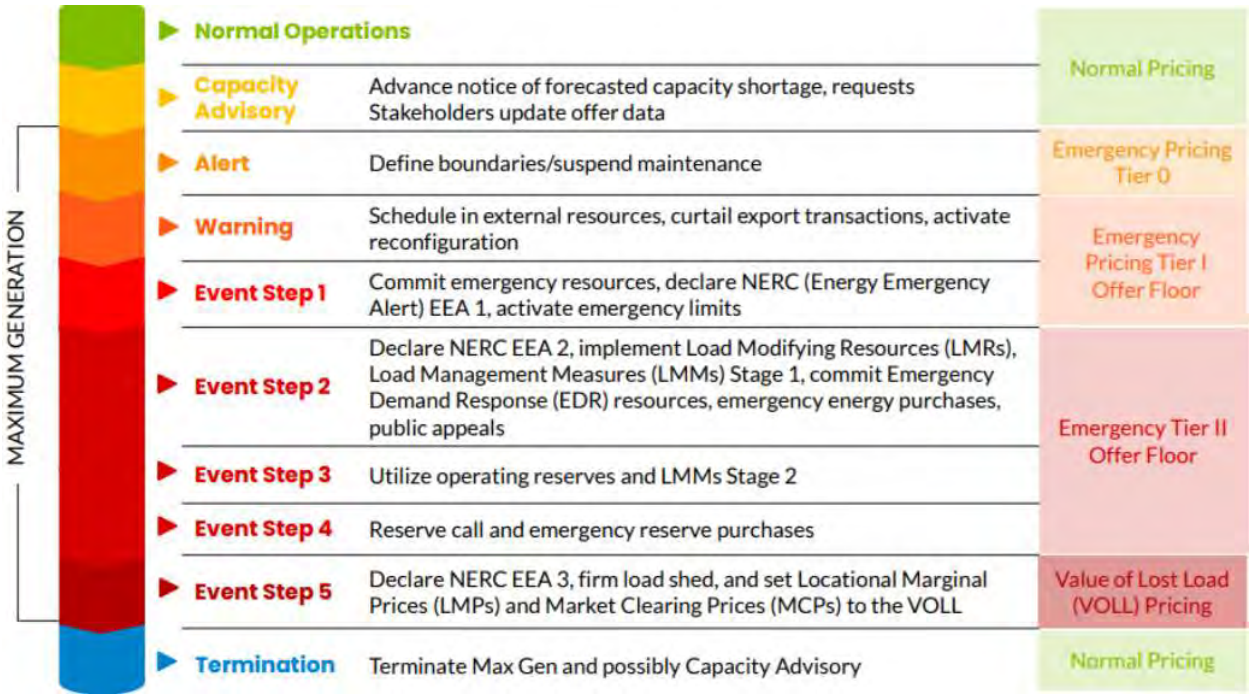


Figure 1: MISO chart showing its steps for Maximum Generation Events

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.

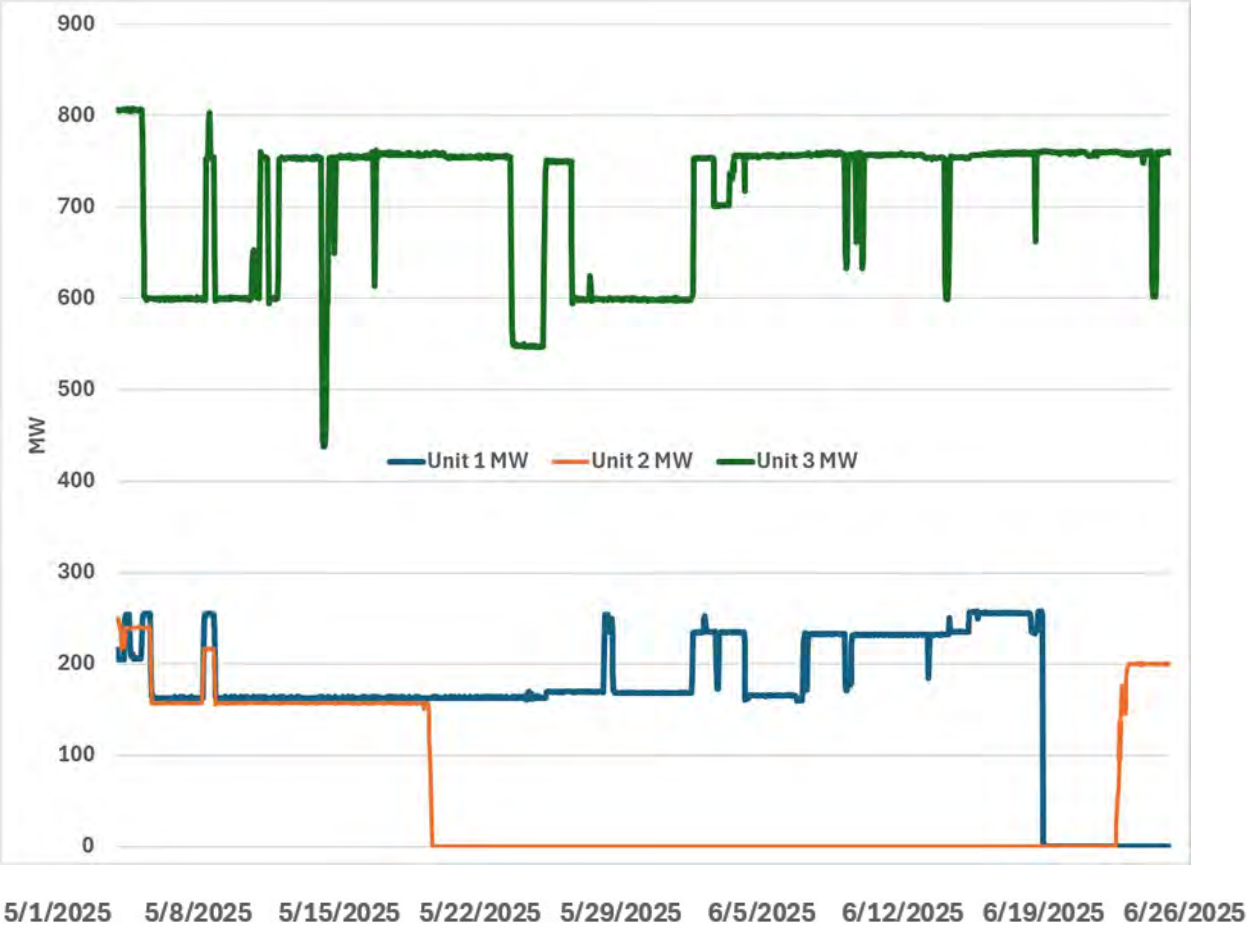


Figure 2: Campbell unit output over May and June 2025, from EPA CEMS dataset

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]

[18] *Consumers Energy Company submits FERC Form 1 report for 2024/Q4*, Docket No. EL25-90 (Mar. 20, 2025), Accession No. 20250320-8006, at 402, *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-8006. Fuel costs in row 20 were subtracted from total production expenses in row 34 to arrive at non-fuel O&M costs. The non-fuel O&M costs for Unit 3 were then divided by .9331 to calculate the total non-fuel O&M costs for Unit 3, reflecting that the cost figures in Form 1 only report Consumers Energy's costs for its 93.31% share of Unit 3.

[19] Form 1 does not distinguish between variable O&M costs that are incurred as a function of generating MWh and fixed O&M costs that are incurred simply by keeping the plant open. However, given that both types of costs will be incurred as a result of DOE mandating that the Campbell plant remain open, and the plant's ongoing capacity factor is unlikely to drastically change from its capacity factor in 2024, expressing O&M costs in $/MWh accurately reflects the ongoing costs of operating the plant. Dollar-per-MWh costs were calculated based on EIA Form 923 generation for 2024.

[20] MISO, *Historical Annual Day-Ahead LMPs* (July 3, 2025) (last visited Sept. 4, 2025), https://www misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Day-Ahead%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc. Coal plants typically sell their output in the Day-Ahead market instead of the Real-Time market due to their inflexibility, so this analysis is based on Day-Ahead market prices.

[21] This period was chosen because DOE issued the 202c order late on May 23, and EPA data showing the hourly generation of Campbell is currently only available through the end of June 2025.

[22] U.S. Sec. and Exch. Comm'n ("SEC"), *Form 10-Q* (July 31, 2025), (report for Consumers Energy for the second quarter of 2025, filed July 2025), *available at* https://d18rn0p25nwr6d.cloudfront net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf.

4. DOE's July 2025 Resource Adequacy report is based on flawed inputs

DOE's order briefly mentions a report it issued on July 7, 2025,[23] entitled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*. That report has been widely criticized,[24] including for vastly overstating the need for resources by using assumptions for nationwide generator retirements, capacity additions, and load growth that are drastically higher than other data and projections from EIA, the DOE entity tasked with "independent statistics and analysis." As summarized in Table 2 below, in total DOE's report overstates the need for resources by around 200 GW relative to other DOE sources. If those inputs were used instead, the report would not even have found a 2030 need because 109 GW of resource additions would more than meet the 92 GW of need created by 40 GW of load growth plus 52 GW of retirements.

Table 2: Assumptions in DOE's July 2025 report vs other DOE data, GW by 2030

	DOE July 2025 report	Other DOE data/projections	Overstatement of need for resources
Capacity retirements	104 GW firm	52 GW nameplate[25]	52 GW
Resource additions	22 GW firm	109 GW[26]	87 GW
Load growth	101 GW	40 GW in high growth case[27]	61 GW
Total overstatement of need for resources			**200 GW**

5. Conclusion

This report builds on the points made in our June report. DOE's two Campbell orders are both unnecessary and costly market interventions.

6. Qualifications of Michael Goggin

Michael Goggin has worked on electricity market and reliability issues for over 20 years. At Grid Strategies he serves as an expert on those topics for a range of clients including state utility

[23] DOE, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, (July 7, 2025), at 1, *available at* https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[24] For example, *see* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), *available at* https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/; *see also* Jennifer Danis, et al., *Enough Energy: A Review of DOE's Resource Adequacy Methodology* (July 2025), *available at* https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf.

[25] EIA, *EIA-860M* (June 2025), (data for May 2025), https://www.eia.gov/electricity/data/eia860m/.

[26] *Id.* To be conservative, the tally of 109 GW of planned resource additions includes only thermal and battery resources and does not account for the significant resource adequacy contributions from planned wind and solar resources. The 22 GW figure for the July 2025 DOE report is based on the statement on page 1 that for capacity additions by 2030, "only 22 GW would come from firm baseload generation sources."

[27] EIA Annual Energy Outlook high growth case assumes 6% growth through 2030, versus 15% assumed in DOE's July 2025 report.

regulators, grid operators, and non-profit organizations. He has testified as an expert in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Iowa, Illinois, Indiana, Wisconsin, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

For the preceding ten years Michael worked at the American Wind Energy Association (now known as the American Clean Power Association), where he provided technical analysis regarding renewable energy, transmission, and wholesale electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, he worked at a firm serving as a consultant to DOE, and at two environmental groups.

7. Sources

The principal documents I relied on in preparing this report include the materials listed below and in footnotes. To the extent feasible, relevant documents are included in the Appendix of the Request for Rehearing.

-DOE, *Order No. 202-25-7* (Aug. 2025), *available at* https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf

-DOE, *Order No. 202-25-3* (May 2025), *available at* https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

-MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, *available at* https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

-MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted May 29, 2025)*, *available at* https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

-MISO, *Attributes Roadmap* (Dec. 2023), *available at* https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

-MISO, *MISO Market Capacity Emergency*, *available at* https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf

MISO, *Historical Annual Day-Ahead LMPs*, *available at* https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistori

cal%20Annual%20Day-Ahead%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc

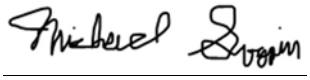
-FERC, *Consumers Energy Company submits FERC Form 1 report for 2024/Q4* (Mar. 2025), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-8006

-U.S. EPA, *Continuous Emission Monitoring Systems: Custom Data Download*, *available at* https://campd.epa.gov/data/custom-data-download

-U.S. DOE, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (July 2025), *available at* https://www.energy.gov/sites/default/files/202507/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf

-DOE Energy Information Administration, *Form EIA-923 June 2025* (Aug. 2025), *available at* https://www.eia.gov/electricity/data/eia923/

-DOE Energy Information Administration, *Form EIA-860M*, (data for May 2025, published June 2025), *available at* https://www.eia.gov/electricity/data/eia860m/



Michael Goggin
Vice President
Grid Strategies, L.L.C.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-25-13

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

Exhibit 69
IN Haze SIP Responses to Public Comments

Appendix V

RH SIP Responses to Public Comments

This page intentionally left blank

RESPONSES TO PUBLIC COMMENTS ON INDIANA'S REGIONAL HAZE STATE IMPLEMENTATION PLAN

United States Environmental Protection Agency (email from Pamela Blakely received on November 15, 2021)

Comment 1
The State should also include the summarized FLM comments and responses in the SIP narrative rather than just an appendix in accordance with 40 CFR51.308(i)(3)

Response 1
The Federal Land Manager's comments are summarized in Appendix U to allow for a more concise document. Since the Appendix is a part of the SIP, IDEM would prefer not to incorporate all of the same language in the body of the document.

Comment 2
As a general matter, EPA expects states to select their largest in-state contributors to visibility impairment for four-factor analysis. See July 8, 2021, Clarification Memo at 4. In Indiana's case, many of these largest contributors appear to be EGUs that have been screened in through the Q/d analysis. In some instances, IDEM may find it appropriate to not select such a source, even if it is one of the largest sources in the state. For instance, IDEM may decline to not select a particular source based on a demonstration that the source is operating existing effective controls. See August 2019 Guidance 22-25: July 8, 2021, Clarification Memo 5.

Comment 3
IDEM suggests that recent emission reductions owing to other control measures are a basis for not conducting a four-factor analysis for the selected EGUs. However, it is generally inappropriate to not select a source simply because it was part of an emissions sector that is the subject of numerous industry-wide EGU control programs and downward emissions trends for the first planning period. As a general matter, once a source is screened in based on visibility impacts, a state should not forgo four-factor analysis merely because of other emission reductions (at the source or other sources) or because of recent improvements in visibility. Therefore, IDEM should explain in greater detail how not selecting EGUs for a four-factor analysis still ensures reasonable progress towards natural visibility. If the various control measures and shutdowns listed in this section are necessary for reasonable progress and therefore part of IDEM's Long-Term Strategy, those must be federally enforceable and in the SIP.

Responses 2 and 3
Indiana received numerous comments related to the state's decision to evaluate all of the electric generating unit (EGU) sources that met Indiana's criteria for selecting sources for four-factor analysis using a reasonable progress analysis for the EGUs. This decision was made early in the State Implementation Plan (SIP) development process based on the EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" document, dated August 20, 2019 (2019 EPA Guidance). According to the 2019 EPA Guidance, a key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period; an analysis of control measures is not required for every source in each implementation period; and for the sources that are not selected for an analysis of control measures for purposes of the second implementation period, it may be appropriate for a state to consider whether measures for such sources are necessary to make reasonable progress in later implementation periods.

Indiana chose to wait until the third planning period to require four-factor analyses from its EGU sources due to the fact that the landscape for the EGU sector has changed so dramatically since the last planning period, resulting in large emission reductions. The EGU sector continues to change rapidly, with a number of additional shut-downs being announced just within the past year. The implementation of new control programs designed to target nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions from the EGU sector have resulted in various upgrades to existing emissions control equipment, several installations of new add-on control devices, a number of conversions to natural gas and numerous EGU retirements with more scheduled shutdowns to come over the second implementation period. In addition, fuel costs have upended the order in which resources are dispatched by the Midcontinent Independent System Operator (MISO) to meet the region's power generation needs and maintain adequate power grid management in the future. Coal fired units that were previously dispatched first are now dispatched last. This change in economic driven dispatching is expected to result in less reliance on the remaining coal fired EGUs and accelerated retirement. As such, Indiana believes that conducting four-factor analyses for EGUs during the next planning period would result in a better use of resources because much of what the state would require based on four-factor analyses conducted for the EGUs would become moot as the EGU sector remains in flux as sources continue to shutdown units, convert to natural gas, and rely more on renewable energy. In fact, allowing the EGU sector to stabilize over the course of the next implementation period would provide more definitive information for better decision-making during the third planning period and produce more feasible and meaningful analyses. Especially in light of the fact that a detailed reliability study would need to be conducted in order to understand the impact that additional shutdowns of coal fired units would have on delivering electricity reliably, dependably, and cost-effectively to the grid.

The RH Rule is purposefully intended to give states discretion and flexibility in meeting their statutory and regulatory requirements to reduce visibility impairment at Class I areas as directed through the RH program. The rule allows states to determine how to show reasonable progress and permits states to leverage emission reductions achieved through other CAA programs that will further improve visibility in protected areas. While the EGU source category was not chosen by IDEM to have four-factor analyses conducted for the second implementation period, these sources were not exempt from being evaluated. A reasonable progress analysis for these units was conducted in lieu of four-factor analyses. Indiana's reasonable progress analysis for these units consists of a quantitative analysis of statewide NO_x and SO_2 emission reductions from Indiana's EGU fleet for 2007-2019; photochemical modeling using 2016 NO_x and SO_2 base-year modeled emissions for all existing Indiana EGUs in 2016 to projected 2028 emissions; and source apportionment modeling to assess visibility impacts of all EGUs in Indiana.

EPA addresses visibility requirements in the preamble of the RH Rule as shown on page 35726 (Federal Register Vol 64, No. 126, Pg. 35726): "Since the national goal is expressed in terms of air quality (i.e., visibility) rather than emissions, we (EPA) believe that it is very important to require the quantitative tracking of visibility impairment as an integral element in measuring reasonable progress." Also, on page 35727, "Tracking "reasonable progress" should involve the tracking of both emissions and visibility improvement". IDEM has demonstrated the decrease of both emissions and visibility impairment by showing significant visibility improvement at Class I areas; and expects the emissions analyses, review of emission controls, current and expected retirements for coal-fired boilers with more renewable energy being utilized for future power generation, and modeled visibility impacts to adequately address Indiana's overall visibility impacts. Both factors (emissions and visibility impairment) are more than adequately addressed in Indiana's EGU reasonable progress analysis with future emission reductions anticipated.

Furthermore, the EGU sector has contributed its fair share of the visibility progress made over the last implementation period which has resulted in emission reductions below the glidepath in all of the Class I areas for which Indiana sources have been found to impact visibility. IDEM has determined existing emission controls are adequate to address regional haze for EGU sources throughout the state based on current "on-the-books" regulatory measures, such as the Cross State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards for the second implementation period. In addition, Indiana will continue to make progress towards the national goal of natural visibility by 2064 with the implementation of other CAA regulations, such as the Revised CSAPR Update Rule and new wastewater regulations for coal ash. The Revised CSAPR Update Rule reduces the 2021 NO_x Ozone Season budget for Indiana from 13,313 to 9,754 tons of NO_x by 2024 forcing optimization of existing controls; and more stringent federal wastewater guidelines have become more of a contributing factor in causing EGUs to move away from coal or shut down. The new wastewater regulations require power plants to clean coal ash and toxic heavy metals such as mercury, arsenic, and selenium from plant wastewater before it is dumped into streams and rivers. Additional emission control measures and potential future reductions will continue to be appropriately evaluated in upcoming implementation periods.

Comment 4
Please indicate which, if any, of the retirements are federally enforceable and planned for inclusion in the long-term strategy (LTS) and SIP. Please describe the regulatory mechanisms IDEM uses to ensure retirements and shutdowns are federally enforceable and permanent.

Comment 5
For these planned retirements, if IDEM chose to perform four-factor analyses on EGUs, IDEM could fully support its assertion that new emission control equipment is not cost-effective, if that is ultimately the case. A cost-effectiveness analysis within a four-factor analysis would provide actual data to support (or refute) this claim. If the State is relying on anticipated source shutdowns as part of its long-term strategy for making reasonable progress, IDEM must make these planned retirements enforceable in the SIP. This includes reliance on shutdowns both to forgo a four-factor analysis and to shorten the remaining useful life of a source in conducting a four-factor analysis. See EPA Clarifications Memo at 10; see also Guidance at 20 and 34. If IDEM does not include these retirements in its SIP, then the State should consider a four-factor analysis for these sources.

Without the four-factor analyses, the reference to "cost-effective method" on page 57 of the draft noted above offers no support for the argument that "additional emissions reductions through the use of new emission control equipment or emissions limitations is not desired". Further, decreasing emissions trends do not free the state from an obligation to meet the CAA and Regional Haze Rule requirements to consider what is necessary for reasonable progress, which may in fact be "new emission control equipment or emissions limitations."

Comment 7
There are various instances throughout the four-factor analyses where IDEM concludes that X (one of the sources) has "no reasonable set of NO_x emission control measures beyond what is currently installed and operated for these emission units" or "[X] already utilizes [Y] as an existing NO_x emission control measure." However, IDEM should take its analysis one step further and indicate whether those conclusions mean that they are determining that existing measures are necessary for reasonable progress. As a general matter, EPA believes that existing measures are necessary for reasonable progress and therefore must be incorporated into the regulatory portion of the SIP. However, the state may make a weight-of-evidence

demonstration that a particular existing measure is not necessary for reasonable progress. See July 8, 2021, Clarification Memo 8-10.

Comment 9
Is there an enforceable prohibition on coal burning at the source or is it now physically impossible to use coal as a fuel source in the future?

Responses 4, 5, 7, and 9
Indiana received numerous comments related to including permanent and enforceable emission limits for existing and new emission controls that are necessary to make reasonable progress in the SIP as part of the state's long-term strategy. IDEM doesn't agree that the state should require stricter enforceable limits through secondary (welfare) control programs than those required to address health-based primary standards unless needed to show visibility improvements. The implementation of health-based primary air quality standards, such as the 2008 1-hour SO_2, the 2012 fine particulate matter standard and the 2015 ozone standard have forced sources to meet new air quality targets that require them to maintain stricter control of NO_x and SO_2 emissions. Whether through source-specific limits that are permanent and federally enforceable, or though federally enforceable programs to address interstate transport, these emission reductions have contributed to the significant progress made over the course of the first implementation period.

It should be noted that to incorporate new emission limits into Indiana's SIP, a new rule must be developed and adopted. The state's rulemaking process takes three to four years to complete, including federal SIP approval. This process would be very resource intensive for what would amount to small visibility benefits for the non-EGUs and a limited amount of time before the units are no longer operated for the EGUs.

Indiana also received a number of comments concerning the weight of evidence demonstration for existing controls. The EPA and other commenters contend that if IDEM concludes that the existing controls at a selected source are necessary to make reasonable progress, a weight-of-evidence demonstration must be conducted to establish emission limits for the existing controls. As previously mentioned, the cost and use of resources and time required to evaluate selected sources for permanence of existing controls and emission limits compared to the visibility benefits realized to address transported NO_x and SO_2 emissions at this time is not warranted.

The RH Rule was designed to be implemented with respect to reasonable visibility progress to natural conditions by the year 2064 with several implementation periods to measure and assess reasonable progress towards the natural visibility conditions. The uniform rate of progress (URP) for each Class I area, especially in the eastern half of the country, shows the visibility progress made during the last implementation period represents another positive step towards attaining natural conditions at all Class I areas by 2064, if not much sooner. A comparison of visibility impairment values over time is an appropriate measure to determine if improvements or progress is made for Class I area visibility. The URP is adjusted to account for several different factors that make up visibility impairment. The fact that the most current monitored and modeled visibility values are below the uniform path to natural visibility conditions for eastern U.S. Class I areas must be considered in establishing Indiana's long-term strategy for the RH SIP second implementation period. Furthermore, the fact that monitored visibility data from the IMPROVE monitoring network has shown progress from 2000 to 2018 is considerable, indicating states have been responsive to reducing emissions through state and federal regulatory measures and as a result, visibility impairment is trending downward. Current 2018 monitored visibility data nearly match the projected modeled visibility values for 2028 at most

Class I areas throughout the eastern U.S. This clearly shows tremendous progress, ranging up to 10 years ahead of what is projected through visibility modeling. These visibility benefits are expected to continue with anticipated future reductions in emissions.

Some commenters provided additional information on individual EGUs and/or information that could be used in a four-factor review that IDEM cannot agree or disagree with because no four-factor review for EGUs was conducted. Many controls are already in place for EGUs, and the RH SIP includes the level of efficiency obtained by each control (as shown in Appendix F of the RH SIP). Regional Haze does not require a specific level of control and many of the control efficiencies of controls on Indiana sources are considered at a high level of control.

Indiana has determined existing emission controls are adequate to address regional haze for sources throughout the state based on the tremendous visibility progress made to date along with current "on-the-books" regulatory measures. Both factors (emissions and visibility impairment) are addressed in Indiana's RH SIP with future emission reductions anticipated. These reductions will be appropriately evaluated in upcoming implementation periods as the natural visibility goals are realized by 2064.

Comment 6
IDEM should specifically address whether the cost-effectiveness of the $1679/ton control option for SNCR is reasonable and make a specific finding as to the Greencastle facility regarding whether new controls will be required for reasonable progress.

Comment 8
As with the other four-factor analyses, IDEM does not appear to make specific findings for each facility of whether the cost effectiveness of the controls evaluated is reasonable. Somewhere in the SIP document, such as Section 26.0 Decision on What Control Measures are Necessary to Make Reasonable Progress, IDEM should make specific findings for each facility regarding whether the cost effectiveness for a new control option within a certain range is reasonable and if it will be required for reasonable progress. As to the cost effectiveness of controls for the Burns Harbor emission units of $4,000/ton SO_2, IDEM would be expected to address the reasonableness of options in this range.

Comment 10
IDEM should specifically address cost-effectiveness estimates in this range and make a specific finding for the facility regarding whether these costs are reasonable and if they will be required for reasonable progress.

Comment 11
If IDEM determines that no additional (i.e., new) measures are necessary to make reasonable progress for a particular source, the State must then determine whether the source's existing measures are necessary to make reasonable progress. See section 4 (pages 8-12) of the Clarifications Memo for information on determining when a source's existing measures are necessary to make reasonable progress. Generally, a source's existing measures are needed to prevent future emission increases and are thus needed to make reasonable progress. If IDEM concludes that the existing controls at a selected source are necessary to make reasonable progress, IDEM must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP).

Comment 12
Section 26.1 contains IDEM's conclusions regarding the State's decision not to require additional control measures. This is the heart of IDEM's main finding, although it doesn't appear until page 225. Therefore, it would be helpful if IDEM would provide conclusions specific to the selected sources indicating what, if any, additional control measures are determined to be necessary for reasonable progress. If no additional control measures are selected by Indiana, IDEM should further explain (1) if that determination means that existing measures are necessary for reasonable progress, and (2) how a determination of no additional control measures nonetheless ensures reasonable progress is made.

Responses 6, 8, 10, 11, and 12
Indiana received numerous comments regarding the state's decision not to require additional controls for some of the sources selected for four-factor analysis based on the cost effectiveness result for specific units. IDEM used the Q/d analyses to quantify and consider the visibility impacts of sources at Class I areas for the purpose of selecting sources to analyze for four-factor analysis. The four-factor analysis is used to evaluate potential controls for specific pollutants emitted from individual emission units at a source to determine what controls are cost effective for reducing that pollutant. The RH Rule requires states with Class I areas to consider these factors in establishing their reasonable progress goals for reducing the impact of emissions from sources within and outside the state on visibility impairment at each Class I area within the state. However, the use of the four-factor analysis and by extension the cost effectiveness evaluation for states that do not have Class I areas for the purpose of establishing a long-term strategy is not clearly defined.

IDEM did not make a determination on whether a specific dollars/ton cost for the affected sources is cost effective because subsequent source apportionment modeling results showed that these sources would not have a measurable impact on improving visibility at Class I areas. In other words, a low-cost effectiveness value at the unit level for sources with modeled insignificant visibility impacts to Class I areas outside the state does not necessarily mean reductions will provide a measurable visibility benefit. Although the cost effectiveness evaluation of the four-factor analysis for some sources shows a low-cost value to install some new control measures, the source apportionment modeling for their associated source sectors does not show that there will be appreciable differences in visibility benefits. This lack of appreciable difference in visibility benefits is due to the significant visibility progress realized so far based on emission reductions and the distance to a Class I area and/or the amount of emissions from the four-factor source. Moreover, the variables used in the cost estimates and cost effectiveness calculations vary depending on a variety of different circumstances and are not consistent across sources. The cost and use of resources and time required to evaluate selected sources for unit-specific emission control measures compared to the visibility benefits realized to address transported NO_x and SO_2 emissions at this time is not warranted. So, when evaluating the selected sources for additional controls, both monitored and modeled visibility benefits were strongly considered.

IDEM received numerous comments on the methods and accuracy of the four-factor analyses included in the draft SIP. IDEM appreciates the thoroughness and amount of detail that went into the review of the draft SIP. IDEM used acceptable methods to estimate costs with input and review from the subject sources. Therefore, IDEM is not updating the cost effectiveness numbers for the final SIP, unless instances of errata. Different decisions on assumptions made could change the cost per ton estimates but not in an appreciable way to change the outcome of reducing emissions enough to have a measurable impact on visibility values. Please see the four-factor analyses in Section 10, the cost estimates and cost effectiveness evaluations in

Appendices H and J, and the responses from affected sources to the Federal Land Managers comments in Appendices P-T for further detail on assumptions used in the analyses.

Indiana has determined existing emission controls are adequate to address regional haze for sources selected for four-factor analysis based on the tremendous visibility progress made to date along with current “on-the-books” state and federal regulatory measures. Both factors (emissions and visibility impairment) are addressed in Indiana’s RH SIP with future emission reductions anticipated. These reductions will be appropriately evaluated in upcoming implementation periods as the natural visibility goals are realized by 2064.

United State Department of Interior – National Parks Service (email from Anne M Thomas/ letter from Herbert C Frost received on November 9, 2021)

Comment 1
The NPS maintains that it is not reasonable for IDEM to exempt electric generating units (EGUs) from four-factor analyses. Regional modeling results show that Indiana EGUs contribute significantly to visibility impairment at multiple Class I areas, accounting for 7% of total visibility impact at Mammoth Cave NP. In fact, five of the top ten facilities impacting Mammoth Cave NP are Indiana EGUs. As previously shared, our analyses demonstrate there may be cost-effective controls available at several EGUs. We recommend IDEM conduct four-factor analyses for these facilities and include cost-effective controls in the regional haze SIP.

Response 1
See the “Responses 2 and 3” under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 2
Based on IDEM’s original and revised analyses, we maintain that there are cost-effective control options available at several facilities including Alcoa Warrick, Burns Harbor, and Greencastle Cement. We recommend that IDEM implement all cost-effective controls to reduce haze causing emissions.

Comment 3
Controls that we consider reasonable were rejected by IDEM as unnecessary “considering the significant progress already made towards achieving the national visibility goal.” In response, we note that the 2017 preamble to the Regional Haze Rule, the August 2019 Guidance, and the recent July 2021 clarification memorandum all clearly state that having made significant progress is not a "safe harbor" that can be used to dismiss otherwise reasonable controls (82 FR at 3099, EPA 2019 RH Guidance §II(5)(a), EPA 2021 Memo §5.4).

Comment 4
Finally, IDEM concluded that the contribution to visibility impairment from the state’s sources is not sufficient to justify additional controls. We note that the visibility benefit of emissions reductions from individual facilities is not one of the four statutory factors that should be considered to determine whether controls are reasonable and should not be used to reject reasonable controls (Clean Air Act §7491, 40 CFR 51.308(f)(2)(ii), EPA 2021 Memorandum §5.2).

Responses 2, 3, and 4
See “Responses 6, 8, 10, 11, and 12” under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Visibility Improvement State and Tribal Association of the Southeast (VISTAS) Member States: Tennessee (email from James Johnston received on November 4, 2021) **and North Carolina** (email from Randy Strait received on November 10, 2021)

Comment
In Section 8.0 and Appendix D of the draft SIP, IDEM discussed the substantial decrease in EGU NO_x and SO_2 emissions from Indiana's EGUs, including specific information for Gibson and Rockport, between 2007 and 2019 and the additional projected decreases for 2028. Those sections of the RH SIP also indicate that IDEMs projected 2028 emissions for Gibson and Rockport are similar to VISTAS 2029 projections.

Since IDEM's projected 2028 emissions are similar to those provided by VISTAS and IDEM has not provided information to counter the NCDAQ's and VISTAS finding that Gibson and Rockport significantly impact visibility impairment at Great Smoky Mountains National Park and Joyce-Kilmer-Slickrock Wilderness Area, the NCDAQ requests that IDEM include four-factor analyses for both of these facilities in their final Regional Haze SIP for the second implementation period. Alternatively, IDEM could include an effectively controlled analysis or anticipated shutdown information for one or both of these facilities.

Response
IDEM has drafted a formal response to the VISTAS interstate consultation letter, which will be completed and sent to VISTAS and its member states and tribal organization after IDEM has completed its work on the draft Indiana RH SIP for the second implementation period. See IDEM's formal response to the VISTAS Inter-RPO Ask in Appendix AA of this document.

Mid-Atlantic/Northeast Visibility Union (MANE-VU) (email from Paul Miller received on November 5, 2021) **and Member State New Jersey** (email from Sharon Davis received on November 1, 2021)

MANE-VU Inter-Regional Planning Organization (RPO) Ask
MANE-VU's technical analysis identified visibility-impairing emissions from Indiana and other upwind states as reasonably anticipated to contribute to visibility impairment at MANE-VU Class I areas. Based on this analysis, MANE-VU developed a "MANE-VU Ask" that was sent to Indiana and the other identified states with five requests for consideration during the upwind states' second regional haze SIP planning effort. With this letter, MANE-VU is providing our overarching perspective on how well IDEM's draft addresses each of these requests. MANE-VU makes note of the past and future EGU retirements and emissions reductions described in Sections 8.1.1 and 8.3 of IDEM's draft. Nevertheless, MANE-VU respectfully requests that its Ask items be addressed in IDEM's regional haze SIP as described in the comments that follow.

Ask #1
EGUs ≥ 25 MW with installed controls, ensure that controls are run year-round. IDEM's draft SIP does not address MANE-VU Ask #1. As described in Section 7.4 of the IDEM draft, IDEM has elected to defer analysis of its EGU sector until the third implementation period. While the workload distribution of source category analysis to different implementation periods is allowed under EPA guidance, IDEM's approach of deferring analysis of its EGU sector is inconsistent with MANE-VU's Inter-RPO Ask for the second implementation period. To this end, MANE-VU notes the Indiana EGU emissions reductions that occurred between 2009 and 2019 as described in Section 8 of IDEM's draft. Nevertheless, MANE-VU reiterates its request that IDEM pursue enforceable mechanisms to ensure that EGUs ≥ 25 MW with installed controls run those controls year-round.

Ask #2
For emissions sources having a 3.0 Mm-1 impact or greater at MANE-VU Class I areas, perform a four-factor analysis. The IDEM draft does not address MANE-VU Ask #2. The Indiana Michigan Power Company (dba American Electric Power) Rockport Plant (Facility ID 6166) was identified by MANE-VU technical analysis as a facility with the potential for 3.0 Mm-1 impact or greater at one or more of MANE-VU's Class I areas. MANE-VU notes the emissions controls and reductions for the Rockport Plant discussed in Section 8.5 of the IDEM draft, including the continuous operation of SCRs and enhanced DSI systems. Nevertheless, MANE-VU respectfully requests that a four-factor analysis be performed for the Rockport Plant, consistent with MANE-VU's Ask #2, to determine the reasonableness of more stringent control efficiencies or stricter emissions limits.

Ask #3
Adopt an ultra-low sulfur fuel oil standard. The IDEM draft does not address the MANE-VU ultra-low sulfur fuel oil Ask. MANE-VU respectfully re-iterates its request that Indiana adopt ultra-low sulfur fuel oil standards as part of its long-term strategy or demonstrate in its SIP why it would not be feasible to do so. For distillate oil, this would be essentially the equivalent of on-road diesel, which is already widely 3 available. We note that all MANE-VU states have successfully adopted low sulfur fuel oil requirements.

Ask #4
For EGUs and other large sources, pursue enforceable mechanisms to lock in lower emission rates. MANE-VU notes the EGU emissions reductions described in Section 8 of the IDEM draft, including those that have come about via enforceable mechanisms, such as consent orders. However, IDEM does not directly address MANE-VU's Ask #4 in its draft SIP.

Ask #5
Encourage and promote energy efficiency and clean technologies. The IDEM draft does not address Ask #5. MANE-VU respectfully asks that IDEM consider, and report in its SIP, measures or programs in Indiana that reduce emissions by encouraging energy efficiency and promoting cleaner energy technologies. Rather than a focus on energy markets, this would be a discussion within IDEM's haze SIP of the energy efficiency measures and clean energy programs under consideration or currently operating in Indiana. Unlike MANE-VU's other Ask items, MANE-VU does not necessarily intend that these measures be enforceable or included as part of a state's long-term strategy. But because such programs can reduce emissions and therefore benefit visibility, MANE-VU is asking its upwind state partners to consider and report such measures in their haze SIPs.

Response to MANE-VU Inter-RPO Ask
IDEM has drafted a formal response to the MANE-VU Inter-RPO Ask, which will be finalized and sent to MANE-VU and its member states and tribal organizations after IDEM has completed its work on the draft Indiana RH SIP for the second implementation period. See IDEM's formal response to the MANE-VU Inter-RPO Ask in Appendix AA of this document.

MANE-VU Section-Specific Comments

Comment 1
7.3 Q/d Screening Analysis for Source Selection
MANE-VU respectfully asks IDEM to describe in its SIP the technical basis for selecting 5 as the Q/d screening threshold for screening sources.

Response 1
As described in Section 7.3 of the SIP, the Q/d threshold value of 5 was chosen due to the number of sources that met this criterion and the commitment among LADCO member states to be consistent in their decision making throughout the SIP development process. Indiana believed that evaluating the 20 highest emitting sources of NO_x and SO_2 pollution in the state would provide an adequate and representative number of sources to be evaluated and observed that most of the other LADCO states choose a similar number of sources for evaluation.

Comment 2
23.1 Class I Area Selection
At the bottom of page 199, below Table 23-2, the text states, "Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions[.]" Although this statement is true for some of the Class I areas shown in Table 23-2, it does not appear to be true for many others.

Response 2
This is correct; therefore, the sentence this comment refers to has been changed from all Class I areas to most Class I areas.

Comment 3
23.11 Brigantine Natural Wilderness Area, NJ; and Lye Brook National Wilderness Area, VT (MANE-VU)
This section asserts that "on-the-books" measures, along with federal measures, are such that the meeting of reasonable progress goals (RPGs) will not be impeded. This section concludes that, as a result, no further analysis for this SIP will be taken. MANE-VU does not challenge the assertion that the meeting of RPGs will not be impeded but re-iterates the fact that RPGs themselves are not enforceable and that the overarching goal of CAA 169A and the regional haze rule is to make progress towards the goal of natural visibility conditions by 2064. As emissions sources such as EGUs become better controlled, smaller additional emissions reductions from these sources, or emissions reductions from other source types, become necessary to make incremental improvements in visibility and to ensure that downward trends in monitored visibility metrics continue. Therefore, MANE-VU further re-iterates its request that IDEM do additional work and analysis to ensure that MANE-VU's Inter-RPO Ask is addressed in its SIP such that incremental progress is made at MANE-VU Class I areas affected by Indiana emissions.

Response 3
See "Response 2 and 3" under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 4
25.0 20% CLEAREST DAYS ANALYSIS
The first sentence in this section states, "Results for all Class I areas analyzed show 2014-2018 baseline monitored values, as determined through the IMPROVE monitoring data, are lower than the modeled visibility impacts at each Class I area for 2028, based on the 2011 emissions[.]" Although this statement is true for almost all of the Class I areas shown in Table 25-1, it does not appear to be true for Isle Royale, Brigantine, and Lye Brook.

Response 4
This is correct; therefore, the sentence this comment refers to has been changed from all Class I areas to most Class I areas.

New Jersey (email from Stella Oluwaseun-Apo received on November 1, 2021)

Response to New Jersey Specific Comments
New Jersey is a MANE-VU member state. Comments included in the state's correspondence are also included in the MANU-VU correspondence; therefore, responses to New Jersey specific comments can be found in IDEM's formal response to the MANE-VU Inter-RPO Ask. See IDEM's formal response to the MANE-VU Asks in Appendix AA of this document.

Duke Energy (email from Aaron Flynn received on November 15, 2021)

Comment 1
It is important to note that the units are subject to the Mercury and Air Toxics Rule Subpart UUUUU, which requires that the installed emission controls be operated at all times coal is burned and which uses SO_2 reductions as a surrogate for acid gases. The Draft SIP should reflect this.

Response 1
Comment 1 has been incorporated into the Draft SIP under Section 9.3.

All other comments in Duke Energy's comments document were found to be in line with the points IDEM already makes in one form or another for the EGU source sector in the Draft SIP. Therefore, these comments were not incorporated into the Draft SIP because IDEM prefers the existing language as it is throughout the document.

United States Steel Corporation (US Steel), Gary Works (email from Jacob Blahut received on November 15, 2021)

IDEM appreciates the comments submitted by US Steel in support of Indiana's draft RH SIP, which do not require a response from IDEM. A copy of the comments submitted can be found in Appendix Y.

Alcoa Warrick Operations (email from Thomas Shaw received on November 3, 2021)

Comment 1
Alcoa would like to correct the cost effectiveness numbers for the Flue Gas Desulfurization for Potlines 2-6 which is $16,800 per ton and the Anode Baking Ring Furnace which is $45,500 per ton as noted on page 2 of the August 13, 2021, report from Burns & McDonnell.

Response 1
The cost effectiveness numbers for Potlines 2-6 and the Anode Baking Ring Furnace were corrected in the Indiana RH SIP for the Second Implementation Period document and Appendix J.

Buzzi Unicem USA (Buzzi Unicem) (email from Michelle Ferguson received on November 15, 2021)

Comment 1
The comments submitted by Buzzi Unicem relate to the different pollution control measures chosen for four-factor analysis, the percentage of control attributed to those measures, and the feasibility of installing them on the cement kilns at the Greencastle facility. The Buzzi Unicem's comments also explain how the cost information in the cost estimate and cost effectiveness evaluation don't accurately represent the costs associated with installing the controls evaluated on the Greencastle cement kilns.

Response 1
IDEM requested cost information from Buzzi Unicem to assist with developing cost estimates for potential control measures evaluated for the Greencastle cement kilns. However, the source had not invested any resources or time into developing information related to upgrades to existing pollution control systems or the installation of new pollution control systems on the cement kilns that would be helpful to IDEM in developing the cost estimates for controls. Therefore, IDEM prepared a more general analysis of the potential controls and costs to install them for the Greencastle kilns using existing information available to the agency.

IDEM used the LADCO whitepaper procured for LADCO member states to use in developing their four-factor analyses for the second implementation period; the cement kiln control device information collected and shared by the Federal Land Managers; and the cost estimate information provide by Lehigh for SNCR and SCR control systems to develop the four-factor analyses for the cement kiln source category and the source-specific analysis for the Greencastle cement kilns. IDEM acknowledges that the information interpolated from the cost estimates are not precise estimates specific to the Greencastle kilns; however, the information provided in the Buzzi Unicem comments submitted do not provide enough source-specific information to develop more accurate cost estimate information or decisively determine the feasibility of the controls evaluated. Therefore, Buzzi Unicem's comments are appreciated and included in Appendix W; but no changes will be made to the cement kiln four-factor analysis as a result of the source's comments.

Lehigh Hanson, Inc. (Lehigh) (email from Adam N. Swercheck received November 12, 2021)

A four-factor analysis for the Lehigh Mitchell facility was not conducted due to the fact that the company was issued a Title V permit and is in the process of constructing a new state-of-the-art facility to replace the old facility. The details of Lehigh's plans for the new facility are included in the RH SIP, therefore the company's comments are appreciated and included in Appendix W; but no changes will be made to the cement kiln four-factor analysis as a result of the source's comments.

Indiana Energy Association (IEA) (email from Mindy Westrick Brown received on November 12, 2021)

IDEM appreciates the comments submitted by IEA in support of Indiana's draft RH SIP, which do not require a response from IDEM. A copy of the comments submitted can be found in Appendix Y.

National Parks Conservation Association (NPCA) (email from Colin Deverell received on October 28, 2021)

Comment 1
Fully analyze reasonable progress emission controls for all coal plants in the state in this planning period. It is commonplace for coal plants to have scrubbers that reduce upwards of 98% of SO_2 emissions and selective catalytic reduction systems to reduce 95% of emissions of NO_x. Indiana cannot disregard these controls or upgrades to those facilities that already have them installed with weak performance.

Response 1
See the "Responses 2 and 3" under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 2
Evaluate all applicable controls for non-power plant sources and correct the cost of controls calculations.

Response 2
See "Responses 6, 8, 10, 11, and 12" under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Comment 3
Thoroughly assess environmental justice impacts.

Response 3
The impact of emission sources on regional haze occurs downwind and the Regional Haze Rule addresses visibility impacts on Class I areas. Therefore, Indiana's RH SIP is only addressing emissions and visibility impacts on surrounding Class I areas. As U.S. EPA continues to evaluate environmental justice issues and how states can consistently and equitably address these issues, Indiana will continue to base its regulatory and permitting decisions on existing federal and state regulations that are protective of all Indiana citizens in all areas of the state.

Comment 4
Set enforceable retirements for any sources being counted on for pollution reduction.

Response 4
See "Responses 4, 5, 7, and 9" under the U. S. EPA summary of comments and responses section on page 4 of this document for this response.

Sierra Club (email from Rebecca Dien-Johns received on October 28, 2021)

Comment 1
Require polluters to reduce harmful air pollution, more specifically sulfur dioxide and nitrogen oxides, to protect visibility at our national parks and the public health of Hoosiers.

Responses 1
Table 8-4 of Indiana's RH SIP details the projected emissions reductions anticipated for NO_x emissions of 59% and SO_2 emissions of 52% from EGUs. This is a result of retirements of EGU boilers and federal regulations that have already gone into effect. Overall, all anthropogenic emissions from Indiana are projected to decrease by 42% of NO_x from 2016 to 2028 while SO_2

emissions will decrease by 32%, as described in Indiana's RH SIP, Section 5.15. These reductions will continue to improve visibility impairment at Class I areas as well as keep air quality throughout Indiana well below health-based air quality standards.

Sierra Club, National Parks Conservation Association, The Coalition to Protect America's National Parks, Just Transition Northwest Indiana, Hoosier Environmental Council, Izaak Walton League, and Save the Dunes (email from Tony Mendoza received on November 15, 2021)

Comment 1
IDEM arbitrarily and unlawfully failed to conduct reasonable progress analyses or consider emissions reductions for many of the state's largest sources of visibility impairment, including the entire electric generation unit ("EGU") sector.

Comment 2
Rather than conduct four-factor analyses for Indiana's EGUs, as required by the Clean Air Act and the Regional Haze Rule, IDEM impermissibly relied on unenforceable and unverifiable emission reductions from planned retirements or reductions in utilization at Indiana EGUs.

Comment 3
IDEM impermissibly exempts EGUs from further control analysis based on the state's purported compliance with the Uniform Rate of Progress.

Comment 4
The proposed SIP fails to properly establish reasonable progress goals and fails to consider the statutory reasonable progress factors for EGUs, and instead relies on factors that Congress did not intend for states to consider to exempt those sources from reasonable, cost-effective controls.

Comment 6
IDEM's control evaluation for the state's EGU sector fails to satisfy the Regional Haze Rule's requirement that the state include the "robust" technical demonstration showing that no additional controls are reasonable.

Comment 7
As explained below and in the attached Kordzi Report, IDEM failed to evaluate cost-effective and achievable emission reductions for several of Indiana's largest sources, including Gibson, Rockport, Warrick, Clifty Creek, Petersburg, Cayuga, and A.B. Brown. If the state had conducted four-factor analyses for those sources, it is clear that cost-effective controls are available.
Responses 1, 2, 3, 4, 6, and 7
See "Responses 2 and 3" under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 5
IDEM improperly defers making any four-factor determinations based on purported emission reductions from existing Clean Air Act programs.

Comment 8
For the sources for which IDEM did include four-factor analyses, the agency cherry picked emitting units from the facilities and did not consider all
emitting units.

Comment 9
IDEM's analyses for control analyses for the following seven sources, Greencastle facility, Indiana Harbor East and West Steel Mills Burns Harbor Steel Mill, U.S. Steel Gary Facility, SABIC Plastics, Warrick Newco (formerly Alcoa Warrick) and Cokenergy, rely on inaccurate and missing information, inflated costs and shortened useful life factors and otherwise are woefully inadequate and fundamentally inconsistent with the Clean Air Act and the Regional Haze Rule.

Comment 10
IDEM failed to consider all emission control options for those sources evaluated, including the most stringent measures.

Comment 11
IDEM's proposed SIP fails to include documentation necessary to independently review the availability of cost-effective controls.

Response 5, 8, 9, 10, and 11
See "Responses 6, 8, 10, 11, and 12" under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Comment 12
IDEM's interstate consultation is inconsistent with the requirements of the Regional Haze Rule.

Response 12
IDEM has acknowledged receipt of the asks received by other regional planning organizations and individual states. However, due to the delay in receiving the results from LADCO's source apportionment modeling until June of 2021, IDEM decided to complete development of Indiana's its RH SIP and then submit the interstate consultation responses along with the final SIP to EPA. IDEM's interstate consultation responses are included in Appendix AA of the final submittal.

Comment 13
IDEM must reevaluate, consider and incorporate the Federal Land Managers' comments.

Responses 13
IDEM summarized and addressed the Federal Land Managers comments in Appendix U and the agency's responses to issues raised by the Federal Land Managers are consistent with IDEM's responses to other similar comments received during the public comment period.

Comment 14
The proposed SIP fails to evaluate environmental justice or disproportionately impacted communities' impacts, resulting in a proposed SIP that does not reduce emissions and minimize harms to environmental justice and other disproportionately impacted communities, as strongly encouraged by the EPA's clarifying memo.

Response 14
While environmental justice (EJ) is an important issue and should be addressed on a case-by-case basis, regional haze addresses the formation of haze from secondary pollutants of which this formation occurs from photochemical reactions. These photochemical reactions can take place several if not hundreds of kilometers away from an emission source. Prevention of Significant Deterioration (PSD) and associated modeling tools are more appropriate regulatory mechanisms to address EJ. EJ should not be a consideration in determining long term strategy decisions for regional haze.

Clarification Responses to statements made in the Sierra Club Comments

1st Statement on Pg. 10, Section II
Based on 2016 emissions, IDEM established screening threshold Q/d value of 5 to screen out sources with either low emissions or located at far distances from Class I areas that would not have visibility impacts.

Clarification Response to 1st Statement
IDEM used 2018 emissions to conduct its Q/d screening, as stated in the draft RH SIP, page 43.

2nd Statement on Pg. 46, Section III.A
Only Missouri and Arkansas were consulted.

Clarification Response to 2nd Statement
IDEM consulted with VISTAS and MANE-VU over the course of the SIP document development period. IDEM has evaluated its visibility impacts on all Class I areas in the eastern half of the United States. Specific responses to each state and multi-jurisdiction organization areas, in which consultation occurred, are included in the final SIP.

3rd Statement on Pg. 46, Section III.A
IDEM must re-initiate consultation with Missouri since Graph 23-18 shows the modeled visibility impact at Mingo for 2028 appears on the unadjusted glidepath for 2028.

Clarification Response to 3rd Statement
The glidepath charts are graphical representations of modeled and monitored results for each Class I area. The URP is the uniform rate of visibility progress in which 2000-2004 represents the baseline period of the URP and 2064 represents the endpoint where the deciview value of the URP is assumed for the purpose of analysis to reach natural visibility conditions. The line between 2000 and 2064 is the graphical representation of this data. IDEM reviewed the LADCO modeling output that determined the URP and the modeled URP value for 2028 was calculated at 19.44 deciviews. Therefore, the modeled visibility impairment value for Mingo of 18.94 deciviews is 0.5 deciviews below the 2028 URP value of 19.44 deciviews. Since the modeled visibility value is below the URP for Mingo, a “robust demonstration” is not required. LADCO’s modeled output can be found in association with the LADCO “Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018-2028 Planning Period - Technical Support Document“ as listed in Appendix L of the RH SIP.

4th Statement on Pg. 55, Section V
Sierra Club stated Indiana ranks #1 in toxics releases per square mile.

Clarification Response to 4th Statement
U.S. EPA's Toxic Release Inventory (TRI) reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal. Indiana's total toxic air releases are only a portion of this total and have consistently declined by nearly 70% since 2006 with continued reductions in air toxics anticipated.

5th Statement on Pg. 56, Section V
Sierra Club stated according to EPA, U.S. Steel - Gary Works is the state's top polluter, producing 22.5 million pounds of pollutants.

Clarification Response to 5th Statement
U.S. EPA's TRI reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal and the air emissions portion of U.S. Steel's releases were 312,203 pounds, accounting for 1.4% of its total releases.

General Public Comments

Numerous emails were received from individuals who made the same general comments summarized below.

Comment 1
Indiana's RH SIP contains no new reductions in pollution.

Comment 2
Indiana's RH SIP plan must require polluters to reduce SO_2/NO_x

Response 1 and 2
Table 8-4 of Indiana's RH SIP details the projected emissions reductions anticipated for NO_x emissions of 59% and SO_2 emissions reductions of 52% from EGUs. This is, in part, a result of retirements of EGU boilers and federal regulations that have already gone into effect. Overall, all anthropogenic NO_x emissions from Indiana are projected to decrease by 42% from 2016 to 2028 while all anthropogenic SO_2 emissions will decrease by 32% over the same time period, as described in Indiana's RH SIP, Section 5.15.

Comment 3
Indiana's RH SIP fails to make reasonable progress at Class I areas and is woefully inadequate.

Comment 4
Set enforceable retirements for any source the state is counting on for pollution reduction.

Response 3 and 4
See "Responses 4, 5, 7 and 9" under the U. S. EPA summary of comments and responses section on page 4 of this document for this response.

Comment 5
Indiana's RH SIP fails to require cost-effective controls/enforceable retirements.

Comment 6
Evaluate all applicable controls for non-power plants and correct cost analysis.

Comment 7
Require US Steel and Alcoa to reduce pollution and protect parks and public health.

Response 5, 6, and 7
See "Responses 6, 8, 10, 11, and 12 under the U. S. EPA summary of comments and responses section on page 6 of this document for this response.

Comment 8
Fully analyze emission controls for all coal plants in the state.

Comment 9
Require Gibson and Petersburg to reduce pollution and protect parks and public health.

Response 8 and 9
See "Responses 2 and 3 under the U. S. EPA summary of comments and responses section on page 1 of this document for this response.

Comment 10
IDEM should thoroughly assess environmental justice.

Response 10
Indiana assesses all areas of the state equally according to current state and federal regulations and uses all available existing data and information to determine air quality impacts. PSD and associated modeling tools are more appropriate regulatory mechanisms to address EJ issues. EJ should not be a consideration in determining long term strategy decisions for regional haze in states without Class I areas.

Emails received from individuals who made general comments are summarized below.

Bill Walters

Comment
Only Texas produces more CO_2 from coal than Indiana.

Response
Without proper context of the commenter's statistical reference and the source of this ranking, it is difficult to provide a direct response. IDEM retrieved U.S. EPA emissions data for states' breakdown of carbon dioxide (CO_2) emissions from 2008 to 2018 (the time period for the first implementation period for regional haze) and Indiana is ranked 8th in CO_2 emissions nationally and 3rd among Midwest states. Indiana is trending downward over this period of time with a 16.5% drop in CO_2 emissions from fossil fuel combustion. www.epa.gov/sites/default/files/2020-10/documents/state_co2_emissions_from_fossil_fuel_combustion_1990-2018.pdf. Additionally, more recent information for 2017 to 2020 from U.S. EPA's Clean Air Market Division (CAMD) shows Indiana CO_2 emissions from electric utilities are dropping. Comparison of 2017 to 2019 showed a 7% drop in CO_2 emissions while 2020 CO_2 emissions, no doubt impacted from Covid-19, showed a 22.7% drop, ahead of the national average decrease from 2017 to 2020 of 17%.

Kimberly Wellman

Comment
EPA's Toxic Release Inventory shows Indiana releases most chemicals per square mile (2019)

Response
U.S. EPA's TRI reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal. Indiana's total toxic air releases have consistently declined since 2006 by nearly 70% with continued reductions in air toxics anticipated.

Dlynn Melo

Comment
Hard to breath on days where temperature inversions push down smoke/haze.

Response
IDEM would encourage all Indiana citizens refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in any area of the state. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx

Diana Allen

Comment
Worsening air pollution worsens her asthma.

Response
Table 25-1 of Indiana's RH SIP demonstrates the vast emissions reductions realized throughout the state with reduction of NO_2 emissions of 65% and SO_2 emissions reductions equating to over 90% since 2007. IDEM would encourage the public to refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in an area. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx.

Thomas Sherer

Comment
Without sanctions and penalties, haze plan will cause more haze.

Response
Indiana's Regional Haze SIP demonstrates tremendous emissions reductions that have greatly improved visibility at Class I areas throughout the eastern half of the country. Indiana sources' projected emissions by the year 2028 are even lower than current emissions so Indiana's visibility impacts will be even less on surrounding Class I areas.

Sharon Smith

Comment
Family deals with COPD which doctors say is caused by air pollution. Polluters get a free pass to pollute.

Response
IDEM would encourage the public to refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in an area. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx.

Jim Merkle

Comment
Concerned about continuing releases into Lake Michigan.

Response
While this does not directly relate to regional haze, IDEM's Office of Water Quality is investigating recent releases and continues to work with the responsible companies, local and county leaders and concerned citizens on addressing these incidents.

Dania Straughan

Comment
Pregnant mom with asthma, reduce toxic waste that she is forced to breathe.

Response
Indiana's Regional haze SIP is focused on sulfur dioxide and nitrogen oxides impacts on visibility on all federal Class I areas. It should be noted that Indiana's total toxic air releases have consistently declined since 2006 by nearly 70% with continued reductions in air toxics anticipated. IDEM would encourage all Indiana citizens to refer to the SmogWatch air quality forecasting website for current and forecasted ozone and fine particulates concentrations. Air quality forecasts take into account natural pollution resulting from wildfires and desert dust events as well as weather conditions in which fine particulates or ozone develop over time in an area. The SmogWatch link is https://apps.idem.in.gov/smogwatch/Today.aspx.

Arianna Grazziani

Comment
Current laws don't protect health and causes destruction of property.

Response
The National Ambient Air Quality Standards consist of primary and secondary standards as determined by science experts and health officials and adopted into U.S. EPA's Code of Federal Register as approved federal regulations. The secondary standards are designed to protect the public welfare from adverse effects, including those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort

and well-being. Indiana is currently meeting all primary and secondary standards at all its ambient air quality monitoring sites for all criteria pollutants throughout the state.

Mark Nowotarski

Comment
Indiana ranks #1 in toxic releases per square mile, 3rd in carbon emissions, has 5 super polluters.

Response
EPA's TRI reporting incorporates releases into the air, water, land disposal or transferred off-site for disposal. Indiana's total air toxic releases have consistently declined since 2006 by nearly 70% with continued reductions in air toxics anticipated. IDEM has retrieved U.S. EPA emissions data for states' breakdown of carbon dioxide (CO_2) emissions from 2008 to 2018 (the time period for the first implementation period for regional haze) and Indiana is ranked 8th in CO_2 emissions nationally and 3rd among Midwest states. Indiana is trending downward over this period of time with a 16.5% drop in CO_2 emissions from fossil fuel combustion. www.epa.gov/sites/default/files/2020-10/documents/state_co2_emissions_from_fossil_fuel_combustion_1990-2018.pdf.

Additionally, more recent information for 2017 to 2020 from U.S. EPA's CAMD shows Indiana CO_2 emissions continue to drop. Comparison of 2017 to 2019 CO_2 emissions showed a 7% drop while 2020 CO_2 emissions, no doubt impacted from Covid-19, showed a 22.7% drop, ahead of the national average decrease in CO_2 emissions from 2017 to 2020 of 17%.

Linda Evinger

Comment
Indiana is a polluted state which leads other companies and individuals to not locate/live in the state. Protect the bees, bats, wildlife.

Response
Indiana's Regional haze SIP is focused on sulfur dioxide and nitrogen oxides impacts on visibility on all federal Class I areas. Table 25-1 of Indiana's RH SIP demonstrates the vast emissions reduction realized throughout the state with reduction of NO_x emissions of 65% and SO_2 emissions reductions equating to over 90% since 2007. It should be noted that the National Ambient Air Quality Standards consist of primary and secondary standards. The secondary standards are designed to protect the public welfare from adverse effects, including those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort and well-being. Indiana is currently meeting all secondary standards for all criteria pollutants.

Drew Davis

Comment
Protect all National Park Service sites in Indiana, Indiana State Parks and State Historical sites.

Response
The National Ambient Air Quality Standards consist of primary and secondary standards. The secondary standards are designed to protect the public welfare from adverse effects, including

those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort and well-being. Indiana is currently meeting all secondary standards for all criteria pollutants at all ambient air quality monitors throughout the state.

Michael Bean

Comment
IDEM must reduce and limit SO_2/NO_x and increase regulations/monitoring of SO_2/NO_x

Response
Table 8-4 of Indiana's RH SIP details the projected emissions reductions anticipated for NO_x emissions of 59% and SO_2 emissions of 52% from EGUs. This is a result of retirements of EGU boilers and federal regulations that have already gone into effect. Overall, all anthropogenic emissions from Indiana are projected to decrease by 42% of NO_x emissions from 2016 to 2028 while SO_2 emissions will decrease by 32%, as described in Indiana's RH SIP, Section 5.15. As such, Indiana has determined that current "on-the-books" regulatory measures and monitoring of NO_x and SO_2 emissions are adequate to address regional haze for sources throughout the state based on the tremendous visibility progress made to date. NO_x and SO_2 emissions are addressed in Indiana's RH SIP with future emission reductions anticipated.

Richard Hill

Comment
Maintain clean natural views/healthy, breathable air. Lives near Clifty Creek which needs to comply with regulations

Response
IDEM compliance staff have confirmed that Clifty Creek complies with its permit conditions and meets compliance and monitoring requirements. There have been no excess emissions issues from the facility and Clifty Creek submits timely monitoring and compliance reports.

Susan Thomas

Comment
Photosynthesis is disrupted, and native plants are damaged.

Response
The National Ambient Air Quality Standards consist of primary and secondary standards. The secondary standards are designed to protect the public welfare from adverse effects, including those related to effects on soils, water, crops, vegetation, man-made (anthropogenic) materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards; economic values, and personal comfort and well-being. Indiana is currently meeting all secondary standards for all criteria pollutants throughout the state.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 70
Konidena Declaration

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").

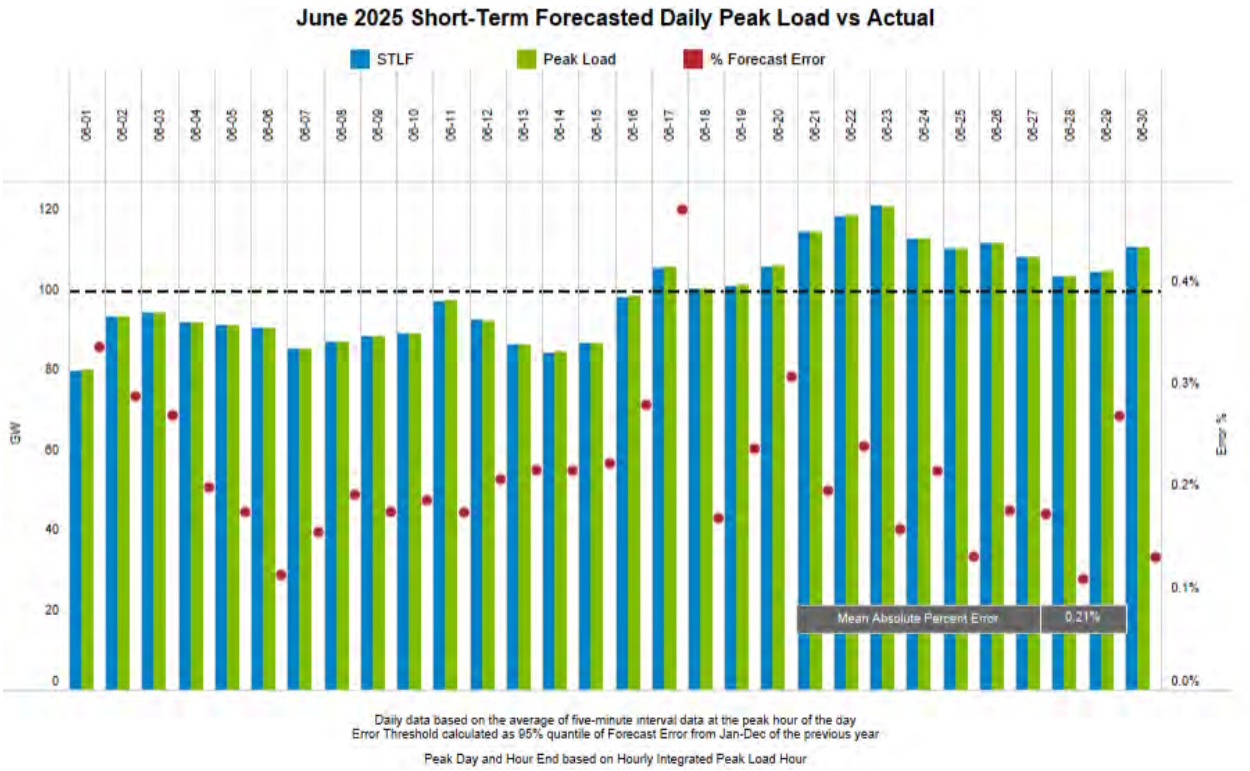
9. I was asked by Earthjustice, Sierra Club, Natural Resources Defense Council, and Environmental Defense Fund to develop an opinion on (A) whether MISO's alerts and operating conditions during June 2025 provide a factual basis for the Order's findings of a shortage of electric energy and a shortage 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

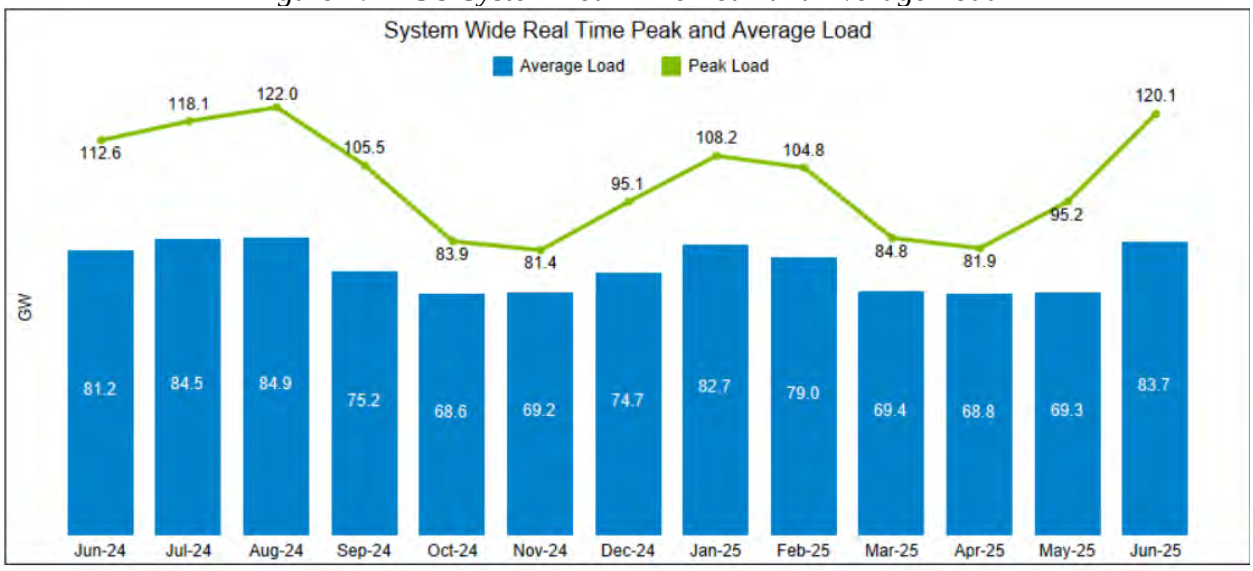
[1] MISO Monthly Operations Report: June 2025 at 25, https://cdn.misoenergy.org/202506%20Market%20and%20Operations%20Report709571.pdf.

[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.

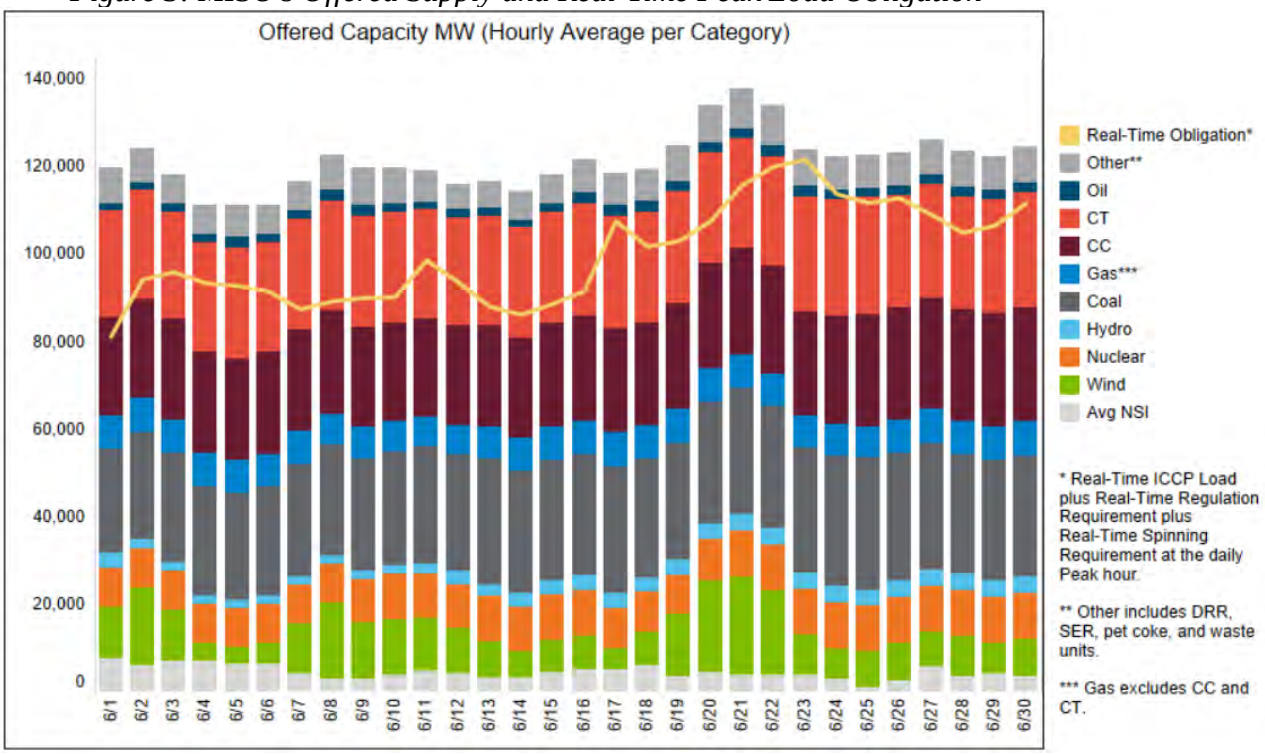
	Offered Supply	122,635 MW
+	Committed Emergency Headroom	3,946 MW
+	Uncommitted Emergency Headroom	3,382 MW
-	Peak Load	119,312 MW
-	Operating Reserve	2,710 MW
=	**Surplus**	**7,941 MW**

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."

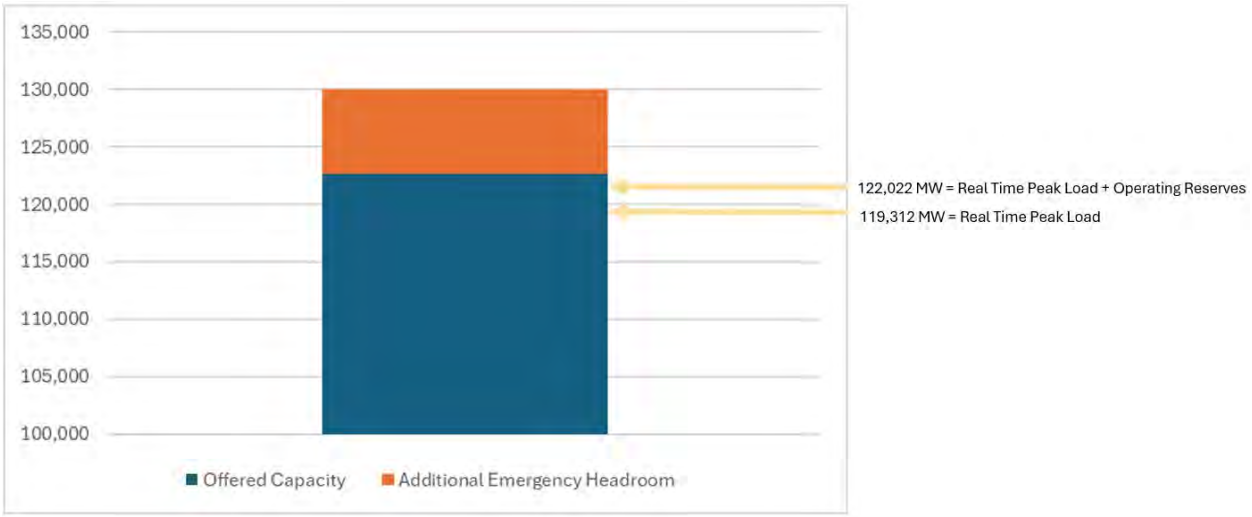
Figure 3: MISO's Offered Supply and Real-Time Peak Load Obligation



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).

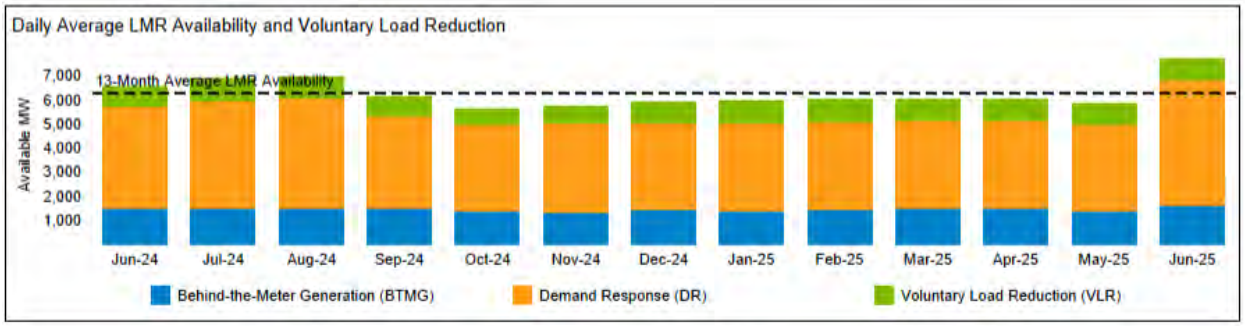
Figure 5: MISO's Available Load-Modifying Resources at Peak Load on June 23, 2025

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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 71
NIPSCO 2018 IRP



Northern Indiana Public Service Company LLC

2018
Integrated Resource Plan

October 31, 2018

YOUR ENERGY YOUR FUTURE

IRP

2018 Integrated Resource Plan Executive Summary

At NIPSCO, we're proud that our work provides the energy that northern Indiana families and businesses rely on to power their daily lives. We work each day with the goal of growing alongside our communities and responding to our customers' needs.

As our customers' needs have changed, so has the energy market. Now we stand at the crossroads of the future, with the opportunity to invest in balanced energy options and make energy more affordable and cleaner.

With an eye toward the future, we've been performing a comprehensive analysis of our future energy mix and meeting with our customers, our employees and local community leaders over the past year. The result of this process is an Integrated Resource Plan (IRP).

The plan—which presents over $4 billion in long-term cost savings—is a balanced, gradual transition that will strengthen our region now and put us on a path to a more cost-effective, cleaner and more sustainable future.

It's "Your Energy" and it's "Your Future."

NIPSCO®
A NiSource Company

About NIPSCO

More than 460,000 northern Indiana homes and businesses depend on NIPSCO each day for safe, reliable and affordable energy. Northern Indiana is fortunate to be home to some of the top production facilities in the United States. This has a unique impact on NIPSCO's energy demand profile. Five of our largest industrial customers, primarily in steel and oil refining, account for about 40 percent of NIPSCO's energy demand.

As a member of the regional transmission organization Midcontinent Independent System Operator (MISO), NIPSCO is able to supplement its own energy resources through other participating utilities in MISO's footprint. This relationship helps ensure reliability and cost-effective operations.

About the 2018 Integrated Resource Plan

To help ensure that we continue to meet the needs of our customers, we must have a road map to prepare for future energy needs. Our 2018 IRP charts a path for how best to meet those needs over the next 20 years. NIPSCO presents this plan to the Indiana Utility Regulatory Commission (IURC).

The electric industry, customer needs, expectations and the way energy is consumed continue to evolve. Technologies are rapidly changing and expanding. The electric generation landscape is shifting dramatically, not just for NIPSCO but for the country as a whole.

NIPSCO's 2018 Integrated Resource Plan

Resource planning is a complex undertaking, one that requires addressing the inherent uncertainties and risks that exist in the electric industry. Key factors referred to in the IRP include market conditions, fuel prices, environmental regulations, economic conditions and technology advancements.

Using in-depth data, modeling and risk-based analysis provided by internal and external subject matter experts, we project future energy needs and evaluate available options to meet those needs.

New to NIPSCO's IRP, we issued a formal Request for Proposals (RFP) solicitation to uncover the breadth of actionable projects that were available to NIPSCO within the marketplace across all technology types. The RFP also served to collapse uncertainty about the costs of various technologies, particularly renewables.

The projections included in our plan are based on the best available information at this point in time. Changes that affect our plan may arise, which is why it's important for us to remain flexible and continually evaluate current market conditions, the evolution of technology—particularly renewables—and demand side resources, as well as laws and environmental regulations.

Engaging Customer and Public Stakeholders

Resource planning requires the consideration of diverse points of view, which is one of the reasons that external stakeholder involvement is a critical component throughout the development of the IRP.

We engaged stakeholder groups and individuals in a variety of ways throughout the entirety of the planning process.

Portfolio

- ✓ **Affordable**
- ✓ **Reliable**
- ✓ **Compliant**
- ✓ **Diverse**
- ✓ **Flexible**

NIPSCO initiated stakeholder advisory efforts for its 2018 IRP in March, hosting a public meeting and launching a web page for interested stakeholders to follow the progress. Four additional public meetings followed in May, July, September and October. NIPSCO also hosted public forums to discuss specific topics arising from the IRP.

In addition to posting public invitations on our IRP web page, we sent an invitation to past IRP stakeholder participants. Members of our executive leadership team and several of our subject matter experts attended each meeting to hear feedback and answer questions.

Throughout the IRP process, stakeholders were also invited to meet with us on a one-on-one basis to discuss key concerns and perspectives. Each interaction provided a forum for discussion and feedback related to the many components of the IRP.

Valuable discussions arose in several key areas, including environmental regulations, fuel costs, load forecasting calculations, energy efficiency program analysis and renewable energy development.

The feedback gathered during the stakeholder process raised valuable questions, helped us better evaluate our options and improved the final plan. A summary of the meeting materials, including presentations and stakeholder questions, is available at NIPSCO.com/IRP.

Forecasting Future Customer Demand

Projecting customers' energy needs is another key component of the IRP process. Looking 20 years into the future does not come without challenges, so we rely on data-driven models to help develop our best estimates. Specific models are developed for residential users, commercial users and industrial users, as well as for all other types of customers, including street lighting, public authorities, railroads and company use.

Data sources used in creating the forecast include energy, customer and price data, economic drivers, weather data and appliance saturation. Given the unique makeup of NIPSCO's customer base, industrial operations are another significant variable. In order to best model their load requirements, we rely on discussions with our 20 largest industrial customers.

With this data, we developed multiple scenario forecasts to capture the range of uncertainty for both energy requirements and peak demand.

Current Supply

NIPSCO's current resource portfolio is composed of hydroelectric, wind, demand-side resources and natural gas-fired sources in addition to the company's coal-fired plants.

Coal remains the largest part of NIPSCO's fleet, accounting for more than half of total capacity, followed by natural gas-fired electric generation.

NIPSCO also offers a Net Metering Program and a Feed-in Tariff Program (FIT), which allows commercial and residential customers to generate their own power from renewable resources such as wind, solar, hydro and biomass.

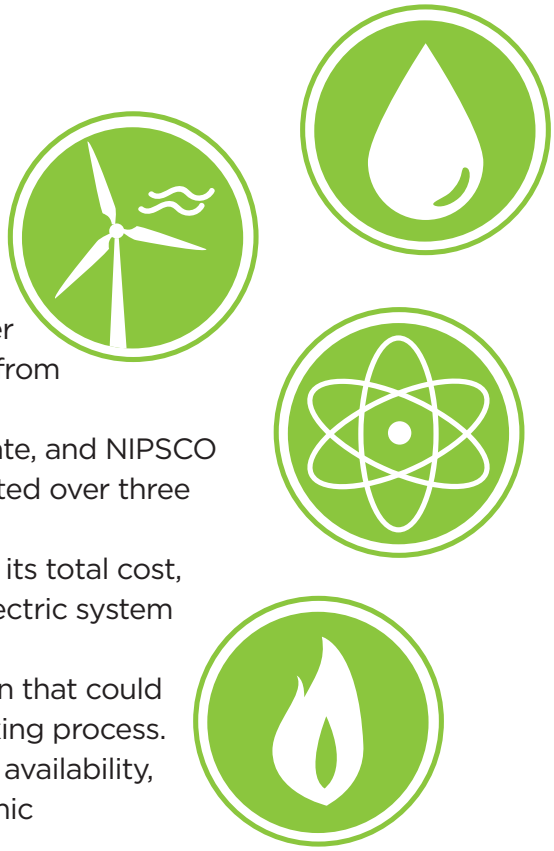
To further support renewable energy development, we give customers the power to choose green energy not only through the Net Metering and FIT Programs, but also through the Green Power Program, in which we buy renewable energy credits on customers' behalf.



NIPSCO Generating Resources

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	14	Coal	431	1976
	15	Coal	472	1979
	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
Subtotal			1,780	
Sugar Creek		NG	535	2002
Bailly	10	NG	31	1968
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
Subtotal			10	
Wind		Wind	100	2009
NIPSCO			2,925	

Analyzing Future Supply Options—Request for Proposals



New to the process in the 2018 IRP, NIPSCO issued a formal Request for Proposals (RFP) to help inform the planning process, and to gain better information on available, real projects at real costs from within the marketplace.

All energy technologies were eligible to participate, and NIPSCO received 90 proposals—the sum of which represented over three times NIPSCO's current generating capacity.

Evaluating each source of electric generation for its total cost, environmental benefits, reliability, impact on the electric system and risks is an important step in the IRP.

Results from the RFP provided better information that could be incorporated into the analysis and decision-making process.

Specific screening criteria include energy source availability, technical feasibility, commercial availability, economic attractiveness and environmental compatibility.

2018 Proposals Submitted to NIPSCO

Technology	CCGT*	CT*	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
# of Bids	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

***CCGT**—Combined Cycle Gas Turbine

***CT**—Combustion Turbine

Energy Efficiency

Promoting energy efficiency not only is good for customers, it can play an important role in helping ensure that we can meet future energy needs. NIPSCO offers a variety of programs to help residential and business customers save energy. The programs are tailored to customers and designed to help ensure energy savings.

Since 2010, NIPSCO customers have saved more than 1 million megawatt hours of electricity by participating in the range of energy efficiency programs offered by NIPSCO.

Technologies continue to change, and it's important that we constantly evaluate our offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings.

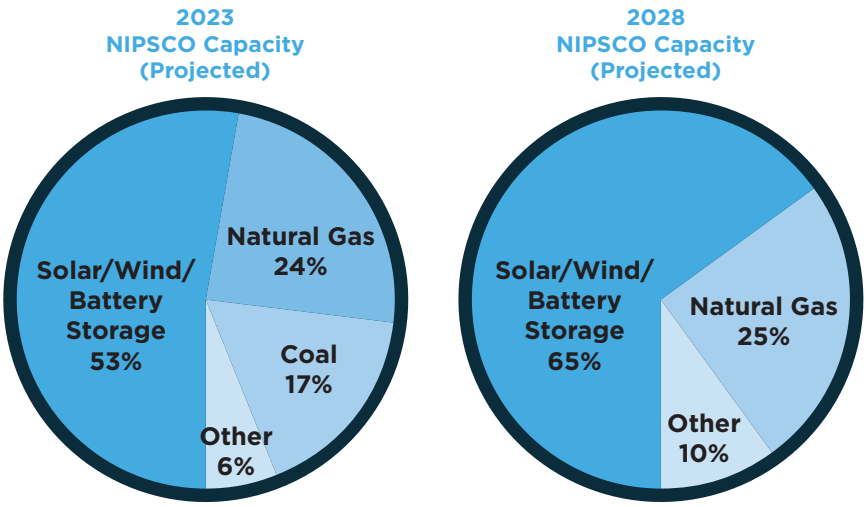
Findings and Next Steps

Throughout the IRP analysis, we are striving to balance the needs of our customers, employees and other community stakeholder interests.

Our goal as we look forward is to transition to the best-cost, cleanest electric supply mix available while keeping options open for the future as technologies and markets change.

Analysis shows that the most viable path for customers involves accelerating the retirement of a majority of NIPSCO's remaining coal-fired generation in the next five years and all coal within the next 10 years. Replacement options point toward lower-cost renewable energy resources such as wind, solar and battery storage technology.

As we gradually transition to creating a more diversified energy mix that will be more cost effective and better serve customers in the future, we are committed to ensuring that this plan limits the impact on local employees and our economy as a result of the remaining coal retirements.



Short-Term Action Plans (2019–Through 2021)

The objective of the plan is to ensure that NIPSCO can confidently transition to the least-cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility for technology and market changes during this period.

- Initiate retirement of R.M. Schahfer Coal-Fired Units 14, 15, 17, and 18 by 2023
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units
- Select replacement projects identified from the 2018 RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost
- File for Certificate(s) of Public Convenience and Necessity and other necessary approvals for selected replacement projects
- Procure short-term capacity as needed from the MISO market or through short-term PPA(s)
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
- Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)
- Continue implementation of filed Energy Efficiency Programs Plan for 2019 to 2021
- Comply with North American Electric Reliability Corporation, U.S. Environmental Protection Agency and other regulations
- Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

Long-Term Action Plans (2023–Beyond)

- Fully retire the R.M. Schahfer Coal-Fired Units 14, 15, 17, and 18 by the end of 2023 and the Michigan City Coal-Fired Unit 12 by the end of 2028
- Monitor market and industry evolution and refine future IRP plans

While NIPSCO will continue to update its long-term plan within the next IRP, we believe that these actions coming out of the 2018 IRP will place NIPSCO on a course to continue providing reliable power while enabling lower costs and providing significant environmental benefits.

Table of Contents

Section 1. Integrated Resource Plan 1
1.1 Short Term Action Plan 1
1.2 Plan Summary 2
1.3 Rationale for NIPSCO 2018 IRP Update Filing 3
1.4 Emerging Issues 4
1.4.1 Customer Risk 4
1.4.2 Technology Risk 4
1.4.3 Market Risk 4
Section 2. Planning for the Future 6
2.1 IRP Public Advisory Process 6
2.1.1 Stakeholder Meeting 1 6
2.1.2 Stakeholder Meeting 2 7
2.1.3 Stakeholder Meeting 3 7
2.1.4 Technical Webinar 7
2.1.5 Stakeholder Meeting 4 8
2.1.6 Stakeholder Meeting 5 8
2.1.7 One-on-one Stakeholder Meetings 8
2.2 IRP Planning Process 9
2.2.1 Contemporary Issues 10
2.2.2 2016 IRP Feedback and 2018 Process Improvement Efforts 10
2.3 Resource Planning Approach 10
2.3.1 Key Planning Assumptions 14
Section 3. Energy and Demand Forecast 17
3.1 Major Highlights / High Level Summary / Discussion of Load 17
3.2 Development of the Forecast – Method and Data Sources 17
3.2.1 Data Sources - Internal 18
3.2.2 Data Sources - External 18
3.3 Residential 19
3.4 Commercial 20
3.5 Industrial 22

3.6 Street Lighting, Public Authority, Railroads, Company Use, Losses.....24
3.7 Peak.....24
3.8 MISO Coincident Peak.....25
3.9 Customer Self-Generation.....26
3.10 Weather Normalization.....26
3.11 Forecast Results – Base Case.....28
3.12 Discussion of Forecast and Alternative Cases.....32
3.12.1 High/Low Growth Cases.....32
3.13 Evaluation of Model Performance and Accuracy.....32
Section 4. Supply-Side Resources.....36
4.1 Fuel Procurement Strategy.....36
4.1.1 Coal Procurement and Inventory Management Practices.....36
4.1.2 Natural Gas Procurement and Management.....40
4.2 Electric Generation Gas Supply Request for Proposal Process.....41
4.3 Existing Resources.....41
4.4 Supply Resources.....41
4.4.1 Michigan City Generating Station.....42
4.4.2 R.M. Schahfer Generating Station.....43
4.4.3 Sugar Creek Generating Station.....44
4.4.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources).....44
4.4.5 Barton and Buffalo Ridge Wind (NIPSCO Purchase Power Agreements).....45
4.5 Total Resource Summary.....46
4.6 Operations Management and Dispatch Implications.....48
4.7 MISO Wholesale Electricity Market.....48
4.8 Resource Adequacy.....48
4.9 Future Resource Options.....50
4.9.1 Third-Party Data Source Review.....50
4.9.2 All Source Request for Proposals.....53
4.10 Incorporation of the All-Source RFP Results into the IRP.....56
4.10.1 Tranche Development.....57
4.10.2 Renewable Resource Tax Incentives and Tax Equity Partnership.....60

4.10.3 Self-build....62
4.10.4 CCGT Breakeven Analysis....63
4.10.5 Coal to Gas Conversion....63
Section 5. Demand-Side Resources....65
5.1 Existing Resources....65
5.1.1 Existing Energy Efficiency Resources....65
5.1.2 Existing Demand Response Resources....72
5.2 DSM Electric Savings Update....74
5.2.1 DSM Electric Savings Update – Purpose and Key Objectives....74
5.2.2 Impact of Opt-out Customers....75
5.2.3 Modeling Framework....75
5.3 Energy Efficiency and Demand Response Bundles....75
5.4 Energy Efficiency Potential Impacts....76
5.4.1 Changes That Impacted Energy Efficiency Potential....76
5.5 Energy Efficiency Measures & Potential....78
5.5.1 Residential Energy Efficiency Measures....78
5.5.2 Achievable Electric Energy Efficiency Potential....80
5.5.3 Recommended Residential programs....81
5.5.4 C&I Energy Efficiency Measures....82
5.5.5 Achievable Electric Energy Efficiency Savings....84
5.6 Future Resource Options....87
5.6.1 Energy Efficiency Bundles....87
5.6.2 Demand Response Program Options....91
5.6.3 Demand Response Load Reduction Assumptions....91
5.6.4 Interruptible Rider....92
5.7 Consistency between IRP and Energy Efficiency Plans....92
Section 6. Transmission and Distribution System....95
6.1 Transmission System Planning....95
6.1.1 Transmission System Planning Criteria and Guidelines....95
6.1.2 North American Electric Reliability Corporation....95
6.1.3 Midcontinent Independent System Operator, Inc.....96
6.1.4 Market Participants....97

6.1.5 Customer Driven Development Projects 97
6.1.6 Transmission System Performance Assessment....97
6.1.7 NIPSCO Transmission System Capital Projects....98
6.1.8 Electric Infrastructure Modernization Plan....98
6.1.9 Evolving Technologies and System Capabilities....99
6.2 Distribution System Planning 99
6.2.1 Evolving Technologies and System Capabilities....101
Section 7. Environmental Considerations 103
7.1 Environmental Sustainability....103
7.2 Environmental Compliance Plan Development....103
7.3 Environmental Regulations....103
7.3.1 Solid Waste Management 103
7.3.2 Clean Water Act....104
7.3.3 Effluent Limitations Guidelines....104
7.3.4 Clean Air Act and Climate Strategy Assessment 105
7.4 Emission Allowance Inventory and Procurement....106
7.4.1 Title IV Acid Rain - SO_2 Emission Allowance Inventory....106
7.4.2 CSAPR Emission Allowance Inventory 107
Section 8. Managing Risk and Uncertainty....108
8.1 Introduction & Process Overview....108
8.2 Base Case Market Drivers and Assumptions....108
8.2.1 Natural Gas Prices....108
8.2.2 Coal Prices 114
8.2.3 Carbon Policy and Prices 117
8.2.4 MISO Energy and Capacity Prices 118
8.2.5 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment 121
8.3 IRP Scenarios....124
8.3.1 Aggressive Environmental Regulation Scenario 124
8.3.2 Challenged Economy Scenario 129
8.3.3 Booming Economy/ Abundant Natural Gas Scenario 136
8.4 IRP Stochastics Development....141
Section 9. Portfolio Analysis....145

9.1 Retirement Analysis....145
9.1.1 Process Overview....145
9.1.2 Retirement Analysis Methodology and Results....145
9.1.3 Identification of Retirement Portfolios....146
9.1.4 Identification of Least-Cost Replacement Capacity....146
9.1.5 Evaluation of Each Retirement Portfolio - Assumptions....147
9.1.6 Evaluation of Each Retirement Portfolio – Scorecard Metrics....149
9.1.7 Evaluation of Each Retirement Portfolio – Results....150
9.1.8 Preferred Retirement Portfolio....156
9.2 Replacement Analysis....158
9.2.1 Process Overview....158
9.2.2 Identification of Replacement Resource Concepts....159
9.2.3 Development of Specific Replacement Portfolios....160
9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics....164
9.2.5 Evaluation of Replacement Portfolios – Results....164
9.3 Preferred Replacement Portfolio....172
9.3.1 Procuring Wind in 2020....173
9.3.2 Preferred Plan Summary....174
9.3.3 Financial Impact....175
9.3.4 Capacity Resource Planning With Non Dispatchable Resources....176
9.4 Short-Term Action Plan....178
9.4.1 Procurement of Preferred Resources....179
9.5 Conclusion....179
Section 10. Customer Engagement....181
10.1 Enhancing Customer Engagement....181
10.1.1 Leveraging Stakeholder Feedback....181
10.1.2 NIPSCO's Customer Workshop Series....181
10.1.3 New Business Department....182
10.1.4 Customer Feedback....182
10.1.5 Community Partnerships - Community Advisory Panels....183
10.2 Customer Programs....183
10.2.1 Feed-in Tariff – Rate 765....183

10.2.2 Net Metering – Rider 780 185
10.2.3 Electric Vehicle Programs (Phase I and Phase II) – Rider 785 186
10.2.4 NIPSCO IN-Charge EV Program – Around Town (Phase II).....188
10.2.5 Green Power Program – Rate 760 189
10.3 Corporate Development and Community Support 191
10.3.1 Supporting Economic Growth 191
10.3.2 Supplier Diversity 192
10.3.3 Workforce Development.....192
10.3.4 Corporate Citizenship 193
10.3.5 Volunteerism.....194
Section 11. Compliance with Proposed Rule 196

Section 1. Integrated Resource Plan

1.1 Short Term Action Plan

Northern Indiana Public Service Company ("NIPSCO" or "Company") developed a short term action plan consisting of the actions NIPSCO will take for the period 2019 through 2021. The objective of the plan is to ensure that NIPSCO can confidently transition to the least cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility for technology and market changes during this three year period.

NIPSCO's short term action plan will focus on initiating the retirement process for all of the coal units at R. M. Schahfer Generating Station ("Schahfer") and selecting/acquiring replacement projects to fill the capacity gap as a result of the retirements in 2023. The retirements of the Units at Schahfer will likely require upgrades to NIPSCO's transmission system to maintain system reliability, and NIPSCO will identify and begin implementing the necessary upgrades during this period.

The robust response to the all-source request for proposal ("All-Source RFP") (discussed in more detail in Section 4) solicitation indicates that there are more than enough diverse resources and projects to meet NIPSCO supply needs in 2023. NIPSCO will adopt a phased-in approach to selecting and acquiring replacement resources, initially prioritizing replacement resources with expiring tax credits in order to maximize the benefits to customers. NIPSCO intends to make the necessary regulatory filings with the Indiana Utility Regulatory Commission ("IURC" or "Commission") in 2019. During the short-term action plan period, NIPSCO will rely on the Midcontinent Independent System Operator, Inc. ("MISO") market, short term purchase power agreements ("PPAs"), or other bilateral agreements for short term capacity and energy as needed. NIPSCO will continue to monitor technology and MISO market trends while staying actively engaged with project developers and asset owners to maintain flexibility and optionality. NIPSCO expects to conduct another All-Source RFP to acquire resources to fill the remainder of the 2023 supply that was not met in the 2019-2021 time frame.

NIPSCO will continue the implementation of its current Demand Side Management ("DSM") plan through 2021.[1] NIPSCO will also continue to comply with exiting environmental regulations and all North American Electric Reliability Corporation ("NERC") compliance standards and requirements. Lastly NIPSCO will continue to invest and modernize its electric infrastructure to maintain the safe and reliable delivery of electricity to its customers

As described in greater detail in Section 9.4 the action items included in NIPSCO's short term action plan include those listed in Table 1-1:

[1] On September 12, 2018, the IURC issued an Order in Cause No. 45011 approving NIPSCO's proposed Electric DSM Program for the period of 2019-2021.

Table 1-1: 2018 IRP Short-Term Action Plan

Initiate retirement of Schahfer units 14,15,17,18 by making required notifications to MISO, NERC and other organizations.
Identify and implement required reliability and transmission upgrades resulting from retirement of the units.
Select replacement projects identified from the 2018 All-Source RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost.
File for certificate(s) of public convenience and necessity ("CPCN(s)") for selected replacement projects.
Procure short-term capacity as needed from the MISO market or through short-term PPA(s).
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape.
Conduct a subsequent All-Source RFP in to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage).
Continue implementation of approved DSM plan for 2019 to 2021.
Comply with NERC, United States Environmental Protection Agency ("EPA") and other regulations.
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services.

1.2 Plan Summary

NIPSCO's preferred portfolio plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply was available to meet future customer needs. NIPSCO carefully planned and considered the impacts to its employees, the environment and the local economy (property tax, supplier spend, employee base) as the plans were developed.

This plan was developed through substantial quantitative and qualitative analysis. NIPSCO completed a thoughtful analysis to evaluate NIPSCO's generation units relative to viable alternatives. (*See* Section 9.) NIPSCO utilized the All-Source RFP process to identify the best combination of supply- and demand-side resources, including those obtained through the market, to meet its capacity needs.

The All-Source RFP provided NIPSCO insight into the most relevant prices and types of resources available to meet customer needs. (*See* Section 4.9.) NIPSCO performed both the retirement and replacement analysis using robust scenario and risk-based (stochastic) analyses for

different economic, environmental, cost, risk and regulatory uncertainty to inform the optimal plan. NIPSCO also evaluated the impact each of the retirement and replacement alternatives would have on reliability, the local communities and the Company's dedicated employees.

It is important to note that the IRP is a snapshot in time, and while it establishes a direction for NIPSCO, it is subject to change as the operating environment changes. NIPSCO will continue to engage its stakeholders and be transparent in its decisions following submission of this 2018 IRP.

NIPSCO's supply strategy for the next 20 years is expected to:

- Lead to a lower cost, cleaner, diverse and flexible portfolio by accelerating the retirement of 85% of NIPSCO's coal capacity by the end of 2023 and 100% by the end of 2028.
- Continue the Company's commitment to energy efficiency and demand response by executing DSM plans.
- Replace retired coal generation resources with lower cost renewables including wind, solar and battery storage.
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units.
- Reduce customer and Company exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply.
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape.
- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services.
- Continue to comply with NERC and EPA standards and regulations.

1.3 Rationale for NIPSCO 2018 IRP Update Filing

The 2016 IRP action plan was focused on the accelerated retirement of approximately 50% of NIPSCO coal fired generation. Specifically, it called for the retirement of Bailly Generating Station ("Bailly") Units 7 and 8 in 2018 and Schahfer units 17 and 18 in 2023. It projected that the 2023 retirements would create a capacity need of about 600 megawatts ("MW") that NIPSCO would have to address. An IRP in 2018 was necessary to preserve NIPSCO's ability to consider all resource options to meet the capacity need in 2023. Furthermore in light of expected future capital expenditures to comply with the Effluent Limitation Guidelines ("ELG") rules, the 2018 IRP was an opportunity to reexamine the long term viability of the Schahfer and Michigan City Generating Station ("Michigan City") coal units.

1.4 Emerging Issues

NIPSCO's preferred plan follows a diverse and flexible supply strategy, with a mix of market purchases and different low variable cost generation resources, to provide the best balanced mitigation against customer, technology and market risks.

1.4.1 Customer Risk

NIPSCO's five largest industrial customers (ArcelorMittal, US Steel, NLMK, BP and Praxair) account for approximately 40% of NIPSCO's energy demand and approximately 1,200 MW of peak load plus reserves when viewed on a non-coincident, individual customer basis. Most of these customers are closely tied to global steel industry cycles. This concentration of customers tied to a single industry poses significant customer risk. Loss of one or more of these customers, for whatever reason, would result in a significant decline in billing revenues.

Residential, commercial, and smaller industrial customers comprise most of the remaining demand. While this load is diversified and not likely to change significantly, those sectors would likely see impacts from a loss of load from any of the large industrial customers who are major employers in NIPSCO's service territory.

1.4.2 Technology Risk

Technology risk can be thought of as two separate risks from the perspective of a regulated utility. Technology risks play a role in inducing market volatility, and it also has the potential to erode the value of existing assets. Technology changes drive a portion (but by no means all) of the volatility in market prices, both for capacity and energy. To the extent that a utility or its customers are exposed to market risk in general, they are exposed to this aspect of technology risk. Separately, technological and regulatory changes can render specific generation technologies obsolete and can force their premature retirement, which is currently happening to coal generation.

It is difficult to avoid exposure to one or the other type of technology risk when supplying demand using a traditional regulated utility approach. Fully avoiding technological obsolescence risk requires avoiding investing in generation, which exposes the utility and its customers to market risk. Investing in generation mitigates or eliminates market risk but exposes the utility and its customers to some amount of technological obsolescence risk.

Balancing these two risks in light of the technology choices available is key to mitigating overall supply portfolio risk. Currently available new build generation technologies, such as a combined cycle gas turbine ("CCGT") and renewable technologies, have very low fixed operating costs, so the likelihood of forced shutdown in the foreseeable future is likely lower than it has been for coal and nuclear which have very high fixed costs.

1.4.3 Market Risk

Historically, the MISO North region, of which Indiana is a part, has had excess capacity above and beyond the regional reliability requirement. This oversupply in the MISO Planning Resource Auction ("PRA"), has resulted in historically low capacity prices over the last few

planning years. In the 2016/2017 planning year capacity prices rose to $72 per megawatt-day ("MWD") as reserve margins declined; however, in the 2017/2018 planning year prices fell to $1.50MW/MWD, driven by increases in renewable technologies and behind the meter supply resources and the relaxing of import constraints between MISO North and South. In the recent 2018/2019 planning year the capacity prices were $10/MWD and the expectation is for prices to remain relatively low for the foreseeable future under the current market design.

NIPSCO also participates in the energy market in MISO, since all resources are dispatched according to MISO market signals, as opposed to NIPSCO's load. The market is currently undergoing change as coal capacity retires and the generation mix shifts towards renewables and natural gas. In recent years, low natural gas prices have resulted in efficient natural gas plants displacing coal-fired generation in the dispatch stack. This dynamic has altered energy prices and has negatively impacted the economics of coal plants. Wind generation has also increased significantly in parts of MISO, and declining technology costs and federal tax credits are likely to result in increased penetration of solar and wind resources. This additional growth of intermittent resources has the potential to shift system peaks, impact capacity credit calculations, and alter the ancillary services markets.

NIPSCO recognizes that system planning with renewable resources is more complex than with dispatchable resources and that assumptions for capacity credit and resource value streams based on today's market constructs may ultimately change based on future MISO evaluation of Effective Load Carrying Capability and ancillary services market needs in a high renewable environment. NIPSCO also recognizes that congestion and nodal price risk is an important factor for renewable resources and that energy deliverability is critical to realize benefits from renewables. Given these major uncertainties and developments in the market, NIPSCO is committed to tracking market evolutions regarding ancillary services, renewable resource availability, and capacity credit calculations. The preferred plan intentionally leaves room to evaluate market and technology changes on a dynamic basis in order to be flexible and responsive to change.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2018 IRP stakeholder process focused on continuing to increase transparency around its planning process and enhance public involvement through extensive stakeholder interactions. At each stakeholder meeting, NIPSCO provided information on the processes and assumptions involved in the development of the IRP and solicited relevant input for consideration. Furthermore, to facilitate stakeholder outreach and ongoing communications, NIPSCO maintained a web page on its website with current information about the IRP. NIPSCO posted all meeting agendas, presentations, meeting notes and other relevant documents to the web page.

As part of the IRP process NIPSCO conducted an All-Source RFP solicitation to identify the most viable capacity resources currently available in the market place to best meet customer needs. NIPSCO sought input from stakeholders regarding the approach and design of the All-Source RFP to ensure a robust and transparent process that yield the desired results.

Stakeholders were invited to meet with NIPSCO throughout the IRP process to discuss key issues, concerns and perspectives. NIPSCO extended an invitation to participate in the stakeholder process to the Commissioners and Commission staff, the Indiana Office of Utility Consumer Counselor ("OUCC") and stakeholders that participated in previous IRP public advisory processes. NIPSCO's executive leadership and its subject matter experts attended each public advisory meeting. In the section that follows, NIPSCO provides an overview of its stakeholder process. A more comprehensive accounting of stakeholder meetings, presentations and meeting notes is included in Appendix A.

As part of the 2018 IRP process, NIPSCO hosted four in-person public advisory meetings and one webinar. As a follow up to the public advisory webinar, NIPSCO conducted an additional technical webinar to focus specifically on a single topic - the integration of the All-Source RFP results into the IRP analysis. For all meetings, NIPSCO posted an open invitation on its website for any party wishing to register.

In addition to the public advisory meetings, NIPSCO participated in a number of one-on-one meetings with individual stakeholders to address specific concerns and issues that were raised as a result of information presented and discussed at the public advisory meetings.

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held in Merrillville, Indiana on March 23, 2018. For those unable to join in person, a conference call was also made available. In this first meeting, NIPSCO explained the rationale for undertaking an update to its IRP and discussed the process improvements from the 2016 IRP being incorporated in the 2018 update. Furthermore, NIPSCO provided an overview of the resource planning approach, the key drivers of risk and uncertainty and the underlying data. NIPSCO also provided information regarding the All-Source RFP for new capacity, and discussed the public advisory process. Stakeholders requested clarification regarding (1) data points used in the IRP (e.g., percentage of renewables, technologies utilized, emissions, etc.), (2) assumptions regarding carbon pricing, (3) selection of supply-side and demand-side

resources, and (4) how solar was included in the modeling. The meeting presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 1 are included in Appendix A, Exhibit 1.

2.1.2 Stakeholder Meeting 2

NIPSCO's second stakeholder meeting was held in Merrillville, Indiana on May 11, 2018. For those unable to join in person, a webinar format was also made available. In this second meeting, NIPSCO described the process for modeling risk and uncertainty, and the methodology for modeling DSM in the IRP. Furthermore, the meeting provided an overview of NIPSCO's existing generation resources including the operating costs and key environmental considerations. Lastly, the meeting described the proposed scorecard that would be used to inform the preferred plan, the framework for the retirement and replacement analysis and provided preliminary results from the analysis. Stakeholders requested clarification regarding (1) the construction of scenario themes and the use of stochastics, (2) environmental compliance, (3) scorecard metrics; and (4) All-Source RFP design. Three stakeholders, Dany Brooks; David Chiesa of S&C Electric Company; and a group comprised of Scott Houldieson (United Auto Workers), Barry Halgrimson, and Sam Henderson (Hoosier Environmental Council) provided stakeholder presentations. The meeting presentation (including the agenda), stakeholder presentations, terminology sheet, notes (including questions / responses), and registered participants for Meeting 2 are included in Appendix A, Exhibit 2.

2.1.3 Stakeholder Meeting 3

NIPSCO hosted its third stakeholder meeting as an on-line webinar on July 24, 2018, with the public also invited to attend at NiSource's South Lake or Indianapolis offices. The webinar focused on sharing the preliminary results from the All-Source RFP solicitation. NIPSCO and the All-Source RFP manager Charles River Associates ("CRA") provided an overview of the proposals received and a summary of the pricing. NIPSCO also explained how the All-Source RFP results would be integrated into the IRP analysis and important next steps for both the IRP and All-Source RFP process. Key issues for stakeholders included clarification relating to (1) number of bids vs projects, and (2) integrating the All-Source RFP results into the IRP. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 3 are included in Appendix A, Exhibit 3.

2.1.4 Technical Webinar

NIPSCO hosted a technical webinar on August 28, 2018. The webinar focused on addressing follow ups from the July 24, 2018 meeting. Key issues for stakeholders included clarification relating to (1) how the All-Source RFP results will be incorporated into the IRP; (2) tranche development and assessment; (3) portfolio creation; and (4) how unforced capacity ("UCAP") was determined from the bid data. The meeting presentation (including the agenda) and registered participants for the Technical Webinar is included in Appendix A, Exhibit 4.

2.1.5 Stakeholder Meeting 4

NIPSCO's fourth stakeholder meeting was held in Fair Oaks, Indiana on September 19, 2018. For those unable to join in person, a webinar format was also made available. In this fourth meeting, NIPSCO explained the preliminary findings from the modeling. Key issues for stakeholders included (1) an explanation of how NIPSCO plans for the future; (2) an update the energy and demand forecasts; (3) a discussion of how NIPSCO models uncertainties; (4) an overview of NIPSCO's preliminary retirement and replacement analyses; and (5) an update on stakeholder requested scenarios. In addition, the Sierra Club provided a stakeholder presentation. The meeting presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 4 are included in Appendix A, Exhibit 5. Please note, the Sierra Club did not provide an electronic version of its presentation to be included with the materials. If provided, the presentation will be available at nipsco.com/irp. The terminology sheet provided as the first meeting was also provided for the fourth meeting, but is not duplicated in Exhibit 5.

2.1.6 Stakeholder Meeting 5

NIPSCO's fifth stakeholder meeting was held in Fair Oaks, Indiana on October 18, 2018. For those unable to join in person, a webinar format was also made available. In this fifth meeting, NIPSCO provided its preferred plan and preliminary action plan. Key issues for stakeholders included (1) a recap of how NIPSCO plans for the future; (2) an update to the stakeholder requested analyses; (3) an update on the retirement and replacement analyses; and (4) NIPSCO's preferred resource plan. In addition, the Indiana State Conference of the NAACP and Indiana DG provided stakeholder presentations. The meeting presentation (including the agenda), stakeholder presentations, notes (including questions / responses), and registered participants for Meeting 5 are included in Appendix A, Exhibit 6.

2.1.7 One-on-one Stakeholder Meetings

NIPSCO held a number of one-on-one meetings with its stakeholders throughout the public advisory process. Generally, the meetings related to either (1) clarifications, (2) additional information regarding the All-Source RFP, or (3) running requested scenarios. Information relating to the results of the requested scenarios can be found in the presentation included in Appendix A, Exhibit 5 (Slides 48 through 52) and Appendix A, Exhibit 6 (Slides 11 through 23).

NIPSCO's 2018 IRP is the result of analysis performed by NIPSCO that includes consideration of stakeholder input. NIPSCO has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. NIPSCO appreciates the participation of its stakeholders, including the Commission staff, the OUCC, NIPSCO's largest industrial customers and community action groups, all of which participated extensively throughout the IRP development process. NIPSCO's stakeholders and Commission staff provided valuable feedback throughout the process, which has been considered and incorporated as applicable. Despite best efforts to address and resolve all input from stakeholders, there were instances wherein NIPSCO still incorporated, for example, methodologies that were not supported by all stakeholders.

2.2 IRP Planning Process

NIPSCO's 2018 IRP is in compliance with the Commission's Proposed Rule to modify 170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans ("Proposed Rule"). A matrix showing NIPSCO's compliance with each section of the Proposed Rule (providing a reference to the appropriate Section(s) of the IRP) is included in Section 10: Compliance with Proposed Rule.

Long term resource planning requires addressing risks and uncertainties and for NIPSCO, the first step in this process is to identify objectives and metrics. Next NIPSCO develops market perspectives for key variables such as customer demand, commodity prices and technology costs. An aspect of the developing market perspectives involves the creation of distinct thematic "states-of-the-world" that represent potential future operating environments for NIPSCO. Lastly NIPSCO constructs integrated resource portfolio strategies and performs detailed modeling and analysis to evaluate the performance of various resource portfolios across range of potential futures. NIPSCO's goal is to develop a resource plan that is reliable, compliant with all regulations, diverse, flexible and affordable for customers with careful consideration of all stakeholder viewpoints.

The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs. The short-term strategic plan identifies the steps NIPSCO will take over the next three years to implement the long-term strategic plan.

NIPSCO recognizes future economic and environmental changes are difficult to accurately predict. The 2018 IRP addresses the most likely contingencies based on uncertainty analyses. New information in NIPSCO's planning process is analyzed and incorporated as it becomes available.

NIPSCO's IRP team included experts from key areas of NIPSCO and its affiliate NiSource Corporate Services Company. The following energy and engineering consultants also provided input:

GDS Associates, Inc. ("GDS") 1850 Parkway Place, Suite800 Marietta, Georgia 30067	Developed DSM measures inputs for a long-term DSM forecast
Itron, Inc. 2111 North Molter Road Liberty Lake, Washington 99019	Provided historical and forecasted end use data
Charles River Associates 200 Clarendon Street Boston, Massachusetts 02116	Provided fundamental long term commodity price forecasts, portfolio modeling and analysis. A separate division of CRA provided assistance in administering the All-Source RFP and evaluating the responses.
Telvent DTN, Inc. 9110 West Dodge Road Omaha, Nebraska 68114	Provided hourly weather data for three Indiana weather stations

2.2.1 Contemporary Issues

NIPSCO also participated in the Commission's IRP Contemporary Issues Technical Conference held April 24, 2018. The meeting focused on using IRPs to develop avoided costs for energy efficiency, the planning models used by MISO, distribution system planning, load growth trends, using smart meter data, distributed energy resources and the potential for peak demand reduction. To the extent the information applicable and appropriate, NIPSCO included the items discussed during the technical conference in its analysis.

2.2.2 2016 IRP Feedback and 2018 Process Improvement Efforts

NIPSCO strives to continuously improve all aspects of its resource planning process and, for the 2018 IRP, NIPSCO reviewed the feedback from the 2016 IRP and implemented key improvements to its process. The process improvements in the 2018 IRP are primarily designed to incorporate advanced risk modeling techniques, as well as to continue to enhance the transparency and credibility of NIPSCO's long-term plans by using assumptions based on fundamentals driven analysis and market based data.

Table 2-1 shows feedback received on NIPSCO's 2016 IRP and the improvements that were included in its 2018 IRP process.

Table 2-1: Process Improvement

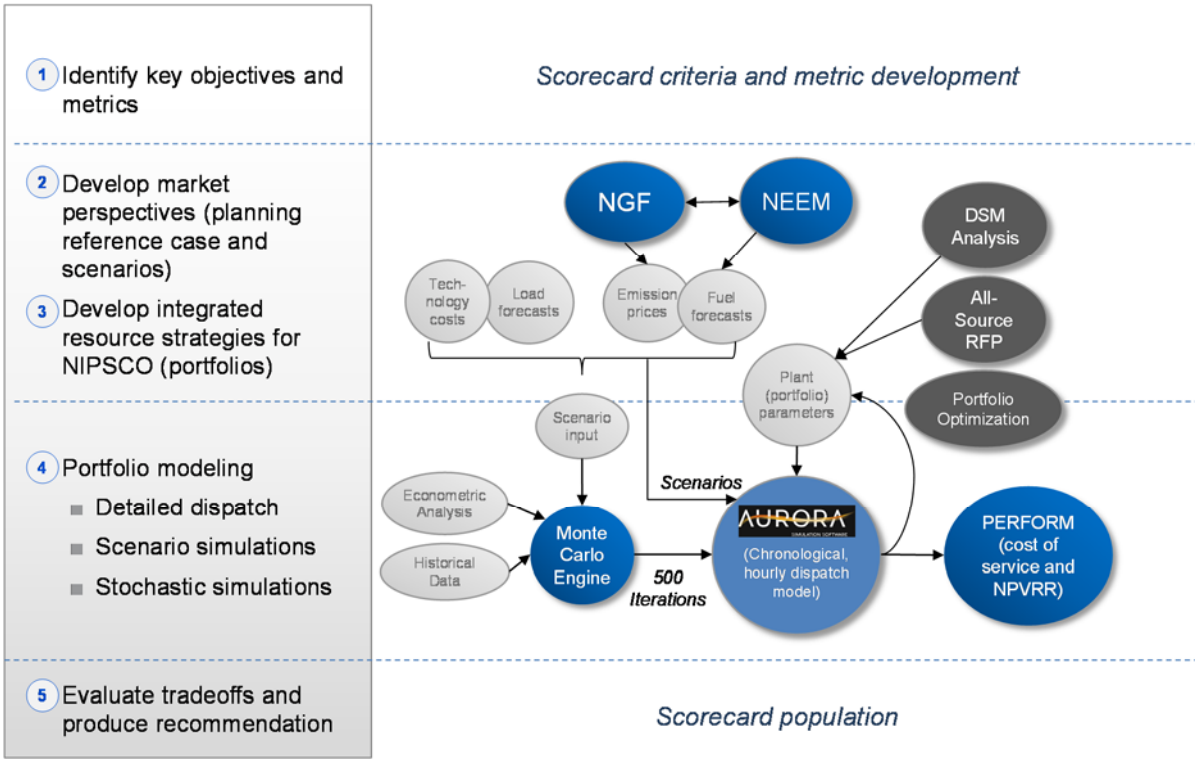
Subject	2016 IRP Feedback	2018 Improvement Plan
Commodity Price Forecasts	• Fuel price projections do not capture the nuanced and dynamic relationships between oil and natural gas, or whether the historic market correlations are evolving • No transparency and availability of underlying assumptions for fuel forecasts	• Utilized independently generated commodity price forecasts using an integrated market model • Provided transparent assumptions related to key inputs and outputs • Benchmarked against publicly available forecasts
Risk Modeling	• NIPSCO IRP planning model was limited to scenarios and sensitivities	• Implemented efficient risk informed (stochastics) analysis with the ability to flex key variables
Scenarios and Sensitivities	• NIPSCO's construction of scenarios and sensitivities in the 2016-2017 IRP is a significant advancement over the 2014 IRP. The clarity of the narratives was commendable and transparency was exceptional	• Built upon the progress made in the 2016 IRP with thematic and modeling informed selections for detailed cost analysis
Capital Cost Assumptions	• Capital cost estimates for new capacity resources were based on proprietary consultant information • No scenario or sensitivity covered uncertainties of resource technology cost	• Leveraged 3rd party and publicly available datasets to develop a range of current and future capital cost estimates for new capacity resources • Conducted an "all-source" Request for Proposal solicitation for replacement capacity resources
Preferred Plan and Scorecard	• Provide additional details around selection of the Preferred Plan and the analysis used to develop • Provide a detailed narrative for those metrics that can be quantified as well as those that do not lead to quantification	• Provided detailed analysis on selection of the Preferred Plan • Developed enhanced scorecard methodology to include more quantifiable metrics that better evaluate tradeoffs
DSM Modeling	• DSM groupings are not getting quite the same treatment as the supply side resources	• Utilized new modeling capabilities to enable DSM to be treated equally with other supply side resources

2.3 Resource Planning Approach

Consistent with the principles set out in Section 1.1, the 2018 IRP identifies changes and additions needed over a 20 year planning horizon for NIPSCO to deliver reliable, compliant, flexible, diverse and affordable electric service to its customers. NIPSCO's 2018 IRP was performed according to the detailed planning approach process that is outlined in Figure 2-1 and

described in more detail below. While structurally similar to the 2016 IRP process, the 2018 approach has incorporated new software, models and several process enhancements in order to respond to feedback that was received.

Figure 2-1: Overall Integrated Resource Planning Approach



Step 1: Identify key objectives and metrics

The first step in NIPSCO's planning approach was to identify key planning objectives and develop specific metrics against which to evaluate future portfolios. As in the 2016 IRP, this involved the development of multiple scorecard criteria prior to the commencement of any analysis. This ensures that the objectives and metrics are established without any bias that may come from the production of IRP model runs and analysis. The planning criteria used in the 2018 IRP includes cost to customer, cost risk, fuel security, environmental stewardship, and impact to employees and the local economy. Section 9 of this report describes the scorecard objectives and metrics in more detail.

Step 2: Develop market perspectives

Prior to performing any portfolio-specific analysis, NIPSCO developed perspectives on key market drivers and other major planning assumptions. This involved the use of several market models and forecasting approaches in order to arrive at a Base Case set of inputs and a set of scenarios against which to evaluate resource options. This step involved the following major tasks:

- Commodity price forecasting for fuel, emission, and power prices: NIPSCO commissioned CRA to develop forecasts for natural gas prices, coal prices,

emission allowance prices, and power prices (energy and capacity) for the Base Case and three integrated market scenarios. The details of all Base Case and scenario forecasts are provided in Section 8. CRA relied on the following models to perform this work:

- CRA's Natural Gas Fundamentals ("NGF") model, which provides a bottom-up forecast of North American gas production and prices with a focus on shale gas supply and other unconventional resources. Key NGF outputs include a long-term price forecast for domestic natural gas, as well as breakeven costs and production data for major gas basins across the United States. NGF is a national model, useful for macroeconomic scenarios. CRA also licenses the Gas Pipeline Competition Model (GPCM) for regional basis analysis.

- CRA's North American Electricity and Environment Model ("NEEM"), which provides an assessment of emission allowance prices, coal consumption and coal pricing, generator retrofit decisions, and capacity expansion and retirements. The NEEM model estimates market prices and unit dispatch using a simplified transmission representation and a select number of representative demand points to produce a fundamentals-based outlook of key macroeconomic outputs for the electricity sector.

- The Aurora model, which CRA licenses, and which provides hourly MISO market prices at a zonal level based on a fundamental dispatch of the market. Market inputs for the Aurora model include fuel prices, emission prices, and capacity expansion and retirement, which are developed through CRA's other models. CRA also deploys a capacity market model, which produces an internally consistent capacity price outlook based on MISO market rules.

- Load forecasting, performed by NIPSCO's internal load forecasting team, and described in more detail in Section 3.

- Development of technology cost estimates for supply side resource options, which were initially produced on a planning-level basis through market research conducted by NIPSCO and CRA. NIPSCO and CRA's Auction and Competitive Bidding Practice then conducted an All-Source RFP, which provided real market data on the resource types available and their associated costs and operational parameters. Section 4 describes this process in more detail.

Step 3: Develop integrated resource strategies or portfolios

The third major step in the 2018 IRP process was to develop resource strategies or portfolios for further evaluation. The portfolio development process relied on multiple inputs and approaches. It was conducted first for a retirement analysis and then for a full replacement analysis, with key elements summarized as follows:

- The definition of retirement portfolio options was influenced by environmental policy considerations (as discussed in Section 7) and management input on feasible retirement paths.

- An update to NIPSCO's 2016 DSM Market Potential Study was conducted by GDS in order to provide a set of plausible DSM program bundles and associated costs for evaluation. The details of this study are provided in Section 5.

- Portfolio optimization analysis was conducted with the Aurora model's portfolio optimization tool to develop least-cost portfolio concepts under a variety of constraints. Both supply side and demand side resources were evaluated in the portfolio optimization framework. The details of the process and a summary of the integrated portfolios that were evaluated are provided in Section 8.

Step 4: Portfolio Modeling

After detailed portfolios were constructed, each of them was evaluated in CRA's suite of resource planning tools, namely Aurora and a utility financial model known as PERFORM. The Aurora model performs an hourly, chronological dispatch of NIPSCO's portfolio within the MISO power market, accounting for all variable costs of operation, all contracts or PPAs, and all economic purchases and sales with the surrounding market. Aurora produces projections of asset-level dispatch and the total variable costs associated with serving load. It also produces estimates for other key metrics, such as carbon dioxide ("CO_2") emissions over time and capacity and generation by fuel type. The Aurora output is then used by CRA's PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, and financial accounting of depreciation, taxes, and utility return on investment. The PERFORM model produces annual and net present value estimates of revenue requirements.

The full set of portfolio modeling is undertaken for all portfolio options for the Base Case, each individual integrated market scenario, and a full stochastic distribution of potential outcomes associated with select commodity prices. The stochastic analysis relies on CRA's Monte Carlo engine, which simulates future price outcomes based on historical data analysis and specification of key statistical parameters. The details of the stochastic development process and the outputs of all portfolio modeling are discussed in more detail in Section 9.

Step 5: Evaluate tradeoffs and produce recommendations

The final step in NIPSCO's IRP process is to evaluate the various portfolios with an integrated scorecard and produce recommendations for a preferred plan. As discussed in Step 1, NIPSCO identified several planning objectives for its scorecard. In this step, metrics were recorded against all key planning criteria, and tradeoffs were evaluated. Ultimately, NIPSCO management is responsible for selecting the preferred portfolio based on the scoring of all options. This process and the preferred portfolio selection is described in Section 9.

2.3.1 Key Planning Assumptions

While many of the assumptions details are described further in subsequent sections of this report, the following information provides an introductory overview of several major planning inputs that drive the 2018 IRP.

Market Forecast Inputs

Market and commodity price forecasts are important drivers for NIPSCO's IRP, since they influence the variable costs of operation for many resources, the dispatch of certain power plants, and NIPSCO's interaction with the MISO market. As discussed above, CRA produced commodity price forecasts for major inputs, relying on support from NIPSCO's subject matter experts for certain details or assumptions that are specific to NIPSCO's current operating fleet. For example, for coal pricing, delivered coal contract details and expected coal transportation rates were provided by NIPSCO's fuel supply group in order to conform to near-term price expectations for the existing fleet of plants. Long-term fundamental forecasts were blended in over time. Figure 2-2 presents a summary of the source and reference information for each of the major market inputs.

Figure 2-2: Major Market Input Sources

Major Input	Source	Section Reference for More Detail
Natural Gas Prices	CRA forecasts and NIPSCO operations team	8 (fundamental forecasts, including scenarios and stochastics) 4 (current gas procurement strategies)
Coal Prices	CRA forecasts and NIPSCO fuel supply group	8 (fundamental forecasts, including scenarios and stochastics) 4 (coal procurement and current contracts/ transportation arrangements)
Emission Prices	CRA forecasts and NIPSCO environmental group	8
MISO Power Prices	CRA forecasts	8
MISO Capacity Prices	CRA forecasts	8

Environmental Planning Inputs

As noted above, emissions price assumptions were provided by CRA, with review provided by NIPSCO's environmental group. Estimates were developed by NIPSCO's Major Projects group for projects required to comply with current and future anticipated regulations pertaining to solid waste management, the Clean Water Act ("CWA"), and the Clean Air Act ("CAA"). A comprehensive review of key environmental planning drivers is provided in Section 7.

Energy and Demand Forecast

NIPSCO's internal load forecasting group produced load forecasts, including high and low cases, which were used in the IRP analysis. For the 2018 IRP modeling NIPSCO utilized the MISO Coincident peak demand forecast. All methods, assumptions and detailed forecast results are provided in Section 3.

Existing NIPSCO Portfolio Parameters

NIPSCO's IRP models incorporate all elements of the existing portfolio. NIPSCO's generation operations and planning groups provided the following characteristics for the existing set of resources: capacity, heat rates, emission rates, other operational characteristics of fossil-fired resources, variable operations and maintenance ("O&M") costs, fixed O&M costs, forced outage rates, maintenance schedules, must run schedules for coal units, energy and capacity contracts, feed-in-tariff contracts, existing DSM data, and renewable shapes. Certain details regarding the existing fleet are provided in Section 4.

New Resource Parameters

NIPSCO relied on multiple sources for major input assumptions associated with new resource options. DSM resource options and costs were developed by GDS, as described in Section 5. Supply-side resource options were developed according to the All-Source RFP conducted in 2018. The All-Source RFP provided cost information and resource operational characteristics, including capacities, heat rates, and expected capacity factors for renewable resources. This is described in further detail in Section 4.

Planning Reserve Margin Target

NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy. The MISO UCAP planning protocol was used to determine the planning reserve margin target to use in the 2018 IRP update, and NIPSCO set its target to 8.4%, as per current MISO standards. This target is based on NIPSCO's coincident peak in MISO. When performing portfolio optimization analysis, NIPSCO set a maximum reserve margin of 20% and a maximum level of off-system energy sales of 5%. This was done to avoid developing portfolios where NIPSCO would be relying on a significant level of excess energy and capacity sales to offset resource costs.

Financial Assumptions

Several financial assumptions are relevant to projecting annual revenue requirements, such as the expected return on equity and debt, tax rates, and the discount rate used when calculating the net present value ("NPV"). A summary of the major financial assumptions used in the 2018 IRP is provided in Figure 2-3.

Figure 2-3: Major Financial Assumptions

Financial Assumption	Value
Cost of Equity	9.98%
Cost of Debt	5.71%
Equity %	58.44%
Debt %	41.56%
After-Tax Weighted Average Cost of Capital	7.61%
Federal Income Tax Rate	21.00%
State Income Tax Rate	4.90%
Blended Income Tax Rate	24.87%
Property Tax Rate	2.16%
Discount Rate	7.61%
Allowance for Funds Used During Construction%	7.44%
Blended Depreciation Rate for Existing Assets	4.60%

Section 3. Energy and Demand Forecast

3.1 Major Highlights / High Level Summary / Discussion of Load

Some of the major highlights include:

- NIPSCO's jurisdictional energy sales are projected to remain flat on average over the next 20 years.
- The Residential and Commercial compound annual growth rates are projected to be 0.8% and 0.7%, respectively, during the period 2018-2039. The Industrial class is projected to decrease at a rate of 0.7% during this same period.
- NIPSCO's internal Peak demand is expected to grow from 3,051MW in 2018 to 3,169 MW by 2039 representing an annual growth rate of 0.2% during the period 2018-2039.
- NIPSCO MISO coincident peak demand is expected to grow from 2907MW in 2018 to 2970 MW in 2039 representing an annual growth rate of 0.1% during the period 2018 to 2039

NIPSCO's long term forecast incorporates historical customer usage and its relationship to economic, demographic, end use and weather data. The load forecast reflects historical impacts of past conservation and DSM programs. Regional saturation and efficiency trends are provided by Itron, Inc., a national utility consulting firm. Economic and demographic data utilized in the forecast is from IHS Global Insight.

3.2 Development of the Forecast – Method and Data Sources

NIPSCO's energy and peak forecast process reflects a system of dynamic models that are continually evaluated, updated and selected based on their ability to provide accurate projections of future energy needs of customers. Current modeling trends, statistical properties, data utilized in the forecast process and current peer utility approaches to forecasting are all considered during the forecast development. NIPSCO utilizes individual forecast models for Residential, Commercial, Industrial, Street Lighting, Public Authority, Railroad and Company use. The forecast also relies upon a 60-minute electric peak demand model. Each of the individual forecast models utilizes methods that account for the unique characteristics of each class. The Residential, Commercial, and Street Lighting energy and total peak demand forecast models use an econometric approach to forecast long-term electric energy sales and peak hour demands.

The Industrial Energy Forecast Model is developed in two parts. The first part uses a grassroots approach by developing forecasts for the largest individual industrial customers. The second part of the Industrial outlook represents all other customers included in the Industrial class. To generate the total industrial class forecast, the individual customer forecasts are combined with the portion of the forecast representing the balance of the Industrial class load. The Public Authority and Railroad class models rely on current usage levels and recent patterns. Projections for Company use and losses also rely on recent usage trends and levels. Historical DSM impacts

and trends are reflected in the Residential and Commercial forecast. The Residential and Commercial outlook incorporate existing or past NIPSCO DSM programs by utilizing historical data in the modeling process. Past DSM impacts and trends are captured through the model structure and used in the calculation of the forecast. After the completion of the forecast process, NIPSCO completes regular internal forecast performance assessments for the Residential, Commercial and Industrial models to ensure the accuracy and reasonableness of the projections.

NIPSCO evaluates the forecast process on an ongoing basis looking to incorporate improvements that result in a more robust process. Currently, some of the improvements under consideration include incorporating electric vehicle impacts, the data frequency used in the forecast modeling, and testing alternative efficiency variables and estimation techniques to capture changing usage trends.

3.2.1 Data Sources - Internal

Class energy sales, number of customers by class, internal peak demand, historical interruptions and electric prices are all collected internally by NIPSCO. This information is used to develop the long term sales and demand forecast. NIPSCO uses North American Industrial Classification System (NAICS) coding for its non-residential customers.

3.2.2 Data Sources - External

Schneider Electric

NIPSCO uses two weather measures in the forecast, specifically cooling degree days ("CDD") and heating degree days ("HDD") as defined by the National Oceanic and Atmospheric Administration ("NOAA"). The Company purchases weather data for three NOAA stations: Valparaiso, South Bend and Fort Wayne. For modeling purposes, the weather from these three stations is represented as a weighted average with the weights based on the number of residential customers assigned to each station. For the forecast period, the Company assumes the weather data to be equal to the 1976-2010 average for both CDD and HDD. The weighted weather concepts for the peak hour model are cooling degree hours, heating degree hours and relative humidity.

IHS Global Insight

NIPSCO purchases national, state and county economic and demographic data from IHS Global Insight. Economic data used in the production of the forecast represents the most current information from the vendor at the time the forecast is developed.

Itron, Inc.

Historical and forecasted saturation and efficiency data are obtained from Itron, Inc., a national utility consulting firm. Itron, Inc. produces an annual statistically-adjusted end use model by census region reflecting historical and future saturation and efficiency trends. Itron, Inc. works closely with the United States Energy Information Agency ("EIA") to embed EIA's latest equipment saturation and efficiency trend forecasts into its annual models. NIPSCO utilizes this

information reflecting the East North Central census region in the long-term Residential forecast model.

3.3 Residential

The Residential Energy Forecast Model is calculated in conjunction with NIPSCO's New Business team, using a residential customer model and an average residential use per customer model. Average residential use per customer projections are multiplied by the total residential customer count forecast to generate the total Residential energy forecast. The residential use per customer model is a function of the residential price of electricity, appliance saturations, and efficiencies as defined in an end use variable supplied by Itron, Inc. and real per capita income. Other forecast considerations integrated into the Residential forecast model include residential customer counts, CDDs and HDDs.

The residential customer count is a function of a five-year outlook for new construction provided by NIPSCO's New Business team and is developed using a grassroots approach. This approach includes conducting interviews with real estate developers and builders; thus, assuring that short-term housing market intelligence and recent trends are included in the forecast. The longer term customer outlook is modeled as a function of housing starts. Both short- and long-term forecasts are adjusted for customer attrition applied at an average historic rate. Total residential customers are calculated by incorporating the new customer outlook, existing customers and the historic attrition rate.

Econometric models are utilized to estimate the residential new customer and usage per customer models. Seventeen years of data was employed in the residential new customer model. The model produces an R-Square of 0.9687 in addition to strong T-Stats for each variable and directionally confirms the relationships expected between the independent and dependent variables. Sixteen years of historical data is used in the development of the residential use per customer long-term outlook. The model yielded an R-Square of 0.9333 and confirms statistically strong relationships between the independent and dependent variables.

- Residential New Customer Equation

  New Residential Customers = f(Local Housing Starts)

- Residential Usage Per Customer Equation

  Residential kWh per Customer = f(Residential Electric Price, Itron Index, Real Per Capita Income, HDD, and CDD)

Table 3-1: NIPSCO Residential Customers

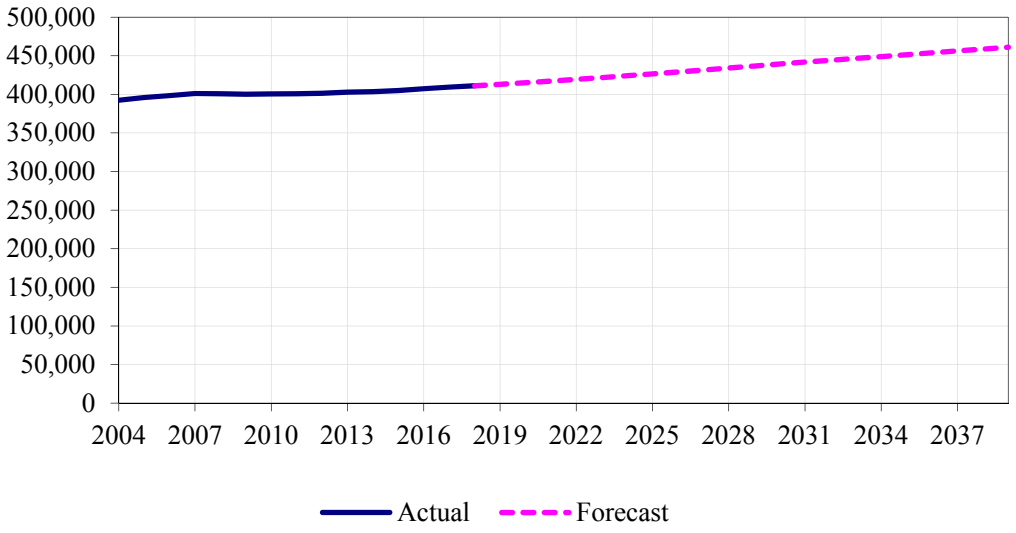
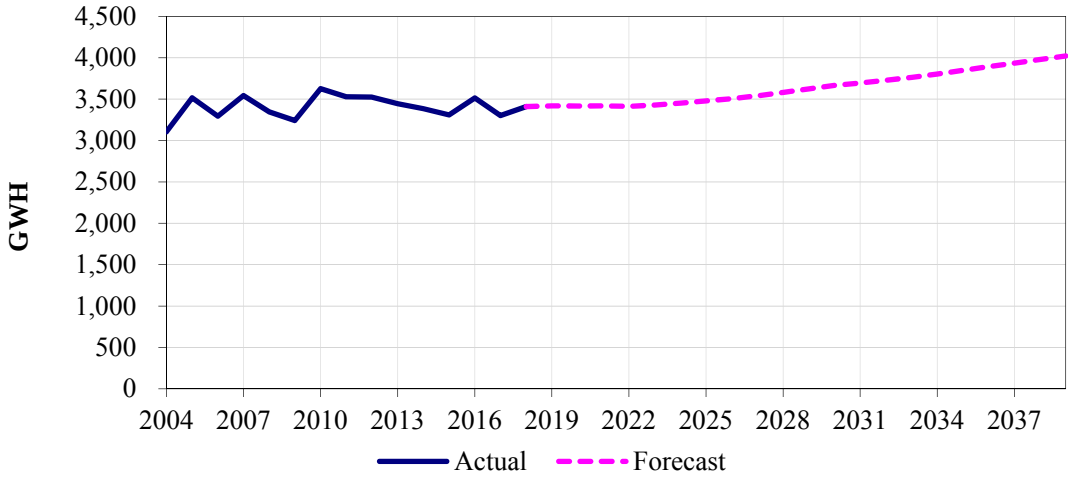


Table 3-2: NIPSCO Residential Energy Sales



3.4 Commercial

The Commercial Energy Forecast Model has been estimated using a total Commercial energy consumption model. Commercial energy consumption is a function of the commercial customer count, employment, commercial electric price, CDD, and HDD. As with Residential, the initial five-year outlook for Commercial customers is provided by NIPSCO's New Business

team. The longer term view is modeled as a function of local population and real gross county product. The commercial customer count forecast also reflects a historical attrition rate.

Econometric models are utilized to estimate the commercial customer and total usage models. Twenty one years of historical data was employed in the commercial customer model. The model produces an R-Square of 0.9950 in addition to strong T-Stats for each variable and directionally confirms the relationships expected between the independent and dependent variables. Fifteen years of data was used in the development of the commercial energy long-term outlook. The model yielded an R-Square of 0.9833 and confirms statistically strong relationships between the independent and dependent variables.

- Commercial Customer Equation

  Commercial Customers = f(Population, Real Gross County Product)

- Commercial Usage Equation

  Commercial Total Use = f(Commercial Customers, employment, Commercial Electric Price, CDD, HDD)

Table 3-3: NIPSCO Commercial Customers

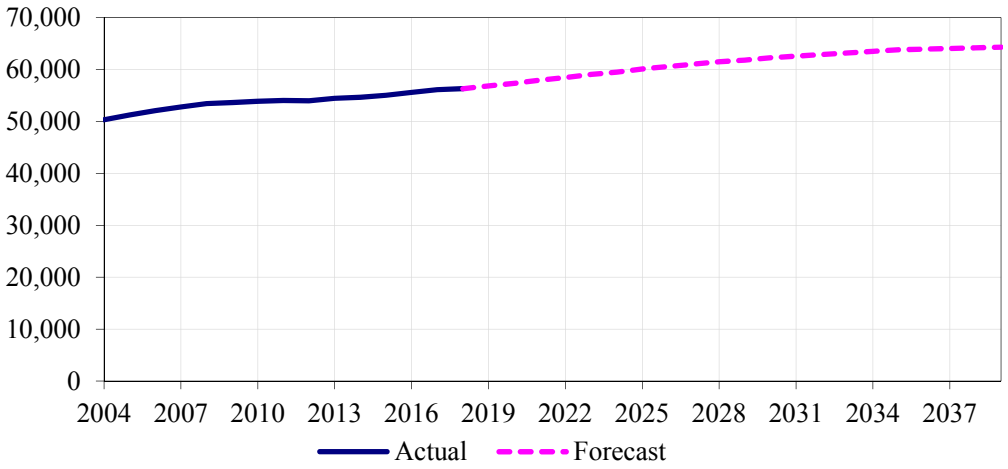
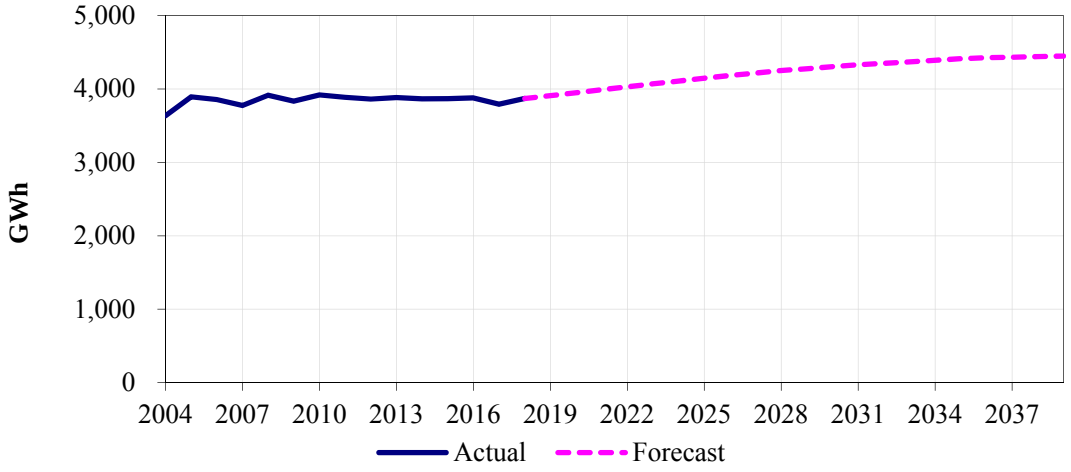


Table 3-4: NIPSCO Commercial Energy Sales



3.5 Industrial

The Industrial Energy Forecast Model projects the expected level of industrial energy sales in NIPSCO's service territory based on individual discussions with its largest industrial customers, recent historical industrial sales trends, and regional and global trends for specific industries. Accordingly, the Industrial Energy Forecast Model contains individual forecasts for the major industrial account customers. This year, the loss of energy demand from a major industrial account customer caused NIPSCO's industrial energy sales forecast to trend downwards compared to previous years' forecasts.

Information specific to the creation of the Industrial sales forecast is obtained through outreach by the NIPSCO Major Accounts Department to each of its 25 individually-forecasted industrial customer accounts. NIPSCO discusses individual business, economic and strategic objectives with each of its individually forecasted industrial accounts. As a part of these discussions, the projected effect of the customer's energy efficiency programs are already taken into account with the forecast provided to NIPSCO. The goals, plans, and concerns outlined in these one-on-one discussions form the basis of a recommendation for each customer's forecast. Other items considered in the development of the forecast include historical consumption, industry trade publications, global market news, business outlook conferences, and routine customer interaction. The resulting forecast incorporates the outlook for steel producers, refiners, industrial gases and a variety of other industrial manufacturing companies in NIPSCO's service territory. Notably, for the development of NIPSCO's industrial energy forecast for the 2018 IRP, this forecast integrates the economic and business projections of these customers and their consumption related to each of their major industrial production sites in NIPSCO's service territory.

The industrial sales forecast model also integrates a sales forecast for the remaining industrial accounts (identified as Other Industrial). This portion of the NIPSCO electric forecast

is based primarily on historical data (billed volume) from the past six years with greater consideration given to use for the most recent year. Annual and monthly volumes were analyzed - min, max, and averages were calculated. Historical trends, if any, were identified and are reflected in the forecast.

Table 3-5: Industrial Energy Sales

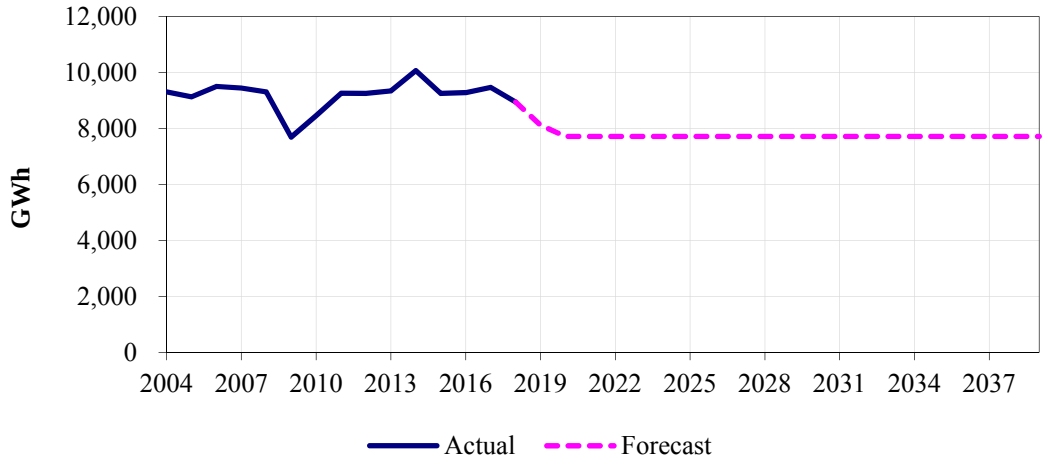


Table 3-6: Total Customers

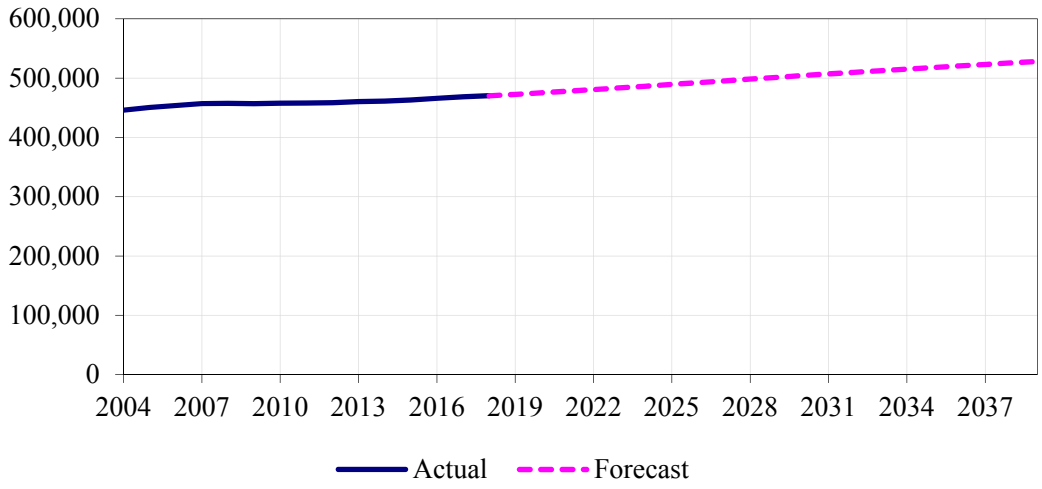
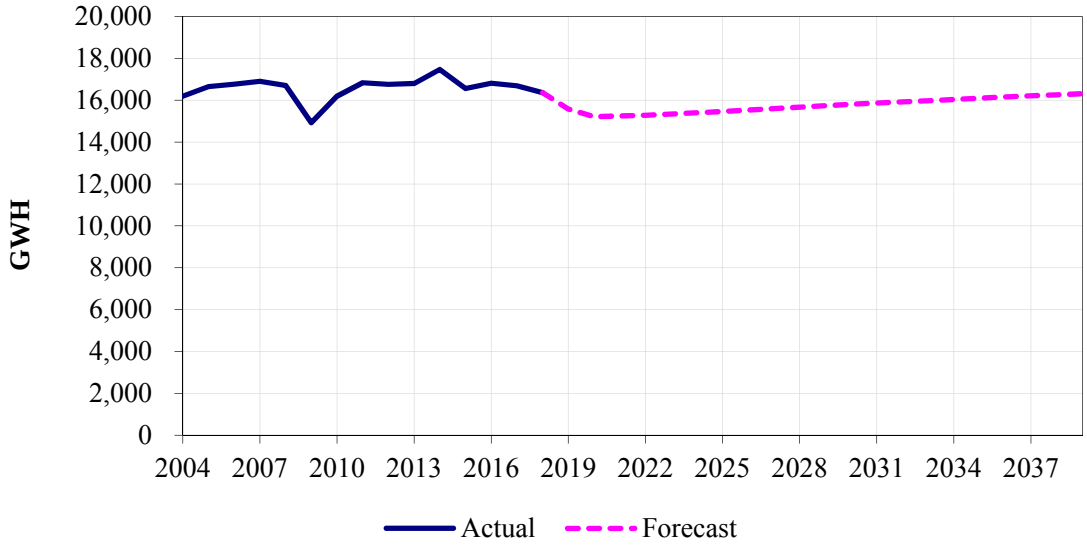


Table 3-7: Total Energy Sales



3.6 Street Lighting, Public Authority, Railroads, Company Use, Losses

The Public Authority, Railroads, Company use and losses forecasts are based on both current usage levels and anticipated future trends. The street lighting model utilizes an econometric model that accounts for the number of hours of dark and anticipated future trends. Nine years of historical data were used in the development of the street lighting long-term outlook. The model yielded an R-Square of 0.9154 and confirms statistically strong relationships between the independent and dependent variables.

Street Lighting Energy Use = f(Number of hours of dark)

3.7 Peak

NIPSCO uses an econometric model to project future peak demand on its system. The model incorporates Residential, Commercial, and Industrial energy levels, cooling degrees (summer) and heating degrees (winter) at peak hour, and the level of relative humidity at peak hour. The model also accounts for recent historical load factor levels and patterns associated with NIPSCO's large industrial customers. Using 32 years of data, the peak forecast is derived with a two-step approach accounting for the large influence of the Industrial class and the contribution of smaller customers.

The first step of the peak model accounts for the impact of Residential, Commercial, and Small Industrial energy levels and patterns. The model also takes into account the influence of weather at the time of the peak. Utilizing 32 years of historical data, the model yielded an R-

Square of 0.9428 and confirms a statistically strong relationships between the independent and dependent variables

The second step of the peak model accounts for the contribution of NIPSCO's large industrial customers to the NIPSCO peak. The model estimates the load factor associated with large customers and utilizes this to project peak. The load factor is estimated using a polynomial model that employs recent monthly load factory data to identify a monthly pattern. Once the load factor is estimated, it is combined with the large customer energy forecast to calculate this portion of the peak forecast. The large customer peak is then added to the initial peak generated from the first step to yield the total company peak outlook.

Peak Model

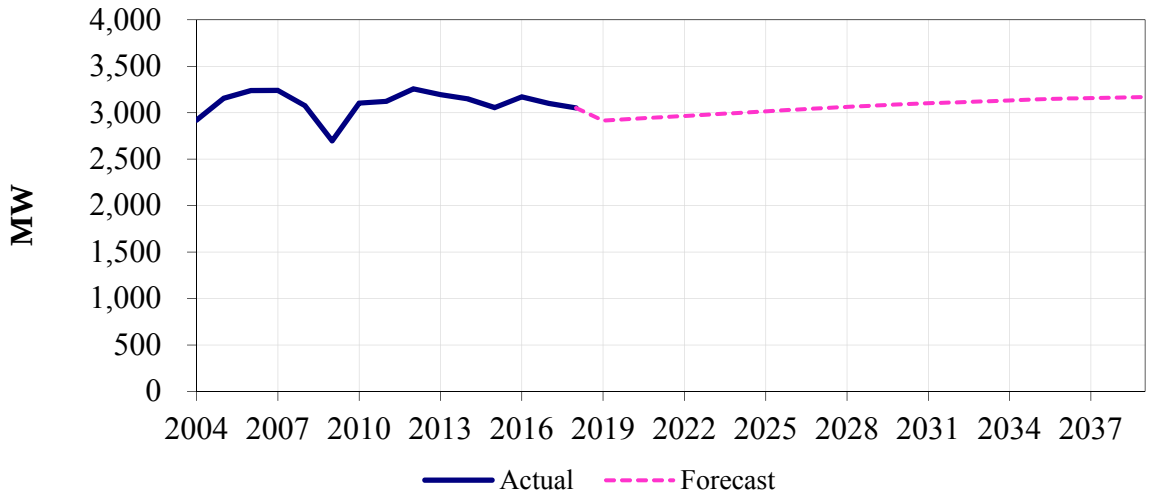
Peak_Step1 = f(Residential Energy, Commercial Energy, Small Industrial Energy, Cooling Degree Hours(Summer), Heating Degree Hours(Winter), Summer Humidity,)

Large Company Load Factor = f(Time, Time²)

Peak_Step2 = f(Large Company Load Factor, Large Company Energy, Monthly Hours)

NIPSCO Peak=Peak_Step1 + Peak_Step2

Table 3-8: Peak Hour



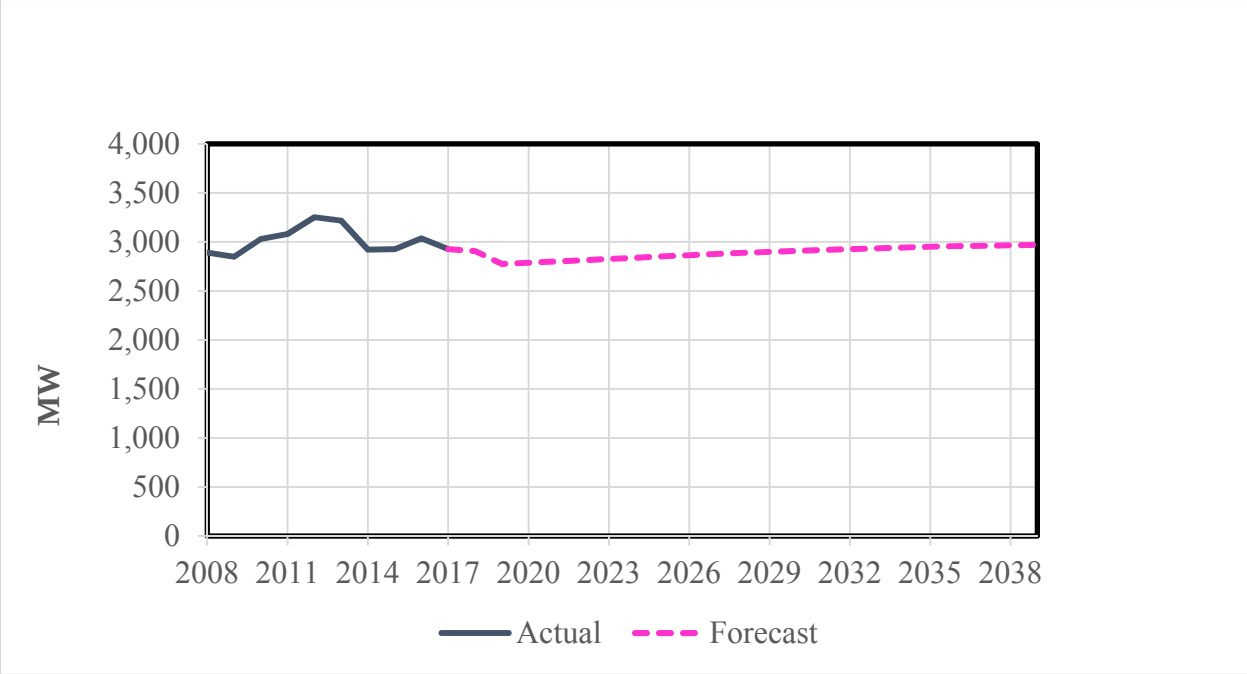
3.8 MISO Coincident Peak

MISO Coincident Peak is NIPSCO's monthly system peak at the time of MISO's system peak. NIPSCO uses an econometric model to project future demand on its system at the time of

MISO's system peak. The model incorporates NIPSCO's monthly peak demand levels and Cooling Degree Hours at the time of MISO's system peak. On average the MISO coincident peak level forecast is about 95% of NIPSCO internal peak level.

MISO Coincident Peak = f(NIPSCO Internal Peak, Cooling Degree Hours)

Table 3-9: MISO Coincident Peak



3.9 Customer Self-Generation

Customer Self-Generation assumes that most of NIPSCO's large electric customers with self-generation utilize the generation as a by-product of process steam production needs. This type of generation is difficult to predict by NIPSCO, and, therefore, challenging to dispatch by NIPSCO without significant coordination between the customer and utility. Although it is difficult to dispatch or coordinate, NIPSCO does have a currently-effective tariff rider available to such customers that enables the purchase from qualifying cogeneration facilities in the situation where the customer's generation exceeds load. Any such purchases are made pursuant to Rider 778 - Purchases from Cogeneration Facilities and Small Power Production Facilities - and this Rider allows for the purchases pursuant to a contract between NIPSCO and the customer. To the extent qualified and provided, Rider 778 also provides the ability to purchase capacity from such qualifying facilities.

3.10 Weather Normalization

NIPSCO produces estimates of weather-normalized energy for prior annual periods. Because industrial class energy consumption varies little with weather, NIPSCO weather-normalizes kWh sales for the Residential and Commercial classes only.

The normalization procedure uses the daily baseload, temperature sensitive load (TS) per CDD, TS per HDD, the daily non-temperature sensitive use per customer (NTSUPC), and the daily temperature sensitive use per customer per customer (TSUPC). Several assumptions are made in the normalization procedure. They are:

- May is the base load month and is not normalized for weather
- Heating energy volumes accounted for October through April
- Cooling energy volumes accounted for June through October
- October is accounted for both heating and cooling energy volumes

The general normalization equation is specified on a monthly per day basis and then scaled to a monthly concept by multiplying by days:

*Normal KWH/Customer = NTSUPC + ((TSUPC/HDD) * NHDD) + ((TSUPC/CDD) * NCDD))*

Where

NHDD: Normal Heating Degree Day, NCDD: Normal Cooling Degree Day
NTS UPC factor = May UPC /day
*NTSUPC = NTS UPC factor * billing days*
TSUPC = Total UPC – NTSUPC
TSUPC/HDD for heating months except October
TSUPC/CDD for cooling months except October
TSUPC/HDD for Oct = TSUPC/HDD from previous September
TSUPC/CDD for Oct = Average of TSUPC/CDD June-September of current season

The actual and normal energy sales for Residential and Commercial customers are shown in Figure 3-1 and Figure 3-2, respectively.

Figure 3-1: NIPSCO Residential GWh

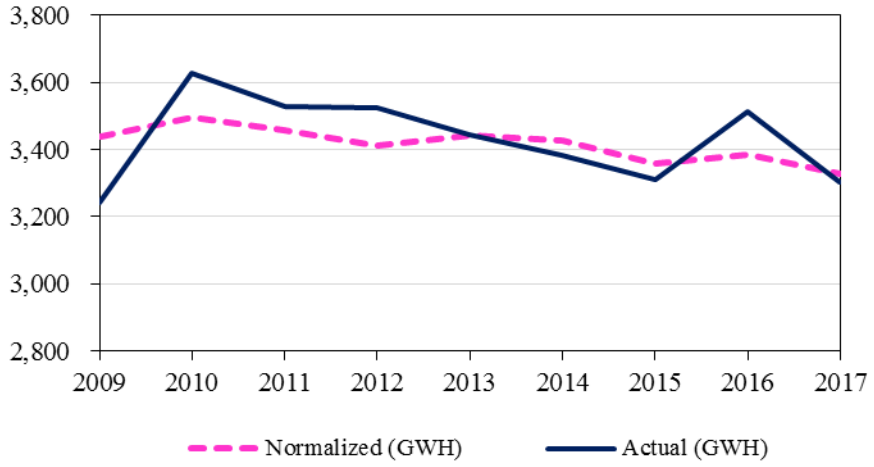
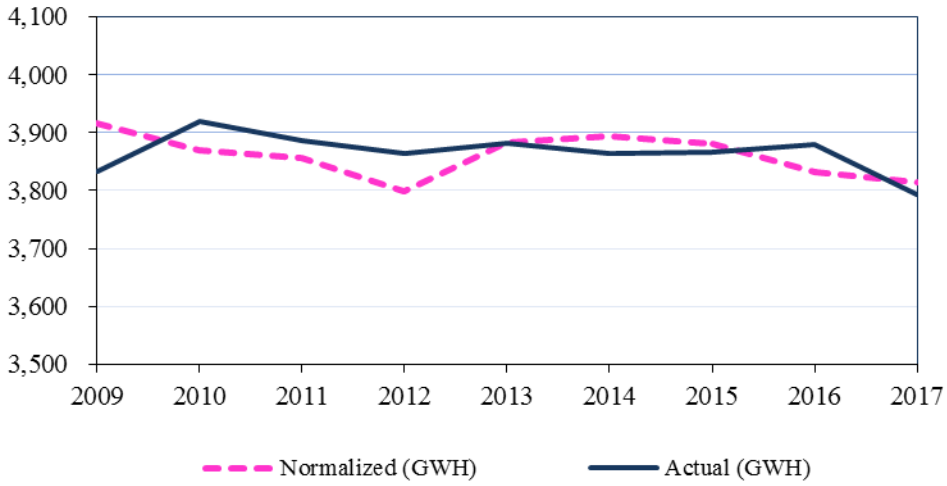


Figure 3-2: NIPSCO Commercial GWh



3.11 Forecast Results – Base Case

Over the forecast period, total energy is projected to remain flat and peak hour demand is projected to grow at 0.2%. NIPSCO expects overall customer growth to increase about 0.6% annually. Table 3-10 illustrates NIPSCO's electric energy and demand forecast.

Table 3-10: Electric Energy and Demand Forecast

	Energies (Gigawatt hour or "GWh")						Internal Peak Hour		MISO Coincident Peak Level	
Year	Total Retail *	% Change	Losses	Total Output	% Change	Load Factor	MW	% Change	MW	% Change
2008	16,705		897	17,602		65.3%	3,076		2,891	
2009	14,925	-10.7%	858	15,783	-10.3%	66.8%	2,696	-12.4%	2,848	-1.5%
2010	16,191	8.5%	915	17,106	8.4%	62.9%	3,103	15.1%	3,029	6.4%
2011	16,836	4.0%	892	17,728	3.6%	64.8%	3,122	0.6%	3,081	1.7%
2012	16,756	-0.5%	925	17,681	-0.3%	62.0%	3,257	4.3%	3,252	5.6%
2013	16,798	0.2%	839	17,638	-0.2%	63.0%	3,194	-1.9%	3,218	-1.0%
2014	17,467	4.0%	940	18,407	4.4%	66.7%	3,149	-1.4%	2,921	-9.2%
2015	16,563	-5.2%	886	17,449	-5.2%	65.2%	3,055	-3.0%	2,926	0.2%
2016	16,813	1.5%	913	17,726	1.6%	63.8%	3,173	3.9%	3,037	3.8%
2017	16,693	-0.7%	844	17,537	-1.1%	64.8%	3,087	-2.7%	2,927	-3.6%
2018	16,362	-2.0%	889	17,251	-1.6%	64.5%	3,051	-1.2%	2,907	-0.7%
2019	15,582	-4.8%	847	16,429	-4.8%	64.3%	2,916	-4.4%	2,776	-4.5%
2020	15,216	-2.4%	827	16,042	-2.4%	62.5%	2,932	0.6%	2,788	0.4%
2021	15,255	0.3%	829	16,084	0.3%	62.3%	2,949	0.6%	2,801	0.5%
2022	15,287	0.2%	831	16,118	0.2%	62.1%	2,965	0.5%	2,813	0.4%
2023	15,344	0.4%	834	16,178	0.4%	61.9%	2,982	0.6%	2,827	0.5%
2024	15,405	0.4%	837	16,242	0.4%	61.8%	2,999	0.5%	2,839	0.4%
2025	15,471	0.4%	841	16,311	0.4%	61.7%	3,016	0.6%	2,853	0.5%
2026	15,535	0.4%	844	16,379	0.4%	61.7%	3,033	0.6%	2,866	0.5%
2027	15,603	0.4%	848	16,451	0.4%	61.6%	3,048	0.5%	2,877	0.4%
2028	15,677	0.5%	852	16,529	0.5%	61.6%	3,064	0.5%	2,890	0.4%
2029	15,744	0.4%	856	16,600	0.4%	61.6%	3,077	0.4%	2,899	0.3%
2030	15,815	0.4%	859	16,674	0.4%	61.6%	3,091	0.5%	2,910	0.4%
2031	15,870	0.4%	862	16,733	0.4%	61.6%	3,103	0.4%	2,919	0.3%
2032	15,923	0.3%	865	16,788	0.3%	61.6%	3,113	0.3%	2,927	0.3%
2033	15,977	0.3%	868	16,845	0.3%	61.6%	3,123	0.3%	2,934	0.3%
2034	16,037	0.4%	871	16,909	0.4%	61.6%	3,133	0.3%	2,943	0.3%
2035	16,105	0.4%	875	16,981	0.4%	61.6%	3,145	0.4%	2,951	0.3%
2036	16,163	0.4%	878	17,042	0.4%	61.7%	3,152	0.2%	2,957	0.2%
2037	16,213	0.3%	881	17,094	0.3%	61.8%	3,158	0.2%	2,961	0.1%
2038	16,265	0.3%	884	17,148	0.3%	61.9%	3,164	0.2%	2,966	0.2%
2039	16,314	0.3%	887	17,201	0.3%	62.0%	3,169	0.2%	2,970	0.1%
Compound Average Growth Rate 2018-2039										
	0.0%			**0.0%**			**0.2%**		**0.1%**	
** Retail does not include bulk sales*										

Table 3-11 illustrates NIPSCO's electric energy by customer class.

Table 3-11: Energies by Customer Class

Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Other (GWh)	Total * (GWh)	Percent Change
2008	3,346	3,916	9,305	138	17,602	
2009	3,241	3,834	7,691	159	15,783	-10.3%
2010	3,626	3,920	8,459	186	17,106	8.4%
2011	3,527	3,886	9,257	166	17,728	3.6%
2012	3,524	3,863	9,250	119	17,681	-0.3%
2013	3,445	3,882	9,340	132	17,638	-0.2%
2014	3,384	3,864	10,071	148	18,407	4.4%
2015	3,310	3,867	9,249	138	17,449	-5.2%
2016	3,514	3,879	9,282	138	17,726	1.6%
2017	3,302	3,793	9,470	128	17,537	-1.1%
2018	3,411	3,871	8,947	134	17,251	-1.6%
2019	3,420	3,910	8,120	131	16,429	-4.8%
2020	3,418	3,949	7,718	129	16,042	-2.4%
2021	3,418	3,992	7,718	127	16,084	0.3%
2022	3,413	4,031	7,718	125	16,118	0.2%
2023	3,430	4,072	7,718	125	16,178	0.4%
2024	3,452	4,109	7,718	125	16,242	0.4%
2025	3,480	4,148	7,718	125	16,311	0.4%
2026	3,507	4,186	7,718	125	16,379	0.4%
2027	3,541	4,219	7,718	125	16,451	0.4%
2028	3,581	4,252	7,718	125	16,529	0.5%
2029	3,624	4,277	7,718	125	16,600	0.4%
2030	3,667	4,305	7,718	125	16,674	0.4%
2031	3,696	4,331	7,718	125	16,733	0.4%
2032	3,728	4,351	7,718	125	16,788	0.3%
2033	3,763	4,371	7,718	125	16,845	0.3%
2034	3,803	4,391	7,718	125	16,909	0.4%
2035	3,849	4,413	7,718	125	16,981	0.4%
2036	3,893	4,426	7,718	125	17,042	0.4%
2037	3,936	4,434	7,718	125	17,094	0.3%
2038	3,979	4,443	7,718	125	17,148	0.3%
2039	4,022	4,450	7,718	125	17,201	0.3%
Compound Average Growth Rate 2018-2039						
	0.8%	**0.7%**	**-0.7%**	**-0.3%**	**0.0%**	

**Includes Total Retail and Losses*

Table 3-12 displays the NIPSCO forecast by customer counts by class.

Table 3-12: Customer Counts by Class

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Total Customers
2008	400,640	53,438	2,484	754	457,316
2009	400,016	53,617	2,441	746	456,820
2010	400,522	53,877	2,432	740	457,571
2011	400,567	54,029	2,405	737	457,738
2012	401,177	53,969	2,445	758	458,349
2013	402,638	54,452	2,374	799	460,263
2014	403,272	54,635	2,338	751	460,996
2015	404,889	55,053	2,327	743	463,012
2016	407,268	55,605	2,313	744	465,930
2017	409,401	56,134	2,302	459	468,296
2018	411,114	56,325	2,302	459	470,199
2019	413,090	56,869	2,302	459	472,720
2020	415,157	57,351	2,302	459	475,269
2021	417,318	57,992	2,302	459	478,072
2022	419,577	58,465	2,302	459	480,803
2023	421,883	59,081	2,302	459	483,725
2024	424,236	59,519	2,302	459	486,517
2025	426,636	60,128	2,302	459	489,525
2026	429,083	60,589	2,302	459	492,433
2027	431,569	61,061	2,302	459	495,391
2028	434,147	61,535	2,302	459	498,443
2029	436,719	61,833	2,302	459	501,313
2030	439,303	62,304	2,302	459	504,368
2031	441,836	62,609	2,302	459	507,206
2032	444,249	62,905	2,302	459	509,915
2033	446,620	63,203	2,302	459	512,584
2034	449,029	63,513	2,302	459	515,303
2035	451,458	63,825	2,302	459	518,044
2036	453,890	63,956	2,302	459	520,606
2037	456,306	64,079	2,302	459	523,146
2038	458,698	64,210	2,302	459	525,669
2039	461,083	64,330	2,302	459	528,174
Compound Average Growth Rate 2018-2039					
	0.5%	**0.6%**	**0.0%**	**0.0%**	**0.6%**

3.12 Discussion of Forecast and Alternative Cases

3.12.1 High/Low Growth Cases

The high and low load growth cases were constructed from the base case forecast models and employed optimistic and pessimistic economic and demographic data from IHS Global Insight. The forecast models are estimated at the 95% confidence level and reflect the high and low model bands. The industrial scenarios are constructed individually for each forecasted customer. The high load growth scenario is created by looking at the customer's previous five years of history and using the peak usage and demand, as well as taking into account current business practices and any other potential growth. The low load growth scenario takes each individual customer's "worst case" scenario, whereas customer's minimum operating levels with major loads are idled, and using Rate limitations and other business protocols as guiding factors. Table 3-13 reflects NIPSCO's base, high and low load forecast scenarios for selected years.

Table 3-13: NIPSCO IRP Scenarios – Selected Year

NIPSCO IRP Scenarios - Selected Year											
	Energy Sales - GWh				Internal Demand - MW				MISO Coincident Peak - MW		
	Base	High	Low		Base	High	Low		Base	High	Low
Year	GWh	GWh	GWh		MW	MW	MW		MW	MW	MW
2018	17,251	17,587	16,909		3,051	3,119	2,982		2,907	2,972	2,842
2023	16,178	17,271	11,568		2,982	3,178	2,446		2,827	3,012	2,319
2028	16,529	18,134	11,770		3,064	3,358	2,500		2,890	3,167	2,358
2033	16,845	18,850	11,869		3,123	3,510	2,513		2,934	3,298	2,362
2038	17,148	19,639	11,960		3,164	3,666	2,509		2,966	3,437	2,352
		v Base				v Base				v Base	
		High	Low			High	Low			High	Low
		GWh	GWh			MW	MW			MW	MW
2018	-	1.95%	-1.98%		-	2.2%	-2.3%			2.2%	-2.3%
2023	-	6.76%	-28.50%		-	6.6%	-18.0%			6.6%	-18.0%
2028	-	9.71%	-28.79%		-	9.6%	-18.4%			9.6%	-18.4%
2033	-	11.90%	-29.54%		-	12.4%	-19.5%			12.4%	-19.5%
2038	-	14.53%	-30.25%		-	15.9%	-20.7%			15.9%	-20.7%

3.13 Evaluation of Model Performance and Accuracy

NIPSCO tracks its forecast in terms of mean absolute error ("MAE"). Data for 2006-2017 show that the MAE of the one-year-ahead peak hour demand forecast is 3.3% (MAE of the one-year-ahead MISO coincident peak hour demand forecast is 0.2%); the two-year-ahead forecast has a 4.2% MAE; and the MAE for the five-year-ahead forecast is 5.9%. These represent total forecast error including the effect of abnormal weather at peak. The comparable MAE GWh sales is 3.2% for the one-year-ahead forecast; 4.7% for the two-year-ahead forecast; and 3.8% for the five-year-ahead forecast. Class comparisons to weather-normalized actual data show variances with residential and commercial of 2.0% and 3.3% MAE for the one-and two-year ahead forecasts. Industrial GWh are not weather normalized because historically they have not fluctuated with

weather and show 5.7% and 8.3% MAE for the one-year-ahead and the two-year-ahead forecast. NIPSCO does not have any firm wholesale power sales.

Table 3-14 and Table 3-15 show data for 2006-2017 for total GWh sales and peak hour MW and compare forecasts to actual data not normalized for weather. Table 3-16 and 3-17 show GWh sales by class. GWh are compared to actual data normalized for weather. Table 3-18 shows the performance of the MISO coincident peak model performance since 2012.

Table 3-14: Internal Peak Hour Demand (MW)

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
2006	3,238	3,099	4.3%	3,077	5.0%	3,064	5.4%
2007	3,239	3,154	2.6%	3,134	3.2%	3,146	2.9%
2008	3,076	3,224	4.8%	3,188	3.6%	3,201	4.1%
2009	2,696	3,024	12.2%	3,248	20.5%	3,170	17.6%
2010	3,103	2,965	4.5%	3,088	0.5%	3,232	4.2%
2011	3,122	3,134	0.4%	3,093	0.9%	3,282	5.1%
2012	3,257	3,183	2.3%	3,195	1.9%	3,323	2.0%
2013	3,194	3,172	0.7%	3,306	3.5%	3,233	1.2%
2014	3,149	3,209	1.9%	3,243	3.0%	3,287	4.4%
2015	3,055	3,173	3.9%	3,259	6.7%	3,300	8.0%
2016	3,170	3,118	1.6%	3,187	0.5%	3,419	7.8%
2017	3,100	3,113	0.4%	3,146	1.5%	3,349	8.0%
Average			**3.3%**		**4.2%**		**5.9%**

**Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance includes weather effect.*

Table 3-15: Total GWh including Losses

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	Actual *	Forecast	% Var.	Forecast	% Var.	Forecast	% Var.
2006	17,500	16,750	4.3%	17,235	1.5%	17,544	0.3%
2007	17,655	17,725	0.4%	16,916	4.2%	17,928	1.5%
2008	17,602	18,355	4.3%	17,938	1.9%	18,374	4.4%
2009	15,783	16,898	7.1%	18,446	16.9%	17,716	12.2%
2010	17,106	15,910	7.0%	17,340	1.4%	17,373	1.6%
2011	17,728	16,715	5.7%	16,931	4.5%	18,389	3.7%
2012	17,681	17,754	0.4%	17,220	2.6%	18,804	6.3%
2013	17,638	17,591	0.3%	18,622	5.6%	18,258	3.5%
2014	18,407	18,275	0.7%	17,786	3.4%	18,367	0.2%
2015	17,449	18,417	5.5%	18,611	6.7%	17,747	1.7%
2016	17,726	18,103	2.1%	18,537	4.6%	18,995	7.2%
2017	17,537	17,647	0.6%	18,175	3.6%	18,118	3.3%
Average			**3.2%**		**4.7%**		**3.8%**

** Actual GWh not adjusted for weather. Forecasted GWh assumes normal weather, therefore, variance includes weather effect.*

Table 3-16: Residential and Commercial GWh

		1-Year Ahead		2-Year Ahead	
	Normal *	Forecast	% Var.	Forecast	% Var.
2008	7,328	7,641	4.3%	7,600	3.7%
2009	7,357	7,534	2.4%	7,757	5.4%
2010	7,366	7,431	0.9%	7,659	4.0%
2011	7,313	7,428	1.6%	7,474	2.2%
2012	7,213	7,382	2.3%	7,492	3.9%
2013	7,323	7,414	1.2%	7,427	1.4%
2014	7,320	7,398	1.1%	7,466	2.0%
2015	7,241	7,409	2.3%	7,461	3.0%
2016	7,216	7,323	1.5%	7,476	3.6%
2017	7,140	7,322	2.6%	7,384	3.4%
Average			**2.0%**		**3.3%**

** Adjusted for weather*

Table 3-17: Industrial GWh

		1-Year Ahead		2-Year Ahead	
	Actual *	Forecast	% Var.	Forecast	% Var.
2008	9,305	9,861	6.0%	9,523	2.3%
2009	7,691	8,579	11.6%	9,833	27.8%
2010	8,459	7,692	9.1%	8,879	5.0%
2011	9,257	8,220	11.2%	8,629	6.8%
2012	9,250	9,243	0.1%	8,632	6.7%
2013	9,340	9,111	2.4%	10,020	7.3%
2014	10,071	9,799	2.7%	9,245	8.2%
2015	9,249	9,923	7.3%	10,055	8.7%
2016	9,282	9,713	4.6%	9,969	7.4%
2017	9,470	9,288	1.9%	9,720	2.6%
Average			**5.7%**		**8.3%**

** No weather effect measured for industrial load*

Table 3-18: MISO Coincident Peak Demand

MISO Coincident Peak Demand - MW
Absolute % Variance of Forecast v Actual

		1-Year Ahead	
Year	Actual *	Forecast	% Var.
2012	2.0%	1.6%	0.4%
2013	3.6%	3.8%	0.2%
2014	2.8%	2.8%	0.0%
2015	2.3%	2.5%	0.2%
Average			**0.2%**

*Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance include weather effect. Please note: MISO coincident Peak model performance is filed with MISO annually on November 1st.

Section 4. Supply-Side Resources

4.1 Fuel Procurement Strategy

4.1.1 Coal Procurement and Inventory Management Practices

4.1.1.1 Coal Supply Strategy

NIPSCO employs a multifaceted strategy to guide coal procurement activities associated with the fuel supply requirements for its coal-fired units. The goal of this strategy is to maximize reliability while maintaining customer affordability. Key elements include: (1) procuring coal supply from sources that minimize the total cost of fuel, O&M costs, environmental costs, inventory costs and other cost impacts ("total cost of ownership"); (2) hedging customers' price exposure with forward purchases to protect against price volatility; (3) supporting environmental compliance; (4) maintaining reliable inventory levels; (5) ensuring reliability of coal supply and delivery; and (6) maximizing operational flexibility and reliability by procuring coal types that can be used in more than one unit whenever possible.

4.1.1.2 Coal Procurement

NIPSCO maintains a five-year baseline coal forecast that is used to create a strategy that drives its fuel procurement plan. It estimates coal and related coal transportation procurement requirements needed to maintain reliable and economic coal inventory levels. The strategy and fuel procurement plan are highly dynamic and are updated on a periodic basis in response to energy market conditions. Over the past several years, environmental regulations, a significant influx of highly variable renewable generation (e.g. wind and solar), low natural gas prices, and energy efficiency and other demand side initiatives have made coal-fired generation the marginal supply source. Consequently, this has created an environment with highly variable and nearly unpredictable coal purchase requirements. Therefore, NIPSCO's fuel procurement plans must remain as flexible as possible while still maintaining reliable supply. Obtaining volume flexibility can be challenging since coal suppliers and transportation providers typically require firm volume commitments.

4.1.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance of coal in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower production costs and highly efficient natural gas extraction processes (horizontal drilling and fracking) have kept natural gas a competitive fuel when used in high efficiency, CCGT units. In addition, increases in wet gas production to gather petroleum liquids further increase natural gas supply when oil prices

rise. Oil prices have risen steadily over the last year helping to spur wet gas production. These dynamics are expected to keep natural gas pricing low in the near term. Longer term natural gas prices are expected to recover somewhat with the addition of new CCGTs and increased natural gas export capacity. These market dynamics continue to displace a significant amount of coal-fired electric generation and are keeping coal prices relatively low. Decreased coal demand and higher mining costs driven by government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies over the last few years. The restructuring of coal companies' debt and other costs through the bankruptcy process should allow them to produce coal in this competitive environment. Supply has been rationalized and any significant increase in demand could result in coal price volatility. However, several factors may limit the upside for coal prices. The first factor is the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal-fired electric generation. A second factor is utilities continue to retire older, higher cost coal-fired generation and this has reduced demand. Lastly, low energy prices driven by natural gas pricing and renewables will also limit demand for coal if coal prices spike.

The competitive energy market has also driven a shift in coal supply regions. Specifically, the cost to produce coal in the Appalachian regions and low coal prices have resulted in declining coal production and this has increased market share of the lower cost Illinois Basin ("ILB") region. Even with its higher sulfur content, ILB coal has become an export resource, and its use has increased domestically as utilities have installed flue gas desulfurization systems ("FGDs") to meet tighter sulfur dioxide limits and other emission standards. Southeast utilities have started using ILB coal to replace higher cost Columbian and Central Appalachia coal.

The use of Powder River Basin ("PRB") coal from Wyoming and Montana has increased significantly over the last decade. Although PRB coal has a lower heat content than coals mined in other regions, utilities typically blend PRB coal with Central Appalachian, ILB, or Northern Appalachian ("NAPP") coals to reduce their overall fuel costs. Asian demand for PRB coal has also grown as Japan and China have built new, high efficiency coal units and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand. Historically, Central Appalachian and NAPP coal have been exported into metallurgical coal and some steam coal markets abroad. Since the end of 2016, demand for seaborne coal has increased. It appears that exports will remain resilient with export volumes over the last year at or near the top of the five year range. Coal suppliers need this to continue in order to offset losses in domestic markets.

Overall, these fundamentals are bearish for coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices and incorporate in its procurement strategies.

4.1.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Domestic demand for coal has continued to trend lower over the last two years; therefore, prices have remained relatively low and stable. NAPP coal, used by NIPSCO as a blend fuel in one of its cyclone units, and ILB coal have had relatively strong price increases off of 2016 lows as export demand and prices have trended higher over the last two years.

Pricing for PRB coal has remained low over the last two years and is close to the marginal cost of production.

The export dynamic will likely keep upward pressure on the market in the near term and this would likely lower domestic demand for coal unless domestic energy prices rise. All domestic coal pricing is expected to remain soft as long as energy prices stay low, and will likely keep coal prices flat for the balance of 2018 into 2019.

4.1.1.5 Coal and Issues of Environmental Compliance

Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to evolve in a manner that meets current and future environmental requirements.

4.1.1.6 Maintenance of Coal Inventory Levels

NIPSCO has an ongoing strategy to maintain stable coal inventories and reviews inventory target levels annually and may make adjustments in anticipation of changes in supply availability relative to demand, transportation constraints and unit consumption. NIPSCO may modify target inventory levels on a unit-by-unit basis depending on the unit consumption, delivery rates, reliability of coal supply and station coal handling operations. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates and variability in delivery performance generally require higher levels of inventory to insure reasonably adequate reliability.

4.1.1.7 Forecast of Coal Delivery and Transportation Pricing

To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts that consider current and future coal supply commitments. All fuel procurement options are compared on a delivered cost basis, which includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have been somewhat stable from the various supply regions, particularly shipments originating in the PRB region due to infrastructure improvements. Railroads typically make investment in infrastructure and equipment to support anticipated shipment rates. The cyclical nature of the railroad business can create short term transportation constraints and can impact NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years.

Transportation rates have declined somewhat given the competition in the energy markets. Railroads have been willing to rationalize rail rates, as shown in the market assessment plots below, to keep market share.

Figure 4-1: PRB Customer Rates

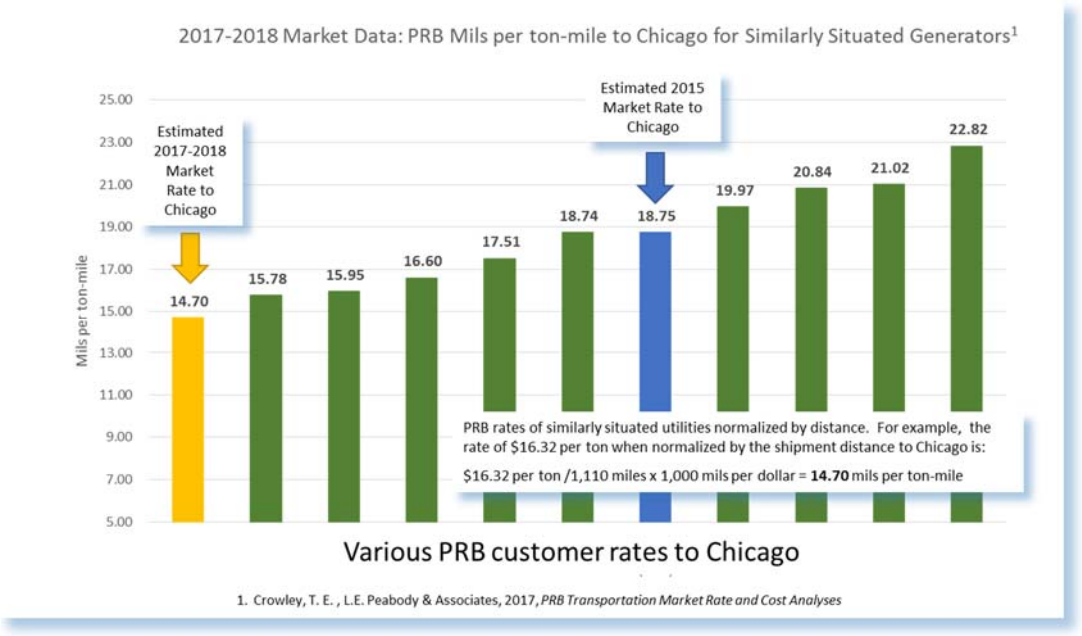
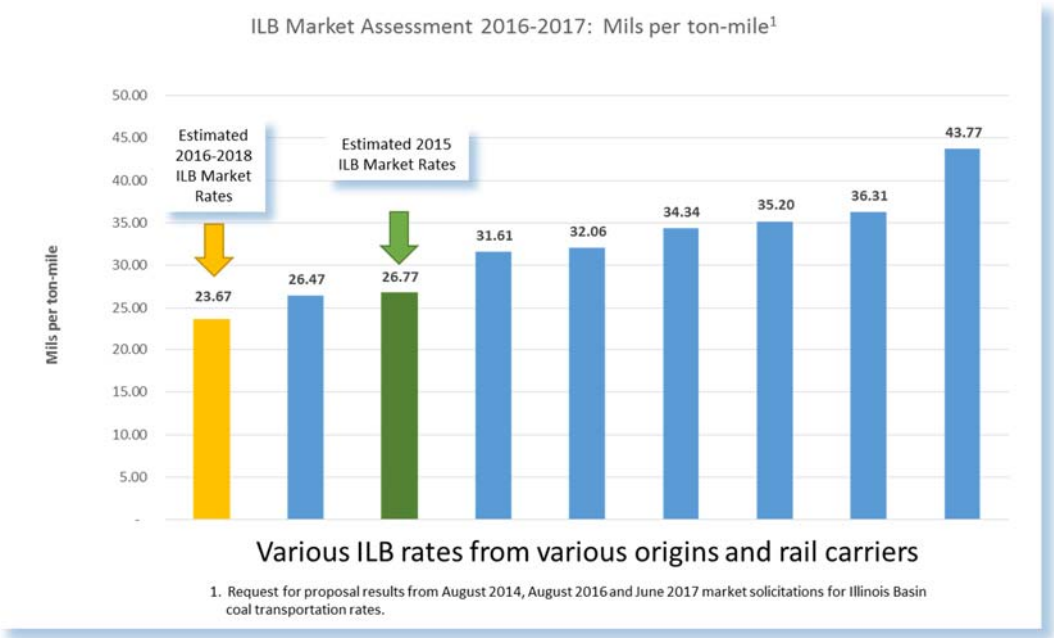


Figure 4-2: ILB Customer Rates



This pricing trend has improved the competitiveness of NIPSCO's coal-fired generation to a certain extent.

4.1.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options from various supply regions and destination for most of its coal transportation moves, and is further disadvantaged due to its geographical location. Not only are rail transportation options limited, other transport modes (trucking, barging and lake vessels) are not economically or logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one railroad. All coal deliveries by this railroad to Schahfer have been transported under agreements that historically escalated transportation rates that also included fuel surcharges indexed to oil prices. However, under this structure, lower power prices lead to a reduction in coal demand. Therefore, NIPSCO and this railroad worked to develop an agreement that lowered rates to improve the station's competitiveness in the market. As stated above, energy markets have forced a rationalization of coal pricing and associated transportation costs. NIPSCO expects this dynamic to continue for the foreseeable future.

As a result, PRB and ILB coal transportation rates have been reduced by nearly 50%. Fuel surcharges continue to fluctuate with the changes in oil prices. The expectation for transportation pricing is also expected to remain soft as long as energy prices stay low, and expect rates to be flat for the balance of 2018 into 2019. Increases in fuel charges could lead to modest transportation cost increases as oil prices trend higher.

4.1.1.9 Coal Contractual Flexibility, Deliverability and Procurement

Contract terms for coal and coal transportation agreements are typically one to five years in duration. Spot purchases are made on an as-needed basis to manage inventory fluctuations. In an effort to minimize variations in inventory levels and accommodate unit maintenance outages, most coal types under contract can be used in more than one unit. The fuel blending strategy can also be adjusted to conserve a particular type of coal if supply problems are experienced. In addition, coal suppliers have been more amenable to providing some volume flexibility. This has supported NIPSCO's inventory management efforts.

4.1.2 Natural Gas Procurement and Management

NIPSCO currently procures natural gas for its CCGT generating station using a natural gas supply contract with an energy manager that delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on the interstate pipeline, Midwestern Gas Transmission Company, and releases the capacity to the energy manager. The contract has provisions to purchase next day and intraday firm gas supplies to serve the daily needs of the facility. NIPSCO nominates and balances the gas supply needs of the CCGT generating station. A portion of the gas supply for the Sugar Creek Generating Station ("Sugar Creek") is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

The coal units and combustion turbines ("CTs") at NIPSCO are located within the NIPSCO natural gas local distribution company service territory. NIPSCO maintains a separate contract for firm delivered natural gas supply and energy management for these units. The contract has

provisions to nominate next-day usage based on the expected usage of each generating station. The actual usage is balanced daily and balancing is the responsibility of the energy manager.

4.2 Electric Generation Gas Supply Request for Proposal Process

NIPSCO conducts two separate RFPs for the electric generation firm natural gas supply, one for the Sugar Creek facility and a separate one for the coal units and CTs. The RFP process may be done on a seasonal or annual basis depending on the current contract length and supplier agreement. The process includes qualifying potential suppliers, customizing the RFP based on near-term system needs, and gas supply trends. Suppliers are chosen based on the overall value of the package and ability to serve the needs of the facility. To date, NIPSCO has entered into electric generation gas supply agreements that extend no longer than one year, but is always evaluating the value and benefits of longer term agreements.

4.3 Existing Resources

NIPSCO has a variety of generation resources to meet its customers' forecast capacity and energy needs. Not only do these resources need to meet the principles set out in Section 1, they must operate within MISO, the Regional Transmission Organization, and subject to NERC standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization, ReliabilityFirst, standards approved by the Federal Energy Regulatory Commission ("FERC").

4.4 Supply Resources

NIPSCO owned generating resources consist of coal, natural gas and hydro units. Additionally NIPSCO meets it customer needs with 2 wind purchase power agreements and has an extensive demand response ("DR") program via its large industrial customers. The total Net Demonstrated Capacity ("NDC") of the existing resources is 2,925 MW across multiple generation sites, including the Schahfer (Units 14, 15, 16A, 16B, 17 and 18), Michigan City (Unit 12), Bailly (Units 10), Sugar Creek and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). Of the total capacity, 61% is from coal-fired units, 21% is from natural gas-fired units and 18% is from industrial interruptible DR program. Consistent with the 2016 IRP preferred plan NIPSCO retired 2 coal fired units (Units 7 and 8) at the Bailly in May 2018.

Table 4-1 provides a summary of the current generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity

Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	14	Coal	431
	15	Coal	472
	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	1,780
Sugar Creek		NG	535
Bailly	10	NG	31
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	100
NIPSCO			2,925

NG=Natural Gas

4.4.1 Michigan City Generating Station

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. It has one base-load unit, Unit 12 and is equipped with selective catalytic reduction ("SCR") and over-fire air ("OFA") systems to reduce nitrogen oxide ("NO_x") emissions. A new FGD ("") system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-2.

Table 4-2: Michigan City Generating Station

	Unit 12
NET Output	
Min (MW)	315
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	Coal
Turbine	General Electric
Frame	G2
In-Service	1974
Environmental Controls	FGD, SCR, OFA

4.4.2 R.M. Schahfer Generating Station

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. It is the largest of NIPSCO's generating stations. There are four coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce sulfur dioxide ("SO_2") emissions and SCR, SNCR, low NO_x burners ("LNB"), and OFA systems to reduce NO_x emissions. Unit 14 burns low and medium sulfur coal blends and Unit 15 burns low-sulfur coals to minimize SO_2 emissions. As part of the Company's Clean Air Interstate Rule (CAIR) Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. Installation of a new LNB with OFA system was completed on Unit 15 in 2009. A new FGD plant on Unit 14 was placed in service in 2013. FGD installation on Unit 15 was completed in 2014. The individual unit characteristics of Schahfer are provided in Table 4-3.

Table 4-3: R.M. Schahfer Generating Station

	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	290	250	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	1976	1979	1983	1986	1979	1979
Environmental Controls	FGD, SCR, OFA	FGD, SNCR, LNB, OFA	FGD, LNB, OFA	FGD, LNB, OFA	----	----

4.4.3 Sugar Creek Generating Station

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired CTs and CCGTs were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is its newest electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two generators and one steam turbine generator are operated in the CCGT mode and environmental control technologies include SCR to reduce NO_x, and dry low NO_x ("DLN") combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 4-4.

Table 4-4: Sugar Creek Generating Station

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	120	120	120
Max (MW)	156	157	222
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA	7FA	D11
In-Service	2002	2002	2003
Environmental Controls	SCR, DLN	SCR, DLN	---

4.4.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources)

Norway Hydro is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has four generating units capable of producing up to 7.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 4-5.

Table 4-5: Norway Hydro

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydro is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has three generating units capable of producing up to 9.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 4-6.

Table 4-6: Oakdale Hydro

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

4.4.5 Barton and Buffalo Ridge Wind (NIPSCO Purchase Power Agreements)

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 4-7.

Table 4-7: Barton Wind PPA

	Barton PPA
NET Output	
Per Unit (MW)	2
Number of Units	25
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County, South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 4-8.

Table 4-8: Buffalo Ridge Wind PPA

	Buffalo Ridge PPA
NET Output	
Per Unit (MW)	2
Number of Units	24
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

4.5 Total Resource Summary

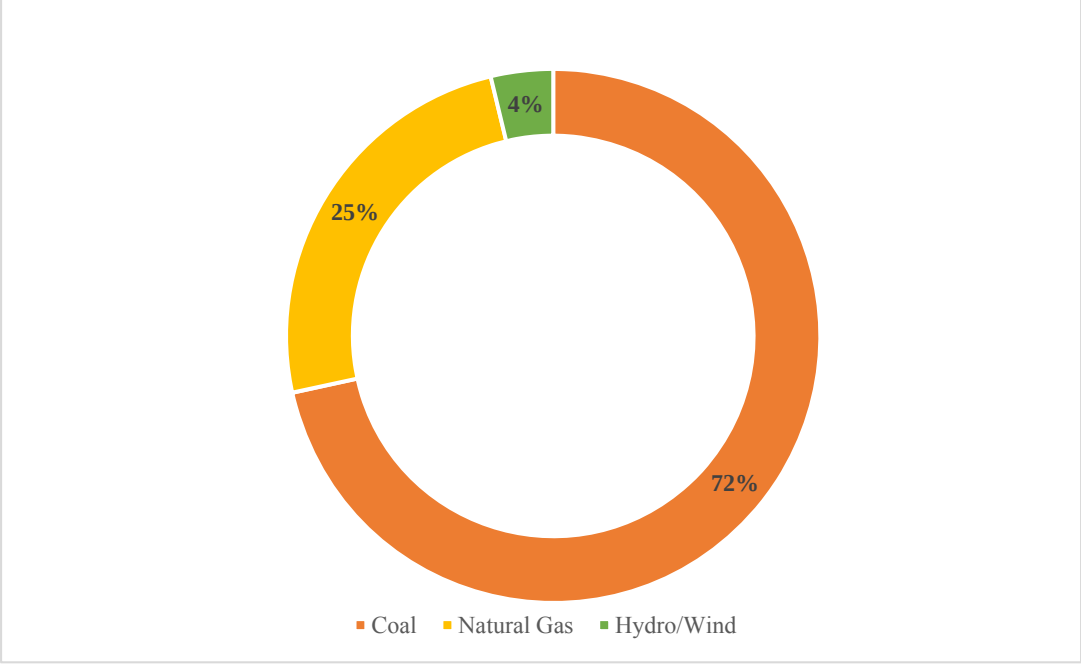
Table 4-9 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-3 illustrates NIPSCO's existing resources by fuel type.

Table 4-9: Existing Generating Units

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	14	Coal	431	1976
	15	Coal	472	1979
	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
		Subtotal	1,780	
Sugar Creek		NG	535	2002
Bailly	10	NG	31	1968
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind		Wind	100	2009
NIPSCO			2,925	

NG=Natural Gas

Figure 4-3: Existing Resources Net Demonstrated Capacity



4.6 Operations Management and Dispatch Implications

The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, environmental considerations and the overall generation mix within MISO may affect the level of future dispatch.

4.7 MISO Wholesale Electricity Market

MISO supplies an important element to NIPSCO's long term plans – ongoing liquidity. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. In 2018, MISO has members from 15 states and one Canadian province with a generation capacity of 200,000 MW and 65,800 miles of high-voltage transmission. MISO manages one of the world's largest energy and operating markets that includes a Day-Ahead Market, Real-Time Market and Financial Transmission Rights Market.

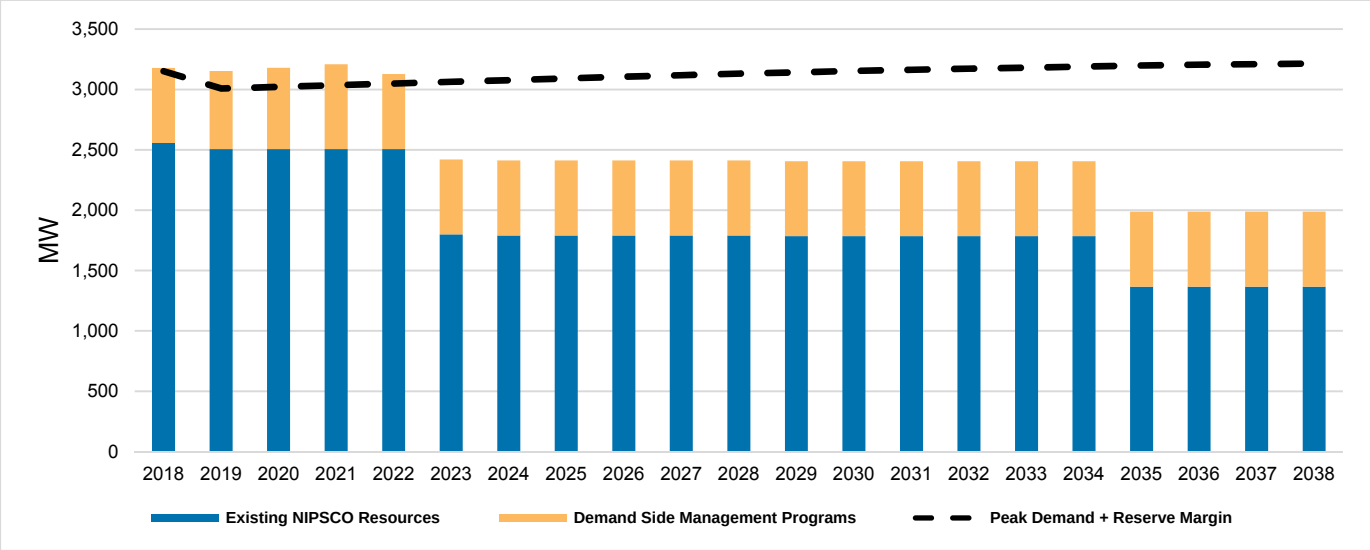
4.8 Resource Adequacy

Consistent with the principles set out in Section 1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse and affordable supply. As part of the Resource Adequacy planning process, NIPSCO is now utilizing the peak demand forecast coincident with the MISO peak demand to determine its capacity requirements. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks, which is typically in the summer. The methodology for calculating the coincident peak demand is described in detail in Section 3. NIPSCO's assessment of its existing resources against the future needs of its customers is shown in Table 4-10.

Table 4-10: Assessment of Existing Resources v. Demand Forecast (Base)

	(a)	(b)	(c)	(d)	(e)
Year	**MISO Coincident Peak Demand**	**Peak Demand + Reserve Margin**	**Demand Side Management Programs**	**Existing NIPSCO Resources**	**Capacity Position/Long Short (c+d-b)**
2018	2,907	3,152	621	2,557	26
2019	2,776	3,009	646	2,507	144
2020	2,788	3,022	673	2,507	158
2021	2,801	3,036	702	2,507	173
2022	2,813	3,050	621	2,507	78
2023	2,827	3,064	621	1,799	(644)
2024	2,839	3,078	621	1,791	(666)
2025	2,853	3,092	621	1,791	(680)
2026	2,866	3,106	621	1,791	(694)
2027	2,877	3,119	621	1,791	(707)
2028	2,890	3,132	621	1,791	(721)
2029	2,899	3,143	621	1,785	(737)
2030	2,910	3,154	621	1,785	(748)
2031	2,919	3,164	621	1,785	(758)
2032	2,927	3,173	621	1,785	(767)
2033	2,934	3,181	621	1,785	(775)
2034	2,943	3,190	621	1,785	(784)
2035	2,951	3,199	621	1,367	(1,212)
2036	2,957	3,206	621	1,367	(1,218)
2037	2,961	3,210	621	1,367	(1,222)
2038	2,966	3,215	621	1,367	(1,227)
Notes:					
Reserve Margin Assumption = 8.4%					
Existing Resource Capacity based on NIPSCO UCAP calculation and reflects retirements in 2023 and 2035 *Demand Side Management Programs include Demand Response and Energy Efficiency Programs*					

Figure 4-4: Resource Adequacy Assessment (MW)



Based on the 2016 IRP preferred plan, NIPSCO would need additional capacity resources to meets its customer demand starting in 2023 after the retirements of Schahfer Units 17 and 18. NIPSCO has evaluated a range of resource options to meet that need.

4.9 Future Resource Options

New resources may be needed to meet the future electricity requirements of NIPSCO's customers over time, so it is critical that valid cost and operational estimates are developed for such future resource options in the IRP modeling. In the 2018 IRP, NIPSCO developed a two-step process to improve the new resource evaluation process and to respond to feedback received in the 2016 IRP.[2] This process entailed:

- A review of multiple third-party data sources to assess current and future estimates of resource technology cost, as well as plausible cost ranges, and performance characteristics
- Development of final inputs for IRP modeling based on real bid data that was received from the All-Source RFP.

4.9.1 Third-Party Data Source Review

NIPSCO worked with CRA to perform a screen of third-party sources for new resource cost and operational parameter estimates. The screen included the study NIPSCO commissioned for its 2016 IRP, public sources that develop estimates, such as government forecasts and other

[2] Note that a discussion of future demand-side resource options is included in Section 5.

utility IRPs, and subscription services which provide data and capital cost estimates over time. Figure 4-5 provides a list of the sources that were relied upon for the third-party screen.

Based on the source review, NIPSCO identified a list of feasible technology options to be assessed in the initial round of review. These included:

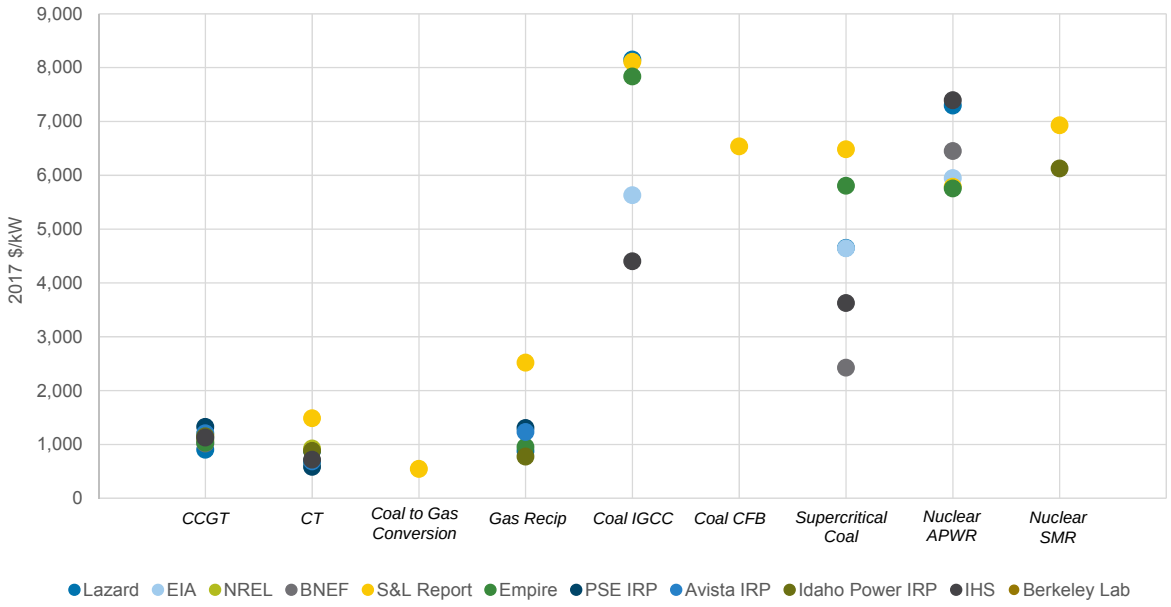
- Coal technologies – integrated gasification combined cycle, circulating fluidized bed, and supercritical pulverized coal
- Natural gas technologies – CTs, CCGTs, reciprocating engines, and coal-to-gas conversion
- Nuclear technologies – small module reactors and advanced pressurized water reactions
- Renewable technologies – onshore wind, offshore wind, distributed wind, utility-scale photovoltaic ("PV") solar, and distributed PV solar
- Other technologies – combined heat and power, battery storage, microturbines, and biomass

Figure 4-5: Data Sources for Third-Party Resource Review

Data Source	Description
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 Annual Energy Outlook)
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)
	Lazard Levelized Cost of Storage Version 3.0 (2017)
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook
	US Wind Capital Cost and Required Price Outlook
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region
	Key cost input in LCOE Scenarios, 1H 2017
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)
National Renewable Energy Technology Laboratory (NREL)	Annual Technology Baseline 2017

NIPSCO then aggregated the cost estimates from all sources by technology type to evaluate current costs on a $/kilowatt ("kW") basis. As part of this assessment, average, median, minimum, and maximum costs were recorded. A summary of the results of the survey is presented in Figure 4-6 and Figure 4-7.

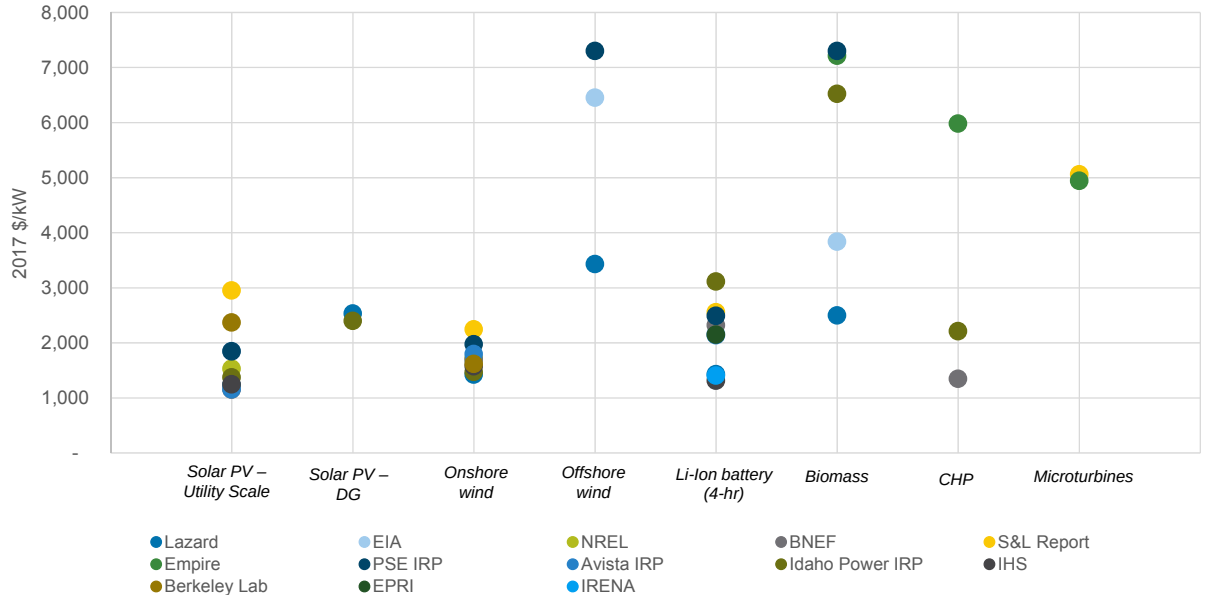
Figure 4-6: Current Capital Cost Summary for Coal, Gas, and Nuclear Technologies (2017$/kW)



2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,276	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927

Gas Recip – Gas Reciprocating Engine
IGCC – Integrated Gasification Combined Cycle
CFB – Circulating Fluidized Bed
APWR – Advanced Pressurized Water Reactor
SMR – Small Modular Reactor

Figure 4-7: Current Capital Cost Summary for Renewable, Storage, and Other Technologies (2017$/kW)[3]



2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

Given relatively large uncertainty ranges for certain technologies and given even larger uncertainty regarding future cost trends, NIPSCO determined that it was necessary to conduct an RFP process to collapse the uncertainty and identify transactable projects that could be available for future capacity needs, especially by 2023. In the 2016 IRP, NIPSCO identified several screening criteria to confirm project viability, including technical feasibility, commercial availability, economic attractiveness, and environmental compatibility. In the 2018 IRP, each of these criteria could be tested with actionable data from the RFP process as opposed to solely relying on engineering advice.

4.9.2 All Source Request for Proposals

NIPSCO worked with CRA's Auctions and Competitive Bidding practice to conduct an All-Source RFP during the spring and early summer of 2018. During NIPSCO's first Public Advisory meeting, an overview of the All-Source RFP design was provided to stakeholders and comments were solicited and accepted through April 2018. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the All-Source RFP on May 14, 2018 and closed the window for proposals on June 29, 2018.

[3] Note that renewable cost data from the S&L summary was excluded in the summaries due to vintage concerns. Old solar PV – Utility Scale data was also excluded from the Berkeley Lab source.

The All-Source RFP provided several guidelines to bidders, which are summarized below:

- Technology: The All-Source RFP requested all solutions regardless of technology, including demand-side options and storage

- Size: The All-Source RFP defined a minimum total need of 600 MW for the portfolio, but placed no size restrictions on the potential bidders. The All-Source RFP explicitly allowed for resources below 600 MW to offer their solution as a piece of a potential total need. The All-Source RFP also encouraged larger resources offer their solution for consideration.

- Ownership Arrangements: The All-Source RFP was open to asset purchases (new or existing) and PPAs. However, it required that resources qualify as MISO internal generation (not pseudo-tied) or load in the form of DR.

- Duration: The All-Source RFP requested delivery beginning June 1, 2023, but indicated that it would evaluate deliveries as early as June 1, 2020. The minimum contractual term and/or estimated useful life was requested to be five years, except for DR, which was allowed to offer for a one-year term.

- Deliverability: The All-Source RFP required that bidders have firm transmission delivery to MISO Local Resource Zone 6 ("LRZ6").

- Participants & Pre-Qualification: The All-Source RFP required counterparties be credit-worthy to ensure an ability to fulfill future resource obligations.

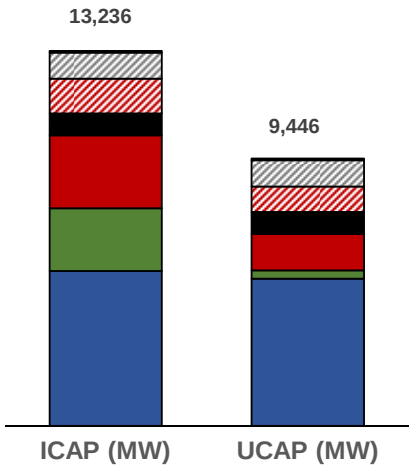
Overall, the All-Source RFP generated a large amount of bidder interest, with 90 total proposals received across a range of deal structures. NIPSCO received bids for 59 individual projects across five states with over 13 GW of installed capacity ("ICAP") represented. Many of the proposals offered variations on pricing structure and term length, and the majority of the projects were in various stages of development. A summary of the total number of proposals received by technology type is shown in Figure 4-8.

Figure 4-8: Summary of Number of Proposals Received by Technology Type

Technology	CCGT	CT	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
Asset Sale	4	-	-	1	-	1	-	-	-	6
PPA	8	-	3	6	-	26	7	8	1	59
Option	3	1	-	7	1	8	4	1	-	25
Total	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

On a total MW basis, the 13 GW of ICAP offered represented just under 10 GW of UCAP, providing a sufficiently large set of candidate options for NIPSCO to evaluate for any capacity need during the All-Source RFP delivery window. Over half of the offered UCAP was in the form of natural gas-fired projects, primarily CCGTs. However, a significant amount of renewable, coal-based, and storage resources were also offered. Figure 4-9 shows a summary of total MW offered in response to the All-Source RFP by type.

Figure 4-9: Summary of Total MW of Proposals Received by Type

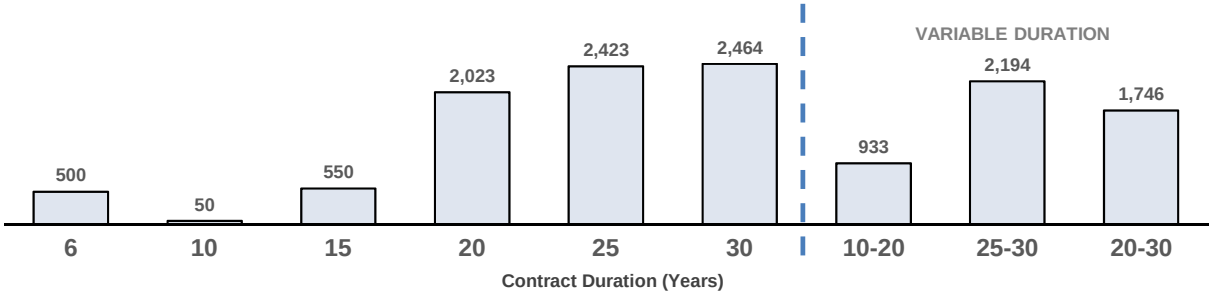


	ICAP (MW)	UCAP (est. MW)
Demand Response	70	70
Storage	925	925
Solar + Storage	1,220	902
Wind + Solar + Storage	0	0
Coal	772	772
Solar	2,580	1,291
Wind	2,209	287
Natural Gas (CT)	0	0
Natural Gas (CCGT)	5,470	5,199
	13,236	9,446

*Note that totals are on a project basis, which eliminates double counting of multiple proposals for the same facility.

Most PPA offers were relatively long in duration, with the majority of proposals offering contracts for 20 year terms or longer. Several bidders offered shorter-term options, including a number that provided NIPSCO with options to select from multiple duration possibilities. Figure 4-10 provides a summary of the total UCAP MW offered by duration.

Figure 4-10: Summary of Proposals Received by Duration (UCAP MW)



Most importantly, the All-Source RFP responses provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was relatively consistent with the third-party data review, but renewable offers were at the low end of the estimates observed in the public literature. This indicated that technology change and developer activity in a competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future. A summary of the various proposals by type and by price is provided in Figure 4-11. Note that due to confidentiality considerations, individual project prices cannot be disclosed.

Figure 4-11: Summary of Proposals by Price

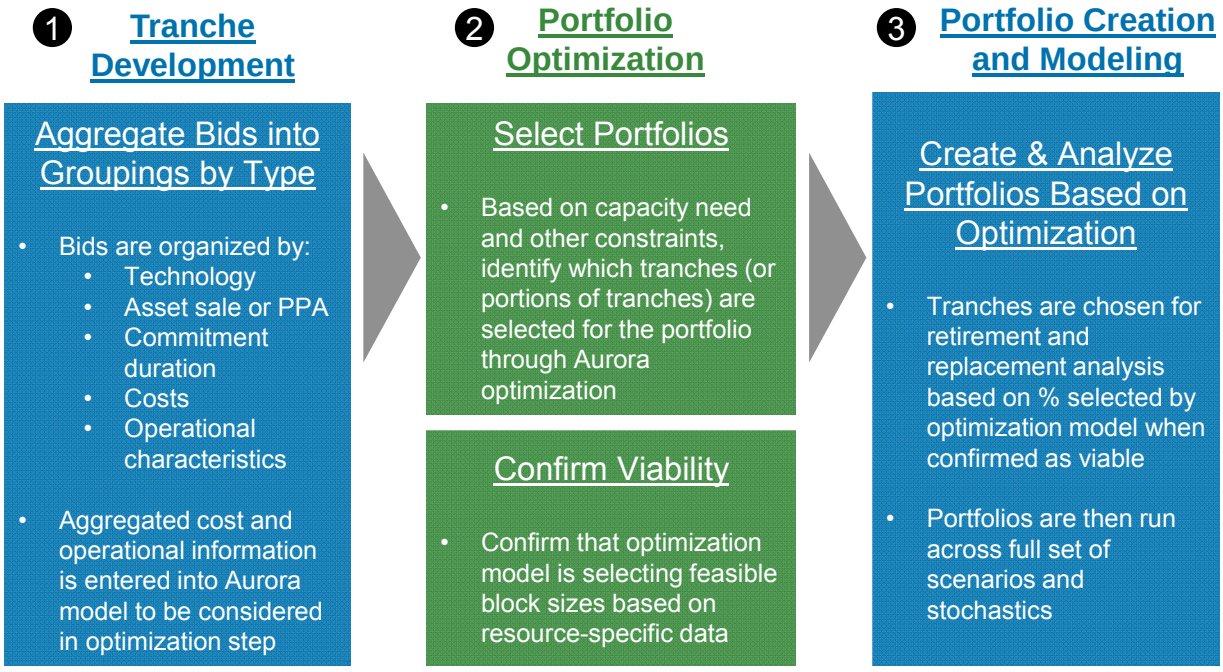
	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

4.10 Incorporation of the All-Source RFP Results into the IRP

After gathering the All-Source RFP bidder data, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for All-Source RFP-IRP integration, which is outlined in Figure 4-12:

1. Organize the various bids into groupings or tranches according to technology, whether the bid offered a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics.
2. Perform portfolio optimization analysis based on NIPSCO's potential capacity need and other portfolio design constraints, confirming option viability based on feasible block sizes of All-Source RFP tranche data.
3. Develop comprehensive portfolios with selected tranches from the portfolio optimization step and analyze them across the full set of scenarios and stochastics.

Figure 4-12: Summary of Proposals by Price



4.10.1 Tranche Development

It was determined that a tranche approach would be most effective in aggregating the numerous data points from the All-Source RFP into useable IRP information for three main reasons:

- The IRP is intended to select the best resource mix and future portfolio concept rather than select specific assets or projects. While the IRP analysis can now be highly informed by actionable All-Source RFP data, it is only meant to develop a planning-level recommended resource strategy. NIPSCO determined that asset-specific selection would require an additional level of diligence, including assessment of development risk, evaluation of locational advantages or disadvantages for specific projects, and review of transmission system impacts, to be conducted outside of the standard IRP process.

- The IRP is a highly transparent and public process that requires sharing of major inputs with stakeholders and the public. There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data.

- The IRP modeling is complex, and resource grouping improves the efficiency of the process. Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set would improve the efficiency of setup and run time.

When developing tranches, the CRA All-Source RFP team first organized resources by technology and then sorted them into categories according to whether they were offered as asset sales or PPAs. Projects were screened by the All-Source RFP team to determine conformity with bid requirements, and any non-conforming bids were eliminated. Duplicate projects that were offered multiple times under different structures were consolidated into the lowest-cost option to avoid double-counting. Beyond the initial organization and screening, the bids were then arranged by commitment duration and finally costs and operational characteristics.

For example, the All-Source RFP received multiple CCGT bids, with some being based on the same project. In developing the tranches, the team first separated the PPAs from the asset sales and then sub-divided PPA bids into short and long duration options for evaluation. The sale bids were all long duration, but had meaningfully different costs, so they were organized into two separate tranches for evaluation. This illustrative example is shown in Figure 4-13.

Figure 4-13: CCGT Tranche Development Example

PPA

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year	PPA Term (years)
PPA Bid 1	CCGT	250	250	2023	6
PPA Bid 2	CCGT	625	575	2023	30
PPA Bid 3	CCGT	625	625	2023	30
PPA Bid 4	CCGT	725	700	2023	20
PPA Bid 5	CCGT	600	600	2023	30

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (years)	Cost range** ($/kW-mo)
PPA CCGT #1	1	250	250	2023	6	
PPA CCGT #2	4	2,575	2,500	2023	27	

Sale

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year
Sale Bid 1	CCGT	625	625	2023
Sale Bid 2	CCGT	625	625	2023
Sale Bid 3	CCGT	1,025	925	2023
Sale Bid 4	CCGT	725	700	2023

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	Price Range** ($/kW)
Sale CCGT #1	2	1,250	1,250	2023	
Sale CCGT #2	2	1,750	1,750	2023	

*Capacity is rounded to the nearest 25 MW.
**Given the small number of projects within each CCGT tranche, PPA costs and asset sale prices are not being shown to preserve confidentiality. Note that PPAs were structured as tolling arrangements with fixed cost capacity payments (in $/kW-mo) plus certain variable charges (in $/MWh).

As another example, the All-Source RFP received 26 solar PPA bids. These bids generally all had similar contract structures, duration commitments, and capacity factors. Therefore, PPA price was the major factor that drove development of the tranches. In this instance, five solar PPA tranches were developed, organizing individual bids into groupings with similar pricing. Figure 4-14 provides an illustrative example of how these bids could be grouped together for evaluation.

Figure 4-14: Solar PPA Tranche Development Example

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)	Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	-	2023	20	$27.xx	-
Bid 9	Solar	275	138	2023	20	$32.00	24%
Bid 10	Solar	100	50	2023	20	$34.00	24%
Bid 11	Solar	75	38	2023	20	$34.00	23%
Bid 12	Solar	25	13	2023	20	$35.00	24%
Bid 13	Solar	500	250	2023	25	$35.00	25%
Bid 26	Solar	-	-	2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	488	2023	23	$33.93	24.2%

Ultimately, the tranche development process resulted in the production of 17 PPA tranches and 11 asset sale tranches. These are summarized by resource type, size, term, and costs in Figure 4-15 and Figure 4-16 for PPAs and asset sales, respectively.

Figure 4-15: Summary of PPA Tranches Used in Modeling

Tranche	Resource Type	Nameplate Capacity (MW)	UCAP (MW)	Storage Capacity (MW)	PPA Start	PPA Term (yrs)	Pricing ($/MWh)	Pricing ($/kW-mo)	Pricing ($/MW-d)
1	CCGT	250	250	-	2023	6		8.71	
2	CCGT	2,570	2,487	-	2023	27		8.58	
3	CT	685	678	-	2023	30		5.17	
4	Demand Response	70	70	-	2023	1			115.00
5	Solar	500	250	-	2023	20	28.45		
6	Solar	975	488	-	2023	23	33.93		
7	Solar	1,352	676	-	2023	26	37.62		
8	Solar	308	154	-	2022	21	62.87		
9	Solar + Storage	175	92	5	2023	20	24.80		
10	Solar + Storage	295	200	52	2023	20	28.24		
11	Solar + Storage	1,525	1,158	395	2023	22	34.54	2.27	
12	Solar + Storage	25	23	10	2024	20	61.41		
13	Storage	510	510	510	2023	16	12.58	4.31	
14	Storage	400	400	400	2023	20			323.14
15	Wind	945	128	-	2021	19	25.54		
16	Wind	479	72	-	2022	22	38.11		
17	Wind + Solar + Storage	300	95	30	2021	20	28.68		

Figure 4-16: Summary of Asset Sale Tranches Used in Modeling

Tranche	Resource Type	Nameplate	UCAP	Transfer Date	Pricing ($/kW)
1	CCGT	1,255	1,242	2023	962
2	CCGT	1,750	1,633	2023	1,084
3	CT	685	678	2023	615
4	Solar	265	133	2023	951
5	Solar	639	320	2023	1,125
6	Solar	400	200	2023	1,287
7	Solar + Storage	265	183	2023	1,067
8	Solar + Storage	440	330	2023	1,253
9	Storage	100	100	2023	932
10	Wind	1,099	165	2020	1,486
11	Wind + Solar + Storage	300	95	2021	1,406

4.10.2 Renewable Resource Tax Incentives and Tax Equity Partnership

Federal tax incentives are currently in place for renewable and paired renewable/storage resources. Resources are eligible for a production tax credit ("PTC") or an investment tax credit

("ITC"). The PTC provides a credit of $24/megawatt hour ("MWh")[4] for all generation produced by the facility, and the ITC provides a credit as a portion of the total cost of the facility. It is generally advantageous for wind resources to take the PTC, due to their high capacity factors, and solar resources to take the ITC.

The tax incentives are currently in the midst of a phase-out, as summarized in Figure 4-17. In order to qualify for the credits, projects need to begin construction by a certain date and be put into service by a certain date. The start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities. The safe harbor for beginning of construction is investment of at least 5% of the total project cost on or before the specified date.

Figure 4-17: PTC (Wind) and ITC (Solar) Phase-Out Schedule

Wind

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Qualify for Continuity Safe Harbor	Credit Percentage
2016	2020	100
2017	2021	80
2018	2022	60
2019	2023	40
2020	n/a	

Solar

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Maximize ITC	ITC Rate
2016	2020	30
2017	2021	30
2018	2022	30
2019	2023	30
2020	2023	26
2021	2023	22
2022	n/a	n/a

Given the importance of these tax incentives, NIPSCO preformed a review of their impact on All-Source RFP bids prior to developing final costs for the portfolio modeling. The impact of the tax incentives needed to be treated differently for the different types of All-Source RFP bids:

- For PPAs, no adjustments were needed, since tax incentives flow to the developer and are theoretically reflected in PPA pricing; and

[4] This value is indexed to inflation.

- For asset ownership, tax benefits flow to the utility and ultimately to the customer in rates, so adjustments needed to be made.

Without proper structuring, the Internal Revenue Code normalization rules stretch the flow of tax benefits to the customers over the regulatory life of the asset, but an alternative tax equity ownership structure can adjust the flow of benefits. In this arrangement, NIPSCO and a tax equity investor would form a partnership to develop a renewable energy project. The tax equity investor would invest to obtain a specified internal rate of return through the receipt of tax benefits in the form of depreciation, tax credits, and cash for a specified timeframe. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.

In order to properly account for the rate base reduction impact of partnering with a tax equity investor, CRA worked with NIPSCO's tax team to develop relevant financial models to estimate the breakdown of capital expenditures. For solar and solar-storage paired projects, the tax equity contribution is estimated to be around 35% of total capital costs, meaning NIPSCO would cover the remaining 65%. For wind assets, the range of tax equity contributions would be between 33 and 60%, depending on the asset's online date and expected capacity factor. Wind assets are assumed to utilize the PTC, while solar assets are assumed to take advantage of the ITC. The expected range of tax equity partner contributions for renewable resources is summarized in Figure 4-18.

Figure 4-18: Capital Cost Adjustments due to Tax Equity Partnership

Resource Type	Tax Equity Capital Cost Contribution
Solar	35%
Wind	33-60%
Solar + Storage	35%
Wind + Solar + Storage	35%

4.10.3 Self-build

As part of the process of evaluating its resource alternatives, NIPSCO investigated the feasibility of building a CCGT facility to meet its resource needs. The study considered an 800MW combine cycle F class 2x1 configuration and a 635MW advance class 1x1 consideration to be located on land at Schahfer.

For the study, NIPSCO developed conceptual site plans, conducted geotechnical studies, established the design criteria, developed single line studies and cost estimates for the two technologies. The study also considered the electric, natural gas and water interconnection requirements.

From the feasibility study results, NIPSCO determined that a self-build option was a more expensive alternative as compared to the All-Source RFP bid results for similar technology. Consequently, NIPSCO believes that a self-build CCGT is not the best resource alternative to meet customers need at this time.

4.10.4 CCGT Breakeven Analysis

NIPSCO's replacement analysis, as discussed in Section 9.2, found that replacement portfolios with renewable resources from the all source RFP are more cost effective than portfolios without. Furthermore, portfolios with CCGT are higher cost and carry increased risk due to exposure to natural gas prices and dispatch cost volatility. Selection of resource portfolios with new-build CCGT would require criteria other than economics and cost risk to justify.

NIPSCO explored the conditions that could support the inclusion of an additional CCGT into its supply portfolio. A CCGT could be part of a transmission/reliability solution to support renewables but analysis using new-build CCGT costs concludes that other reliability solutions are more cost effective. NIPSCO performed an analysis to identify the purchase price at which CCGT would be economically competitive with renewable resources. NIPSCO's analysis shows that, to be economically competitive with its preferred resource portfolio, CCGT costs would need to be approximately $284/kW or lower in the Base Scenario. This breakeven price does not appear to be likely for new-builds, but may be a possibility for re-sale of existing CCGT. A breakeven price was not achievable in the Aggressive Environmental Regulation Scenario, was $589/kW or lower in the Challenged Economy Scenario, $637/kW or lower in the Booming Economy / Abundant Natural Gas Scenario. Additional details are in Confidential Appendix D.

4.10.5 Coal to Gas Conversion

NIPSCO evaluated the potential to convert one or two units at Schahfer from coal-fired units to natural gas-fired units. As part of this analysis, NIPSCO developed operational assumptions for the potentially converted units as well as cost estimates associated with the conversion. In evaluating the operational parameters for a converted unit, NIPSCO relied on the Sargent & Lundy ("S&L") study conducted as part of the 2016 IRP process. The study concluded that a conversion would result in a 15% capacity de-rate for either Schahfer 17 or 18 when fired by gas instead of coal, as well as a slight efficiency penalty for the plant's heat rate. The key operational parameters for the conversion option are shown on a per-unit basis in Figure 4-19.

Figure 4-19: Coal-to-Gas Conversion Operational Parameters

	Category	NIPSCO Assumption
Operating Parameters	Conversion Capacity(MW) per unit	309.2
	Heat Rate (Btu/kWh)	11,106
	Forced Outage Rate	10%

Separately, NIPSCO developed capital and ongoing maintenance cost assumptions associated with a potential conversion. These costs were developed from the S&L study from 2016, as well as NIPSCO's internal experts in generation, plant operations, and major projects. The key assumptions included:

- The capital cost for conversion, which includes materials, construction labor, contingency, and owners and indirect costs were estimated by S&L .

- Gas interconnection costs were reviewed by S&L and NIPSCO's operational teams. Based on the data from the S&L study and a preliminary review with NIPSCO Gas Systems Engineering, it would be possible to convert Unit 17 or Unit 18 to natural gas without installing an additional pipeline as long as both Units 14 and 15 are retired. Leaving Units 14 and 15 in operation would likely create operational limitations related to when the units would be available to start up. Conversion of Units 17 and 18 to run simultaneously would require an additional pipeline. The size of the additional line could be smaller than the 30" used in the engineering study, but further detailed engineering analysis would be required to determine the appropriate size. Therefore, to be conservative and to evaluate whether conversion would be economic in the event that gas interconnection costs were minimal, NIPSCO assumed zero cost in its analysis.

- Environmental compliance costs were assumed to be zero.

- Maintenance capital needs were assumed to be 25% lower than current coal operations. This assumption was based on a review of NIPSCO's last three years of capital expenditures for Schahfer Units 17/18 that showed 25% of maintenance capital expenditures were for coal-specific components.

- Fixed O&M costs were estimated by S&L in the engineering study.

A summary of the assumptions for each of these cost categories is shown in Figure 4-20.

Figure 4-20: Coal-to-Gas Conversion Capital and Maintenance Cost Estimates

	Category	Estimated Cost
Conversion Investment Costs	Conversion (2015$)	$43M for 17 $87M for 17/18
	Gas Interconnection	$0M
	Environmental Compliance	$0M
Maintenance Capital	Maintenance Capital (Total 2024-2038) Nominal $	$122M for U17 $298M for 17/18
Ongoing Costs	Fixed O&M Costs (2015$/KW-yr)	$39

Ultimately, the analysis showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the All-Source RFP results and replacing both units would cost customers at least $540 million more. Based on this, it is not economically feasible to complete the conversion of either unit. This is discussed more in depth in Section 9.1.7.

Section 5. Demand-Side Resources

5.1 Existing Resources

5.1.1 Existing Energy Efficiency Resources

NIPSCO actively promotes energy conservation and efficiency to customers and works with its third party vendors to offer cost-effective energy efficiency programs. To support the continuance of its program offerings for the period 2019 through 2021, NIPSCO worked with its Oversight Board ("OSB") to develop two DSM RFPs – one for residential programs and one for commercial and industrial ("C&I") programs. Upon review of the bids and materials presented by the invited bidders, NIPSCO recommended, and its OSB approved, the selection of Lockheed Martin as the vendor to continue implementing both its residential and C&I programs. The OSB also issued a DSMRFP for an evaluation, measurement and verification ("EM&V") vendor and selected ILLUME Advising, LLC to provide an evaluation of both the residential and C&I vendors for all three program years. On November 22, 2017, NIPSCO filed its request with the IURC for approval of the following energy efficiency programs to become effective for the period January 1, 2019 through December 31, 2021 (the "2019-2021 Plan"):[5]

2019-2021 Residential Programs

Residential Heating, Ventilation and Air Conditioning ("HVAC") Energy Efficient Rebates Program

The HVAC Energy Efficient Rebates Program is designed to provide incentives to residential customers to replace inefficient HVAC equipment with energy-efficient alternatives. These measures will be paid per-unit installed, reimbursing customers for a portion of their cost. The program's intent is to help remove the financial barrier associated with the initial cost of these energy-efficient alternatives. The program will promote premium efficiency air conditioners, heat pumps that have high-efficiency, electronically commutated motors, and smart Wi-Fi thermostats.

Residential Lighting Program

The Residential Lighting Program is designed to increase the purchase and use of energy-efficient lighting products among NIPSCO's residential electric customers. The program will provide instant discounts on lighting products that meet the energy efficiency standards set by the United States Department of Energy's ENERGY STAR® Program. ENERGY STAR specifications are an important external factor to certify the quality and efficiency of program measures. As the ENERGY STAR specifications change, the program offerings will be adjusted accordingly. These adjustments ensure that the program offers incentives for lighting products that meet the latest standards and highest quality of efficiency.

[5] The 2019-2021 Plan reflected herein reflects the parties' agreements set forth in the Stipulation and Settlement Agreement reached among NIPSCO, the Indiana Office of Utility Consumer Counselor, and Citizens Action Coalition of Indiana, Inc. (the "Settling Parties"), was approved in Cause No. 45011 on September 12, 2018.

Residential Home Energy Assessment Program

The Home Energy Assessment Program is designed to help eligible customers improve the efficiency and comfort of their homes, as well as deliver an immediate reduction in electricity (kWh) consumption and promote additional efficiency work. This program will provide homeowners with the direct installation of low-cost, energy-efficient measures followed by the delivery of a Comprehensive Home Assessment report.

Residential Appliance Recycling Program

The Appliance Recycling Program is designed to provide an incentive to residential customers who choose to recycle a qualifying primary or secondary working refrigerator and/or freezer. Lockheed Martin will utilize a qualified subcontractor for the implementation of this program.

School Education Program

The School Education Program is designed to produce cost-effective electric savings by influencing fifth grade students and their families to focus on the efficient use of electricity. It will provide classroom instruction, posters, and activities aligned with national and state learning standards and energy education kits filled with energy-saving products and advice. Students will participate in an energy education presentation at school, learning about basic energy concepts through class lessons and activities. Students will also receive an energy education kit of quality, high-efficiency products and are instructed to install the energy-efficient products at home with their families as well as complete a worksheet. The experience at home will complete the learning cycle started at school.

Residential Multifamily Direct Install ("MFDI") Program

The MFDI Program is designed to provide a "one-stop shop" to multifamily building owners, managers, and tenants of multifamily units containing three or more residences. With flexible and affordable options, the program will generate immediate energy savings and improvements in two distinct program phases. Phase I is a walkthrough assessment of each property, which is conducted to determine eligibility for direct installation services provided by the MFDI Program, along with complementary incentive offers available through other NIPSCO programs. Property managers will be presented with an Energy Improvement Plan that prioritizes recommendations along with a proposal to provide the direct installation services outlined in Phase II. Phase II is an in-unit direct installation of energy-efficient devices at no-cost or low-cost to the tenant or landlord, such as light emitting diode ("LED") light bulbs, low-flow showerheads, faucet aerators, pipe wrap, and Wi-Fi or smart thermostats. Educational materials about home operation, maintenance, and behavior factors that may reduce energy consumption, will be provided to tenants in each living unit.

Residential Home Energy Report Program

The Home Energy Report Program is designed to encourage energy savings through behavioral modification. The program will provide customers with home energy reports that contain personalized information about their energy use and provide ongoing recommendations to

make their homes more efficient. Customers will be randomly chosen to participate in the program and may opt-out if they do not wish to participate. The reports engage customers and drive them to take action to bring their energy usage in line with similar homes. The program will empower customers to understand their energy usage better and uses competition through neighbor comparisons to influence customers to act on this knowledge, resulting in changed behavior.

Residential New Construction Program

The Residential New Construction Program is designed to increase awareness and understanding by home builders of the benefits of energy-efficient building practices, with a focus on capturing energy efficiency opportunities during the design and construction of single family homes. This program is designed to produce long-term, cost-effective savings as a result of the training they have received to achieve the various Home Energy Rating System tiers, along with strategies for incorporating the Silver, Gold, and Platinum designations into their marketing efforts to attract home buyers.

Residential HomeLife Energy Efficiency EE Calculator Program

The HomeLife Energy Efficiency Calculator Program is designed to offer NIPSCO's residential customers an online "do-it-yourself" audit and an energy savings kit for carrying out this audit, at no cost to the customer. The goal of the audit tool is to effectively: (1) identify low-cost/no-cost measures that a NIPSCO residential customer can easily implement to manage electric consumption; (2) allow eligible customers to request a free home energy kit; (3) educate customers about the variety of programs available to them through the residential energy efficiency portfolio; and (4) assist customers in finding qualified and experienced contractors through a network of trade allies.

Employee Education Program

The Employee Education Program is designed to offer valuable information to employees of NIPSCO's C&I customers by providing residential energy efficiency training seminars at the place of employment. At these seminars, educational materials will be provided to inform residential customers of energy savings opportunities and methods to proactively manage their energy consumption. These materials will also direct NIPSCO's customers to navigate to a web portal to request a free energy efficiency kit by entering their account information to confirm eligibility.

Residential Income Qualified Weatherization ("IQW") Program

The IQW Program is designed to provide energy efficiency services to qualifying low-income households. In order for a household to be eligible to participate in the IQW Program, the customer will need to be a NIPSCO residential customer with active service and must not have received weatherization services in the past 10 years from the date of application. If the household meets this initial criteria, they will automatically qualify for services regardless of income if the household receives Low-Income Home Energy Assistance (LIHEAP), Temporary Assistance for Needy Families (TANF), Supplemental Security Income (SSI) or Supplemental Security Disability Income (SSDI). Qualifying participants will receive the direct installation of no-cost

energy efficiency measures and a Comprehensive Home Assessment to identify areas of the home where additional energy savings can be achieved to make the home more comfortable and reduce energy costs.

Table 5-1 shows the projected energy savings (MWh) by year for each of the Residential programs.

Table 5-1: 2019-2021 Projected Residential Energy Savings (MWh)

Residential Programs	2019	2020	2021	Total
HVAC	2,396	2,393	2,389	7,178
Lighting	26,172	26,172	26,172	78,516
Home Energy Assessment	2,145	2,143	2,140	6,428
Appliance Recycling	1,647	1,645	1,643	4,935
School Education	2,580	2,577	2,574	7,731
MFDI	1,127	1,126	1,125	3,378
Home Energy Report	9,786	9,774	9,763	29,323
New Construction	854	854	854	2,562
HomeLife Energy Efficiency Calculator	2,064	2,062	2,059	6,185
Employee Education	1,006	1,005	1,004	3,015
IQW	1,197	1,196	1,195	3,588
Total Residential Programs	**50,974**	**50,947**	**50,918**	**152,839**

Table 5-2 shows the annual total program budget for each of the Residential programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[6]

[6] In the Settlement, the Settling Parties agree that NIPSCO (with Oversight Board ("OSB") approval) should be authorized to increase any individual program funding by up to 10% of the total program budget, even if this exceeds the overall 2019-2021 DSM Plan budget approved by the Commission.

Table 5-2: 2019-2021 Residential Program Budget

Residential Programs	2019	2020	2021	Total
HVAC	$531,302	$530,558	$529,843	$1,591,703
Lighting	$4,919,279	$4,919,279	$4,919,279	$14,757,837
Home Energy Assessment	$852,009	$851,003	$850,040	$2,553,052
Appliance Recycling	$431,926	$431,417	$430,928	$1,294,271
School Education	$638,243	$637,491	$636,741	$1,912,475
MFDI	$374,314	$377,243	$376,817	$1,128,374
Home Energy Report	$566,969	$566,298	$565,630	$1,698,897
New Construction	$312,095	$312,095	$312,095	$936,285
HomeLife Energy Efficiency Calculator	$487,374	$486,798	$486,225	$1,460,397
Employee Education	$279,497	$279,167	$278,838	$837,502
IQW	$424,502	$424,003	$423,520	$1,272,025
Total Residential Programs	**$9,817,510**	**$9,815,352**	**$9,809,956**	**$29,442,818**

2019-2021 C&I Programs

C&I Prescriptive Program

The Prescriptive Program is designed to provide incentives for a set list of energy efficient measures and will be paid based on per unit installed, reimbursing the customer for a portion of the cost. The Prescriptive Program will offer incentives to NIPSCO's C&I customers that are making electric energy efficiency improvements in existing buildings.

C&I Custom Program

The Custom Program will be available to C&I customers for installing new energy-saving equipment. Custom incentives are designed for more complicated projects, or those that incorporate alternative technologies. Project pre-approval will be required for all Custom incentives to ensure that only cost-effective projects are approved. Qualifying measures will be required to have a Total Resource Cost ("TRC") test score greater than 1.0, have a simple payback greater than 12 months and not be included as an energy efficiency measure in the Prescriptive Program.

C&I New Construction Program

The C&I New Construction Program is designed to encourage construction of energy efficient C&I facilities within the NIPSCO service territory. This program will offer financial incentives to encourage building owners, designers and architects to exceed standard building practices and achieve efficiency, above and beyond the 2010 Indiana Energy Conservation Code. The goal of the New Construction Program is to produce newly constructed and expanded

buildings that are efficient from the start. New construction projects that may be eligible for incentives under the New Construction Program may include any of the following: (1) new building projects wherein no structure or site footprint presently exists; (2) addition to or expansion of an existing building or site footprint; and (3) a gut rehabilitation for a change of purpose requiring replacement of all electrical and mechanical systems/equipment.

Small Business Direct Install ("SBDI") Program

The SBDI Program is designed to facilitate participation in the NIPSCO business energy efficiency program of small C&I customers that do not possess the in-house expertise or capital budget to develop and implement an energy efficiency plan. The SBDI Program will offer a variety of ways for small businesses, with billing demands not exceeding 200 kW, to improve the efficiency of their existing facilities. Measures will be paid out on a per unit basis, much the same way as the Prescriptive Program, but with slightly higher incentive rates in an effort to encourage energy efficient investment from these smaller business customers. Incentive payments to the approved trade allies will occur following measure implementation and submission of all required paperwork. If additional incentives are available through other programs, customers will be directed to the appropriate application.

Retro-Commissioning ("RCx") Program

The RCx Program is designed to help NIPSCO C&I customers determine the energy performance of their facilities and identify energy-saving opportunities by optimizing their existing systems. Projects in the program will examine energy consuming systems for cost-effective savings opportunities. The RCx process will identify operational inefficiencies that can be removed or reduced to yield energy savings. Qualifying measures will be required to have a TRC test score greater than 1.0, have a simple payback of less than 12 months and not be included as an energy efficiency measure in the Prescriptive Program.

Table 5-3 shows the projected energy savings (MWh) by year for each of the C&I programs.

Table 5-3: 2019-2021 Projected C&I Energy Savings (MWh)

C&I Programs	2019	2020	2021	Total
Prescriptive	20,880	23,200	25,520	69,600
Custom	30,240	33,600	36,960	100,800
New Construction	9,360	10,400	11,440	31,200
SBDI	7,920	8,800	9,680	26,400
RCx	3,600	4,000	4,400	12,000
Total C&I Programs	**72,000**	**80,000**	**88,000**	**240,000**

Table 5-4 shows the total annual program budget for each of the C&I programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[7]

Table 5-4: 2019-2021 C&I Program Budget

C&I Programs	2019	2020	2021	Total
Prescriptive	$2,454,485	$2,727,206	$2,999,926	$8,181,617
Custom	$3,814,322	$4,238,137	$4,661,950	$12,714,409
New Construction	$1,155,142	$1,283,490	$1,411,838	$3,850,470
SBDI	$1,138,860	$1,265,400	$1,391,940	$3,796,200
RCx	$484,380	$538,200	$592,020	$1,614,600
Total C&I Programs	**$9,047,189**	**$10,052,433**	**$11,057,674**	**$30,157,296**

Table 5-5 shows the projected energy savings (MWh) by year for all Residential and C&I programs included in the 2019-2021 Plan.

Table 5-5: 2019-2021 Projected Combined Energy Savings (MWh)

	2019	2020	2021	Total
Total Residential Programs	50,974	50,947	50,918	152,839
Total C&I Programs	72,000	80,000	88,000	240,000
Total 2019-2021 Plan	**122,974**	**130,947**	**138,918**	**392,839**

Table 5-6 shows the annual total program budget for all Residential and C&I programs included in the 2019-2021 Plan.

Table 5-6: 2019-2021 Combined Program Budget

	2019	2020	2021	Total
Total Residential Programs	$9,817,510	$9,815,352	$9,809,956	$29,442,818
Total C&I Programs	$9,047,189	$10,052,433	$11,057,674	$30,157,296
Total 2019-2021 Plan Budget	**$18,864,699**	**$19,867,785**	**$20,867,630**	**$59,600,114**

Table 5-7 shows the eligible customer classes and rate schedules for each of the Residential and C&I programs included in the 2019-2021 Plan.

[7] In the Settlement, the Settling Parties agree that NIPSCO (with Oversight Board ("OSB") approval) should be authorized to increase any individual program funding by up to 10% of the total program budget, even if this exceeds the overall 2019-2021 DSM Plan budget approved by the Commission.

Table 5-7: Customers

Program	Customer Class	Electric Rate Schedule
Residential HVAC Rebates	Residential	711
Residential Lighting	Residential	711
Residential Home Energy Assessment	Residential	711
Residential Appliance Recycling	Residential	711
School Education	Residential	711
Residential MFDI	Residential	711
Residential Home Energy Report	Residential	711
Residential New Construction	Residential	711
Residential HomeLife Energy Efficiency Calculator	Residential	711
Employee Education	Residential	711
IQW	Residential	711
C&I Prescriptive	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
C&I Custom	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
C&I New Construction	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744
SBDI	C&I	720, 721, 722, or 723 who have not had a billing demand of 200 kW or greater in any month during the previous 12 months
RCx	C&I	720, 721, 722, 723, 724, 725, 726, 732, 733, 734, 741, or 744

5.1.2 Existing Demand Response Resources

5.1.2.1 Capacity Resources

The Commission approved Rider 775 – Interruptible Industrial Service Rider in its Rate Case Order in Cause No. 44688, issued July 18, 2016 ("Rate Case Order"). Rider 775 is available

to customers taking service under Rates 732, 733 or 734. Rider 775 balances the needs of all customer groups by securing the ability and willingness of participating customers to curtail or interrupt service upon demand. NIPSCO's participating industrial customers provide a benefit to all customers, and are accordingly compensated through demand credits that are funded by all other customers. The interruptible credits are provided for two reasons, reliability and economic, each of which provides short- and long-term value to all customers.

The Interruptible Contract Demand is the demand that the customer intends to make available for interruptions and/or curtailments from one or more of customers' premises taking service under Rates 732, 733 or 734. Customers electing service under Rider 775 specify a Firm Contract Demand for each affected premise or facility that the Customer intends to exclude from interruptions or curtailments. Customers who contract for this service are required to interrupt or curtail at the stated notice by NIPSCO and the provisions of service under the Rider. Customers are also required to meet the applicable Load Modifying Resource ("LMR") requirements pursuant to MISO Tariff Module E, or any successor. NIPSCO will register all subscribed 527.776 MW of Rider 775 capacity with MISO. The LMR value is grossed-up by the Planning Reserve Margin and the Transmission Losses, since such resources have neither transmission losses, nor forced outages. As such, the 527.776 MW of LMR becomes 586.984 MW of Capacity Resources that NIPSCO can utilize to meet its MISO resource adequacy requirements.

In addition to NIPSCO's Rider 775 – Interruptible Industrial Service Rider, Rate 734 – Industrial Power Service for Air Separation & Hydrogen Production Market Customers, makes available interruptions and/or curtailments of electric demands greater than 276 MW to customers taking service under this Rate. Provisions for interruptions and/or curtailments are similar to that of Rider 775 and thus qualify as a LMR. As such, NIPSCO has registered 31.000 MW of LMRs under Rate 734. The Capacity Resource realized from the registration is 34.477 MW that NIPSCO can utilize to meet its MISO resource adequacy requirements.

On October 31, 2018, NIPSCO filed an electric rate case that revises its industrial service structure by replacing Rider 775 and Rates 732, 733, and 734 with Rates 830 and 831. The new industrial service structure requires NIPSCO's largest industrial customers on Rate 831 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR which is by definition curtailable. NIPSCO expects an increase in registered LMRs as a result of this new industrial service structure unless those Rate 831 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, the large industrial customers will continue to be eligible to participate in MISO's Demand Response Resource program discussed below.

5.1.2.2 Energy-Only Resources

NIPSCO offers Demand Response Resource Type 1 ("DRR1") and Emergency Demand Response Resource ("EDR") through Riders 781 and 782, respectively. These Riders are available to a Customer on Rates 723, 724, 725, 726, 732, 733 and 734 that has a sustainable ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as dispatched by MISO. Through these Riders, the Customer or Aggregator of Retail Customer (ARC) curtails a portion of its electric load through participation

with the Company acting as the Market Participant (MP) with MISO. These Riders are available to any load that is participating in the Company's other interruptible or curtailment Riders, unless MISO rules change and do not permit load used by the Company as a LMR to also participate as a DRR1 or EDR. Although the DRR1 and EDR offered under Riders 781 and 782, respectively, do not qualify as a Capacity Resource, they do offer a means for Customers to offer into the MISO market and to be paid for the portion of their electric load curtailed. This provides economic benefit to the Customers participating in these Riders and for other NIPSCO Customers through an overall lower electric system demand, which can avoid purchased power or the need for higher cost generation resources to be committed through the MISO market. Currently, NIPSCO has two Customers participating in Rider 781 as DRR1. No Customers are participating in Rider 782 as EDR.

5.2 DSM Electric Savings Update

5.2.1 DSM Electric Savings Update – Purpose and Key Objectives

To update the electric DSM resource potential for the 2018 IRP, NIPSCO contracted with GDS to conduct a DSM Savings Update Report (the "DSM Savings Update") (a copy of which is included in Appendix B, Demand Side Management Savings Update and the 2016 Market Potential Study ("MPS"), and Action Plan.[8] GDS participated in Public Advisory Meeting 2 and provided details of its engagement with the DSM Savings Update. *See* Appendix A, Exhibit 2 (Presentation), Slides 24 through 43.

The DSM Savings Update provides an update of DSM program costs and savings for a 30-year time horizon (2019-2048). The report captures the insights from NIPSCO's prior MPS that was completed in August 2016 as well as NIPSCO's current and planned program offerings for the period 2019 to 2021 described in NIPSCO's testimony filed in Cause No. 45011. The objectives of NIPSCO's DSM Savings Update included:

- Develop a detailed plan identifying recommended cost-effective DSM savings measures and programs, as well as any possible market barriers for each recommended program. Identify best practices and programs and explain how the recommended practices and programs will achieve the desired results in NIPSCO's service territory.
- Place emphasis on innovative energy efficiency and DR programs and technologies.
- Provide detailed budgets for each program and related expenditures.
- Provide a lifetime cost analysis.

[8] A new MPS and Action Plan will be completed in 2019.

- Provide a cost-effectiveness[9] comparison or ranking for all technologies (measures) reviewed.

- Complete cost-effectiveness evaluations for each proposed program.

5.2.2 Impact of Opt-out Customers

GDS reviewed the latest information available from NIPSCO related to energy efficiency program participation, measure and program savings data, results of NIPSCO's 2016 MPS, NIPSCO's electric load and customer forecasts, NIPSCO load research data, electric avoided costs, program evaluation reports and NIPSCO's 2019-2021 Plan. NIPSCO requested that GDS prepare its base case DSM Plan update assuming that C&I electric customers that had opted out of NIPSCO's energy efficiency programs prior to January 1, 2017 would be excluded from the DSM Plan Update. These "opt-out" C&I customers represent over 60 percent of NIPSCO's 2017 non-residential kWh sales. It is important to note that the base case energy efficiency forecast for the DSM Savings Update does not include any energy efficiency savings for these opt-out C&I customers.

5.2.3 Modeling Framework

GDS used its Excel-based energy efficiency and DR planning models to prepare the DSM Savings Update. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, savings of other fuels, and benefit/cost ratios for planning periods ranging from one to thirty years. These GDS models are transparent and all formulas, model inputs and model outputs can be viewed by the model user. The GDS energy efficiency and DR planning models come with a user guide that explains where to input program data, measure data and assumptions relating to the general rate of inflation, the discount rate for financial analysis, avoided costs, line losses, planning reserve margin and other key input assumptions.

5.3 Energy Efficiency and Demand Response Bundles

For purposes of modeling energy efficiency programs in NIPSCO's 2018 IRP, GDS grouped DSM Plan energy efficiency measures into bundles according to each measure's cost of saved energy over its measure life. For energy efficiency measures, the following three bundle categories were created:

Bundle 1	Measures with a utility incentive cost ranging from $.00 to $.01 per lifetime kWh saved
Bundle 2	Measures with a utility incentive cost ranging from $.011 to $.05 per lifetime kWh saved

[9] GDS calculated the TRC Test, the Utility Cost Test ("UCT") , the Participant Test and the Ratepayer Impact Measure Test ("RIM") for each measure. GDS used the UCT test to determine measure, program and portfolio cost effectiveness. All of the results may be found in Appendices E and F.

Bundle 3	Measures with a utility incentive cost over $.05 per lifetime kWh saved

For purposes of modeling DR programs in NIPSCO's 2018 IRP, GDS grouped DR programs into three bundles by calculating the levelized cost per cumulative kW over the 30-year lifetime of the program. For DR programs, the following three bundles were created:

Bundle 1	$40/kW-year to $60/kW-year: includes C&I Direct Load Control ("DLC") of Air Conditioning ("AC") and DLC of Electric Water Heating Equipment
Bundle 2	$60/kW to $80/kW-year: includes Residential DLC of Water Heating Equipment and the C&I Third-Party Aggregator program
Bundle 3	Over $100/kW-year: includes Residential DLC of AC and Interruptible Rider

Both Residential and C&I DLC of space heating programs were found to be not cost-effective and, therefore, were not included in any DR bundles.

5.4 Energy Efficiency Potential Impacts

5.4.1 Changes That Impacted Energy Efficiency Potential

GDS updated several input assumptions during the process of preparing the DSM Savings Update. The changes made for a few of these input assumptions are discussed below.

5.4.1.1 Updated NIPSCO Load Forecast, Avoided Cost Forecast and General Planning Assumptions

In March 2018, NIPSCO sent GDS the latest electric load forecast for 2018 through 2039. CRA then extended the NIPSCO load forecast through the year 2048. GDS used this new load forecast to calculate the percent of electric MWH sales and peak demand saved each year by DSM programs. NIPSCO's new load forecast projects that total MWH sales to ultimate customers will only increase 0.3% a year on average through the year 2048. NIPSCO also provided GDS with updated planning assumptions for the general inflation rate, escalation rates for NIPSCO electric rates, the utility discount rate, line losses by class of service and the planning reserve margin. GDS used these assumptions to develop the DSM Savings Update.

5.4.1.2 NIPSCO DSM Plan Assumptions for Measure Costs, Savings, Useful Lives

GDS reviewed the assumptions for measure costs, savings and useful lives included in the 2019 to 2021 NIPSCO DSM plan and updated these assumptions where appropriate. GDS revised costs and/or savings assumptions for some energy efficiency measures if more recent data was available from NIPSCO evaluation reports or recently published technical resource/reference manuals from Michigan and Illinois.

The largest change for a measure assumption was to the baseline energy efficiency level for residential light bulbs. The NIPSCO 2019 to 2021 DSM plan assumed that the baseline technology for a residential light bulb was a 60-Watt incandescent bulb.

GDS collected information from industry experts and program implementation contractors, showing uncertainty about when the new Energy Independence and Security Act ("EISA") backstop provisions for lighting efficiency will take effect. The EISA lighting backstop provisions specify 45 lumens per Watt efficacy starting January 1, 2020. Efficiency Vermont, however, decided for planning purposes that LEDs would be the baseline standard in 2020. Efficiency Vermont assumed a one-year phase-in period for this efficacy standard. Other experts recommend allowing a sell-through period to the year 2022, or 2023 at the latest. Another recommendation GDS received was to shorten the useful life of LEDs. GDS previously used a useful life of 15 years for LEDs.

The new efficacy standard for lighting is scheduled by law to go into effect on January 1, 2020. Energy industry news articles have indicated a potential for the delay or cancelation of these new lighting efficacy standards. As of August 2018, there is uncertainty about whether these efficacy standards will go into effect on January 1, 2020. The EISA standard will not allow bulbs to be sold that do not meet the new efficacy requirements. Therefore, the new EISA standard will decrease the achievable potential for lighting savings because the baseline efficiency for most light bulbs will be significantly increased. Based on this, for planning purposes, NIPSCO assumed that the baseline technology after 2021 for general service bulbs would be a compact fluorescent light (CFL) or equivalent bulb that meets the EISA backstop provision efficacy level of 45 lumens per Watt.

5.4.1.3 Federal Appliance and Equipment Efficiency Standards

The U.S. Department of Energy ("DOE") develops and implements federal appliance and equipment standards to improve energy efficiency that will save consumers energy and money. This DOE program was initially authorized to develop, revise, and implement minimum energy efficiency standards by the federal Energy Policy and Conservation Act ("EPCA") in 1975. Several subsequent legislative amendments have required regular updates these standards and has expanded the list of products covered by the standards. The DOE is currently required to periodically review standards and test procedures for more than 60 products, representing about 90% of home energy use, 60% of commercial building energy use, and 30% of industrial energy use.

The standards program's predictable rulemaking schedule is driven by statutory deadlines the DOE must meet to comply with EPCA. These are amended by subsequent energy legislation and reflect the program's obligation to review all standards every six years and test procedures every seven years. The DOE encourages all stakeholders, including consumers, manufacturers, trade associations, utilities, energy efficiency advocates, and the general public, to participate in the rulemaking process. The standards program established the Appliance Standards and Rulemaking Federal Advisory Committee ("ASRAC") to facilitate deeper stakeholder engagement by allowing for negotiated rulemakings under the guidelines set forth in the Federal Advisory Committee Act (FACA). The process culminates in a final rule in which the DOE is required to set efficiency standards that maximize energy savings that are technologically feasible and economically justified.

The DOE considers the impact on consumers, manufacturers, and small C&I businesses when determining whether any new or amended standard is economically justified. The DSM Savings Update takes into account the impacts of federal appliance and equipment efficiency standards for those standards that are currently in place or expected to be implemented by the DOE after 2021, including the EISA backstop provisions for general service, reflector and specialty light bulbs discussed above.

5.5 Energy Efficiency Measures & Potential

5.5.1 Residential Energy Efficiency Measures

For the residential sector, there were 249 unique electric energy efficiency measures included in the energy efficiency potential analysis update. Table 5.8 provides a summary of the types of measures included for each end use in the residential sector. The measures included in this analysis are based on 2019-2021 Plan with several new measures added by GDS or suggested by NIPSCO's stakeholders. These new measures were included in the NIPSCO 2016 MPS that were not already included in the 2019-2021 Plan. GDS obtained the majority of data on residential energy efficiency measure costs, kWh and kW savings and costs from the 2019-2021 Plan. GDS reviewed this data and updated these measure assumptions for years after 2021 where necessary.

Table 5-8: Types of Electric Energy Efficiency Measures included in the Residential Sector Analysis

End Use	Measure Types Included
Electronic Equipment	ENERGY STAR Desktop and Laptop Computers, Monitors, Printer/Fax/Copier/Scanner, and Sound Bars ENERGY STAR Smart Power Strips ENERGY STAR Televisions
Appliances	ENERGY STAR Refrigerators ENERGY STAR Freezers ENERGY STAR Washing Machines ENERGY STAR Clothes Dryers ENERGY STAR Dehumidifier Refrigerator Pick-up and Recycling Freezer Pick-up and Recycling Refrigerator Replacement in Low Income Homes
Envelope	Building Insulation Improvements (Attic, Wall, Floor, Etc.) Air sealing (Weatherization) High Efficiency Windows Cool Roofing
HVAC Equipment	High Efficiency Heating Equipment (e.g., Heat Pump with electronically commutated motor) HVAC Filter Whistle Heating & Cooling Duct Sealing and Repair High Efficiency Natural Gas Furnace High Efficiency Natural Gas Boiler Wi-Fi Smart Thermostat
Lighting	Interior LED Bulbs and Fixtures Exterior LED Bulbs and Fixtures LED Nightlights
Pools	Pool Pump Controls High Efficiency Pool Pumps High Efficiency Pool Pump Heaters
Space Cooling	High Efficiency Central Air Conditioning System Air Source Heat Pump ENERGY STAR Room Air Conditioner
Water Heating	High Efficiency Water Heater Heat Pump Water Heater Faucet Aerators & Low Flow Showerheads Hot Water Pipe and Tank Insulation Solar Water Heating System
Other	Home Energy Reports and Other Types of Behavioral Programs Energy Efficiency Education Kits for Employees of NIPSCO's Customers High Efficiency Well Pump High Efficiency Hot Tub Dryer Vent Cleaning Refrigerator Coil Cleaning

5.5.2 Achievable Electric Energy Efficiency Potential

The achievable electric energy efficiency potential for the residential sector includes savings associated with measures that are:

- Included in the 2019-2021 Plan.
- Added to the plan by GDS (included in NIPSCO's 2016 MPS or that were suggested by NIPSCO's stakeholders).

Table 5-9 shows the cumulative annual achievable residential sector energy efficiency potential for the years 2019 to 2048 and estimates of the annual NIPSCO energy efficiency budgets for residential sector programs.

Table 5-9: Achievable Residential Sector Incremental Annual Energy Efficiency Potential and Annual Utility Budgets (Base Case)

Year	Incremental Annual Energy Savings (MWh)	Incremental Annual Demand Savings (MW)	Annual Utility Cost ($)
2019	50,974	10	$9,817,510
2020	50,947	17	$9,815,352
2021	50,918	24	$9,809,956
2022	46,240	42	$20,822,174
2023	46,887	61	$21,039,511
2024	47,503	79	$21,266,204
2025	48,178	98	$21,494,687
2026	48,716	117	$21,714,354
2027	49,287	137	$21,941,024
2028	49,744	156	$22,134,851
2029	50,231	175	$22,347,479
2030	50,686	195	$22,551,800
2031	51,166	215	$22,763,349
2032	51,645	234	$22,980,009
2033	52,173	254	$23,222,465
2034	52,411	268	$23,417,367
2035	52,659	281	$23,617,690
2036	53,050	294	$23,829,888
2037	53,050	298	$23,975,771
2038	53,050	301	$24,124,717
2039	53,050	304	$24,276,791
2040	53,050	307	$24,432,059
2041	53,050	310	$24,590,588

Year	Incremental Annual Energy Savings (MWh)	Incremental Annual Demand Savings (MW)	Annual Utility Cost ($)
2042	53,050	311	$24,752,445
2043	53,050	313	$24,917,702
2044	53,050	314	$25,086,429
2045	53,050	315	$25,258,699
2046	53,050	316	$25,434,587
2047	53,050	317	$25,614,169
2048	53,050	318	$25,797,522

5.5.3 Recommended Residential programs

GDS recommends that NIPSCO retain the residential energy efficiency programs that are included in its 2019-2021 Plan, but consider adding a new program such as whole-house retrofit program for qualifying low-income households if such a program can be designed to be administered in an efficient and effective manner. In addition, GDS recommends that NIPSCO add several new energy efficiency measures to its existing programs, including such measures as solar water heating, heat pump water heating, refrigerator coil cleaning brushes, dryer ductwork and vent cleaning, high efficiency clothes washers and other measures that GDS added that were cost effective.

Table 5-10 below provides the UCT benefit/cost ratios for the period 2019 to 2048 for residential programs[10]. All twelve residential energy efficiency programs included in the DSM Savings Update have a UCT ratio greater than or equal to 1.0. The overall UCT benefit/cost ratio for the residential portfolio of energy efficiency programs is 2.1. The NPV savings to NIPSCO's residential customers is $277.1 million for the thirty-year planning horizon.

[10] NIPSCO utilized the UCT as the test for screening measures for inclusion. This is different from prior years when the TRC was utilized.

Table 5-10: Utility Cost Test Benefit/Cost Ratios for Residential Programs (2019 to 2048 Period)

Residential Sector Program	NPV Benefits	NPV Utility Costs	Net Benefits	BC Ratio
HVAC Energy Efficient Rebates	$20,240,111	$7,423,449	$12,816,661	2.7
Residential Lighting	$38,182,714	$13,738,788	$24,443,926	2.8[11]
Home Energy Assessment	$7,720,421	$5,194,212	$2,526,210	1.5
Appliance Recycling	$7,481,400	$4,676,459	$2,804,941	1.6
School Education	$20,025,721	$7,765,296	$12,260,425	2.6
Multifamily Direct Install	$11,325,004	$4,749,094	$6,575,911	2.4
Home Energy Report	$15,204,076	$12,735,292	$2,468,784	1.2
Residential New Construction	$18,270,532	$5,017,439	$13,253,094	3.6
HomeLife Energy Efficiency Calculator	$18,414,941	$6,111,400	$12,303,541	3.0
Employee Education	$6,151,825	$2,864,091	$3,287,734	2.1
IQW	$7,149,749	$4,261,258	$2,888,490	1.7
New Measures	$332,828,064	$174,474,645	$158,353,418	1.9
Total	**$502,994,559**	**$249,011,424**	**$253,983,135**	**2.0**

5.5.4 C&I Energy Efficiency Measures

For the C&I sector, there were 340 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-11 provides a summary of the types of measures included for each end use in the C&I sector. The measures included in this analysis are based on the 2019-2021 Plan with some new measures added by GDS. These new measures are based on a review of measures included in the 2016 MPS and discussions with stakeholders. A total of 167 additional measures were considered. Although NIPSCO's current Custom Program may technically be able to accommodate many of these measures, most would typically be considered to be prescriptive measures.

[11] The NIPSCO 2017 Portfolio Evaluation Reports lists a UCT ratio of 3.4 for the NIPSCO Residential Lighting Program and 2.9 for the Home Energy Analysis Program for calendar year 2017. It is important to note that the 2017 Portfolio Evaluation Report used a nominal discount rate of 6.53%. The DSM Savings Plan Update used a nominal discount rate of 7.65% to be consistent with the IRP modeling.

Table 5-11: Types of Electric Energy Efficiency Measures included in the C&I Sector Analysis

End Use	Measure Types Included
Office Equipment	High Efficiency Servers, Computers and Office Equipment Plug Load Sensors and Smart Power Strips
Compressed Air	Air System Maintenance Variable Frequency Drive Compressed Air Engineered Nozzle Custom Compressed Air Measures Retro-Commissioning
Cooking	Efficient Cooking Equipment Custom Kitchen
Envelope	Building Insulation Improvements High Efficiency Windows Cool Roofing
HVAC Controls	Programmable and Smart Thermostats Custom Energy Management System Installation/Optimization Occupancy Control System Retro-Commissioning
Lighting	Fixture Retrofits Premium Efficiency T8 and T5 lightbulbs High Bay Lighting Equipment LED Bulbs and Fixtures Light Tube Lighting Occupancy Sensors Custom Interior and Exterior Lighting Retro-Commissioning
Pools	Pool Pump Controls High Efficiency Pool Pump Heaters
Refrigeration	Vending Machine Misers Strip Curtains and Auto Door Closers Efficient Refrigerators/Freezers/Ice Machines High Efficiency/Variable Speed Compressors Electronically Commutated Motors Cooler Motors Door Heater Controls Efficient Compressors and Controls Door Gaskets Floating Head Pressure Controls Display Case Lighting and Controls Custom Refrigeration Retro–Commissioning
Space Cooling	Efficient Cooling Equipment Evaporative Pre-Cooler Economizer Air Source Heat Pump Geothermal Heat Pump Chiller/HVAC Maintenance Chilled Water Reset

End Use	Measure Types Included
	Room AC Custom HVAC/Chillers Retro-Commissioning
Ventilation	Enthalpy Economizer Variable Speed Drive Duct Repair and Sealing Controlled Ventilation Optimization Demand Controlled Ventilation Custom Ventilation
Water Heating	Efficient Equipment High Efficiency Hot Water Appliances Faucet Aerator/Low Flow Nozzles Pipe and Tank Insulation Heat Recovery Systems Efficient Hot Water Pump and Controls Solar Water Heating System Pre-Rinse Spray Valves Desuperheater Custom Water Heating
Other	Efficient Point of Sale Terminal Efficient Transformers Custom Motors and Drives Custom Process Custom Pumps/Fans Retro-Commissioning Process Retro-Commissioning Motors and Drives
Agriculture	Engine Block Heater Timer Energy Efficient/Energy Free Livestock Waterer High Volume Low Speed Fans High Efficiency Exhaust Fans Dairy Refrigeration Tune-up

5.5.5 Achievable Electric Energy Efficiency Savings

The achievable electric energy efficiency savings for the C&I sector includes savings associated with measures that are:

- Included in the 2019-2021 Plan
- New energy efficiency measures added to the plan by GDS that pass the UCT.

Table 5-12 shows the cumulative annual achievable energy efficiency savings for the years 2019 – 2048 and estimates of the annual energy efficiency budgets.

Table 5-12: Achievable C&I Sector Energy Efficiency Potential and Annual Budgets

Year	Cumulative Annual Energy Savings (MWh)	Cumulative Annual Demand Savings (MW)	Annual Cost ($)
2019	72,000	9.4	$9,047,188
2020	152,000	19.8	$10,052,432
2021	240,000	31.3	$11,057,675
2022	325,796	43.1	$11,839,493
2023	419,550	55.1	$12,140,734
2024	510,798	66.9	$12,444,981
2025	602,907	78.9	$12,775,475
2026	696,948	91.0	$13,163,727
2027	786,971	102.8	$13,478,238
2028	873,445	114.6	$13,798,511
2029	959,682	126.5	$14,119,573
2030	1,046,587	138.5	$14,432,594
2031	1,127,019	149.8	$14,849,184
2032	1,206,636	161.1	$15,187,942
2033	1,286,733	172.5	$15,544,398
2034	1,317,466	176.5	$15,824,693
2035	1,342,307	179.7	$16,074,726
2036	1,361,070	182.1	$16,307,510
2037	1,379,659	184.6	$16,544,828
2038	1,397,364	187.0	$16,786,479
2039	1,412,165	189.1	$16,943,342
2040	1,425,373	190.9	$17,103,500
2041	1,437,179	192.6	$17,267,020
2042	1,447,692	194.1	$17,433,974
2043	1,456,960	195.5	$17,604,435
2044	1,465,211	196.7	$17,778,475
2045	1,472,341	197.7	$17,956,170
2046	1,477,839	198.5	$18,137,597
2047	1,482,283	199.2	$18,322,833
2048	1,485,725	199.7	$18,511,960

Table 5-13 shows the cumulative annual energy efficiency savings as a percent of total C&I sector sales, excluding C&I customers that have opted out of NIPSCO's energy efficiency programs.

Table 5-13: Achievable C&I Sector Energy Efficiency Savings as a Percent of Sales (Base Case)

Year	Cumulative Energy Savings (MWh)	C&I Sector Sales Forecast (Excl. Opt-Out) (MWh)	Cumulative Savings Percent of Sales
2019	72,000	4,652,224	1.5%
2020	152,000	4,697,257	3.2%
2021	240,000	4,739,576	5.1%
2022	325,796	4,778,968	6.8%
2023	419,550	4,819,735	8.7%
2024	510,798	4,856,840	10.5%
2025	602,907	4,895,604	12.3%
2026	696,948	4,933,514	14.1%
2027	786,971	4,966,699	15.8%
2028	873,445	5,000,237	17.5%
2029	959,682	5,025,190	19.1%
2030	1,046,587	5,052,855	20.7%
2031	1,127,019	5,078,996	22.2%
2032	1,206,636	5,099,000	23.7%
2033	1,286,733	5,118,796	25.1%
2034	1,317,466	5,139,223	25.6%
2035	1,342,307	5,161,284	26.0%
2036	1,361,070	5,174,258	26.3%
2037	1,379,659	5,181,773	26.6%
2038	1,397,364	5,190,437	26.9%
2039	1,412,165	5,197,508	27.2%
2040	1,425,373	5,209,258	27.4%
2041	1,437,179	5,221,038	27.5%
2042	1,447,692	5,232,850	27.7%
2043	1,456,960	5,244,693	27.8%
2044	1,465,211	5,256,567	27.9%
2045	1,472,341	5,268,473	27.9%
2046	1,477,839	5,280,410	28.0%
2047	1,482,283	5,292,379	28.0%
2048	1,485,725	5,304,379	28.0%

Table 5-14 shows the NPV of benefits, costs, net benefits and the benefit-cost ratio for each program and for the portfolio as a whole.

Table 5-14: Benefit Cost Analysis Results – UCT

Program	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
Custom	$340,264,393	$60,474,877	$279,789,516	5.6
New Construction	$98,374,129	$18,786,751	$79,587,378	5.2
Prescriptive	$396,617,207	$38,748,919	$357,868,288	10.2
Retro-Commissioning	$16,901,754	$7,739,152	$9,162,602	2.2
Small Business Direct Install	$87,942,866	$16,596,204	$71,346,663	5.3
New Measures Prescriptive	$23,743,405	$5,029,889	$18,713,516	4.7
New Measures Custom	$9,439,944	$1,990,940	$7,449,004	4.7
New Prescriptive Ag Measures	$2,859,702	$523,495	$2,336,207	5.5
New Measures New Construction	$15,594,391	$3,778,988	$11,815,403	4.1
Total	$991,737,791	$153,669,216	$838,068,576	6.5

5.6 Future Resource Options

5.6.1 Energy Efficiency Bundles[12]

GDS converted the measure incentive costs into an equivalent annual payment spread over the life of the measure and divided the equivalent annual payment by the measure's first-year kWh savings to calculate the incentive cost per lifetime kWh saved for each measure. According to the November 2008 National Action Plan for Energy Efficiency guide titled "Understanding Cost Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods and Emerging Issues for Policy-Makers," program administrative costs are typically not included when calculating cost effectiveness at the measure level. Based on this recommendation, program administrative costs were not included in this cost calculation. Tables 5-15 and 5-16 show the cumulative annual MWh savings, MW savings and annual utility budgets for these three bundles for the energy efficiency base case scenario for residential and C&I customers, respectively. Table 5-17 summarizes the total. The cumulative MWh and budget costs are additive for residential and C&I to arrive at the total, but the peaks are not, due to the fact that different programs are not coincident. The total bundles were used in the IRP modeling.

[12] Please note, the MWh, MW and budgets utilized in the IRP were from an earlier draft of the Energy Efficiency Savings Update and may differ slightly from the numbers in the final report included in Appendix B. This was due to the timing of the final report compared to when numbers were required for the model runs. However, the differences are not significant. The tables in this section reflect the numbers utilized by CRA in the IRP modeling efforts.

Table 5-15: Residential Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	23,198	9.8	$3,120,947	27,435	6.6	$6,363,684	341	0.2	$332,842
2020	36,732	12.0	$3,118,788	55,160	13.1	$6,363,871	599	0.3	$332,467
2021	50,064	14.5	$3,115,234	82,515	19.5	$6,362,402	856	0.5	$332,085
2022	70,676	18.9	$4,169,756	86,004	20.4	$1,216,278	13,208	3.5	$15,436,140
2023	91,166	23.8	$4,300,842	89,310	22.2	$1,256,494	24,414	6.8	$15,482,175
2024	112,679	28.3	$4,429,560	93,419	23.3	$1,306,866	35,635	9.7	$15,529,778
2025	133,822	32.8	$4,569,988	96,910	24.5	$1,350,188	46,866	12.6	$15,574,511
2026	155,209	37.4	$4,699,753	100,720	25.8	$1,393,143	58,108	15.5	$15,621,458
2027	176,419	41.8	$4,836,631	104,348	26.8	$1,433,990	69,363	18.1	$15,670,403
2028	199,234	46.6	$4,970,286	108,790	28.1	$1,446,694	80,604	21.0	$15,717,871
2029	217,904	50.9	$5,106,871	112,422	29.6	$1,474,239	91,853	24.2	$15,766,369
2030	237,319	55.2	$5,247,332	116,343	31.1	$1,486,926	103,112	27.4	$15,817,541
2031	254,732	59.2	$5,394,368	119,996	32.5	$1,497,348	114,383	30.5	$15,871,633
2032	274,152	63.3	$5,544,922	124,489	34.0	$1,509,677	125,665	33.7	$15,925,409
2033	290,429	67.5	$5,698,959	127,935	35.4	$1,545,193	136,952	36.9	$15,978,312
2034	300,194	69.8	$5,823,060	104,480	30.4	$1,561,017	148,249	40.3	$16,033,291
2035	309,001	71.9	$5,952,395	80,860	25.9	$1,574,207	152,798	42.1	$16,091,088
2036	320,400	74.4	$6,099,762	57,323	22.7	$1,584,608	157,352	44.0	$16,145,518
2037	323,194	75.3	$6,198,431	58,462	23.3	$1,596,027	159,923	44.8	$16,181,313
2038	326,486	76.2	$6,299,172	59,653	23.9	$1,607,685	162,493	45.6	$16,217,860
2039	328,471	76.6	$6,402,029	60,152	24.1	$1,619,588	164,753	46.0	$16,255,174
2040	332,568	75.3	$6,507,046	60,938	18.7	$1,631,741	166,995	42.1	$16,293,272
2041	333,792	75.9	$6,614,269	61,276	19.1	$1,644,149	169,223	43.0	$16,332,170
2042	335,604	76.4	$6,723,743	61,617	19.6	$1,656,818	169,385	43.5	$16,371,885
2043	336,350	76.8	$6,835,516	61,761	20.1	$1,669,753	169,537	44.2	$16,412,433
2044	338,661	77.1	$6,949,636	62,046	20.2	$1,682,960	169,620	44.2	$16,453,834
2045	338,978	77.4	$7,066,152	62,014	20.2	$1,696,443	169,698	44.2	$16,496,103
2046	340,018	77.6	$7,185,116	62,077	20.2	$1,710,210	169,770	44.3	$16,539,261
2047	340,876	77.8	$7,306,578	62,112	20.3	$1,724,267	169,832	44.3	$16,583,324
2048	342,462	78.0	$7,430,590	62,240	20.3	$1,738,618	169,882	44.3	$16,628,313

Table 5-16: C&I Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	57,477	13.7	$7,093,091	14,523	2.9	$1,954,097	0	0.0	$0
2020	121,341	28.9	$7,881,212	30,797	6.1	$2,171,219	0	0.0	$0
2021	191,591	45.6	$8,669,334	48,518	9.7	$2,388,341	0	0.0	$0
2022	258,294	62.0	$9,025,573	67,461	13.5	$2,703,163	193	0.0	$110,756
2023	332,676	78.7	$9,252,548	86,486	17.4	$2,770,426	387	0.1	$117,760
2024	408,406	95.7	$9,484,921	102,260	20.4	$2,835,287	592	0.1	$124,773
2025	485,669	113.0	$9,752,695	116,719	23.3	$2,890,234	784	0.2	$132,546
2026	564,928	130.5	$10,033,029	131,295	26.1	$2,979,807	1,025	0.2	$150,891
2027	645,287	148.4	$10,273,287	140,436	28.0	$3,046,937	1,249	0.3	$158,013
2028	722,917	166.1	$10,524,231	149,709	29.8	$3,107,737	1,497	0.3	$166,543
2029	801,264	184.1	$10,777,543	157,031	31.3	$3,168,288	1,744	0.4	$173,742
2030	880,358	202.4	$11,027,368	164,628	32.9	$3,224,944	1,975	0.4	$180,283
2031	953,821	219.3	$11,348,675	170,945	34.2	$3,311,363	2,254	0.5	$189,145
2032	1,026,654	236.3	$11,619,566	178,316	35.6	$3,372,494	2,470	0.5	$195,882
2033	1,099,943	253.4	$11,900,715	184,506	37.0	$3,440,787	2,701	0.6	$202,895
2034	1,126,736	258.8	$12,151,635	188,173	37.8	$3,482,137	2,981	0.6	$190,921
2035	1,148,291	262.9	$12,362,496	190,812	38.4	$3,520,890	3,203	0.7	$191,340
2036	1,164,268	265.7	$12,559,119	194,251	39.0	$3,556,600	3,421	0.7	$191,791
2037	1,180,955	269.5	$12,759,892	195,605	39.4	$3,592,662	3,539	0.8	$192,274
2038	1,196,990	273.1	$12,964,294	197,155	39.7	$3,629,416	3,663	0.8	$192,769
2039	1,210,329	276.2	$13,090,516	198,060	39.9	$3,659,638	3,777	0.8	$193,188
2040	1,222,254	279.1	$13,219,389	200,104	40.2	$3,690,495	3,912	0.8	$193,616
2041	1,232,984	281.7	$13,350,967	200,623	40.4	$3,722,000	4,022	0.8	$194,052
2042	1,242,596	284.0	$13,485,309	201,428	40.6	$3,754,167	4,119	0.9	$194,498
2043	1,251,057	286.0	$13,622,472	201,699	40.7	$3,787,009	4,205	0.9	$194,953
2044	1,258,590	287.8	$13,762,516	202,762	40.8	$3,820,541	4,313	0.9	$195,418
2045	1,265,087	289.4	$13,905,500	202,854	40.9	$3,854,778	4,400	0.9	$195,892
2046	1,270,045	290.7	$14,051,487	203,301	41.0	$3,889,733	4,495	0.9	$196,377
2047	1,274,014	291.7	$14,200,540	203,681	41.0	$3,925,422	4,588	0.9	$196,871
2048	1,277,052	292.5	$14,352,723	204,442	41.1	$3,961,861	4,690	1.0	$197,376

Table 5-17: Total Energy Efficiency Base Case Bundles

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2019	80,676	20.5	$10,214,038	41,958	8.4	$8,317,781	341	0.2	$332,842
2020	158,073	35.8	$11,000,000	85,957	16.8	$8,535,090	599	0.3	$332,467
2021	241,655	53.2	$11,784,567	131,033	25.4	$8,750,744	856	0.5	$332,085
2022	328,971	71.9	$13,195,329	153,465	28.9	$3,919,442	13,401	3.5	$15,546,896
2023	423,842	91.1	$13,553,390	175,796	33.5	$4,026,920	24,801	6.9	$15,599,935
2024	521,084	110.3	$13,914,481	195,680	37.1	$4,142,153	36,228	9.8	$15,654,551
2025	619,491	129.9	$14,322,683	213,629	40.5	$4,240,422	47,650	12.7	$15,707,057
2026	720,137	149.7	$14,732,782	232,015	43.9	$4,372,950	59,132	15.7	$15,772,349
2027	821,705	169.6	$15,109,918	244,784	46.3	$4,480,928	70,612	18.4	$15,828,416
2028	922,151	189.7	$15,494,517	258,499	49.0	$4,554,431	82,101	21.4	$15,884,414
2029	1,019,167	209.7	$15,884,414	269,453	51.9	$4,642,527	93,596	24.5	$15,940,111
2030	1,117,676	230.0	$16,274,700	280,971	55.0	$4,711,870	105,087	27.8	$15,997,824
2031	1,208,553	248.7	$16,743,044	290,941	57.8	$4,808,711	116,638	30.9	$16,060,778
2032	1,300,805	267.6	$17,164,488	302,805	60.7	$4,882,171	128,134	34.2	$16,121,291
2033	1,390,371	286.6	$17,599,674	312,441	63.6	$4,985,981	139,653	37.5	$16,181,207
2034	1,426,931	293.0	$17,974,695	292,653	61.6	$5,043,153	151,229	40.9	$16,224,212
2035	1,457,292	298.1	$18,314,890	271,672	59.5	$5,095,098	156,000	42.7	$16,282,428
2036	1,484,668	302.1	$18,658,881	251,574	58.1	$5,141,208	160,773	44.7	$16,337,309
2037	1,504,149	306.3	$18,958,323	254,067	59.0	$5,188,689	163,461	45.5	$16,373,587
2038	1,523,475	310.3	$19,263,467	256,808	59.9	$5,237,101	166,155	46.3	$16,410,629
2039	1,538,800	313.7	$19,492,545	258,212	60.2	$5,279,226	168,530	46.8	$16,448,362
2040	1,554,823	315.6	$19,726,435	261,042	55.2	$5,322,236	170,907	42.8	$16,486,888
2041	1,566,776	318.5	$19,965,236	261,899	55.9	$5,366,150	173,245	43.8	$16,526,222
2042	1,578,200	321.0	$20,209,052	263,046	56.5	$5,410,985	17,504	44.3	$16,566,383
2043	1,587,407	323.3	$20,457,988	263,459	57.2	$5,456,763	173,742	45.0	$16,607,387
2044	1,597,250	325.2	$20,712,151	264,809	57.4	$5,503,501	173,933	45.0	$16,649,251
2045	1,604,065	326.9	$20,971,653	264,868	57.5	$5,551,221	174,098	45.1	$16,691,996
2046	1,610,063	328.3	$21,236,603	265,378	57.6	$5,599,943	174,265	45.1	$16,735,637

	Bundle 1			Bundle 2			Bundle 3		
	Cumulative			Cumulative			Cumulative		
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2047	1,614,891	329.4	$21,507,118	265,793	57.7	$5,649,688	174,420	45.1	$16,780,196
2048	1,619,514	330.2	$21,783,313	266,682	57.8	$5,700,478	174,572	45.2	$16,825,690

5.6.2 Demand Response Program Options

Five DR options were considered, including two options for NIPSCO's Interruptible Tariff. The objective of these options is to realize demand reductions from eligible customers during the highest load hours of the summer or winter as defined by the utility. Each program type provides DR using different load reduction and incentive strategies designed to target different types of customers. From the utility perspective, load reduction events for each of the different program types can be called with different notification time. Using a mix of programs provides load reduction resources that can be called under many different conditions. Table 5-18 lists the DR programs included in this DSM Savings Update.

Table 5-18: Demand Response Program Options

DR Program Option	Eligible Customer Classes	Mechanism	Season
DLC Central Air Conditioner Cycling	Residential, Small and Medium C&I	DLC Switch for Central Cooling Equipment	Summer
DLC Space Heating	Residential, Small and Medium C&I	DLC Switch for Space Heating Equipment	Winter
DLC Water Heater Cycling	Residential, Small and Medium C&I	DLC Switch for Water Heating Equipment	Summer and Winter
Interruptible Load Tariffs	Large C&I	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance.	Summer
Interruptible Load Tariffs with Third Party Aggregator	Large C&I	Customer enacts their customized, mandatory curtailment plan. Penalties apply for non-performance. Typically managed as a portfolio by third party contractor.	Summer

5.6.3 Demand Response Load Reduction Assumptions

The per-customer kW electric peak load reduction, multiplied by the total number of participating customers, provides the potential demand savings estimate. Load reduction impact assumptions are based on program performance for current or past NIPSCO programs and on secondary research for new programs. The Interruptible Rider impact was sourced from actual program performance. The percentage was scaled to match current program performance. The

remaining program impacts were developed by taking an average of existing/past program performance from programs in states within the region. Table 5-19 shows the per-customer load reductions used for estimating the potential, along with sources. The majority of load reductions were obtained from the 2016 MPS, with the exceptions noted in the table.

Table 5-19: Demand Response Program Load Reduction Assumptions

Sector	DR Program Option	Load Reduction	Source
Residential	DLC AC	0.972 kW	FERC 2012 Survey adjusted to IN using National Oceanic and Atmospheric Administration temperatures
	DLC Space Heating	0.62 kW	2016 MPS
	DLC Water Heating	0.9 kW	2016 MPS
Business	DLC AC	3.1 kW	2016 MPS
	DLC Space Heating	1.5 kW	PGE Brattle Group 2016 Study
	DLC Water Heating	2.7 kW	2016 MPS
	Interruptible Rider	18% of Coincident Peak Load	2016 MPS
	Third Party Aggregator	18% of Coincident Peak Load	2016 MPS

The DR options for large C&I customers included in the Savings Update are described below:

5.6.4 Interruptible Rider

As described above and under Rider 775, large commercial customers enroll directly with NIPSCO in an agreement to curtail their load during system contingencies.

5.7 Consistency between IRP and Energy Efficiency Plans

Ind. Code § 8-1-8.5-10 ("Section 10"), which became law on May 6, 2015, requires, among other things, that a utility's energy efficiency goals are (1) reasonably achievable; (2) consistent with the utility's IRP, and (3) designed to achieve an optimal balance of energy resources in the utility's service territory. A utility is required to petition the Commission for approval of an energy efficiency plan under Section 10 beginning not later than calendar year 2017, and not less than once every three years.

To remain consistent with the requirements of Section 10, NIPSCO carried out a lengthy analysis of the DSM resources included in its IRP process. As noted above, NIPSCO completed an update to its 2016 MPS to determine the achievable amount of savings. *See Appendix B.* NIPSCO, through the MPS and the DSM Electric Savings Update process discussed above, then conducted an in-depth review of the amount of savings that would be achievable in its service

territory with its current customer base. Following that in-depth review process, NIPSCO incorporated 3 energy efficiency DSM bundles and 3 DR bundles into the model for selection as resources. As defined above, energy efficiency measures were bundled according to each measure's cost of saved energy over its measure life and the DR programs were bundled by calculating the levelized cost per cumulative kW over the 30-year lifetime of the program.

NIPSCO allowed DSM and energy efficiency measures, broadly referred to as DSM resources, to be selected across all six portfolio concepts. As discussed further in this section, three separate DSM bundles were developed by GDS for potential selection in the portfolio optimization model. The bundles were organized according to cost, and all of the resources in the first two bundles were selected by the optimization model across all portfolios.

In accordance with Section 10, NIPSCO intends to request approval in 2020 of an energy efficiency plan for implementation in 2022 ("2020 Filing") that includes:

- energy efficiency goals that are (1) reasonably achievable; (2) consistent with NIPSCO's 2018 IRP, and (3) designed to achieve an optimal balance of energy resources in its service territory;

- energy efficiency programs that are (1) sponsored by an electricity supplier and (2) designed to implement energy efficiency improvements;

- program budgets;

- program costs that include (1) direct and indirect costs of energy efficiency programs, (2) costs associated with the EM&V of program results, (3) recovery of lost revenues and performance incentives. For purposes of this filing, the "direct costs" are those associated with implementing the programs, including any costs associated with program start up, while "indirect costs" are the NIPSCO administrative costs; and

- EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Action Plan prior to its 2020 Filing based on the energy efficiency selected by the IRP model. This may be updated depending on the results of the 2019 MPS and/or another mechanism (i.e. DSM RFP results). The DSM Action Plan will take into account the results of the IRP for implementation and evaluation of the Energy Efficiency Plan.

It is important to note that the final program design is determined by the bidder(s) selected by NIPSCO, with consideration of input from its OSB. The selected bidder's(s') predictions of the market into the program design as they determine what may or may not work in the NIPSCO's service territory is important for designing an energy efficiency program. That means that the programs included in the MPS/DSM Savings Update typically change. NIPSCO uses the MPS/DSM Savings Update as a feed into the IRP to develop the Action Plan. This Action Plan allows NIPSCO to take into account not just the results of the IRP, but also the experience of NIPSCO and its vendors with a particular program or measure. For example, electric hot water heating has a great deal of potential, but NIPSCO has not found there to be much interest from

customers in the program. Knowing this means that NIPSCO will either (a) not structure a large amount of savings around a measure which has historically shown little participation or (b) need to increase the incentive to increase participation, which may impact the cost effectiveness of the program.

The benefit of an Action Plan is that it uses various forms of information, including the IRP, to develop the best strategy for an energy efficiency plan. The Action Plan will then be used to develop the DSM RFPs. The results of the winning bids will be utilized to develop the filing, with support from the MPS/DSM Savings Update, IRP and Action Plan. This is the most effective way to ensure NIPSCO has an Energy Efficiency Plan that is based on real-world, achievable results from vendors who are committed to those results. Bidders' responses to the groupings identified in NIPSCO's DSM RFP will vary based on the individual bidder's perception of NIPSCO's customer base and their previous experiences within other service territories, etc. This unique process for development of the DSM RFPs and creation of the Energy Efficiency Plan allows NIPSCO to compensate for the long lead time between the completion of a market potential study and the actual implementation of a program.

That does not mean that the Energy Efficiency Plan will be without change. Until the programs are administered to the customer base and the first-hand experiences with energy efficiency occur, informed judgments must be used to establish the initial estimates of program impacts in NIPSCO's service territory. That is the benefit of utilizing an OSB. It provides an on-going mechanism to adjust to changing market conditions, including codes and standards and new technologies, and to ensure NIPSCO is capturing as much energy efficiency savings as possible for the amount of funding available.

Section 6. Transmission and Distribution System

Consistent with the principles set out in Section 1, NIPSCO continues to invest in its existing Transmission and Distribution ("T&D") resources to ensure reliable, compliant, flexible, diverse and affordable service to its customers. NIPSCO continually assesses the current physical T&D system resources for necessary improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at the state, regional, and federal levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. The goals of the planning process include:

- Adequately serve native customer load and maintain continuity of service to customers under various system contingencies.
- Proactively maintain and increase availability and reliability of the electric delivery system.
- Minimize capital and operating costs while being consistent with the above guidelines

6.1 Transmission System Planning

6.1.1 Transmission System Planning Criteria and Guidelines

NIPSCO Transmission System Planning Criteria requires performance analysis of the transmission system for the outage of various system components including but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy of transmission system performance is measured in terms of NIPSCO planning voltage criteria, facility thermal ratings, fault interrupting capability, voltage stability, and generator rotor angle stability as documented in the NIPSCO 2018 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix F). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

6.1.2 North American Electric Reliability Corporation

NIPSCO is subject to the NERC, which is certified by the FERC to establish and enforce reliability standards for the bulk-electric system and whose mission is to ensure the reliability of the North American bulk electric system. NIPSCO is registered with NERC as a Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Resource Planner, Transmission Owner, Transmission Operator, and Transmission Planner. Together with MISO, in a Coordinated Functional Registration, NIPSCO is registered as a Balancing Authority, Transmission Owner, and Transmission Operator. Each Registered Entity is subject to compliance with applicable NERC standards, and ReliabilityFirst Regional Reliability Organization standards approved by FERC. Non-compliance with these standards can result in potential fines or penalties.

6.1.3 Midcontinent Independent System Operator, Inc.

NIPSCO participates in the larger regional transmission reliability planning process through participation in the MISO, which annually performs a planning analysis of the larger regional transmission system through the MISO Transmission Expansion Plan ("MTEP"). The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies. It should be noted that while any transmission project NIPSCO wishes to build must generally be timely submitted for planning review by MISO to ensure that there is no harm to other systems in MISO, so long as NIPSCO does not request cost sharing of the project with other MISO members, NIPSCO does not have to obtain MISO Board approval to proceed with a transmission project if NIPSCO deems it necessary. Additionally, under extenuating circumstances, NIPSCO can request expedited review of those cost-shared projects that do require MISO Board approval.

Requests by generation owners to connect new generators to the NIPSCO transmission system, to change the capacity of existing generators connected to the NIPSCO transmission system, or otherwise modify existing generators connected to the NIPSCO transmission system are handled through the MISO Generation Interconnection Process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests. Requests by generation owners connecting to the PJM Interconnection LLC ("PJM") transmission system are to be coordinated with NIPSCO by PJM through MISO.

Requests by generation owners in the MISO footprint to retire existing generators are handled through the MISO Attachment Y process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify either operating procedures or improvements and upgrades necessary to accommodate these requests. Requests by generation owners in the PJM footprint to retire existing generators may be reviewed by MISO for impacts on the NIPSCO transmission system, but the generation owners in the PJM footprint are under no obligation to mitigate any resulting constraints on the NIPSCO transmission system.

Requests by generation owners to secure transmission service are handled through the MISO Transmission Service Request process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

Because NIPSCO is situated on a very significant boundary (seam) between MISO and PJM, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM under the MISO-PJM Joint Operating Agreement.

In addition, MISO may propose transmission system projects or other upgrades that are not reliability based, but are economically based and should relieve congestion. These projects must pass the Benefit Cost Ratio test established by MISO before approval. NIPSCO participates in this effort through the MISO Market Efficiency Planning Study, and the MISO-PJM Interregional Planning Stakeholder Advisory Committee which performs a coordinated system planning study with PJM.

NIPSCO is also an active participant in the Market Efficiency Project ("MEP") planning processes in both MISO and PJM. The MEP processes focus on evaluating potential future transmission projects to lower the overall production cost and lower delivered energy costs to the end use customer for the MISO and/or PJM footprint. These planning efforts require the benefits of proposed projects to exceed the costs (usually 1.25 or greater benefit to cost ratio) before the RTOs will consider it a viable solution.

6.1.4 Market Participants

MISO has developed a process through which market participants can request voluntary upgrades on the NIPSCO transmission system to better accommodate generation outlet capacity, increases in transmission rights, reduce congestion, address reliability considerations, or other market driven needs. If the Market Participant wishes to pursue these types of upgrades, they must submit their proposal to MISO, and NIPSCO and the Market Participant must negotiate payments for these upgrades as defined in the MISO tariff and corresponding Business Practice Manuals. Market Participant-Funded Projects must be filed in a timely manner with MISO for review in its transmission planning process.

6.1.5 Customer Driven Development Projects

NIPSCO may be contacted to undertake transmission upgrades by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts and NIPSCO Economic Development, will determine if identified transmission upgrades are identified necessary to meet the customer's development or expansion plans.

6.1.6 Transmission System Performance Assessment

In NIPSCO's 2018 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix F), Confidential Part 2 contains the regional power flow cases. The cases include solved real and reactive flows, voltages, detailed assumptions, sensitivity analyses, and model description. Confidential Part 3 contains applicable transmission maps. Part 4 describes the reliability criteria used for transmission planning. Confidential Part 5 presents the assessment practice used.

Confidential Part 6 contains an evaluation of the reliability criteria in relation to the present performance and the expected performance of the NIPSCO transmission system. Performance assessments are conducted annually for the near-term (5 year) and long-term (10 year) planning horizons, for both peak and off-peak load conditions, assuming known or forecasted changes in generation resources and load demand. Sensitivities to baseline forecasts or assumptions may also be considered for performance analysis of the transmission system.

NIPSCO also participates in the MISO and PJM Market Efficiency Project planning processes as discussed in Section 6.1.3: Midcontinent Independent System Operator, Inc. The MISO process includes multiple future scenarios to test future sensitivities against baseline assumptions.

6.1.7 NIPSCO Transmission System Capital Projects

NIPSCO's portfolio of transmission system projects has been identified through its annual transmission system performance assessment to establish base line reliability projects. This portfolio has been expanded to include transmission projects initiated by market participants, by customer driven development projects, and to include regional transmission projects designated through the MISO MTEP planning effort, with the most recent iteration approved by the MISO Board of Directors (MTEP 17) in 2017. NIPSCO's current portfolio includes:

- Multi-Value Project 11: Sugar Creek Substation upgrades to accommodate the new 345 kV circuit from Ameren's Kansas West substation to the NIPSCO/Duke Energy Indiana jointly-owned Sugar Creek substation
- Circuit 13812 Maple Substation upgrade
- Circuit 13854 Aetna Substation line drop upgrade
- LaGrange Substation 138kV Ring bus conversion

In addition to current portfolio, NIPSCO recently completed all transmission system projects approved by MISO (MTEP 11) as part of Multi-Value Project 12. Projects included:

- Reynolds to Burr Oak to Hiple 345kV Lines
- Reynolds to Greentown 765kV Line

6.1.8 Electric Infrastructure Modernization Plan

The Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") is an initiative to modernize infrastructure through upgrades to the NIPSCO electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year Electric TDSIC Plan (2016-2022). NIPSCO's 7-Year Electric TDSIC Plan is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time.

NIPSCO's 7-Year Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of two main segments: (1) investments that target replacement of aging assets (Aging Infrastructure) and (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability). In developing its Plan, NIPSCO considered the need to maintain a safe and reliable system. The approximate cost of the transmission portion of the TDSIC plan is $453M over the seven-year period.

6.1.9 Evolving Technologies and System Capabilities

NIPSCO Transmission Planning has provided for the installation of two variable shunt reactors ("VSRs") at the Hiple 345kV substation as part of the Multi-Value Projects. The VSRs, which will enable better and more precise control of transmission system voltage, are a relatively recent development in the industry.

6.2 Distribution System Planning

As part of the long term view, NIPSCO continues to evaluate the benefits of smart grid and distribution automation ("DA") technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure.

NIPSCO's distribution system is periodically reviewed for local circuit, substation and source feed adequacy. Normal operating status as well as single element or contingency failure loading and voltage operating characteristics are evaluated along with circuit and system wide reliability metrics (i.e., CAIDI, SAIDI, SAIFI).[13] Distribution operating and design criteria rely on NIPSCO design maximums in accordance with Company Standards and equipment manufacturer ratings. Voltage operating criteria are based on American National Standards Institute (ANSI) C84.1 and Indiana Administrative Code 170 IAC 4-1-20.

System improvement plans are developed and applied based upon mitigation of identified deficiencies associated with service capacity, service voltage, reliability levels, and load growth patterns. Specific and trending distribution component failures are mitigated through capital and infrastructure improvement processes. Infrastructure upgrade and replacement activities consider system characteristics that include severity of operating deficiencies, likelihood of failure, potential customer impact, current substation and line topology, equipment age and condition. Available new technologies are integrated into improvement and replacement activities where appropriate.

Net metering is an electricity policy for consumers who own renewable (solar, wind, biomass) energy facilities. Its application provides an incentive for customers to install renewable energy systems by reimbursing them for their generation output, at utility retail rates, for energy in excess of their service's base load electricity purchase from the utility. Typically this represents the aggregate excess power produced that is not utilized internally by the customer but is instead delivered into the utility's local electric system.

Feed-in tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources and to help accelerate the move toward renewable energy sources. This tariff provides power developers with a predictable purchase price for self-generation under a long-term power purchase arrangement, which helps support financing opportunities for these types of projects.

---

[13] CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year.

NIPSCO implemented its renewable feed-n tariff in July 2011 along with its existing net metering program. These programs introduced customer-owned renewable resource based generation onto NIPSCO's electric distribution system. A relatively significant amount of renewable generation projects began coming "on line" in 2012 and that amount has continued to grow. NIPSCO's net metering and feed-in tariff generation interconnection programs provide an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's electric distribution systems. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts across the service territory.

At the end of 2017, the renewable generation data identified 10.7 MWs associated with the net metering program and 33.4 MWs of generation associated with the feed-in Tariff program. An aggregate breakdown by renewable fuel type is provided below. These values represent generation resources that include landfill gas combustion engines, animal waste gas combustion engines, PV solar array farms, small roof mounted and ground mounted residential solar arrays, intermediate sized commercial wind turbines, and small commercial and residential wind turbines.

Net Metering Generation:

- 8.64 MWs - Solar Generation
- 1.92 MWs - Wind Generation
- 0.132 MWs - Solar/Wind Combination Generation

Feed-In Tariff Generation:

- 18.87 MWs - Solar Generation
- 0.16 MWs - Wind Generation
- 14.35 MWs - Biomass Generation

The above biomass related generation value excludes 13.6 MWs of existing landfill based generation interconnected to NIPSCO's distribution system. Although these renewable generation sources feed into NIPSCO's network, the power deliveries are associated with customer PPAs with parties other than NIPSCO. These customers do not participate in NIPSCO's net metering or feed-in tariff programs. In total, approximately 55 MWs of generation is interconnected to NIPSCO's distribution system.

Based on the implementation of the net metering and feed-in tariff programs, Distribution Planning has observed voltage related operating impacts on its electric system due to larger customer-owned generation. Impacts on system operations has yet to be fully determined and will depend upon the demonstrated long term performance and reliability of various installed generating resources including solar, wind, and biomass based generation fueled resources. Differences in operational characteristics, generation penetration, power delivery timing, and location all affect the relative impact on local distribution system operations at any given time. The diverse types of customer-owned generation also have varying effects on the electric system.

NIPSCO has observed that local generation most often varies substantially depending upon individual customer equipment and generation input resources. Fuel resource type affects power delivery in various ways depending upon owner controlled resources as is the case of landfill and animal by-product gas inputs, or external environmental conditions such as wind velocity and solar irradiance. Highly variable outputs have been observed to occur on both solar and wind turbine installations. For instance, rapid changes in solar generation have exhibited swings of 85% of full rated output, within seconds. These conditions represent sizable down-up-down shifts in system operating characteristic on local circuits associated with some of the larger half MW or greater rated customer owned solar fields. These swings can present challenges to maintaining appropriate service voltage stability on distribution circuits. In addition to these more rapid changes relating to industry recognized "cloud affect," NIPSCO has also observed that more widespread weather patterns such as seasonal rain or snow storms also dramatically influence individual daily peak PV generation outputs on a longer term scale. Longer duration output reductions of 75% to 92% of rated equipment output are observed during seasonal inclement weather conditions. Significantly reduced output levels can be seen extending over several or more days, especially during winter season months. Wind powered generation was also observed to be as much, if not more, unpredictable and variable in power delivered to the distribution system. On the other hand, large biomass fueled combustion turbines appear to be less volatile in generated outputs in comparison to solar and wind associated generation. Landfill based biomass generation facilities tend to be the most predictable followed by animal waste gas associated generation. However, even though biomass fueled resources exhibit a steadier dispatch of power, there were experiences of random events where customer generation dropped completely off line. The impact of lost generation becomes more significant as the generation level increases since the local distribution system needs to adjust and compensate for fast change in power sources.

Based upon several years of operating data for currently installed renewable generation resources, these technologies present a recognized energy resource that can be utilized in supplementing customer electric energy needs. However, at this time, the impact on local electric distribution service infrastructure has not demonstrated to be sufficiently available or stable to be considered an adequate 24 hours a day/seven days a week/365 days a year substitute for NIPSCO's local electric sources in reliably meeting electric capacity and service needs. Considering that these distributed generation resources have no guarantee of power dispatch, operate in a "take it as we make it" mode, and can permanently cease operations at any time, results in a lower confidence level regarding the availability of power supply at all times, especially during periods of system stress or problems. Consequently, continued traditional capital investment into local distribution infrastructure is necessary to insure that the utility can meet all of its service obligations to its customers.

6.2.1 Evolving Technologies and System Capabilities

NIPSCO Distribution Planning continues the expansion of DA. This can be defined as the coordinated automatic control of substation breakers and interrupting-type line switches within an electric distribution system, along with the centralized retrieval of associated operating data for control and monitoring purposes.

NIPSCO's DA System enables control and automatic isolation of electric distribution line faults and the restoration of customer services during various system outage conditions. This

action is accomplished through independent sectionalizing of specific circuits through the use of automatic line switches and computer-controlled substation breakers. Built-in algorithms are utilized to analyze operating conditions such as line and substation loading, to determine best response to system disturbances. Automatic restoration increases distribution system reliability by reducing the number of customers experiencing a sustained outage. In addition to the quick restoration of electric service, real-time operating data can also be retrieved and stored on the electric management system. DA Systems provide timely and accurate outage-related information to restoration teams, speeding up problem identification. This action supports quicker overall response time to identify system problems and develop repair procedures. These factors result in further improvements in customer service and system reliability. An added benefit of real-time data retrieval and device remote control is the more effective use of labor resources for operation and maintenance of the electric distribution system.

NIPSCO currently utilizes DA (communications and remote switching) on approximately 25% of its distribution substations and 30% of its distribution circuit population. Approximately two-thirds of all DA associated circuits utilize autonomous contingency switching equipment in their operations. All new and rebuilt distribution substations, and associated circuits, are assessed for need of distribution automation as part of their infrastructure projects. As part of annual system capital investment programs, new and/or rebuilt substation projects are being implemented at an approximate rate of one to two stations per year.

NIPSCO continues to evaluate the benefits of smart grid and DA technology and to assess deployment of various new technologies based upon corporate investment strategies in infrastructure as part of its long term approach.

Section 7. Environmental Considerations

7.1 Environmental Sustainability

NIPSCO is committed to compliance, stewardship, and continuing to provide energy in an environmentally responsible way. NIPSCO's current electric generation portfolio consists of assets that includes coal and natural gas plants, wind contracts, and hydroelectric power plants. Environmental improvement targets were announced in 2017, and this resource plan contemplates a transition of coal generation assets to renewable energy that would result in enhanced environmental improvements in electric generation by 2028 (from 2005 levels), as follows:

- 90% Reduction in Greenhouse Gas ("GHG") Emissions
- 99% Reduction in Water Withdrawal and Wastewater Discharge
- 99% Reduction in NO_x Emissions
- 99+% Reduction in SO_2 and Mercury Emissions
- 100% Reduction in Coal Ash Generated

7.2 Environmental Compliance Plan Development

NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste, and solid waste that protect health and the environment. NIPSCO is committed to complying with all regulatory requirements. This commitment is embodied in the NiSource Environmental, Health & Safety and Climate Change Policies and is implemented through a comprehensive environmental management system. Compliance plans are developed, reviewed, and evaluated for implementation to meet new and changing legislative and regulatory developments.

NIPSCO uses a combination of external and internal resources to develop and adapt environmental compliance plans. Consultants and engineering firms are utilized to assist NIPSCO in developing cost estimates and performing modeling. Compliance plans are drafted to address proposed and final EPA and Indiana Department of Environmental Management ("IDEM") rules. As rules change, compliance plans are modified to comply with new requirements.

7.3 Environmental Regulations

7.3.1 Solid Waste Management

The EPA finalized a rule regulating the management and disposal of Coal Combustion Residuals ("CCR") which became effective on October 19, 2015. The CCR rule regulates CCRs under the Resource, Conservation, and Recovery Act (RCRA) Subtitle D as nonhazardous. The CCR rule is implemented in phases establishing requirements related to groundwater monitoring,

CCR management and disposal, reporting, recordkeeping, and document management.[14] The rule allows NIPSCO to continue its byproduct beneficial use program, significantly reducing CCR that must be disposed.

To comply with the rule, NIPSCO is required to incur capital expenditures to modify its infrastructure and manage CCRs. Capital compliance costs for Schahfer Units 14 and 15 and Michigan City Unit 12 are expected to total approximately $193 million. Schahfer Units 17 and 18 will not incur any capital costs related to the CCR rule. On December 13, 2017, the IURC approved a set of projects related to CCR compliance in Cause No. 44872. NIPSCO continues to assess and monitor groundwater quality at Bailly, Michigan City, and Schahfer to comply with CCR rule requirements and to determine if historic CCR management and disposal practices will require corrective measures.

7.3.2 Clean Water Act

The CWA establishes water quality standards for surface waters as well as a permit program for regulating discharges into the waters of the United States. Under the CWA, EPA created a program to establish wastewater discharge standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge from a point source into navigable waters without a permit. The National Pollutant Discharge Elimination System ("NPDES") permit program implements the CWA's provisions.

7.3.3 Effluent Limitations Guidelines

EPA first promulgated the Steam Electric Power Generating Effluent Guidelines and Standards ("ELG Rule") in 1974, and has amended the regulation many times, with the latest revision finalized on November 3, 2015, with an effective date of January 4, 2016. The ELG rule regulates wastewater discharges from power plants operating as utilities. The implementing requirements are incorporated into NPDES permits. The ELG Rule imposes new wastewater treatment and discharge requirements on NIPSCO's electric generating facilities to be applied between 2018 and 2023. For example, the Michigan City NPDES permit was renewed in April 2016, and ELG requirements were incorporated effective November 1, 2018. On April 25, 2017, the EPA published notice in the Federal Register stating that the EPA is reconsidering portions of the ELG Rule in response to several petitions for reconsideration. On September 18, 2017, the EPA postponed the earliest compliance dates for FGD wastewater and bottom ash transport water requirements from 2018 to 2020 to potentially consider revisions to technology and numeric limits achievable.

Michigan City Unit 12 is equipped with a dry FGD, which does not require any capital expenditure for ELG rule compliance. The CCR-related infrastructure investment will allow Michigan City to comply with other aspects of the ELG Rule by the November 2018, NPDES permit compliance date. Furthermore, no capital expenditure is expected for ELG compliance on Schahfer Units 14, 15, 17, and 18, which, based on this resource plan, NIPSCO anticipates retiring by 2023.

[14] https://www.nipsco.com/about-us/ccr-rule-compliance-data-information

7.3.4 Clean Air Act and Climate Strategy Assessment

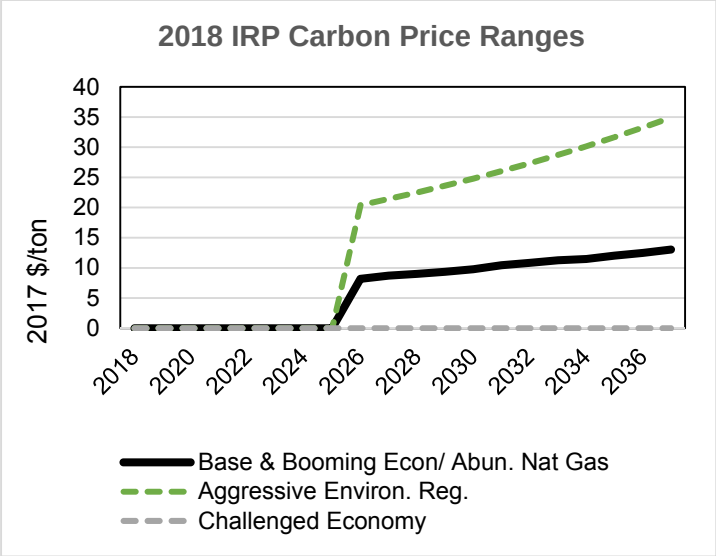
Over the last decade, NIPSCO has invested more than $800 million in new technologies to reduce emissions at its electric generating stations, improve air quality, and comply with CAA requirements. Emissions of NO_x, SO_2, and mercury have been reduced by more than 80% since 2005. All Northern Indiana counties are in attainment of the National Ambient Air Quality Standards with the exception of the ozone standards in Lake and Porter Counties, which are included in Chicago metropolitan area nonattainment.

NIPSCO has reduced GHG emissions by more than 40% since 2005, and emissions reductions are expected to continue with the anticipated retirement of coal generation and transition to renewable energy. Still, climate-related environmental laws and regulations may be developed that could result in significant cost or restrictions on NIPSCO's operations.

On October 23, 2015, the EPA issued a final rule, the CPP, to regulate CO_2 emissions from existing fossil-fuel electric generating units ("EGUs") under authority of the CAA. The CPP establishes national CO_2 emission standards that are applied to each state's mix of affected EGUs to establish either state-specific rate-based or mass-based emission limits. The U.S. Supreme Court has stayed implementation of the CPP until litigation is decided on its merits, and the EPA has proposed to repeal the CPP. On August 31, 2018, the EPA proposed to replace the CPP with the Affordable Clean Energy ("ACE") rule. The timing and cost of compliance with the ACE rule are unknown at this time and are likely dependent on future state rulemaking.

Although the timing and magnitude of required GHG reductions are uncertain, it does not appear likely that a price on carbon emissions will be required by regulation or legislation until the year 2026 or later. In the IRP modeling, NIPSCO assumed three carbon price scenarios as shown in the figure below. The base scenario assumes a new federal rule or legislative action effective by the mid-2020s, the second scenario does not assume any price on carbon, and the Aggressive Environmental Regulation scenario assumes a new stricter federal rule or legislative action effective by the mid-2020s. In the Aggressive Environmental Regulation scenario, price levels are generally consistent with a 50-60% reduction in electric sector CO_2 emissions relative to 2005 by the 2030s.

Figure 7-1: 2018 IRP Carbon Price Ranges



This resource plan considered the framework by Ceres and M.J. Bradley & Associates, *Climate Strategy Assessments for the U.S. Electric Power Industry: Assessing Risks and Opportunities Associated with a 2-Degree Transition and the Physical Impacts of Climate Change*. NIPSCO used scenario analysis to assess the potential implications of climate change and inform its strategy. The plan to transition coal generation assets to renewable energy would reduce NIPSCO greenhouse gas emissions by more than 90% by 2028 compared with 2005 levels.

Retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures to reduce NOx emissions in addition to expenditures for CCR, ELG, and GHG compliance. The IRP modeling assumed compliance with updates to the Cross-State Air Pollution Rule ("CSAPR") and ozone regulations that have not yet been proposed. Although both Schahfer Units 17 and 18 are already equipped with low-NO_x burners and OFA systems for NO_x reduction, SCR or selective non-catalytic reduction ("SNCR") could be installed for post-combustion NO_x control. SCR technology allows for greater NO_x reduction rates which leads to better operational flexibility. Therefore, SCR technology was assumed for compliance with the anticipated regulation. Conceptual cost estimates were used in the modeling.

7.4 Emission Allowance Inventory and Procurement

7.4.1 Title IV Acid Rain - SO_2 Emission Allowance Inventory

In conjunction with CSAPR, the Title IV Acid Rain Program will continue to regulate SO_2 emissions. Table 7-1 lists the actual number of SO_2 Acid Rain Program emission allowances held in inventory by NIPSCO as of September 2018 for the period 2018 through 2048. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the Acid Rain Program.

Table 7-1: SO_2 Acid Rain Program Emission Allowances

Acid Rain Program SO_2 Allowance Inventory*	
Year	**Allowances**
Bank**	264,764
2018-2048 Annual Allocation	50,706
Total* **	**1,836,650**

* Allowance inventory available in September 2018
** Reflects emission allowances from 2017 and earlier
***To obtain the total, multiply the annual allocation by 31 and add the bank.

7.4.2 CSAPR Emission Allowance Inventory

Under CSAPR, allowances are allocated to NIPSCO and managed separately from the Acid Rain Program. Table 7-2 lists the annual SO_2, annual NO_x, and ozone season NO_x allowance inventory issued to NIPSCO. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the CSAPR rule.

Table 7-2: CSAPR Allowance Inventory

CSAPR Allowance Inventory*			
Year	**Annual SO_2**	**Annual NO_x**	**Ozone Season NO_x**
Bank**	81,347	2,402	444
2018 – 2020 Annual Allocation	23,522	13,178	3,321
Total* **	**151,913**	**41,936**	**10,407**

** Allowance inventory available in September 2018.*
*** Reflects emission allowances from 2017 and earlier.*
****To obtain the total, take the annual allocation and multiply by three and add to the bank.*

Section 8. Managing Risk and Uncertainty

8.1 Introduction & Process Overview

In the 2018 IRP, NIPSCO has deployed an approach that involved the development of a fundamentals-based set of key Base Case market drivers and assumptions and the use of both scenarios and stochastics to assess risk and uncertainty. NIPSCO developed the major inputs and associated uncertainty ranges for the 2018 IRP through the following process:

- Development of the Base Case set of assumptions through fundamental energy sector and commodity price models and NIPSCO's internal load forecasting models.
- Identification of the key drivers of uncertainty and whether they can be evaluated through scenarios or stochastics.
- Development of distinct scenario themes with accompanying model-based forecast assumptions.
- Development of stochastic distributions for relevant variables.

The major market assumptions for the base case and the scenarios were developed using a set of fundamental market models deployed by CRA and discussed in more detail in Section 2.3. These models include the NGF model for natural gas price projections, the NEEM model for electric sector capacity expansion and retirement decisions and coal pricing, and the Aurora model for granular power price projections.

The following sections provide an overview of the fundamental drivers that underpin the NIPSCO Base Case for gas prices, coal prices, carbon prices, and power market prices, while the remainder of the chapter discusses the scenarios and associated assumptions and the stochastic distributions that have been developed.

8.2 Base Case Market Drivers and Assumptions

8.2.1 Natural Gas Prices

NIPSCO's 2018 Base Case natural gas price forecast is driven by a number of key market assumptions regarding the major supply and demand dynamics in the North American natural gas market. Figure 8-1 summarizes the major drivers, along with CRA's approach and assumptions for each driver, as well as supporting explanations. The remainder of this section provides additional detail related to each driver.

Figure 8-1: Natural Gas Price Drivers – Base Case

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) 2016 "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2016 "Minimum" resource, and grows the resource base to achieved PGC 2016 "Most Likely" volumes by 2050
Well Productivity	• IP rates based on historic data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data for initial mode year, IP rates improve annually in line with EIA assumptions The "Poor Heavy" resource base is conservative, and reflects the fact that sampled data reflects only geology expected to be productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA based individual well productivity on available historic data, adopted EIA assumptions for cost improvements over time
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2017 Reference Case (with CPP)	The AURORA case assumes "base case" carbon pressure and AEO 2017 Reference assumes CPP, meaning demand estimates are consistent
LNG Exports	• Under-construction projects completed, ~9 bcf/d exports assumed by 2019, volumes grow another ~5 bcf/d from 2021 to 2031	Current advanced-stage projects expected to come online and be highly utilized driving 2019 view Low domestic prices drive further international interest for US gas, but no other projects able to complete before 2021
Pipeline Exports	• Mexican export increase to ~8bcf/d by 2021, 10.5bcf/d by 2030	CRA expects pipeline export capacity to meet growing gas demand in Mexico will be ~60% utilized by 2021, and 75% utilized by 2031
NGL & Condensate Value	• Liquids valued at 70% of AEO 2017 Reference Oil Price	AEO17 for long-term oil price forecast; 70% value for NGLs is consistent with last 5 years of price history

*IP = Initial Production

Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on the Potential Gas Committee ("PGC") 2016 "minimum" value as the starting value for recoverable shale reserves, with the resource base growing over time at a steady rate until the PGC "most likely" value is reached in 2050. The assumed values and ranges are shown in Figure 8-2.

PGC evaluates three categories of potential resource:

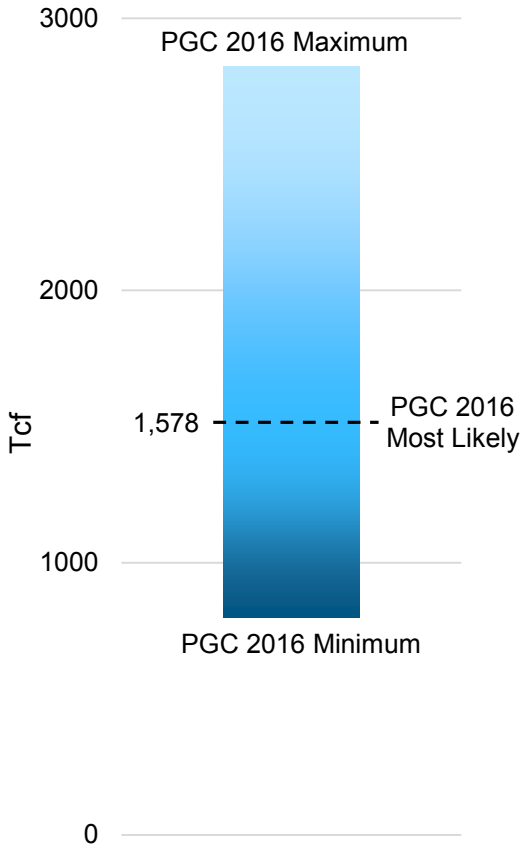
- Probable – gas associated with known fields
- Possible – gas outside of known fields, but within a productive formation in a productive province
- Speculative – gas in formations and provinces not yet proven productive

PGC assigns resource to three probability categories:

- Minimum – 100% probability that resource is recoverable
- Most Likely – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions

- Maximum – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present

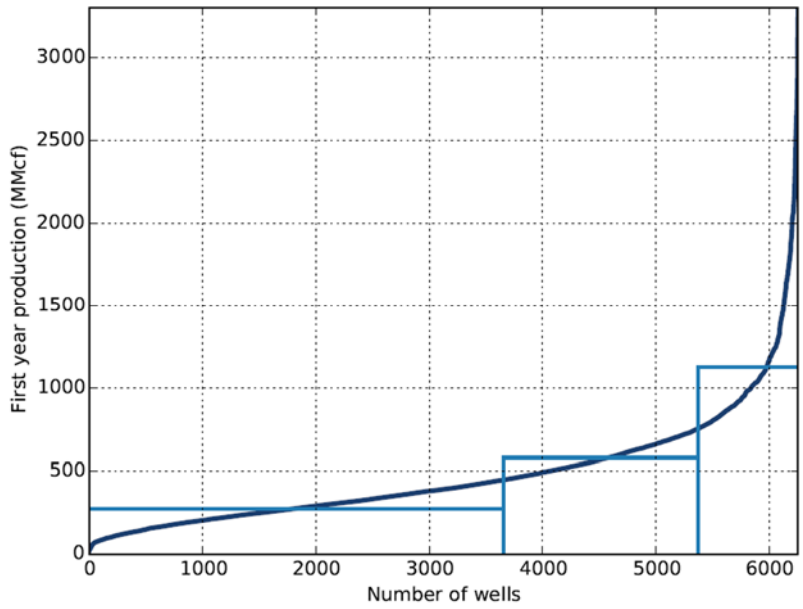
Figure 8-2: Uncertainty Range for Shale Resources in PGC 2016



Well Productivity

Natural gas well productivity assumptions are important drivers of ultimate production efficiency, especially since the bulk of gas resource is currently unproven, meaning that the geology of that resource is currently unknown. In developing assumptions for this variable, CRA generated productivity distributions for each production basin based on 2010-2016 drilling data in regions that producers expected to have favorable geology. An example of this distribution is shown in Figure 8-3, with the number of wells shown on the x-axis and the level of first-year production shown on the y-axis. In the Base Case, CRA assumed a "Poor Heavy" productivity distribution (50% poor, 20% prime, 30% average) for future undiscovered resource, as summarized in the graphic.

Figure 8-3: Well Productivity Illustration

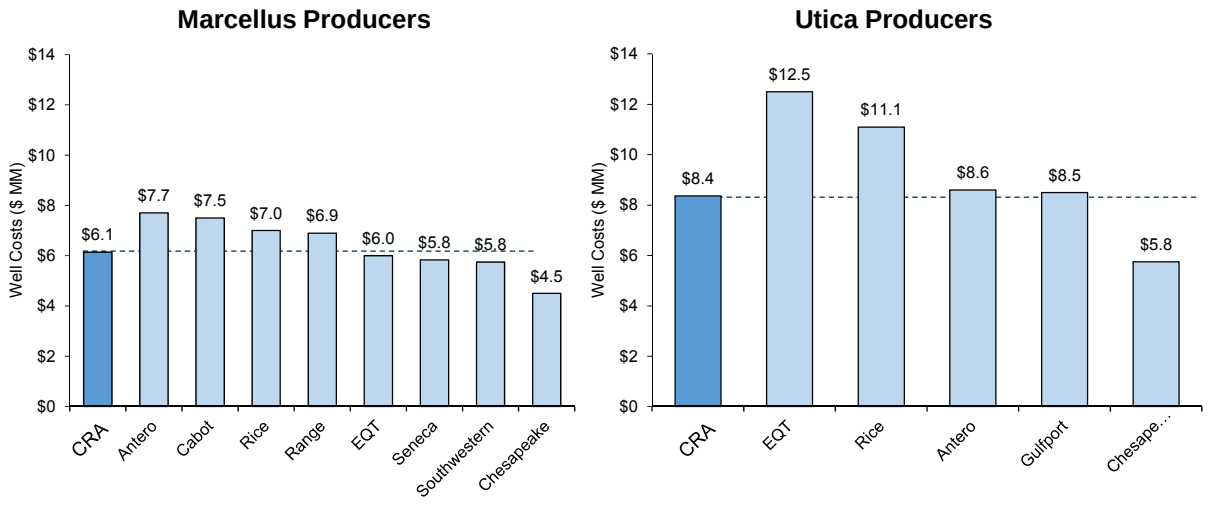


Well Costs

CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region. Figure 8-4 illustrates 2016-2017 reported costs in the Marcellus and Utica basins across major producers. Producers in these regions have been reporting declining costs over the last several years, with some producers (Antero, Seneca, Chesapeake) reporting cost reductions up to 35-37% since 2014.

For going forward costs, CRA relies on the EIA's Annual Energy Outlook ("AEO") projections for productivity improvements, fixed costs, and operations and maintenance costs. EIA's approach incorporates annual improvements to key well inputs that account for ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources from historical time periods.

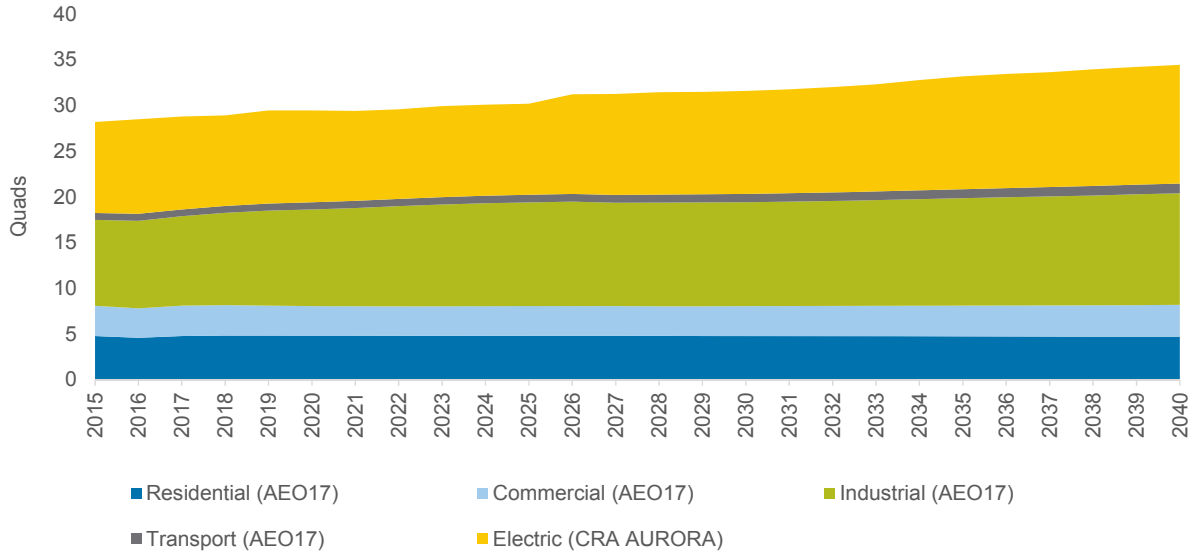
Figure 8-4: Well Costs by Producer with CRA Average



Domestic Demand

In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for residential, commercial, industrial, and transport demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-5 presents historical and forecast domestic demand assumptions through 2040 from these sources. Electric sector demand is expected to be relatively flat in the near-term, but increase substantially after the potential introduction of a carbon price, such that the demand by 2040 is 30% higher than current levels. The AEO's growth expectations for other sectors are more modest, with some growth expected in the industrial and transportation sectors over time.

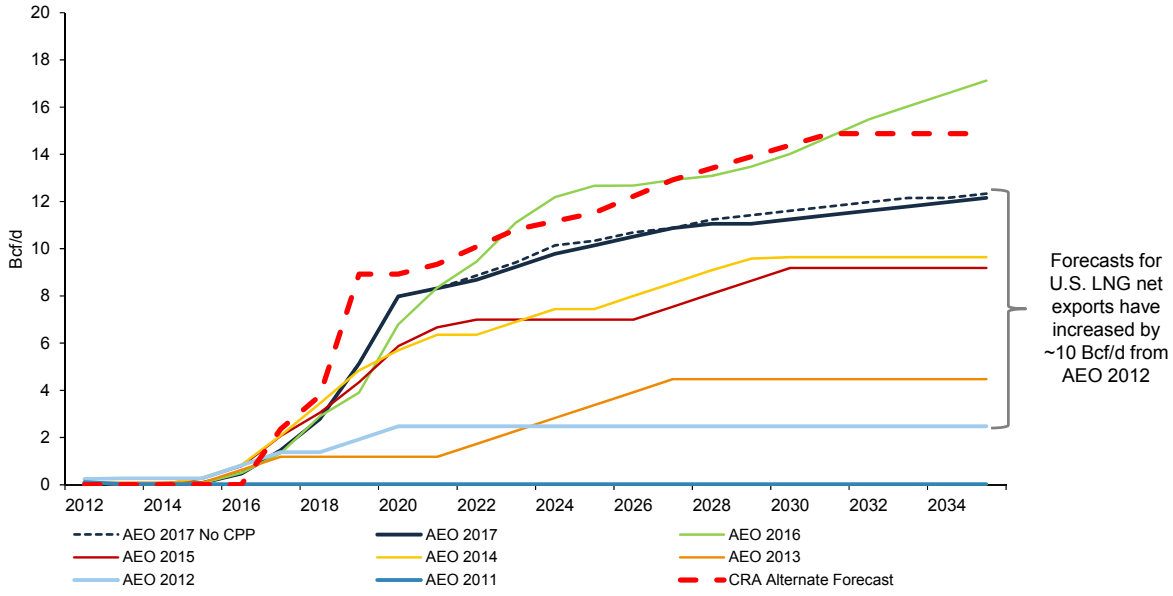
Figure 8-5: Domestic Natural Gas Demand Assumptions



Exports – LNG and to Mexico

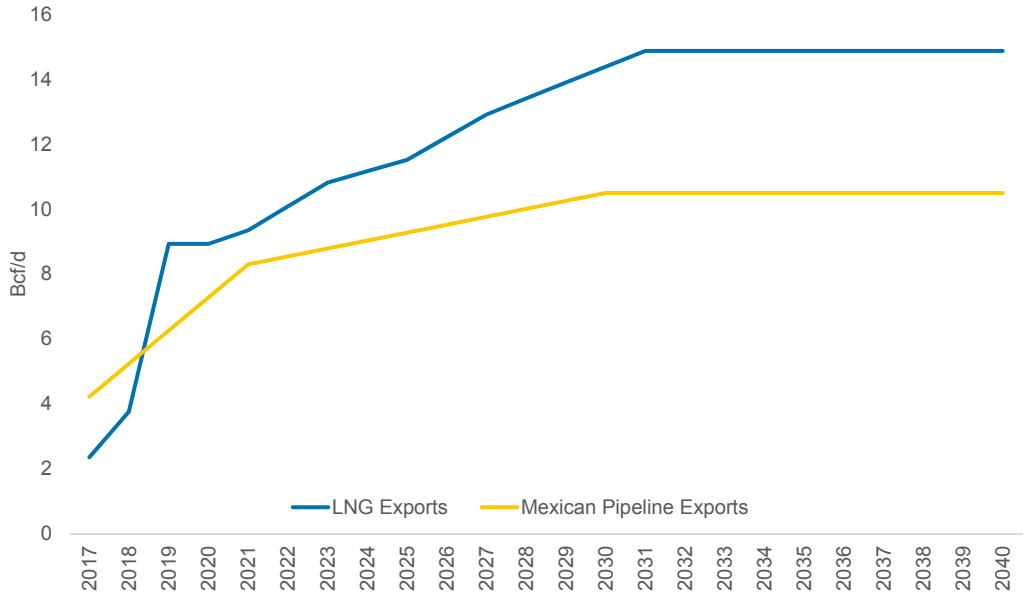
CRA develops projections for natural gas exports to Mexico via pipeline and to other international markets through LNG by reviewing estimates published by sources like the AEO and conducting analysis of specific export projects under development. The AEO has generally increased its outlook in recent years, as LNG exports in the AEO 2017 Reference Case are between 25%-35% higher than those in the AEO 2015, although lower than the more bullish long-term outlook produced in AEO 2016. CRA's review of current LNG export projects suggests that export levels will be slightly higher than AEO 2017 projects. The Base Case forecast projects about 9 billion of standard cubic feet ("bcf")/day of LNG exports by 2020, rising to nearly 15 bcf/day by 2030. CRA's Base Case projection is shown with recent AEO projections in Figure 8-6.

Figure 8-6: LNG Export Volume Projections



In addition, CRA expects that exports to Mexico will also increase, as U.S. production grows and as Mexican demand increases, primarily due to additional demand from the power sector. Mexican exports are projected to increase to around 8 bcf/day by 2021 and 10.5 bcf/day by 2030. These Base Case projections are shown along with the LNG export projections in Figure 8-7.

Figure 8-7: LNG and Mexican Pipeline Export Projections



Base Case Price Forecast

CRA's Base Case price forecast was developed based on each of the supply-demand inputs discussed above and is shown in Figure 8-8. The Base Case projects prices at Henry Hub to increase to around $3.50/ million per British thermal unit ("MMBtu") in real 2017$ by the early 2020s and approach $4/MMBtu by 2030. Recent AEO forecasts are shown with CRA's Base Case for comparison.

8.2.2 Coal Prices

NIPSCO's 2018 Base Case coal price forecast was driven by a fundamental view of the major supply and demand dynamics for each of the four major coal basins in the United States. The forecast was developed through CRA's NEEM model in an integrated fashion with other Base Case assumptions for natural gas prices (discussed above), carbon prices (discussed below), and the expected evolution of the power sector over time.

Overall, U.S. coal prices are expected to be mostly flat in real terms over the study period. The forward prices as of the time of forecast production were generally either flat or slightly backward-dated, indicating that many market participants expected relatively weak coal demand during 2018-2021, consistent with CRA's expectations. Beyond the near-term, CRA's fundamental analysis expects U.S. steam coal demand to fall significantly (~25%) over the next decade as a result of increased renewable generation and the retirement of about 33 GW of coal-fired capacity over the next five years. Increasing production costs offset the impact of declining demand in the Base Case forecast, resulting in a relatively flat price outlook.

Coal Supply and Demand Trends

Figure 8-9 summarizes historical and projected supply and demand for U.S. coals over the period from 2006 through 2037, which shows that coal demand has generally been in decline over the last ten years. Over the last three years, total coal production declined from 897 million tons to about 728 million tons (or 19%) between 2015 and 2016, but then increased 6.5% (to about 775 million tons) in 2017 as natural gas prices recovered from low levels in 2016. Modest additional declines are expected in the next five years, with more substantial declines expected by 2027 if carbon pricing is implemented, as is projected in the Base Case.

Figure 8-8: Base Case Henry Hub Natural Gas Price Forecast

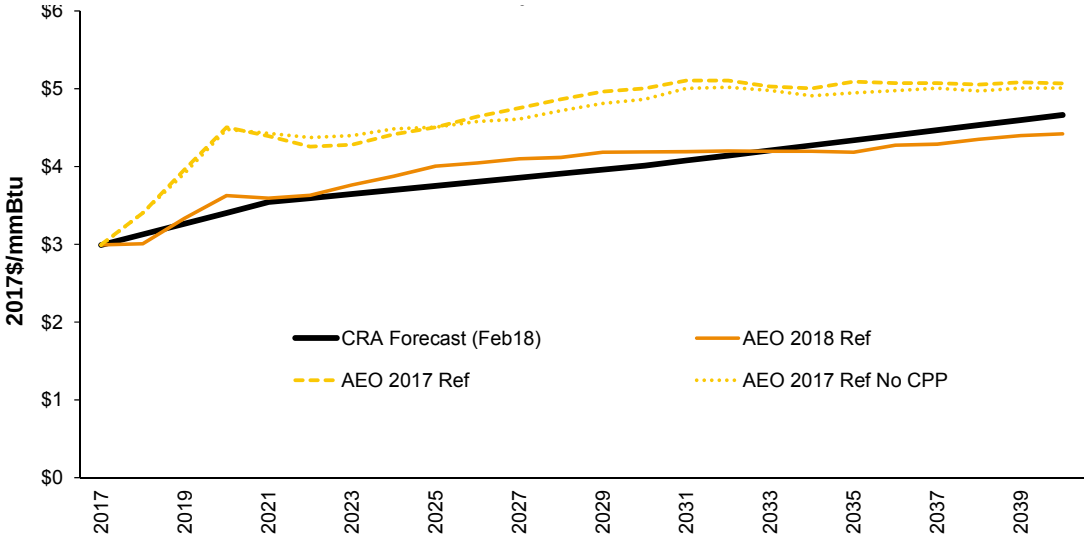
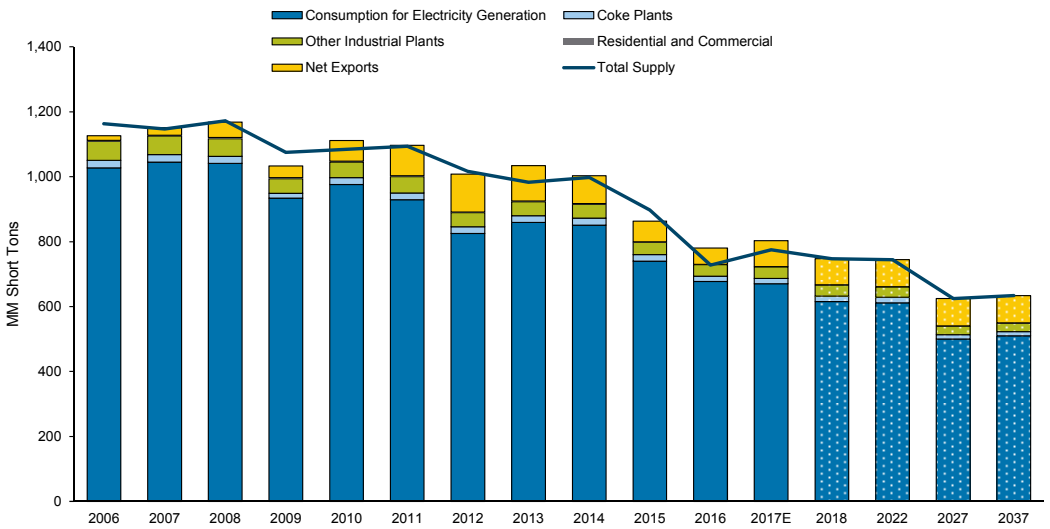


Figure 8-9: Supply-Demand Balance for U.S. Coal – 2006-2037



Regional Coal Production Expectations

While coal demand is broadly expected to decline across the U.S., each of the four major basins faces different dynamics based on regional demand from coal-fired power plants as well as international export demand. Figure 8-10 presents CRA's Base Case production estimates over the next ten years for each of the four major production basins.

Figure 8-10: Ten-Year Coal Production Expectations by Basin

Coal Type	Current to 2027 Production Forecast (% decline)	Comments
CAPP	-21%	High cost drives decline in electric sector demand; met coal demand sustained
NAPP	-13%	Increased int'l demand and some replacement of CAPP demand
ILB	-9%	Increased int'l demand and some replacement of CAPP demand
PRB	-22%	Domestic steam coal demand declines, especially after CO_2 pressure

CAPP = Central Appalachian

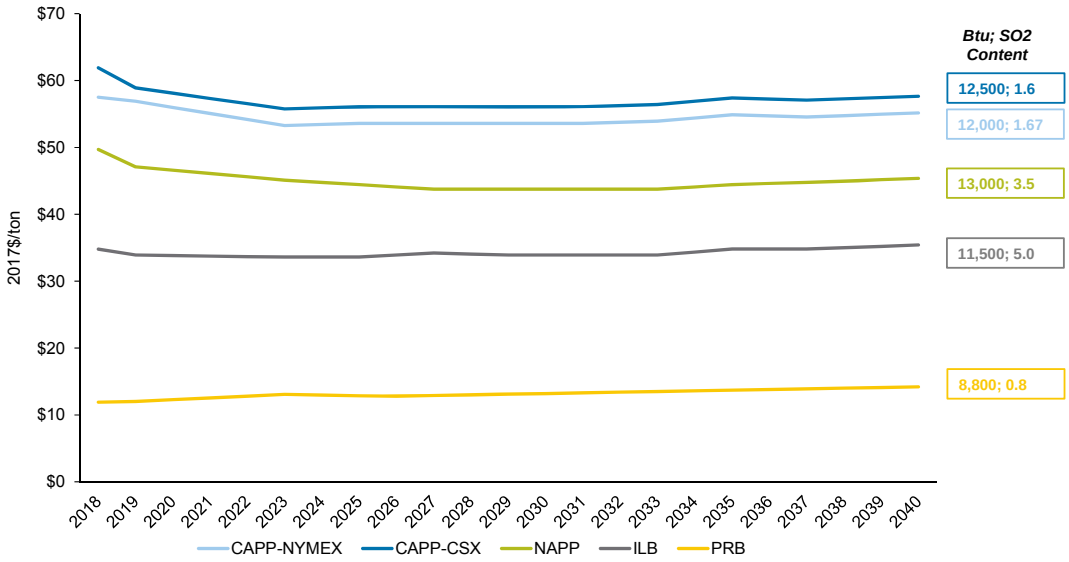
Base Case Price Forecast

CRA's Base Case price forecast is driven by both the regional production outlook and an assessment of production costs at various demand levels, which are represented as coal supply curves within the NEEM model. Figure 8-11 presents the Base Case price outlook by coal supply region, with additional basin-level commentary provided below:

- Central Appalachia ("CAPP"): Lower demand is expected to drive a price decline (in real dollars per ton) for Appalachian coal through the early-to-mid-2020s. Thereafter, reserve depletion is expected to drive modest increase in real coal price for Appalachian coals.
- NAPP: Prices for NAPP coals trend with CAPP, but reflect the lower production costs in Northern Appalachia. NAPP's lower cost profile, due to larger longwall mines, allows highly efficient mining of large-block coal reserves.
- ILB: Abundant reserves of ILB coal and low production costs (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth.

PRB: Prices are expected to increase modestly (in real dollars per ton) at an average rate of 0.8%/year through the forecast period. This price growth is driven by higher production costs due to downward-sloping coal seams and reserve depletion, even as demand is expected to decline.

Figure 8-11: Base Case Coal Price Forecast

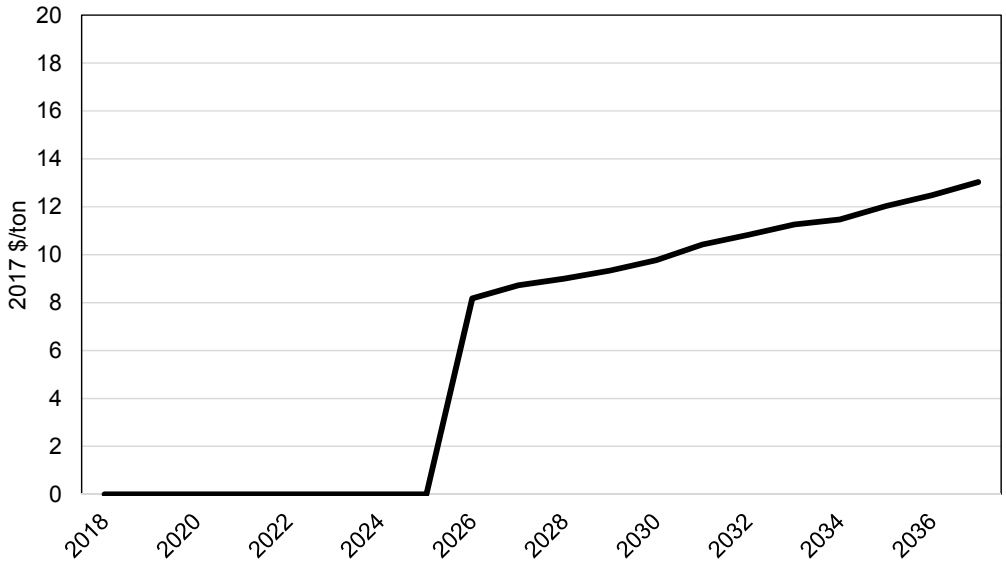


8.2.3 Carbon Policy and Prices

Although several legislative and executive actions related to carbon emissions have been attempted over the last decade, there is currently no price on carbon and no binding emission limits at the federal level. While the EPA has been given the authority to regulate carbon emissions, the Obama administration's CPP was held up in the federal courts and eventually withdrawn by the Trump administration. Although regulation that would implement a carbon price does not currently exist, NIPSCO believes that it needs to plan for the potential of such federal regulation to be implemented over the next decade.

As a result, the Base Case forecast includes a price on carbon, premised on a new federal rule or legislative action coming into force by 2026. The Base Case timing implies that a new federal administration after 2020 would need to re-promulgate a rule through the EPA or pursue a legislative solution with a newly constructed Congress. The Base Case expectation is that a new carbon regulation would be in line with the CPP and would aim to achieve 30-40% reductions in emissions from the electric sector versus an historical baseline likely to be set around the time of rule passage. CRA's analysis suggests that pricing between $8-14/ton between 2026 and 2037 would achieve such reductions and result in a 20% reduction in U.S. coal demand. The pricing outlook assumed in the Base Case is shown in Figure 8-12 in real dollars per short ton.

Figure 8-12: Base Case Carbon Price Forecast



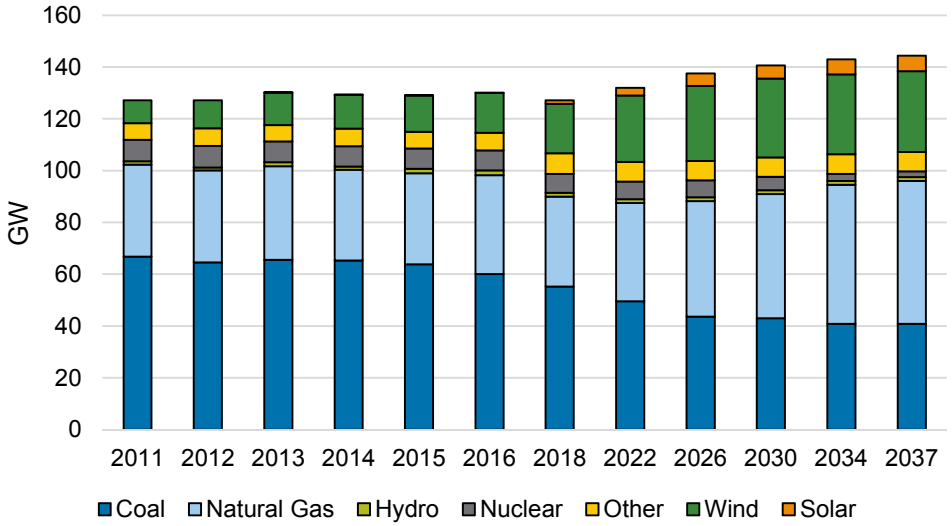
8.2.4 MISO Energy and Capacity Prices

NIPSCO operates within the MISO region, which includes parts of fifteen states throughout the Midwest and South. The traditional MISO North footprint covers parts of Indiana, Michigan, Illinois, Missouri, Kentucky, Iowa, Wisconsin, Minnesota, North Dakota, South Dakota, and Montana. NIPSCO territory and resources fall within LRZ6, covering Indiana and northern Kentucky. In developing the Base Case market price forecasts for energy and capacity, CRA deployed its Aurora market model to represent the entire MISO footprint and produce fundamental, hourly price projections that are internally consistent with the fundamental outlook for natural gas prices, carbon prices, and the future capacity mix in the region.

MISO Capacity Mix

Based on the market inputs from fuel and carbon prices, the Base Case analysis expects a continued shift from coal capacity to natural gas-fired capacity and renewables throughout MISO. Between 2011 and 2016, 7.5 GW of coal capacity retired in the MISO North region, with a net decline of 6.3 GW, due to some additions that came online prior to 2013. The Base Case forecast expects that an additional 10.5 GW of MISO North coal capacity will retire by 2023. Over half of the coal fleet is at least sixty years old, and pressure from potential carbon prices and competition from natural gas-fired and renewable resources, which are realizing lower costs, is likely to result in further retirements over time. CRA's projection of the evolution of the MISO North capacity mix is presented in Figure 8-13.

Figure 8-13: MISO North Net Winter Capacity by Fuel Type – History and Forecast



MISO Electricity Demand Growth

Electricity demand growth in MISO has been relatively modest in recent years, with total net energy for load growing at a compound annual growth rate of 0.4% between 2010 and 2016. While energy demand within the Indiana zone has grown at a rate of around 1% per year since 2010, peak load has been quite flat over the same time period. Going forward, CRA's Base Case expects MISO peak loads to grow at a 0.24% compound annual growth rate over the next ten years. This outlook is based on MISO Module E filings rather than the Independent Load Forecast, which historically has projected higher growth rates.

Base Case Energy Price Forecast

CRA's Base Case MISO market analysis uses the load growth projections, expectations for supply mix changes, and fuel and emission price forecasts to develop forecasts for power prices on an hourly basis. Overall, power prices are projected to be relatively flat in real dollars in the near-term, due to flat gas and coal prices and relatively modest load growth. Some upward pressure is expected into the 2020s as a result of higher natural gas price projections, although growing renewable quantities are likely to lower the market heat rate over time. The expectation for a national carbon price, starting in 2026, drives a noticeable price increase in that year. On a seasonal basis, market prices are expected to be highest in the summer months when load is highest, but also to display increases during the winter months when load is elevated and when gas prices are likely to be high as a result of winter heating demand. Figure 8-14 presents the annual Base Case power price projections for the Indiana region, which is LRZ6, while Figure 8-15

presents the same projections on a monthly basis.

Figure 8-14: LRZ6 (Indiana) Base Case Annual Price Projections

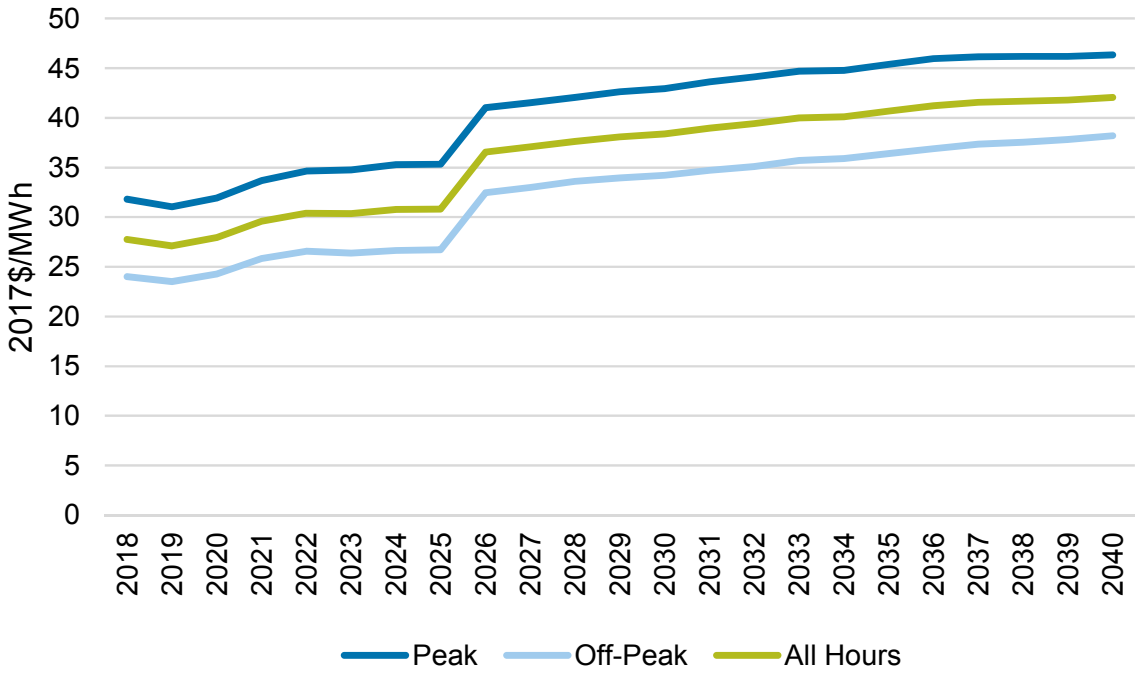
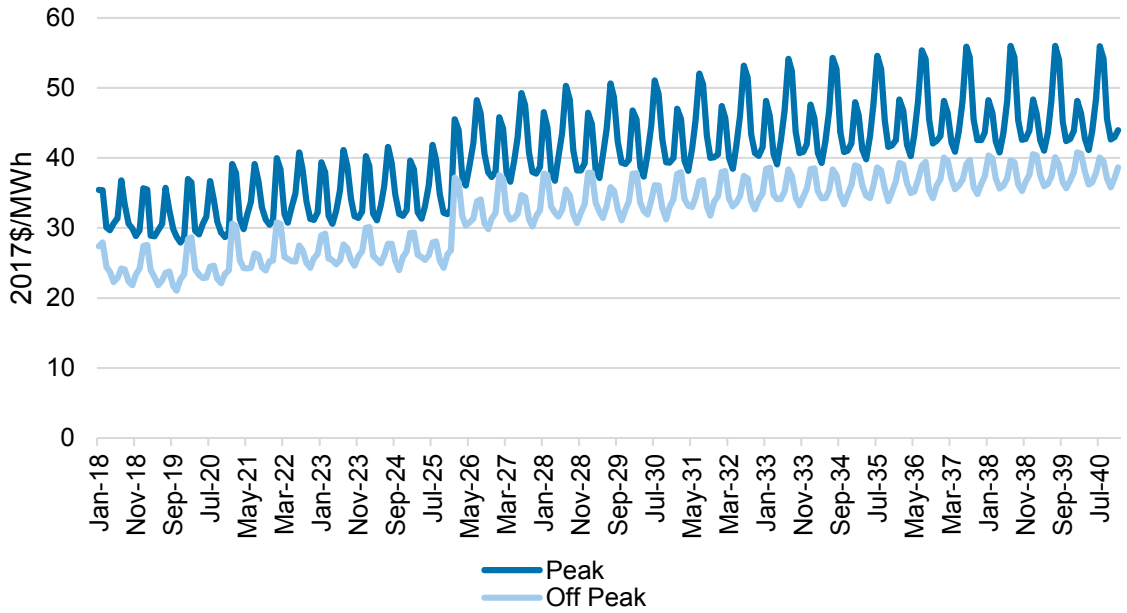


Figure 8-15: LRZ6 (Indiana) Base Case Monthly Price Projections

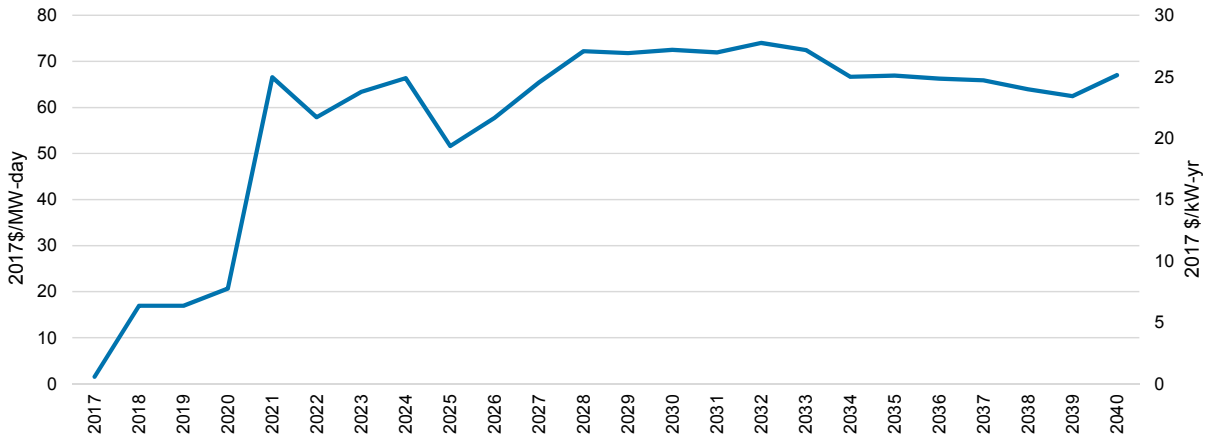


Base Case Capacity Price Forecast

In addition to the energy market, MISO also operates a capacity market which procures capacity in an annual auction. The capacity market is based on an administratively-set demand requirement and supply offers from market participants that are willing to sell capacity. Recent market prices have been relatively low even as coal capacity retires as a result of flat load, increases in renewable capacity, and increases in behind-the-meter, demand response, and energy efficiency supply. Furthermore, recent tariff revisions have impacted reduced supply offer thresholds, resulting in clearing prices around or below $10/MW-day in recent auctions.

CRA's capacity price forecast includes a fundamental evaluation of supply and demand in the market, as well as the expected offer prices for generators throughout the market. CRA expects low market prices to persist through 2021, when coal and nuclear retirements may drive prices up towards the going-forward costs of existing units. The Base Case does not expect increases in price towards MISO's cost of new entry (CONE) benchmark even as new capacity is needed, since it is likely that electric utility builds, under cost-of-service ratemaking, will enter the market and keep reserve margins in the 17-19% range. Figure 8-16 presents the Base Case capacity price projections over time.

Figure 8-16: MISO Capacity Price Projections



8.2.5 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment

After defining the Base Case market drivers and conditions, NIPSCO worked to identify the key uncertainties and drivers that could impact its business environment and future portfolio performance over the long-term. Drawing on its work from the 2016 IRP, NIPSCO identified five major drivers of uncertainty, as shown in Figure 8-17. These include commodity prices, especially for natural gas, power, and coal; environmental policy, particularly with regard to carbon pricing; economic growth, including its impact on electric sector load growth and commodity prices; NIPSCO load growth, and technology costs for new resources.

Figure 8-17: Major Drivers of Uncertainty



After identifying the major drivers of uncertainty, NIPSCO then assessed whether they should be addressed through scenario or stochastic analysis. In the 2018 IRP, NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across both scenarios and stochastics since the two approaches answer different questions and quantify risk in different fashions. Scenarios can be structured to assess major changes to specific market driver assumptions, along with related feedbacks, while stochastics can evaluate volatility and tail risk, based on observed historical data, particularly in the commodity price markets. Figure 8-18 provides a summary of the primary purposes and benefits of using deploying each approach. Based on NIPSCO's review of the different uncertainty approaches, it was determined that stochastic distributions would be developed for natural gas and power commodity prices and evaluated in concert with the ranges established through a fundamental scenario development process.

Figure 8-18: Scenario and Stochastic Uncertainty Approaches

Scenarios
Integrated Set of Assumptions

- **Can be used to answer "What if…"**
- Major events can change fundamental outlook for key drivers, altering portfolio performance
  - New policy or regulation (carbon regulation)
  - Fundamental gas price change (change in resource base, production costs, large shifts in demand)
  - Loss of a major load
- **Can tie portfolio performance directly to a "storyline"**
  - Easier to explain a specific reasoning why Portfolio A performs differently than Portfolio B

Stochastics:
Statistical Distributions of Inputs

- **Can evaluate volatility and "tail risk"**
  - Short-term price volatility impacts portfolio performance
    - Value of certain portfolio assets is dependent on market price volatility
    - Commodity price exposure risk is broader than single scenario ranges
- **Develops a dataset of potential outcomes based on observable data, with the recognition that the real world has randomness**
  - Large datasets can allow for evaluation of key drivers and broader representation of distribution of outcomes

In the scenario development process, NIPSCO developed narratives to describe possible futures, which were organized around "themes" or "states-of-the-world." The first step in developing the themes was to construct assumptions for key macro drivers, which would ultimately translate into changes for the more detailed drivers impacting NIPSCO's portfolio costs. Ultimately, NIPSCO developed three scenarios to supplement the Base Case, relying on the foundation that was built in the 2016 IRP process, but incorporating recent trends and specific risks related to the 2018 IRP Base Case assumptions. A summary of the scenario themes is shown in Figure 8-19.

Figure 8-19: Scenario Theme Overview

Theme	Drivers			
	Technology	Policy	Load	Economy
Base Case	Expected continued declines in solar/storage costs; base case nat. gas production costs	National carbon price expected in 2026 with new federal policy; current regulations on CCR/ELG	Base load forecast	Long-term growth trends in line with historical averages
Aggressive Environmental Regulation	**Renewable (wind and solar) and storage costs decline significantly, supported by policy push**	**Policy forces drive stricter carbon controls and stronger renewable targets**	Base load forecast	Reference case macroeconomic factors persist
Challenged Economy	Base technology assumptions	**No national carbon policy**	**Loss of industrial load; remaining customer load growth stagnates**	**Economic downturn with growth stalling**
Booming Economy & Abundant Natural Gas	**Continued efficiency gains in NG extraction drive lower operations costs and focus on most productive plays**	Base environmental policy; strong support for gas extraction	**Greater load growth, maintenance of industrial customers**	**Low-cost energy paradigm prevails and economic growth greater than expected**

NIPSCO then assessed the themes for diversity and robustness and translated the scenario themes into specific assumptions for the key inputs of load, carbon price, natural gas price, coal price, and power price based on additional rounds of modeling with CRA's fundamental market tools. Given that NIPSCO's All-Source RFP resulted in a range of resource technology costs to use in the IRP analysis, this variable was not specifically evaluated in the scenario development phase. Figure 8-20 summarizes the directional movement of the key input assumptions relative to the Base Case, while the subsequent section of this chapter outlines the detailed inputs that were developed as part of the scenario analysis process.

Figure 8-20: Summary of Four Major Scenarios

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Base	Base	Base	Base	Base	Base
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**

8.3 IRP Scenarios

8.3.1 Aggressive Environmental Regulation Scenario

Description

The Aggressive Environmental Regulation Scenario represents a future in which environmental regulations will be more stringent than currently anticipated for power sector emissions, particularly related to carbon dioxide. As a result, carbon environmental compliance costs will be greater for NIPSCO than in the Base Scenario, starting at about $20/ton in real dollars in 2026, escalating to about $35/ton (real dollars) by 2037. Natural gas prices will be greater as a result of greater demand from gas in the power sector as coal generation declines. In the scenario, natural gas prices are projected to trend towards $5.50/MMBtu in real dollars over time. Coal prices are expected to be lower due to reduced coal demand. Power prices will be greater as a result of both higher carbon prices and higher natural gas prices, even though there is a faster shift in the MISO supply mix from coal to natural gas and renewables. The key directional assumptions changes are summarized in Figure 8-21.

Figure 8-21: Summary of Aggressive Environmental Regulation Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Aggressive Environmental Regulation	Base	**High**	**High (CO_2)**	**Low (CO_2)**	**High (CO_2)**

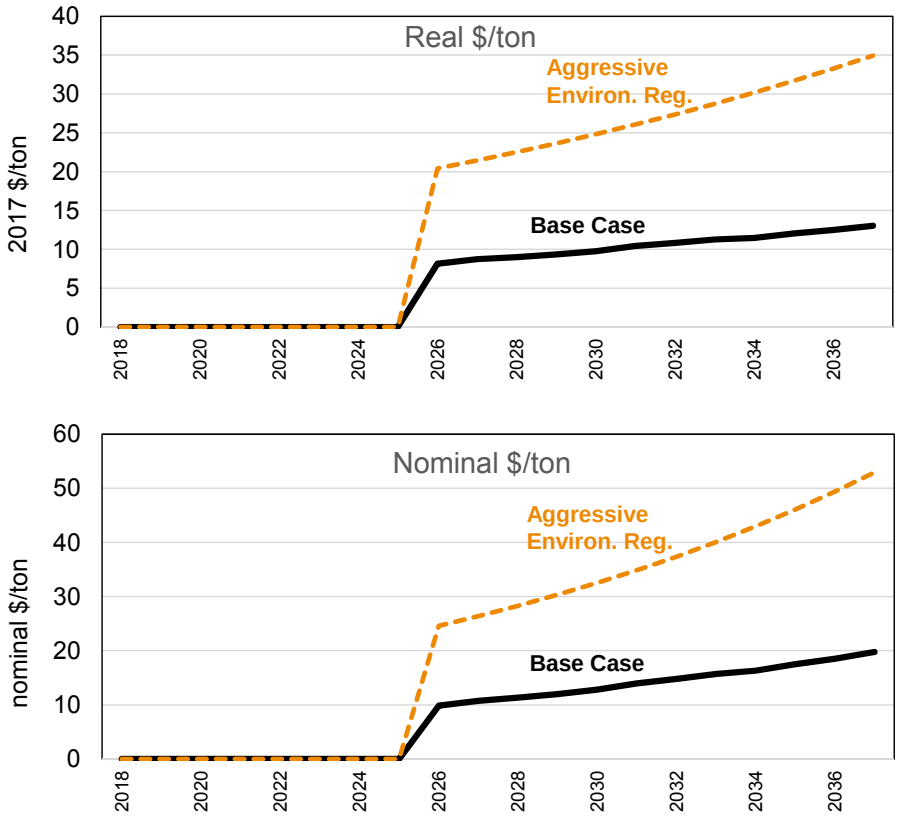
Risks Addressed

The Aggressive Environmental Regulation Scenario addresses the risk that carbon environmental regulations will be more stringent than expected in the Base Scenario. This scenario addresses the risk of higher carbon prices after 2026, which will tend to favor renewable generation and, to a lesser extent, natural gas-fired generation over coal capacity. The scenario also addresses the risk of higher prices for natural gas and power, which are correlated. Assumptions regarding load growth remain unchanged from the Base Scenario.

Detailed Scenario Assumptions

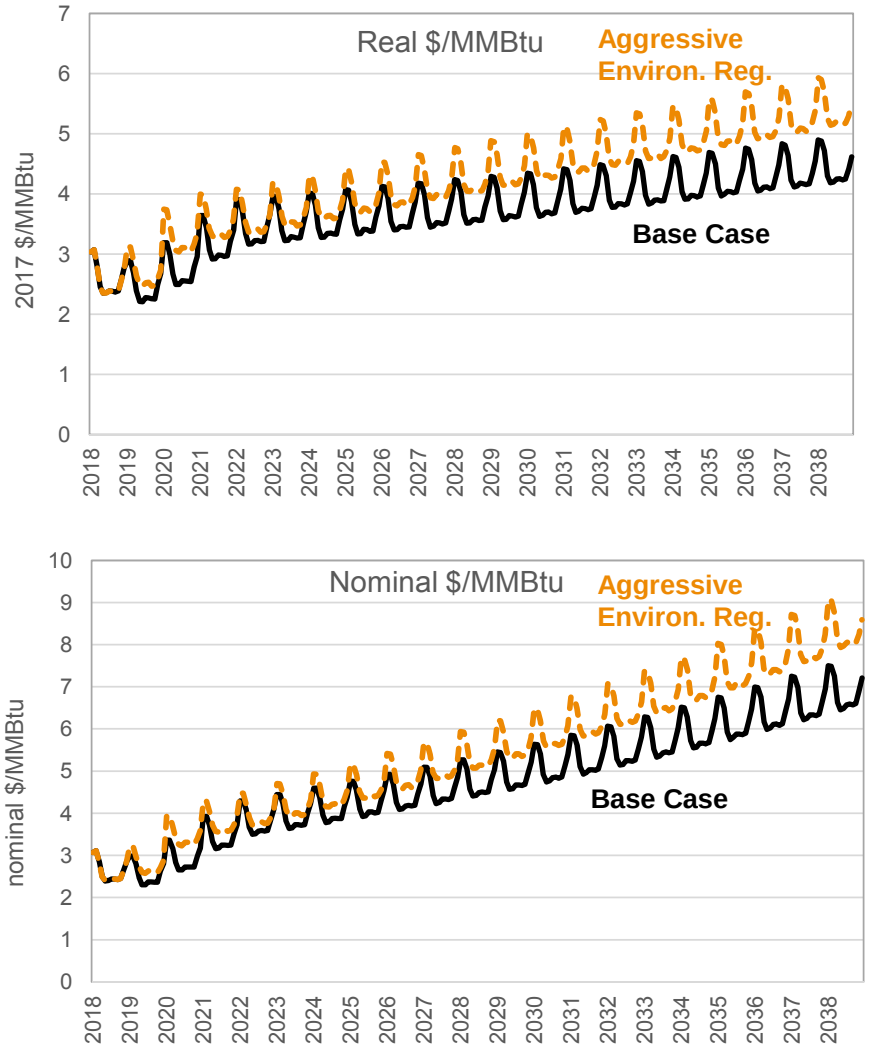
The Aggressive Environmental Regulation Scenario assumes a stricter new federal rule or legislative action on carbon dioxide emissions coming into force by the mid-2020s. Based on CRA's analysis, price levels are generally consistent with a 50-60% reduction in electric sector carbon emissions relative to 2005 by the 2030s. The scenario's timing is the same as the Base Case's, based on the fact that program implementation prior to 2026 is unlikely, given the required changes in executive administration or Congressional control, as well as the potential for legal challenges. This type of policy, however, would represent an initial pathway towards aggressive carbon reduction goals. The carbon prices over time are shown in both real and nominal dollars per ton in Figure 8-22.

Figure 8-22: Carbon Prices in Aggressive Environmental Regulation Scenario



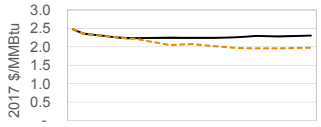
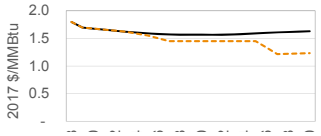
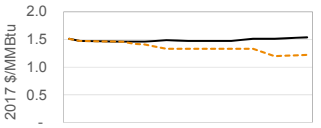
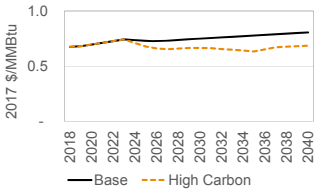
Such high carbon prices are likely to result in additional coal retirements and less coal generation in the electric power sector. Over the long-term, this is projected to result in higher demand for natural gas, even as renewable generation also expands significantly. The long-term increase in natural gas demand in the power sector is projected to be around 15%. CRA's NGF modeling projects that such an increase in gas demand will result in upward pressure on long-term gas prices on the order of about $1/MMBtu (real). The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-23.

Figure 8-23: Natural Gas Prices in Aggressive Environmental Regulation Scenario



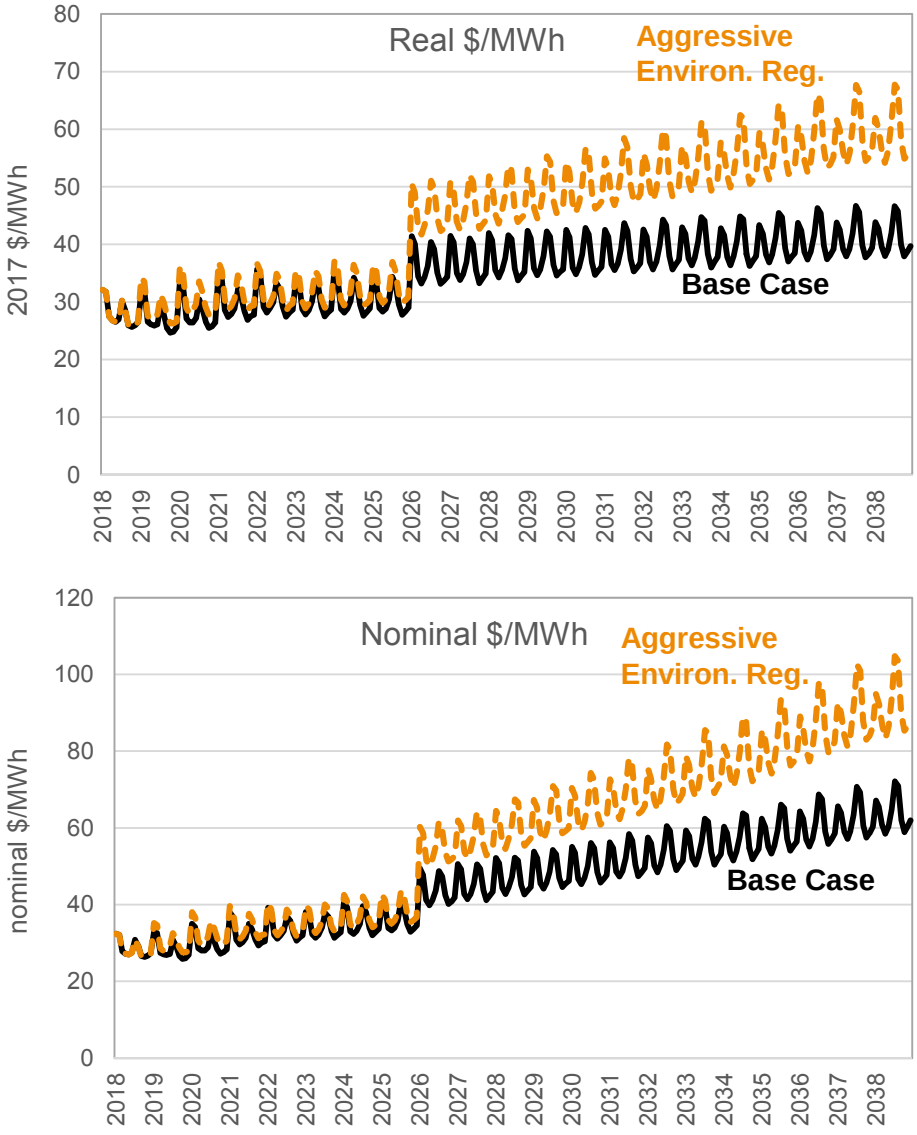
While demand for natural gas is projected to increase, demand for coal is likely to decline in the Aggressive Environmental Regulation Scenario due to reduced coal plant dispatch and additional coal retirements. In this scenario, coal demand is broadly expected to be around 10-20% lower than the Base Case in 2026 (the first year of the carbon price) and 30-50% lower over the long-term. The impacts vary based on coal production basin, but such demand declines are projected to result in price that are $0.10-$0.40/MMBtu lower than those in the Base Case. Figure 8-24 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Aggressive Environmental Regulation Scenario in real 2017 dollars.

Figure 8-24: Coal Demand and Prices in Aggressive Environmental Regulation Scenario

Coal	Base Case	High Carbon Case	
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	**-10%** in demand in 2026 with nearly **50%** reduction by 2037 keeps long-term prices declining, down $8-10/ton ($0.30/MMBtu) vs. base	
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**-10%** in demand in 2026 with nearly **50%** reduction by 2037 drives long-term prices down $10/ton ($0.40/MMBtu)	
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**-10%** in demand in 2026 and **-30 -35%** by 2037 drives prices down steadily, $3-7/ton (~$0.15-0.30/MMBtu) less than base	
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	**-20%** in demand in 2026 and **50%+** decreases thereafter drives prices down $2/ton (~$0.10/MMBtu)	

The projected changes in fuel prices and carbon prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Aggressive Environmental Regulation Scenario. Over a twenty-year period, coal generation in MISO is expected to decline by nearly 70% in this scenario, while natural gas and renewable generation are expected to make up the difference. Although renewable generation is significantly higher than in the base case, higher gas and carbon prices result in higher variable costs for the type of plant most often setting the market price in MISO. Over time, this drives average, around-the-clock ("ATC") LRZ6 power prices up by about $20/MWh (in real dollars) by the late 2030s. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-25.

Figure 8-25: LRZ6 Power Prices in Aggressive Environmental Regulation Scenario



8.3.2 Challenged Economy Scenario

Description

The Challenged Economy Scenario represents a future where economic growth is stagnant and environmental policy is focused on maintaining low energy prices through limited federal regulation of carbon emissions from the power sector. The scenario is premised on the assumption that federal regulation that would result in increased energy costs would be unlikely if economic growth is low. Thus, this scenario has no price on carbon and assumes that any future emission regulation is based on plant-specific efficiency measures or other rules without a specific cap or tax on emissions. As a result of weaker economic growth and no price on carbon, demand for

natural gas is expected to fall over time, keeping natural gas prices stable at around $3.50/MMBtu (real dollars) over time. Stronger coal demand is expected to result in modestly increasing coal prices versus the Base Case. Under these scenario assumptions, fewer coal retirements and fewer renewable additions are expected when compared to the Base Case. Natural gas resources are expected to remain marginal during most hours, and lower gas prices and no carbon price result in a relatively flat power price forecast in real terms over time. Finally, under the assumption that economic growth impacts demand for electricity, including industrial demand, the Challenged Economy Scenario includes a lower load growth outlook for NIPSCO. The key directional assumptions changes are summarized in Figure 8-26.

Figure 8-26: Summary of Challenged Economy Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Challenged Economy	**Low**	**Low**	**Low (No CO_2)**	**High (No CO_2)**	**Low (No CO_2)**

Risks Addressed

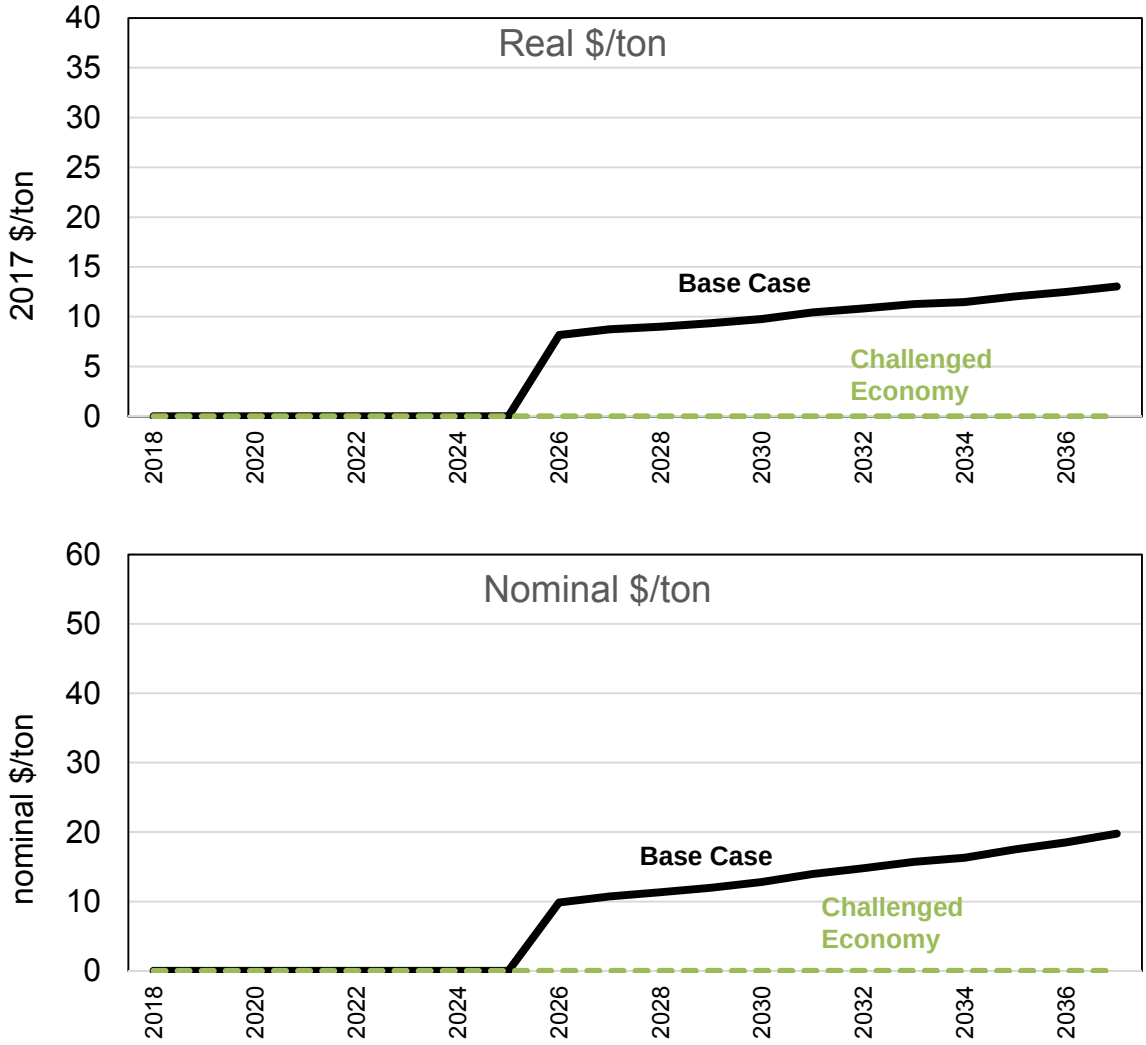
The Challenged Economy Scenario addresses the risk of an economic downturn as well as the risk of no carbon price coming into effect over the study horizon. The scenario addresses the combined risks of very low load growth, no carbon price, and low commodity prices for gas and power. Given the large amount of uncertainty related to federal action to control carbon emissions, the scenario specifically develops a future where carbon emissions are never priced, testing the robustness of portfolios against this important risk.

Detailed Scenario Assumptions

The Challenged Economy Scenario assumes no federal price on carbon, as shown in

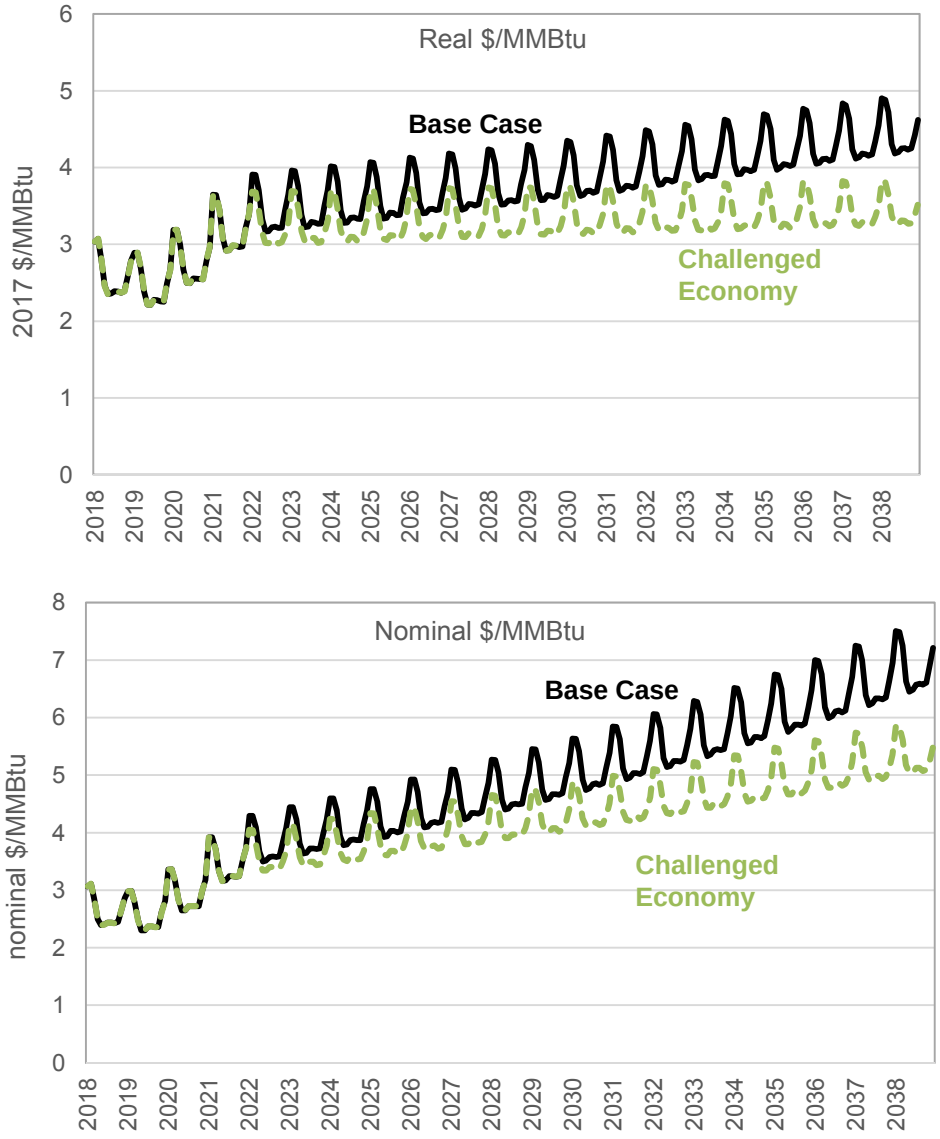
Figure 8-27 versus the Base Case. This scenario assumes that EPA regulation is broadly consistent with the recently proposed ACE rule, which focuses on heat rate efficiency improvements for existing coal plants. This proposed rule and other future regulations under this scenario would avoid specific tax-based costs or an emission cap requirement.

Figure 8-27: Carbon Prices in Challenged Economy Scenario



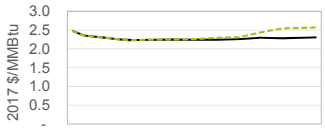
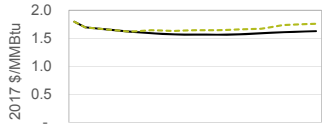
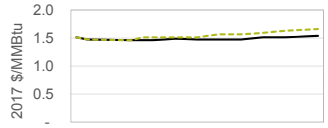
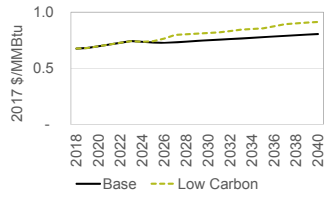
Lower carbon prices and lower overall electric demand growth are expected to reduce natural gas demand over time. CRA's modeling has found that, rather than increasing like in the Base Case, power sector natural gas demand is projected to be relatively flat over the next twenty years in the Challenged Economy Scenario. This is due to higher levels of coal generation, as well as continued renewable additions, driven by state-level policy. These expected power sector dynamics result in 15-20% lower natural gas demand than in the Base Case, flattening the natural gas price outlook at around $3.50/MMBtu (real dollars). This results in long-term prices that are about $0.90/MMBtu (real dollars) lower than those in the Base Case. The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-28.

Figure 8-28: Natural Gas Prices in Challenged Economy Scenario



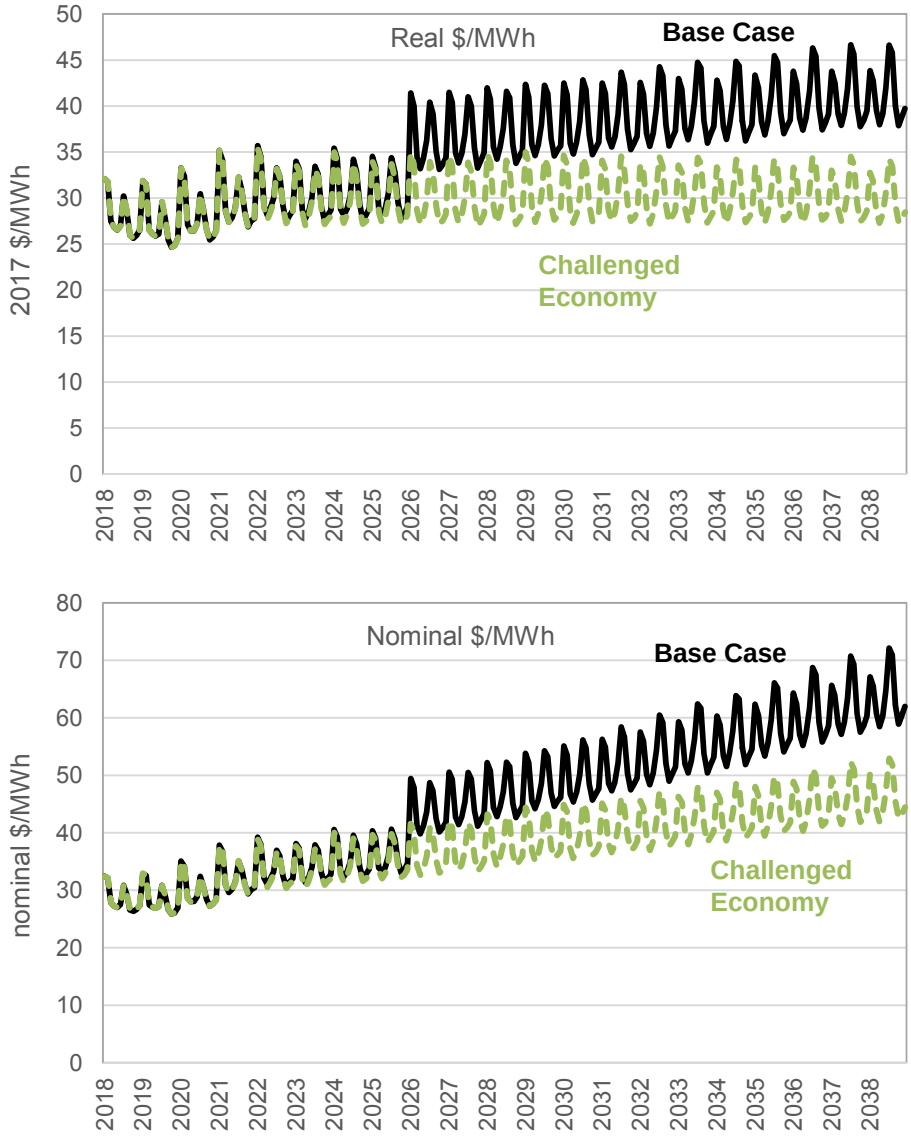
While demand for natural gas is projected to decrease, demand for coal is likely to increase in the Challenged Economy Scenario due to increased coal plant dispatch and fewer coal retirements without the influence of a carbon price. In this scenario, coal demand is broadly expected to be around 10% higher than the Base Case in 2026 (the first year of the carbon price in the Base Case) and 0%-30% higher over the long-term. The impacts vary based on coal production basin, but such demand increases are projected to result in price that are $0.10-$0.25/MMBtu higher than those in the Base Case. Figure 8-29 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Challenged Economy Scenario in real 2017 dollars.

Figure 8-29: Coal Demand and Prices in Challenged Economy Scenario

Coal	Base Case	Low Carbon Case	
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	Initial **+10-20%** impact in demand, but long-term demand similar to base case; prices initially stable, but increase ~$5/ton ($0.25/MMBtu) due to reserve depletion	
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**+10%** in demand in 2026 and **+20%** by 2037 drives prices up $2-3/ton (~$0.10/MMBtu)	
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**+6%** in demand in 2026 and **+20%** by 2037 drives prices up $2-3/ton(~$0.10/MMBtu)	
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	**+13%** in demand in 2026 and **+33%** by 2037 drives prices up $2/ton (~$0.10/MMBtu)	

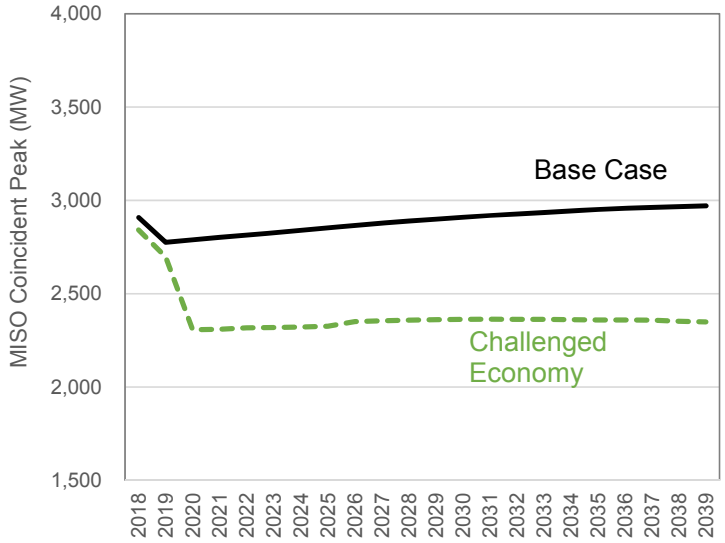
The projected changes in fuel prices and carbon prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Challenged Economy Scenario. In this scenario, coal generation is expected to stabilize after 2026, especially as coal retirements are reduced and as variable costs of operation for coal-fired plants are lower without the presence of a carbon price. The lack of a carbon price and the flatter natural gas price forecast drive power prices down, such that average, ATC prices remain around $30/MWh (in real dollars) over the long-term. This is represents a decrease of about $10-15/MWh (real dollars) versus the Base Case. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-30.

Figure 8-30: LRZ6 Power Prices in Challenged Economy Scenario



As part of the Challenged Economy Scenario, NIPSCO developed a lower load forecast that included the loss of significant industrial demand and lower load growth that is associated with lower regional economic growth. The load forecast chapter includes additional information on the detailed assumptions and methodology, while Figure 8-31 summarizes the peak load forecasts for the Base Case and the Challenged Economy Scenario. The compound annual growth rate for the high load trajectory is -0.9% versus 0.10% in the Base Case, primarily due to the significant loss of load assumed by 2020. Note that these forecasts are shown for MISO coincident peak and not NIPSCO's internal peak.

Figure 8-31: NIPSCO Peak Load Growth Forecast in Challenged Economy Scenario



8.3.3 Booming Economy/ Abundant Natural Gas Scenario

Description

The Booming Economy & Abundant Natural Gas Scenario represents a future where natural gas production costs remain low and the resource base remains highly productive, keeping natural gas prices low and flat in real terms over the next decade. Low natural gas costs are a contributing factor to higher economic growth, as low energy prices contribute to higher levels of industrial and commercial economic activity. As a result of the flat forecast for natural gas prices, coal demand is projected to erode, which leads to lower coal prices over time. Power prices remain correlated to natural gas and carbon prices and remain relatively flatter for longer in real terms in this scenario when compared to the Base Case. A spike in power prices is still projected to occur in 2026 with the introduction of a carbon price, which is the same as in the Base Case. Fewer renewables and significantly more coal retirements are projected in the MISO supply mix as a result of very cheap gas over the next ten years. Finally, under the assumption that economic growth remains robust, the Booming Economy/ Abundant Natural Gas Scenario includes a higher load growth outlook for NIPSCO. The key directional assumptions changes are summarized in Figure 8-32.

Figure 8-32: Summary of Booming Economy/ Abundant Nat. Gas Scenario

Scenario Theme	NIPSCO Load	CO_2 Price	Natural Gas Price	Coal Price	Power Price
Booming Economy & Abundant Natural Gas	**High**	Base	**Low**	**Low (Low Gas)**	**Low (Low Gas)**

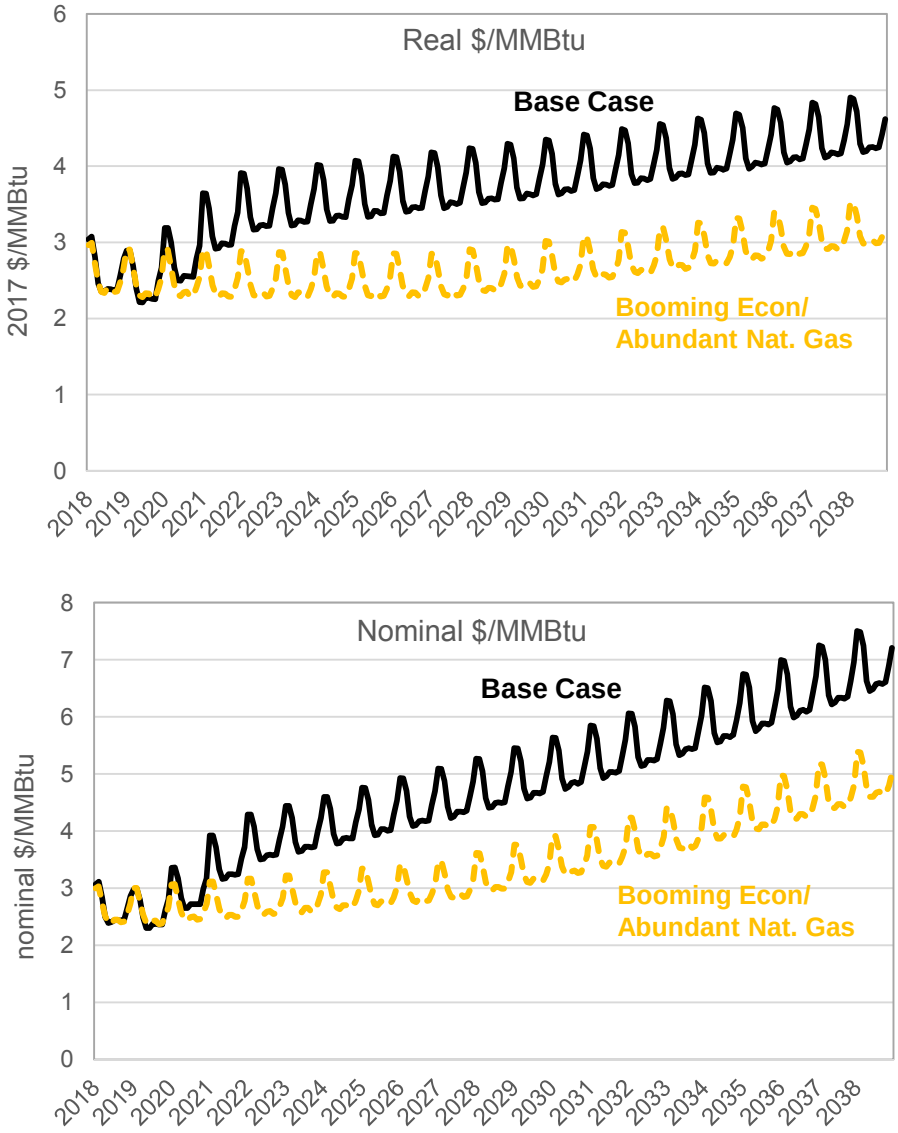
Risks Addressed

The Booming Economy/ Abundant Natural Gas Scenario addresses the risk of higher load growth for NIPSCO versus the Base Case. Higher load growth could result in higher exposure to the MISO market for NIPSCO depending on its portfolio selection. In addition, this scenario addresses the risk of persistently low natural gas prices, which would generally have the impact of favoring the economics of natural gas capacity and harming the economics of coal-fired and renewable generation. Assumptions regarding carbon prices remain unchanged from the Base Scenario.

Detailed Scenario Assumptions

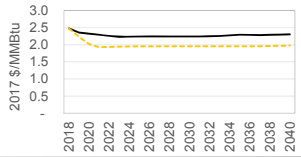
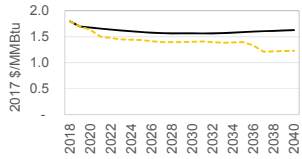
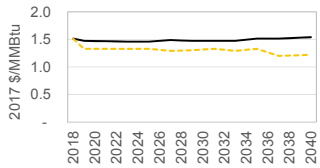
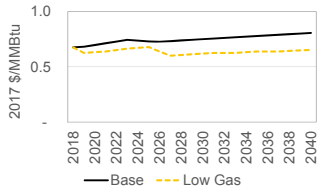
The Booming Economy/ Abundant Natural Gas Scenario assumes that natural gas prices stay relatively low for a longer period of time, primarily as a result of lower production costs. This could be the result of continued expansion of the resource base, producers continuing to effectively hold operations costs down, and producers focusing on the most productive plays for a longer period of time. In order to develop natural gas price projections for this scenario, CRA adopted the long-term forward strip for natural gas for a ten-year period. As of the time of the development of the 2018 IRP assumptions, natural gas forwards at Henry Hub were relatively flat in real dollars at around $2.60/MMBtu for the next ten years. In 2028 and beyond, CRA's fundamental modeling suggested that modest increases in real prices to above $3/MMBtu by the late 2030s were likely in this case. The natural gas prices over time are shown in both real and nominal dollars per MMBtu in Figure 8-32.

Figure 8-33: Natural Gas Prices in Booming Economy/ Abundant Nat. Gas Scenario



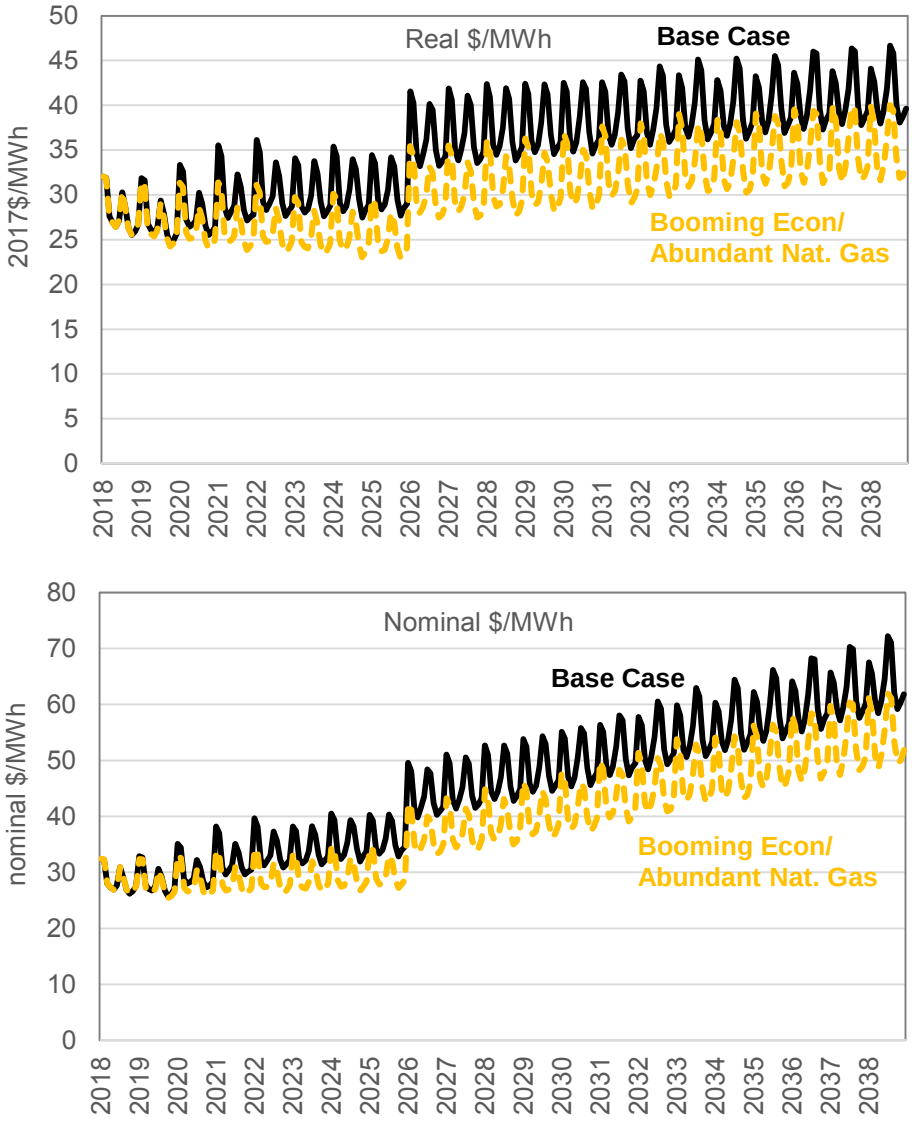
With significantly lower natural gas prices in the Booming Economy/ Abundant Natural Gas Scenario, coal demand is expected to decrease significantly as the variable costs of coal generators remain higher than those of gas plants. In this scenario, coal demand is expected to be significantly lower than the Base Case, with 30-50% lower coal demand expected across most basins, especially with the implementation of a carbon price in 2026. The impacts vary based on coal production basin, but such demand declines are projected to result in price that are $0.15-$0.40/MMBtu lower than those in the Base Case. All coal price forecasts in this scenario are flat or declining in real dollars versus currently market prices. Figure 8-34 presents a summary of the projected impacts for each coal basin as well as the projected prices for the Booming Economy/ Abundant Natural Gas Scenario in real 2017 dollars.

Figure 8-34: Coal Demand and Prices in Booming Economy/ Abundant Nat. Gas Scenario

Coal	Base Case	Low Gas Case	
CAPP	• Lower demand is expected to drive a price decline (in real dollars per ton), but reserve depletion expected to drive modest long-term increases	**-30%** in demand by early to mid-2030s, with flat demand thereafter; long-term prices down $8-10/ton ($0.30/MMBtu) vs. base	
NAPP	• NAPP prices trend with CAPP, but reflect the lower production costs in Northern Appalachia, which allows highly efficient mining of large-block coal reserves	**-30%** in demand by mid-2020s, with nearly **50%** reduction by 2037 drives long-term prices down $10/ton ($0.40/MMBtu)	
ILB	• Abundant reserves of ILB coal and low production cost (longwall mines) mitigate depletion effects in the Illinois Basin, leading to relatively flat real prices, with modest long-term growth	**-10%** in demand in early 2020s and **-30-35%** by 2037 drives prices down steadily, $3-7/ton (~$0.15-0.30/MMBtu) less than base	
PRB	• PRB prices increase modestly (in real dollars per ton) as a result of higher production costs due to downward-sloping coal seams/reserve depletion.	Immediate demand erosion, growing to **50% decline** in demand in 2026 and more thereafter; drives prices down $3/ton (~$0.15/MMBtu)	

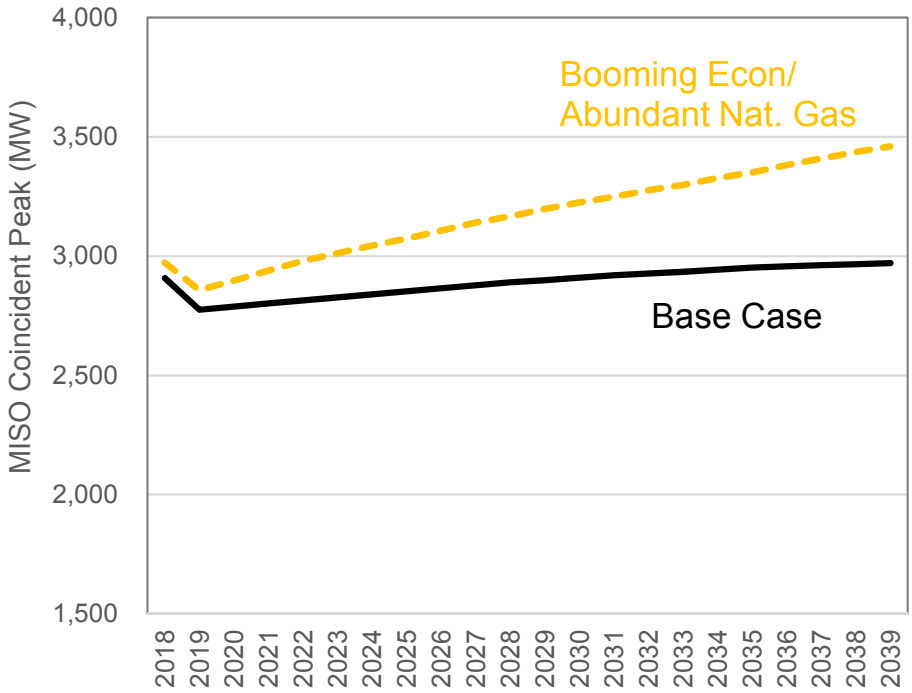
The projected changes in fuel prices, along with expected impacts on capacity additions and retirements in the MISO market, lead to different power price outcomes in the Booming Economy/ Abundant Natural Gas Scenario. Similar to the Aggressive Environmental Regulation Scenario, coal generation in MISO is expected to decline by nearly 70% in this scenario over a twenty-year period. The decline in coal generation, however, is more significant in the early years in the Booming Economy/ Abundant Natural Gas Scenario. With gas generation being marginal during more hours with lower gas prices and more coal retirements, the low gas price projections result in power prices remaining very flat in real dollars and below $30/MWh on average through 2025. Although a carbon price is still incorporated in 2026, lower gas prices drive MISO power prices about $5-6/MWh lower than prices in the Base Case after 2030. The ATC LRZ6 power price projections over time are shown in both real and nominal dollars per MWh in Figure 8-35.

Figure 8-35: LRZ6 Power Prices in Booming Econ/ Abundant Nat. Gas Scenario



As part of the Booming Economy/ Abundant Natural Gas Scenario, NIPSCO developed a higher load forecast that is associated higher lower regional economic growth. The load forecast chapter includes additional information on the detailed assumptions and methodology, while Figure 8-36 summarizes the peak load forecasts for the Base Case and the Booming Economy/ Abundant Nat. Gas Scenario. The compound annual growth rate for the high load trajectory is 0.73% versus 0.10% in the Base Case. Note that these forecasts are shown for MISO coincident peak and not NIPSCO's internal peak.

Figure 8-36: NIPSCO Peak Load Growth Forecast in Booming Economy/ Abundant Nat. Gas Scenario



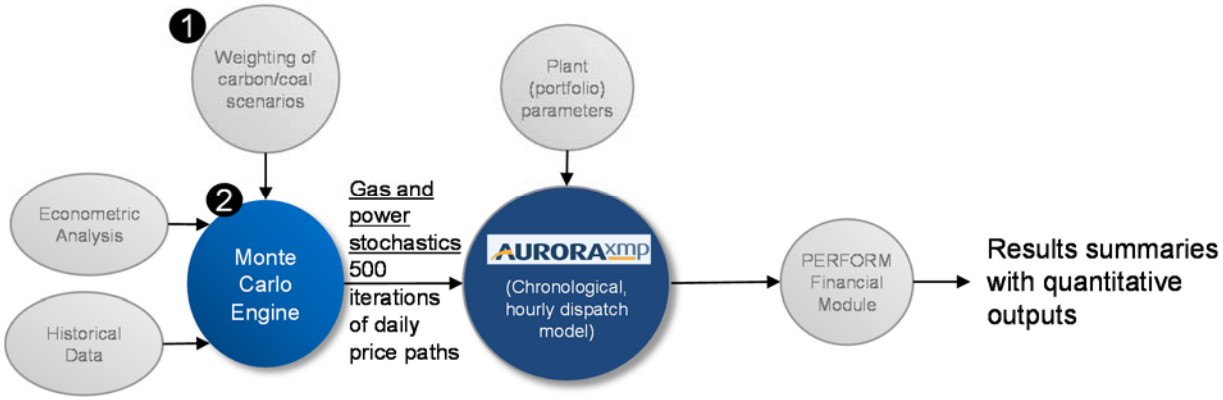
8.4 IRP Stochastics Development

The development of stochastic inputs was a separate, but complementary part of NIPSCO's assessment of risk and uncertainty. As discussed above, NIPSCO determined that stochastic analyses would be performed for key commodity prices with sufficient price history, with the full stochastic distribution of outcomes also including probability weightings for other relevant drivers like carbon prices. Overall, scenario development supported the stochastic parameter definition, with granular distributions of major commodity price inputs developed with CRA's Monte Carlo engine. The major elements of the stochastic input distribution development process included:

1. Establishment of probability weightings for major discrete variables like carbon prices and coal prices, based on the scenario assumptions.
2. Deployment of CRA's Monte Carlo engine to produce daily and hourly price paths for natural gas and power prices for each weighted scenario, based on historical data analysis, which incorporated:
    - Daily price spikes for gas; and
    - Power price volatility on a daily and hourly level, implicitly based on historical data observations that include market load shocks, fuel price changes, and plant outages.

Figure 8-37 summarizes the stochastic input development process and how the stochastic inputs were deployed in the IRP models to assess risk and uncertainty for potential portfolio options. As is shown, CRA's Monte Carlo engine relies on econometric analysis of historical price data, as well as weightings for major discrete variables based on the scenario development process. The Monte Carlo engine itself develops 500 iterations of daily and hourly price paths for gas and power prices which are fed into the Aurora model. The Aurora model is then run 500 times, incorporating each set of price paths, along with other market assumptions and portfolio parameters for NIPSCO. The 500 runs are then each analyzed within CRA's PERFORM financial model to estimate revenue requirements and total portfolio costs.

Figure 8-37: Overview of Stochastic Input Development Process



Stochastic Input Development Methodology

The development of stochastic inputs within the Monte Carlo engine incorporated several steps, which are described in more detail below:

- Step 1: Historical Data Analysis – CRA first analyzed historical commodity prices at the liquid commodity price points most relevant to NIPSCO, which included Chicago Citygate for natural gas prices and the Indiana Hub, representative of LRZ6, for power prices. The historical data analysis was performed to find a stochastic (or econometric) model that best captured the observed behavior of prices in the modeled regions. Key statistical parameters were developed from the data analysis in order to define the stochastic price processes. These included:
    - volatility levels (a measure of the price randomness);
    - mean-reversion rate (a measure of the convergence to long-term price trends and forecasts); and
    - the correlation between power and natural gas prices in the regions.
- Step 2: Parameter Estimation – Based on this analysis, CRA then fit the historical data to an econometric model by running regressions and estimating stochastic process parameters.
- Step 3: Monte Carlo Simulations – Based on the parameter estimation, CRA then deployed its Monte Carlo engine to simulate future spot prices for both natural gas and

power. The simulation included the development of 10,000 price paths for each commodity, using antithetic draw techniques to ensure fast convergence and a balanced and risk-adjusted coverage of the full spectra of positive and negative price jumps in the simulated price time series.

- Step 4: Final Probability Distributions for Each Scenario – Given the range of scenario-based inputs for key discrete variables (such as carbon prices), CRA performed the Monte Carlo simulations across multiple fundamental market scenarios and probability-weighted them to develop the full set of stochastics that preserve internal consistency with the fundamentals-based carbon and coal price inputs. In order to develop a set of inputs that could feasibly be run through the Aurora and PERFORM IRP models, 500 draws were sampled for the full portfolio dispatch analysis.

Stochastic Input Distributions

The stochastic input development process results in 500 daily or hourly price paths for the major commodities, which can be summarized with distribution plots showing monthly confidence intervals over time. Probability distribution plots for the twenty-year forecast period for natural gas prices, including historical price data, and power prices are shown in Figure 8-38 and Figure 8-39, respectively. These graphics show, on a monthly level, the broad range of the individual price paths (in gray) along with representations of the monthly confidence intervals at the 5th, 25th, 50th, 75th, and 95th percentiles.

The confidence intervals do not represent specific price trajectories, but instead indicate the probability of the price being at or below the specified level at any given point in time. For example, the top orange line in Figure 8-38 represents the monthly 95th percentile for natural gas prices, which means that 95 percent of the data set is below this price at any given point in time. In other words, five percent of the price observations in any given month across the full distribution would be expected to be above this value. These observations can come from different price paths over time, since each path is likely to be relatively volatile, moving up and down. In fact, it is highly unlikely that a single path would be at the 95th percentile for a sustained period of time. Overall, the stochastic inputs allow for evaluation of portfolio performance against extreme price outcomes on the high side and on the downside, including at the daily and hourly price levels, which are not shown in these graphics.

Figure 8-38: Stochastic Distribution for Natural Gas Prices

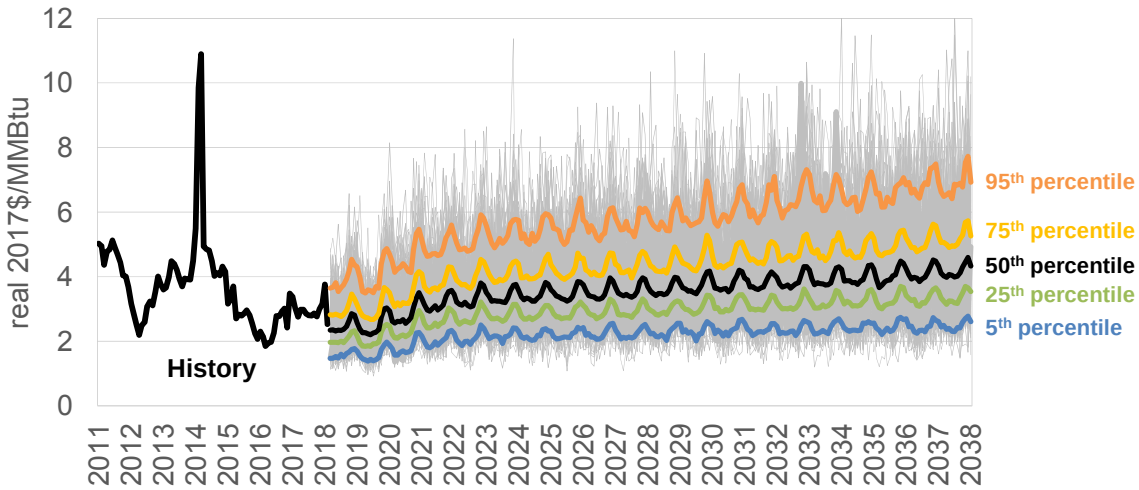
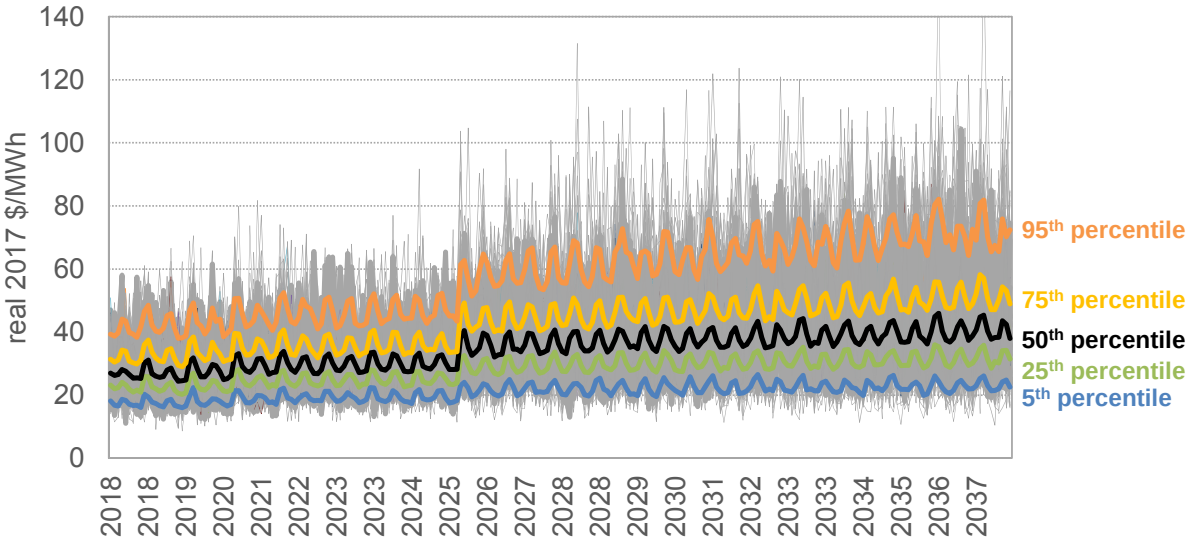


Figure 8-39: Stochastic Distribution for Power Prices



Section 9. Portfolio Analysis

9.1 Retirement Analysis

9.1.1 Process Overview

As in the 2016 IRP, NIPSCO performed a retirement analysis in its 2018 IRP to evaluate the preferred coal retirement strategy over time. Given the number of permutations around the magnitude and timing of potential retirements, NIPSCO determined that it was most efficient and effective to evaluate retirement decisions on a stand-alone basis, while performing an additional replacement analysis to assess a number of replacement resource strategies. Although performed in two steps, the retirement and replacement analyses are both based on the same major inputs and assumptions, which are described in earlier parts of Section 8 and below.

NIPSCO believes that performing a retirement analysis requires careful planning and consideration of several factors in addition to the cost of generation. To that end, NIPSCO has used an integrated scorecard methodology to evaluate retirement portfolios. In addition to the net present value of revenue requirements in the Base Case, NIPSCO has also considered cost certainty and cost risk metrics based on a full stochastic analysis, the ability to confidently transition resources and maintain system and customer reliability, and the effect of unit retirements on NIPSCO's employees, the local economies of the communities it serves, and the environment.

9.1.2 Retirement Analysis Methodology and Results

The retirement analysis has been conducted according to the following steps:

- Identify plausible retirement plans and specify individual retirement combinations or "portfolios"
- Identify the least-cost replacement capacity to fill the resulting capacity gap for each retirement portfolio based on the results from the All-Source RFP conducted by NIPSCO (*See* Section 4.9.2 for additional information on the details of the All-Source RFP.).
- Evaluate each retirement portfolio, including its associated least-cost capacity replacement, in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed earlier in this section). The evaluation includes a full accounting of the ongoing operations of each existing plant (including any additional environmental compliance requirements) and the costs of alternatives.
- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred retirement portfolio.

9.1.3 Identification of Retirement Portfolios

All five of NIPSCO's coal-fired units were evaluated for retirement. This includes Michigan City Unit 12 and Schahfer Units 14, 15, 17 and 18. The operational dependency as well as technology and vintage similarity of the Units at Schahfer would make Unit-level retirement impractical. As a result, the analysis created Unit pairs (14&15, and 17&18) that would be jointly considered for retention or retirement. NIPSCO identified eight retirement portfolios for analysis based on different combinations of unit retirements at different points in time. The plans range from one that keeps all existing coal units in service through end-of-life to one that retires all coal in 2023. In between, the portfolios evaluate different levels of retirement at different dates over time. Figure 9-1 provides a summary of the eight portfolios, including the timing of the various retirement permutations and the assumed environmental compliance investments.

Figure 9-1: Overview of Retirement Combination Portfolios

	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City in 2035)	**15% Coal in 2023** (Mich. City in 2028)	**15% Coal by 2023** (Schfr. 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR* ELG**: non-ZLD***	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Michigan City 12	**Retain** CCR ELG: N/A	→	→	→	→	**Retire 2028** CCR ELG: N/A	→	**Retire 2023** CCR ELG: N/A
Schahfer 14	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 15	**Retain** CCR ELG: non-ZLD	→	**Retire 2028** CCR ELG: non-ZLD	**Retire 2028** CCR ELG: Extended Retirement	**Retire 2023** CCR ELG: Retirement	→	→	**Retire 2023** CCR ELG: Retirement
Schahfer 17	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement
Schahfer 18	**Retain** CCR ELG: non-ZLD NOx: SCR	**Retire 2023** CCR/ELG: Retirement	→	→	→	→	**Retire 2021** CCR/ELG: Retirement	**Retire 2023** CCR/ELG: Retirement

Currently NOT a viable path for ELG compliance

Note: Retirement Combination 4, 15% Coal in 2028 without ELG, is not currently a viable from an ELG compliance standpoint and is shown for discussion purposes..

*CCR: Coal Combustion Residuals
**ELG: Effluent Limitation Guidelines
***ZLD: Zero-Liquid discharge

9.1.4 Identification of Least-Cost Replacement Capacity

While NIPSCO's 2016 IRP relied on market price benchmarks for replacement capacity and energy, the All-Source RFP conducted in 2018 provided insight into the supply and pricing of alternatives available to NIPSCO. Thus, for the 2018 IRP, data from this process was used to develop detailed cost and operational estimates for the least-cost replacement capacity that was available for each of the eight retirement portfolios.

As discussed further in Section 4, representative replacement resource tranches were constructed from the All-Source RFP results based on technology, ownership structure, cost, and other operational characteristics. Then, all of the resource tranches, along with the bundles developed in the DSM assessment (*See* Section 5.), were available to the portfolio optimization model in Aurora. A portfolio optimization was then performed under each of the eight retirement portfolios to identify a least-cost set of replacement resources for each. The portfolio optimization modeling was performed to minimize the net present value of revenue requirements, with certain constraints for minimum and maximum reserve margins and maximum off-system energy sales.

Overall, the economic optimization model selected a combination of DSM and renewable resources across all retirement portfolios. Along with a small amount of flexible MISO capacity market purchases, the optimization model selected 125 MW of total DSM by 2023, approximately 150 MW of wind (UCAP), and a combination of solar and solar plus storage resources, depending on the capacity gap that was required to be filled. Figure 9-2 provides a summary of the type of capacity that was selected under the various retirement portfolios. Note that this does not represent NIPSCO's preferred replacement strategy, but only a least-cost optimization that is used to evaluate retirement implications.

Figure 9-2: Summary of Least-Cost Replacement Capacity by Retirement Portfolio

Higher

COST-EFFECTIVENESS

Lower

2 3 4 Schahfer 17/18 Retirement ~600MW UCAP need		5 6 7 Schahfer 14/15/17/18 Retirement ~1,350MW UCAP need		8 All Coal Retirement ~1,750MW UCAP Need	
TECHNOLOGY	MW	TECHNOLOGY	MW	TECHNOLOGY	MW
MISO Market Purchase	50	MISO Market Purchase	50	MISO Market Purchase	50
DSM	125	DSM	125	DSM	125
Wind	150	Wind	150	Wind	150
Solar, Solar + Storage	390	Solar, Solar + Storage	1,070	Solar, Solar + Storage	1,500
	715		1,395		1,825

9.1.5 Evaluation of Each Retirement Portfolio - Assumptions

Analyses were performed for each of NIPSCO's coal-fired units that evaluated the ongoing operations versus retirement and replacement of the units with an alternative under various potential future states of the world. NIPSCO used a number of factors in analyzing the retirement timing of the coal units including economics, cost risk, reliability risk and impacts to NIPSCO's employees, and the local economy. The evaluation of each retirement portfolio was performed through a full portfolio analysis that included dispatch in Aurora and financial accounting in PERFORM. Market assumptions were consistent with those outlined earlier in Section 8 for the Base Case, the three deterministic scenarios, and the full range of stochastic inputs. In addition to the major market inputs and the costs of replacement resources from the All-Source RFP results, several relevant assumptions were made regarding the ongoing costs of the existing coal fleet.

Ongoing costs include fuel, fixed O&M costs, maintenance capital, costs associated with future environmental controls, as well as the recovery of remaining book value associated with each plant as of December, 2017. This recovery includes return of (depreciation), return on, and income and property taxes associated with the remaining net book value of NIPSCO's existing fleet.

Fixed O&M costs included all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. For all units, nine-year projections of incremental O&M budgets were obtained. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix D.

Maintenance capital costs included the projected capital expenditures necessary to keep the units running through the analysis period at the projected level of operations.
For all units, nine-year projections of incremental O&M budgets were obtained. The average of these budgets was then escalated at 2% per year for the remaining years. Additional detail is provided in Confidential Appendix D. As coal units' projected retirement dates move up, the relative capital spend decreases during the years leading up to retirement. This is different than expected fixed O&M costs leading up to a retirement, which stay relatively constant over time, regardless of retirement expectation.

Capital for environmental controls and the associated O&M expenditures that are projected to be required for future environmental compliance are additive to the ongoing capital and O&M expenditures. These incremental capital estimates were provided by NIPSCO's Major Projects department based on outside engineering studies. The most recently available capital estimates, escalated by 2% for inflation, were used in the analyses as specified in the unit retirement studies. For each of the units analyzed, environmental control requirements and dates included in the analyses were based on the expected compliance requirements of final, proposed, and/or expected environmental rules and regulations.

A unique environmental capital and O&M spending schedule was developed for each retirement portfolio, with compliance retrofits required for the coal combustion residuals (CCR) and ELG rules. In Retirement Portfolio 1, NIPSCO also assumed that Schahfer Units 17 and 18 would require additional environmental upgrades associated with a selective catalytic reduction system, a de-watering system, and stack lining. NIPSCO also developed a hypothetical portfolio (Retirement Portfolio 4) that retains Schahfer 14 and 15 through 2028 with no ELG compliance spending, though this is not currently a viable ELG compliance pathway.

NIPSCO also included estimated costs to mitigate transmission related issues that would arise as a result of the various retirement combinations at Schahfer. An additional $79.8 million of capital expenditures was incorporated for transmission upgrades at the time of the Schahfer 17 and 18 retirement in any retirement portfolio. When all of Schahfer is retired, a total of $147 million in additional capital expenditures related to transmission upgrades has been incorporated. These estimates developed by NIPSCO transmission planning group are based on NERC transmission planning standards and incorporate the impact of the MISO retirement study process (Attachment Y)

Recovery of remaining depreciation expenses by 2030 has also been incorporated in the retirement analysis. NIPSCO has prudently ensured that each of its facilities has been ready and available to meet customer needs over the past several decades through appropriate capital investment and O&M expenditures. Upon retirement, due to this continued capital investment, there will be a remaining net book value associated with the generation assets. The retirement analysis assumes that when a unit is retired prior to end of life, it still recovers the return on and return of its net book value.

NIPSCO assumes that each unit continues to depreciate at the same blended rate of 4.60%, regardless of whether the unit has been retired or not. The unit continues to depreciate until its book value is equal to the negative "cost of removal" for each asset. The cost of removal was estimated by John J. Spanos, an expert witness supporting NIPSCO electric depreciation studies. In addition to the "return of" (depreciation) the existing net book value, NIPSCO continues to earn a "return on" the net book value equal to NIPSCO's assumed weighted average cost of capital, or "WACC.". Additionally, NIPSCO assumes that property and income tax will *not* be collected on the remaining net book value of the plant if it is retired.

9.1.6 Evaluation of Each Retirement Portfolio – Scorecard Metrics

NIPSCO developed a set of decision criteria objectives and metrics against which to evaluate the full set of retirement portfolios. The analysis was then conducted to quantify the performance of each portfolio against each scorecard metric. The following section describes each of the key objectives and metrics in more detail:

- Cost to Customer is measured by the overall net present value of revenue requirements ("NPVRR").

- Cost Certainty measures the certainty that the net present value of revenue requirements falls within the most likely range of the distribution of outcomes. It is quantified by the 75th percentile of cost to customer in the stochastic analysis.

- Cost Risk measures the risk of unacceptable, high-cost outcomes and is quantified by the by 95th percentile of cost to customer in the stochastic analysis.

- Reliability Risk assess NIPSCO's ability to confidently transition its portfolio of resources and maintain customer and system reliability. Reliability Risk considers the activities, timelines and risks of the MISO retirement process, transmission system and reliability upgrades, remaining unit dependencies, outstanding fuel and other contracts, future resource procurement, and the percent of NIPSCO's supply resources turning over at once. Reliability risk is a qualitative assessment made by NIPSCO of how orderly the transition would be from its current portfolio. It considers NIPSCO's ability to analyze, plan for and execute any transmission system upgrades and/or other equipment needed to ensure that customers' needs for reliability met.

- Other factors, such as the loss of work for employees, and the reduction of property tax base for surrounding communities also factored into NIPSCO's decision

making process. While these do not directly impact power supply costs to customers, they are factors that should be included in the analyses. The employee metric is represented by the net impact on NiSource jobs at existing facilities, and the local economy metric is represented by the expected impact on local property taxes as compared to NIPSCO's 2016 IRP.

A summary of the decision criteria metrics is provided in Figure 9-3.

Figure 9-3: Scorecard Metrics for Retirement Analysis

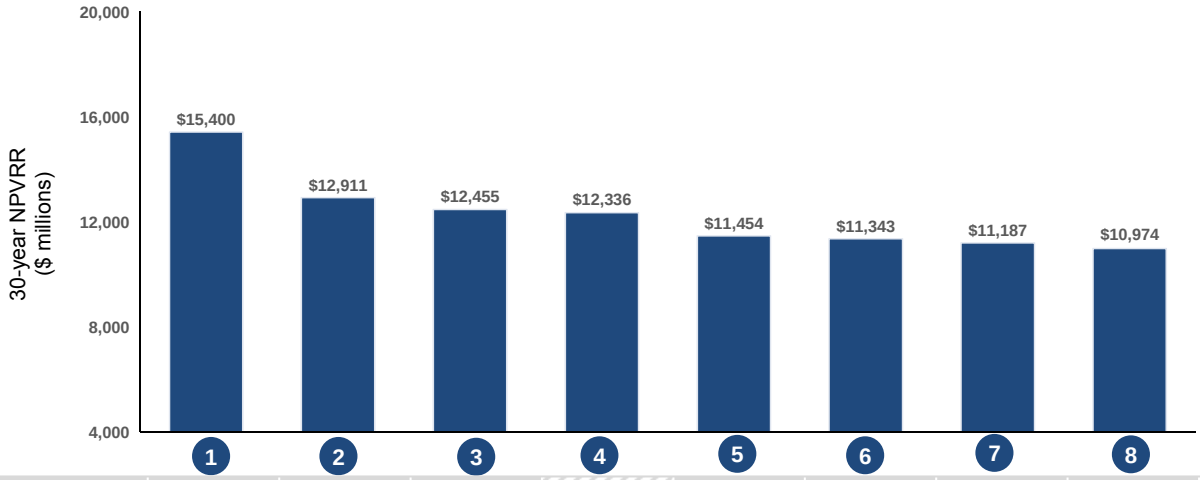
2018 Retirement Scorecard	
Criteria	**Description**
Cost to Customer	• Impact to customer bills • Metric: 30-year net present value ("NPV") of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Reliability Risk	• Assess the ability to confidently transition the resources and maintain customer and system reliability • Metric: Qualitative assessment of orderly transition
Employees	• Net impact on NiSource jobs by 2023 • Metric: Approximate number of permanent NiSource jobs affected
Local Economy	• Property tax amount relative to NIPSCO's 2016 IRP • Metric: Difference in NPV of estimated modeled property taxes on existing assets relative to the 2016 IRP

9.1.7 Evaluation of Each Retirement Portfolio – Results

Base Case Cost Results

The eight retirement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail.) to estimate revenue requirements for each over time. The assessment was first performed across the Base Case set of market assumptions and inputs in order to calculate baseline projections of the NPVRR over the thirty-year planning horizon. Under the Base Case market conditions, Retirement Portfolio 8 (retiring all coal in 2023) was the least cost option, with a thirty-year NPVRR of just over $11 billion, while Retirement Portfolio 1 (keeping all existing coal units until 2035) had the highest costs, with an NPVRR of nearly $15.4 billion. Generally speaking, retiring more coal earlier resulted in a lower NPVRR. Figure 9-4 summarizes the cost results for each retirement portfolio under the Base Case, along with a summary of the cost premium for each option relative to Portfolio 8, which is least cost.

Figure 9-4: Cost to Customer Impacts – Retirement Portfolios



Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035) Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Least Cost:	$4,426M 40%	$1,937M 18%	$1,481M 13%	$1,361M 12%	$479M 4%	$369M 3%	$213M 2%	$0M

Scenario Cost Results

In addition to the analysis under Base Case conditions, NIPSCO also evaluated each retirement portfolio against each scenario described earlier in Section 8. The NPVRR for each retirement portfolio across each scenario is summarized in 9-5, with additional details regarding the scenario results described below.

Figure 9-5: Cost to Customer across All Scenarios – Retirement Portfolios (30-year NPVRR – millions of $)

Retirement Portfolio	Base	Aggressive Env Reg	Challenged Econ	Booming Econ/ Abund Nat Gas
1	15,400	17,557	11,598	15,030
2	12,911	14,271	9,642	12,758
3	12,455	13,304	9,479	12,291
4	12,336	13,184	9,359	12,171
5	11,454	12,298	8,474	11,245
6	11,343	12,084	8,428	11,125
7	11,187	11,820	8,351	11,023
8	10,974	11,688	8,079	10,745

Under the Aggressive Environmental Regulation scenario, higher carbon prices drive higher portfolio costs, especially for those retirement portfolios that retain more coal capacity. The NPVRR of Retirement Portfolio 1 increases to about $17.5 billion, and the difference in cost between retaining all coal and retiring all coal in 2023 grows to about $6 billion. In addition, the

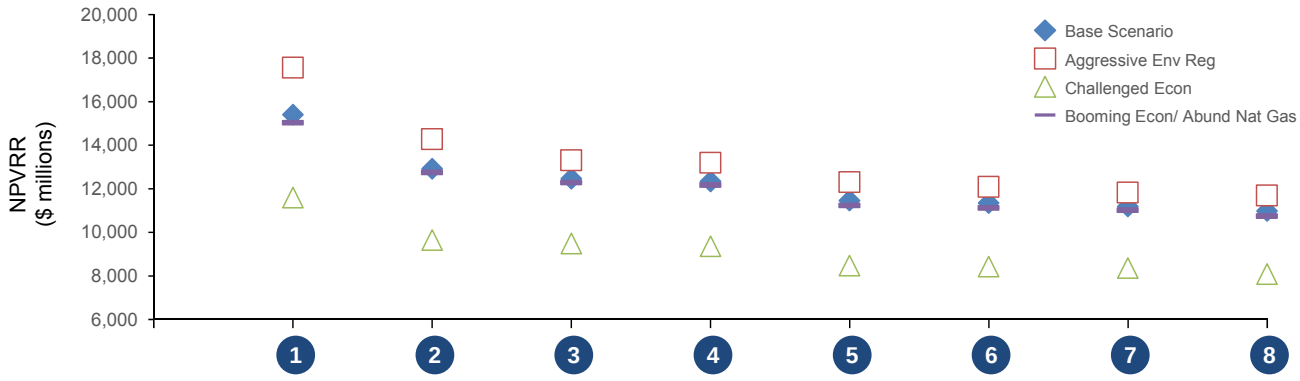
costs associated with keeping Schahfer Units 14/15 beyond 2023 (Retirement Portfolio 2) rise considerably relative to the other options.

Under the Challenged Economy scenario, all portfolio costs decline due to no carbon price and lower gas and power prices. Larger NPVRR declines are observed for the portfolios that retain more coal, but the overall costs are still lowest for Retirement Portfolio 8 (retiring all coal in 2023). While the savings associated with retiring coal are lower than those in the Base Case, the difference in cost between retaining all coal and retiring all coal in 2023 is still around $3.4 billion.

Under the Booming Economy & Abundant Natural Gas scenario, cost savings associated with coal retirements are similar to those under Base Case conditions, as low natural gas prices impact the coal units and the replacement renewable options similarly. The difference in cost between retaining all coal (Retirement Portfolio 1) and retiring all coal in 2023 (Retirement Portfolio 8) is about $4.2 billion, which is similar to the difference in the Base Case.

Overall, while coal retirement economics are relatively sensitive to carbon prices, the performance of the different retirement portfolios is less impacted by changes in natural gas prices, since the lowest-cost replacement option primarily comprises renewable resources. Thus, the relative savings associated with retiring coal grow under high carbon price conditions and fall when there is no price on carbon. However, under all market scenarios that were evaluated, there is significant savings associated with retiring more coal capacity. These results are summarized for each portfolio and each scenario in Figure 9-6.

Figure 9-6: NPVRR Summary across All Scenarios – Retirement Portfolios



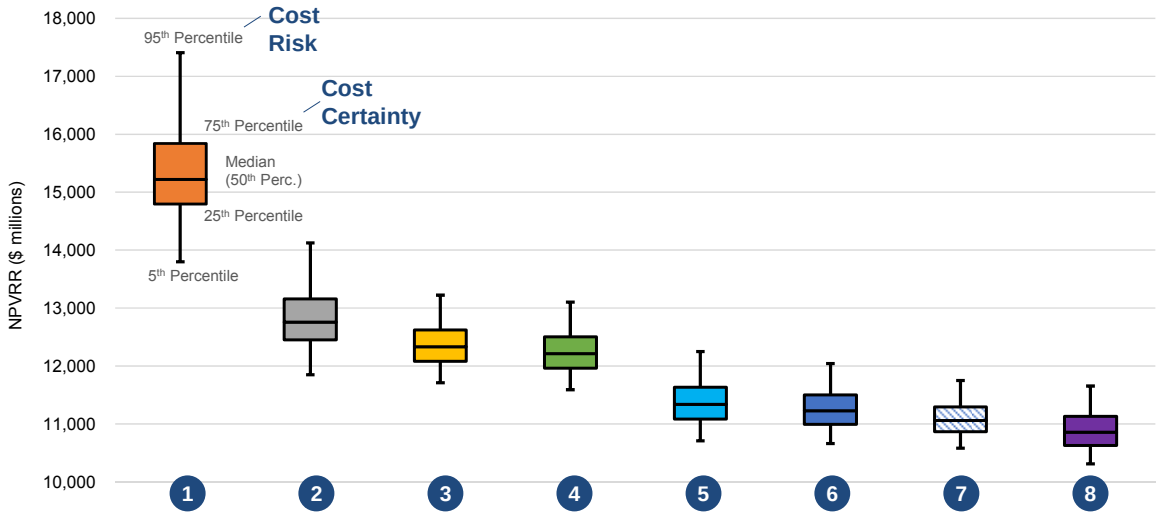
Stochastic Analysis Results

In addition to assessing each retirement portfolio against each market scenario, NIPSCO has also evaluated the retirement options against the full stochastic distribution of potential market outcomes, as described earlier in this Section. The stochastic analysis is used to further evaluate the risk of each of the retirement portfolios against a broad range of commodity price conditions for natural gas and power prices and against the potential for market price volatility on a granular daily or hourly basis. Overall, the results of the stochastic analysis suggest that retaining more

coal in the portfolio increases risk, given that portfolios with more coal generally have a higher range of cost outcomes and higher NPVRR costs at the 75th percentile and the 95th percentile of the stochastic distribution.

Figure 9-7 presents a summary of the stochastic results for each of the retirement portfolios. This plot displays the distribution of outcomes for each retirement portfolio across the full 500 iterations that were analyzed in the stochastic analysis. The median value (or 50th percentile) is represented by the center line of each box, with the top and bottom of the box indicating the 75th and 25th percentiles, respectively. The lines above and below each box end at the 95th and 5th percentiles, respectively. NIPSCO's cost certainty metric is represented by the 75th percentile NPVRR value, while the cost risk metric is represented by the 95th percentile NPVRR value.

Figure 9-7: Summary of Stochastic Results – Retirement Portfolios



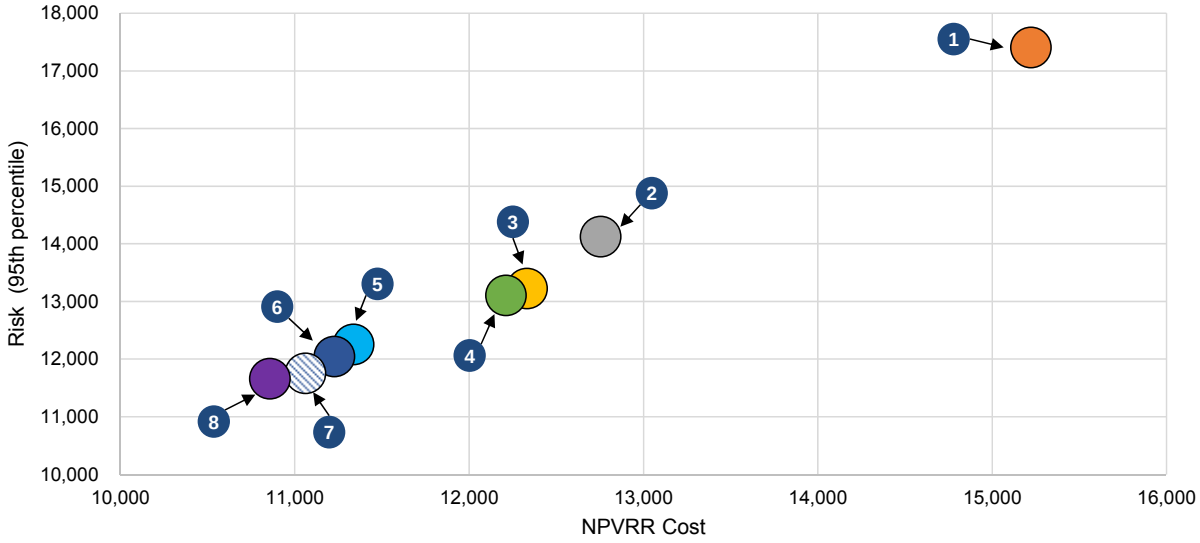
Portfolio Transition Target:	65% Coal through 2035	40% Coal in 2023	15% Coal in 2028 w/ ELG	15% Coal in 2028 w/o ELG	15% Coal in 2023 (MC 2035)	15% Coal in 2023 (MC 2028)	15% Coal in 2023 (17/18 2021)	0% Coal in 2023
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Delta from Lowest Cost Certainty	+$4,708 42.3%	+$2,026 18.2%	+$1,490 13.4%	+$1,370 12.3%	+$502 4.5%	+$372 3.3%	+$163 1.5%	- $ - %
Delta from Lowest Cost Risk	+$5,750 49.3%	+$2,467 21.2%	+$1,569 13.5%	+$1,449 12.4%	+$596 5.1%	+$389 3.3%	+$93 0.8%	- $ - %

Overall, portfolios that hold more coal not only tend to be higher in median cost, but also have a broader range of outcomes due to uncertainties associated with future coal plant dispatch and relatively significant carbon and commodity price uncertainty. Meanwhile, the portfolios that retire more coal and replace that capacity with fixed-price renewable resources are less subject to market price and dispatch uncertainties. Retirement Portfolio 1 (keeping all existing coal units until 2035) has a cost certainty value that is around $4.6 billion higher than that of Portfolio 8 (retiring all coal in 2023), and a cost risk value that is around $5.7 billion higher. Generally

speaking the portfolios that replace more coal with more DSM and renewables result in lower NPVRR for both risk metrics.

Another way to examine the cost and risk performance of the various retirement portfolio options is to plot the median cost expectation against the cost projection at the 95th percentile. This is done in Figure 9-8, which shows that higher costs are generally associated with higher risks, as measured through the 95th percentile outcome. At the 95th percentile, portfolios that hold more coal are exposed to the risk of higher carbon prices, as well as potentially low power prices and reduced dispatch in the market. Thus, they are considered riskier than the retirement portfolios that limit such exposure with resources that have more certain dispatch and no variable costs (renewables) over the long-term.

Figure 9-8: Summary Cost and Tail Risk – Retirement Portfolios



Scorecard Summary

Figure 9-9 presents a summary of all scorecard metrics for each of the eight retirement portfolios. This includes the cost metrics associated with the Base Case NPVRR and the risk metrics associated with the stochastic analysis, as well as the impacts of each option on portfolio flexibility, NIPSCO employees, and the local economy, as described above.

Figure 9-9: Retirement Portfolio Scorecard

Preferred Retirement Path

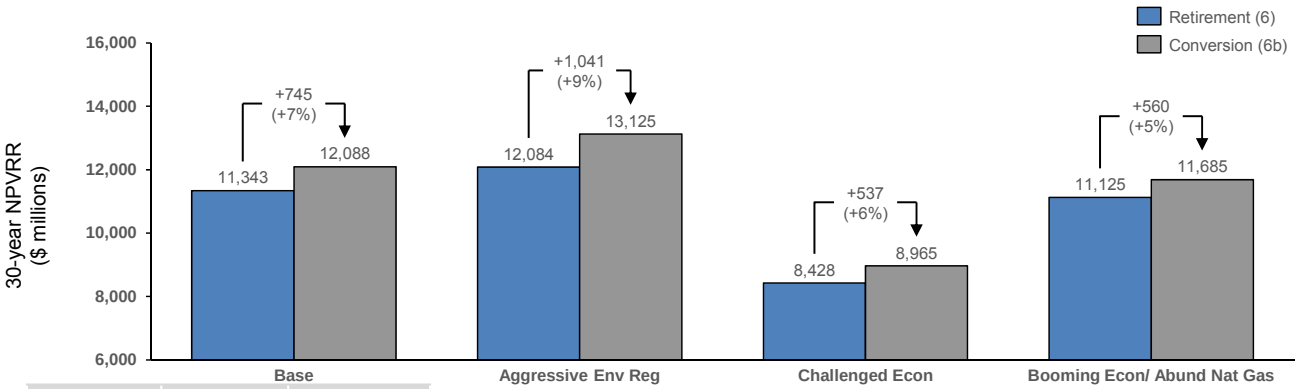
	1	2	3	4	5	6	7	8
Portfolio Transition Target:	**65% Coal through 2035**	**40% Coal in 2023**	**15% Coal by 2028 w/ ELG**	**15% Coal by 2028 w/o ELG**	**15% Coal in 2023** (Mich. City 2035)	**15% Coal in 2023** (Mich. City 2028)	**15% Coal by 2023** (Schfr 17/18 2021)	**0% Coal in 2023**
Retire:	None	Schfr:17,18 (2023)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2028)	Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:17,18 (2021) Schfr:14,15 (2023)	Mich.City:12 (2023) Schfr:17,18 (2023) Schfr:14,15 (2023)
Retain beyond 2023:	Mich. City: 12 Schfr:14,15,17,18	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 Schfr:14,15	Mich. City: 12 (2035)	Mich. City: 12 (2028)	Mich. City: 12 (2028)	None
Env. Compliance	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: non-ZLD	CCR ELG: Extended Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement	CCR ELG: Retirement
Cost To Customer	$15,400 +$4,426 40.3%	$12,911 +$1,937 17.7%	$12,455 +$1,481 13.5%	$12,336 +$1,361 12.4%	$11,454 +$479 4.4%	$11,343 +$369 3.4%	$11,187 +$213 1.9%	$10,974 - $ - %
Cost Certainty	$15,840 +$4,708 42.3%	$13,158 +$2,026 18.2%	$12,622 +$1,490 13.4%	$12,502 +$1,370 12.3%	$11,634 +$502 4.5%	$11,504 +$372 3.3%	$11,295 +$163 1.5%	$11,132 - $ - %
Cost Risk	$17,406 +$5,750 49.3%	$14,123 +$2,467 21.2%	$13,225 +$1,569 13.5%	$13,105 +$1,449 12.4%	$12,252 +$596 5.1%	$12,045 +$389 3.3%	$11,750 +$93 0.8%	$11,656 - $ - %
Reliability Risk	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Acceptable	Unacceptable	Unacceptable
Employees	0	125	125	125	276	276	276	426
Local Economy	+$118M +47%	$0M -%	($23M) (9%)	($31M) (12%)	($65M) (26%)	($74M) (29%)	($74M) (29%)	($94M) (37%)

Coal-to-Gas Conversion

As part of the retirement analysis, NIPSCO also evaluated the cost-effectiveness of converting one or two units at Schahfer to natural gas. The key assumptions for this analysis, including the operational parameters for the converted units and the costs associated with conversion and ongoing operations, are documented in Section 4. In developing this analysis, NIPSCO started with the Retirement Portfolio 6 and evaluated whether converting Schahfer 17/18 instead of replacing the capacity with the lowest-cost resources from the optimized All-Source RFP analysis was higher or lower cost. This analysis was performed for the conversion of both Units 17 and 18 and for just Unit 17 across all four market scenarios.

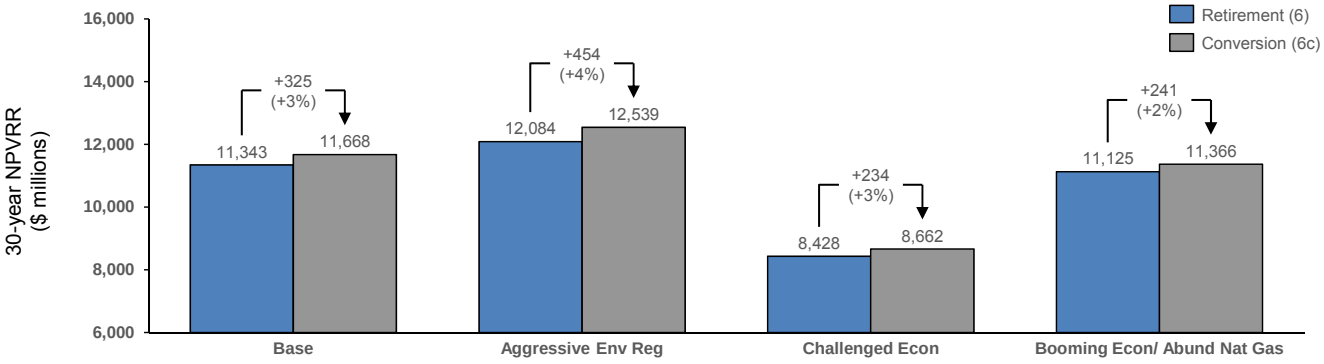
Across all scenarios coal to gas conversion is not a viable capacity alternative., Converting both Units 17 and 18 was projected to cost customers between $540 million to $1.04 billion more on a 30-year NPVRR basis than retirement and replacement of the units with economically optimized selections from the All-Source RFP results. This is shown in Figure 9-10. Converting a single unit was projected to cost customers between $230 million and $450 million more than retirement and replacement with economically optimized selections from the All-Source RFP results, as shown in Figure 9-11. While the conversion portfolio's economics improved under lower natural gas price and CO2 price conditions (the Challenged Economy and Booming Economy/ Abundant Natural Gas scenarios), it was still significantly higher cost across all scenarios.

Figure 9-10: Coal-to-Gas Conversion Analysis Results – Two Units



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)						
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17,18 (gas) Mich. City: 12 (2028)						

Figure 9-11: Coal-to-Gas Conversion Analysis Results – One Unit (Schahfer 17)



Portfolio Transition Target:	15% Coal in 2023	15% Coal in 2023 (17 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)	15% Coal in 2023	15% Coal in 2023 (Schfr.17/18 gas)
Retire:	Mich.City:12 (2028) Schfr:17,18 (2023) Schfr:14,15 (2023)	Mich.City:12 (2028) Schfr:14,15 (2023)						
Retain beyond 2023:	Mich. City: 12 (2028)	Schfr:17(gas) Mich. City: 12 (2028)						

9.1.8 Preferred Retirement Portfolio

Retirement Portfolio 6 has been determined to be the most viable retirement pathway for NIPSCO, providing significant cost savings versus the status quo and offering an acceptable outcome for portfolio flexibility and with regard to the impact on employees and the local economy. This retirement portfolio retires all four units at Schahfer in 2023 and retires Michigan City in 2028.

Combination 6 was selected because it was the lowest cost option that held acceptable reliability risk for customers and the system. The analysis shows that Combination 6 saves customers over $1.5 billion relative to NIPSCO's 2016 IRP preferred plan. From a reliability risk standpoint, it provides enough time to reasonably erect the necessary transmission upgrades that are critical for system and customer reliability. Additionally, the replacement resources can be reasonably secured and constructed by 2023. While the transition still encompasses roughly 60% of NIPSCO's physical generation, it maintains Michigan City through 2028 and Sugar Creek, a CCGT, even longer. Both are dispatchable units that can be used to support the transition while we implement the replacement path. Another benefit of staggering the retirements is that it allows NIPSCO to continue to assess customer, technology and market changes over the next decade and adjust as appropriate versus locking the entire transition in at once.

It is anticipated that NIPSCO's 2018 IRP preferred retirement path will require certain upgrades to the transmission system in order to maintain system reliability and remain compliant with NERC TPL standards, NIPSCO Planning criteria, and MISO requirements. This assumption will be validated once NIPSCO proceeds with filing the required forms with MISO (Attachment Y). As part of the retirement analysis, NIPSCO transmission planning group performed preliminary studies to evaluate the impact of the 2018 IRP preferred retirement path that calls for the retirements of Schahfer units 14,15,17,18 and replacement with primarily wind and solar/storage resources in central and southern Indiana by 2023. The studies identified a number of circuits on the NIPSCO transmission system that will likely violate NERC planning standards requirements. Once NIPSCO files its Attachment Y, making the retirement of Schahfer's units 14, 15, 17, 18 official with MISO, any violations found in MISO's analyses in the Attachment Y process and in NIPSCO's subsequent annual transmission planning analyses would need to be mitigated prior to the units' retirement in 2023. The mitigation of those issues consist of 5 separate projects to rebuild over 47 miles of transmission lines and to add a reactive power source to support system voltage. The initial high level estimated cost of the projects is $150 million, which is included in the retirement analysis.

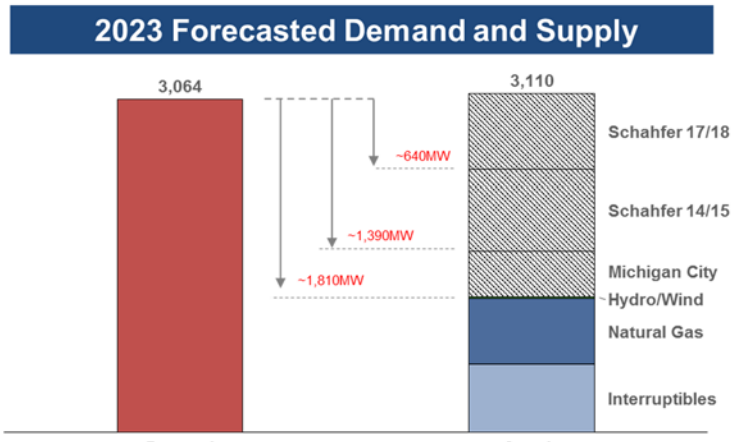
Initial estimates indicated that construction of these projects is anticipated to take until late 2022, early 2023 to complete. The projects are complex to engineer and construct because they require planned outages that need to be coordinated with MISO and PJM, as all of the projects impact PJM's system operation (reliability and markets). Furthermore, some of the rebuild projects are in urban areas or environmentally sensitive terrain like wetlands which carry additional environmental and other risks. There could also be potential outage conflicts with previously planned infrastructure improvement projects not associated with retirements.

Starting in early 2019, NIPSCO will begin engineering the projects and will begin initial construction and outage planning activities. Construction is expected to begin in early 2020. All of the projects are anticipated to be placed in service prior to the units being retired.

With its preferred retirement combination, NIPSCO has balanced customer cost and cost risk, with portfolio flexibility and the ability to successfully and reliability transform its supply resources to meet its customers' needs. Although not the least expensive solution, in all modeling analyses, the preferred portfolio results in savings to customers, greater cost certainty and lower cost risk over alternatives that hold more coal capacity. This option balances other non-economic considerations such as portfolio flexibility, employee and property tax impacts.

Under such a portfolio, a capacity gap of around 1,300 MW will open up in 2023, as shown in Figure 9-12, which summarizes current capacity resources against NIPSCO's Base Case load forecast, inclusive of reserve margin requirements. This capacity gap is the subject of the replacement analysis that is described next.

Figure 9-12: Future Capacity Need under Preferred Retirement Portfolio



2023 Estimated Capacity Excess/(Need) in MWs

As-Is	50
Retire Schahfer 17/18	(640)
Retire Schahfer 14/15/17/18	(1,390)
Retire Schahfer and Michigan City	(1,810)

9.2 Replacement Analysis

9.2.1 Process Overview

NIPSCO has evaluated a range of potential resource replacement options to fill the capacity gap that would develop under Retirement Portfolio 6. The replacement analysis was performed in a similar manner to the retirement analysis, with the following major steps:

- Identify replacement resource concepts for NIPSCO, primarily around considerations for ownership and commitment duration and portfolio diversity captured via the emissions profile of resources.

- Develop specific replacement portfolios within each concept using IRP optimization tools and data from the All-Source RFP.

- Evaluate each replacement portfolio in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed earlier in this Section).

- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred replacement portfolio.

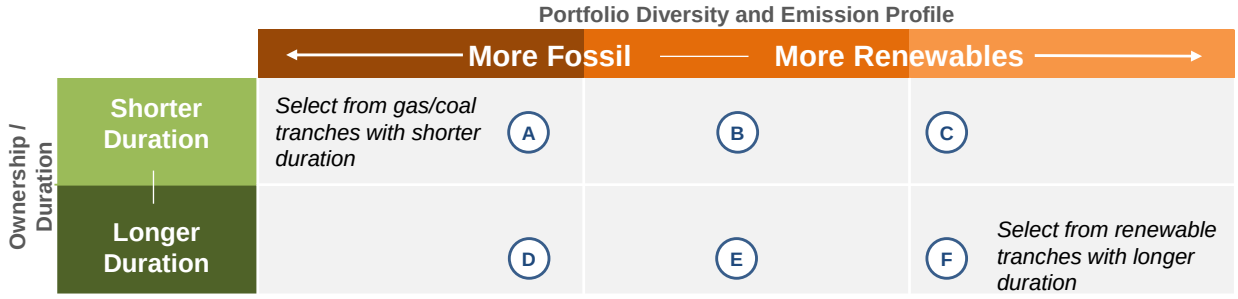
9.2.2 Identification of Replacement Resource Concepts

NIPSCO developed a matrix of replacement resource concepts based on several key planning considerations. The first consideration was structured around the commitment duration being assumed by NIPSCO under each potential portfolio option. Duration is defined as the length of time commitment to a specific resource; shorter duration resources, generally in the form of short-term PPAs, can partially mitigate industrial risk since they do not lock-in a commitment over the very long term. Longer duration resources, on the other hand, generally in the form of longer-duration PPAs or owned assets, tend to have commitments of twenty years or more. By developing portfolios across a range of duration commitments, NIPSCO was able to evaluate the costs and risks associated with different resource procurement strategies.

The second consideration was structured around the potential portfolio's diversity, specifically related to carbon dioxide emission intensity. NIPSCO currently has a portfolio with a high concentration of coal generation, and portfolio concepts were developed with varying levels of fossil and renewable resource replacements in order to evaluate the costs and risks associated with strategies that align with NIPSCO's environmental targets and various stakeholder interests.

After reviewing the type of replacement resources available from the All-Source RFP (*See* Section 4.9.2 for more detail.), NIPSCO determined that portfolio concepts could feasibly be developed across two duration levels (shorter and longer) and three diversity levels (all fossil replacements, a mix of fossil and renewable replacements, and all renewable replacements). Thus six difference concepts were identified for more detailed portfolio development, as shown in Figure 9-13. These portfolios are referred to as Portfolios A-F throughout the rest of this Section.

Figure 9-13: Replacement Consideration Matrix



9.2.3 Development of Specific Replacement Portfolios

Based on the six replacement concepts, NIPSCO then developed specific portfolios that met the desired considerations. This was done through the Aurora model's portfolio optimization capability, which allows the user to specify a set of options and portfolio constraints that drive towards a least cost revenue requirement solution.

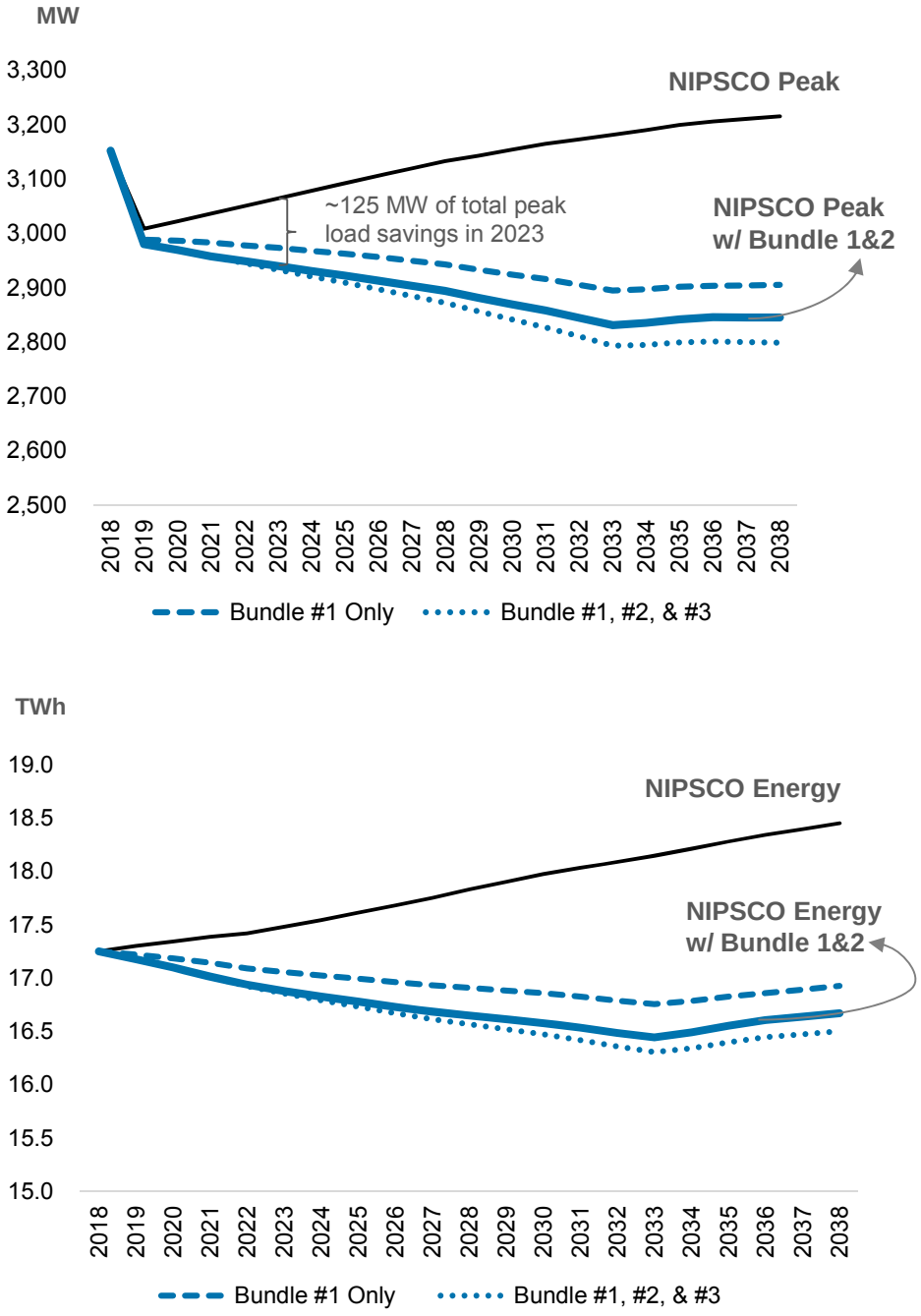
DSM Portfolio Selection

NIPSCO allowed demand side management (DSM) and energy efficiency measures, broadly referred to as DSM resources, to be selected across all six portfolio concepts. As discussed further in Section 5, three separate DSM bundles were developed by GDS Associates for potential selection in the portfolio optimization model. The bundles were organized according to cost, and all of the resources in the first two bundles were selected by the optimization model across all portfolios. Figure 9-14 summarizes the peak and average DSM MW that were selected by bundles in 2023 (the year of the capacity gap under Retirement Portfolio 6) and in 2038 (the final year of the fundamental modeling horizon). Figure 9-15 summarizes the impacts of the various DSM bundles over time, indicating the expected savings for peak load and total energy sales with Bundles 1 and 2 selected.

Figure 9-14: DSM Selection in 2023 and by 2038

DSM Bundle #	Weighted Avg. Cost ($/MWh)	MW Selected by 2023 (Peak / Average)	MW Selected by 2038 (Peak / Average)
1	17	91 / 48	310 / 174
2	23	34 / 20	60 / 29
3	159	0 / 0	0 / 0

Figure 9-15: Selected DSM Resources across Replacement Portfolios (Peak and Energy)



All-Source RFP Resource Selection

Beyond DSM selection, NIPSCO then evaluated the candidate resource options from the All-Source RFP to be selected for each of the six replacement portfolio concepts. In performing this analysis, the Aurora optimization model was constrained differently for each portfolio in order to meet the duration and diversity targets. Along the duration axis, for Portfolios A, B, and C, 400 MW of short-term MISO market purchases were assumed for each portfolio to offer a minimal

duration commitment that could protect against industrial load loss. After that, short-term contract options were available first, followed by longer-term contracts when shorter-term resources were exhausted. For Portfolios D, E, and F, long-term contracts and asset ownership options were available, with no short-term PPAs eligible to be selected. Along the diversity axis, Portfolios A and D only had access to fossil-fired resources, while Portfolios C and F only had access to renewable and storage resources. Portfolios B and E were allowed to select a portion of the lowest cost fossil resources within the relevant duration concept, with the remaining capacity gap filled with renewables.

Figure 9-16 summarizes the UCAP MW selected by All-Source RFP tranche (*See* Section 4 for more detail on All-Source RFP tranche development.) across all six portfolio concepts, and Figure 9-17 summarizes the total incremental resource replacement additions in 2023 by type. The preferred fossil resources were CCGT, along with a small, fossil-based system power contract, while the preferred renewable resources were wind projects, followed by solar and solar plus storage options. Although the replacement portfolio selection process is not reflective of a specific, preferred action plan, it was able to construct a range of portfolio strategy concepts to be fully evaluated with the IRP analysis tools and against the full scorecard of key criteria metrics. A summary of NIPSCO's potential capacity position by fuel type across all of the six replacement portfolios is shown in Figure 9-18.

Figure 9-16: Selected Resource Tranches by Replacement Portfolio

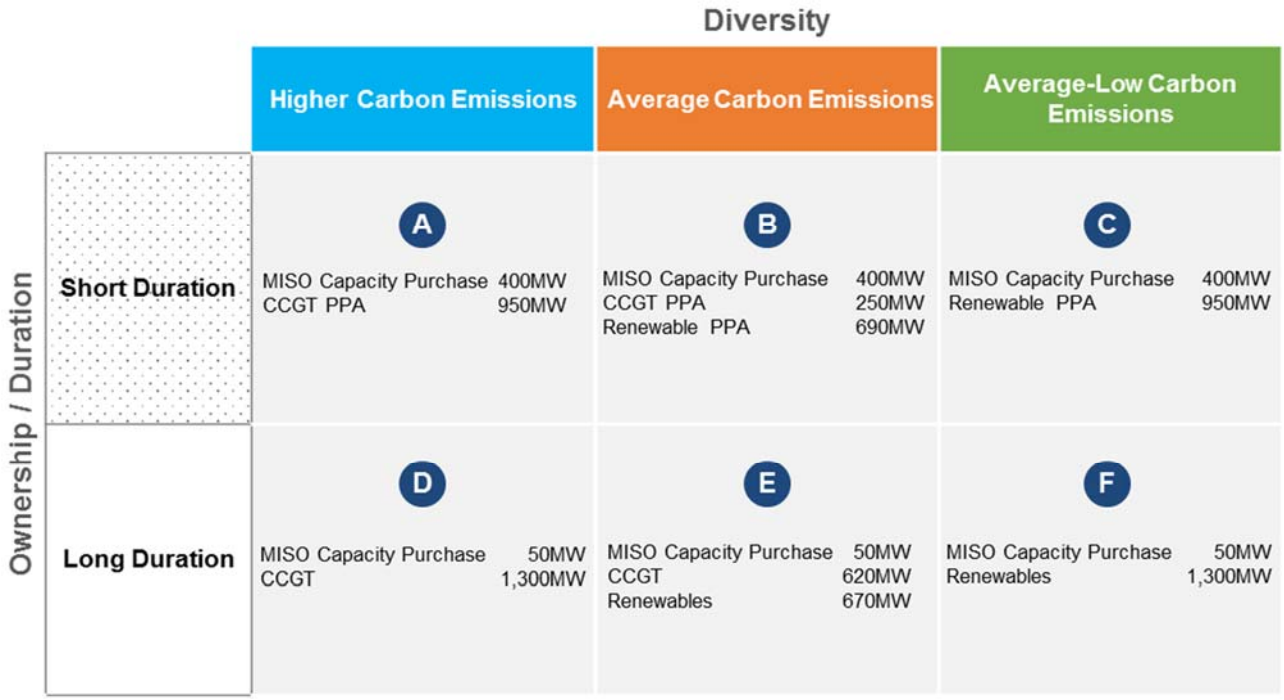


Figure 9-17: 2023 Incremental Replacement Resources by Portfolio (UCAP MW)

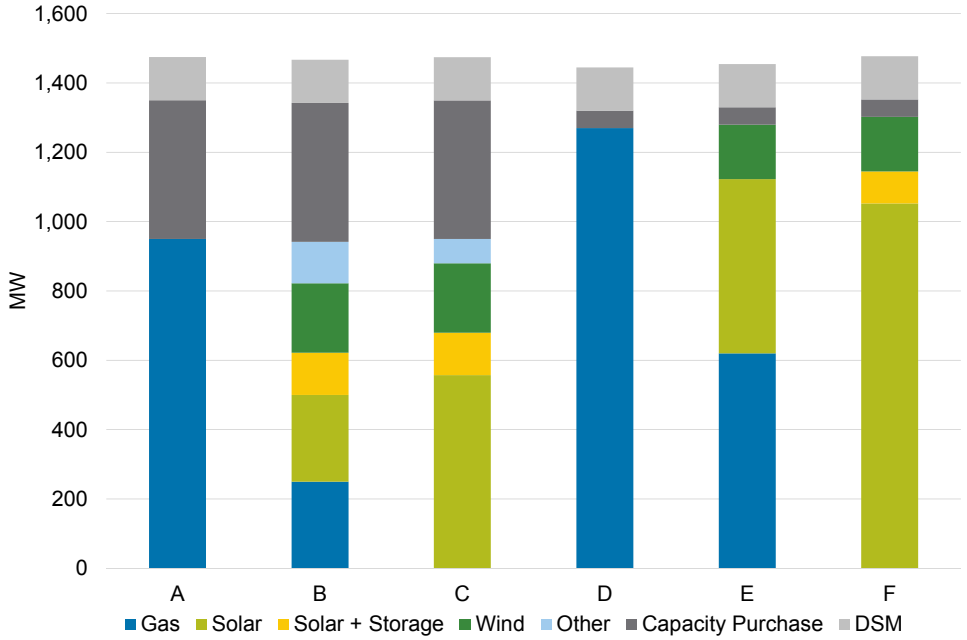
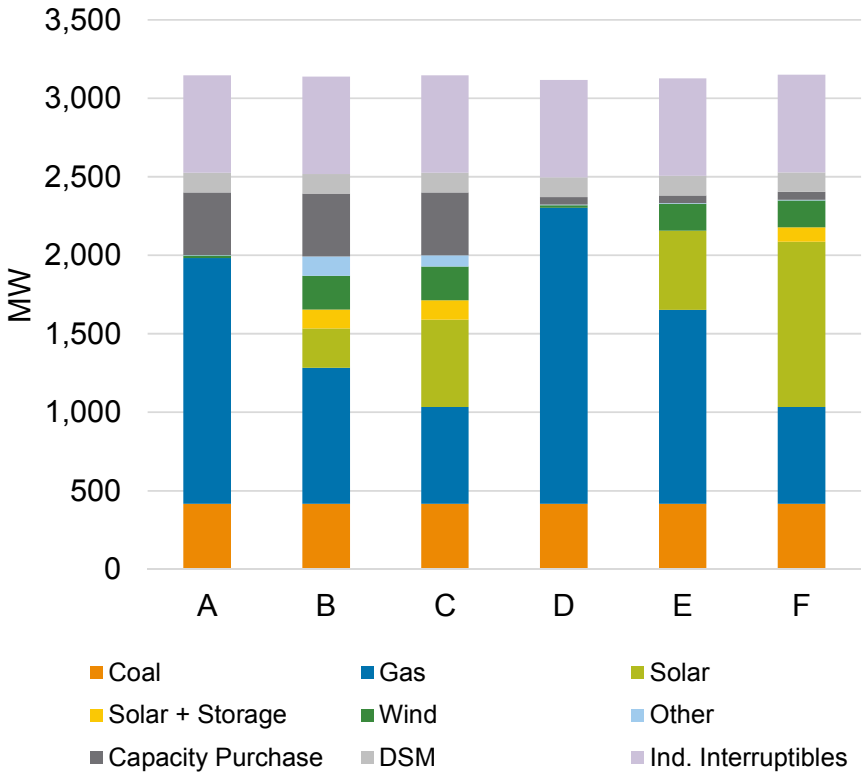


Figure 9-18: 2023 Total Projected Capacity Mix by Portfolio (UCAP MW)



9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics

Similar to the scorecard developed for the retirement analysis, NIPSCO developed a scorecard of criteria and key metrics associated with the replacement analysis. Many of the metrics are the same, with two additions: fuel security, defined as the percentage of capacity sourced from resources other than natural gas, and environmental emission intensity, defined as the total carbon emissions in 2030 from the full generation portfolio. A summary of the decision criteria metrics for the replacement analysis is provided in Figure 9-19.

Figure 9-19: Scorecard Metrics for Replacement Analysis

2018 Replacement Scorecard

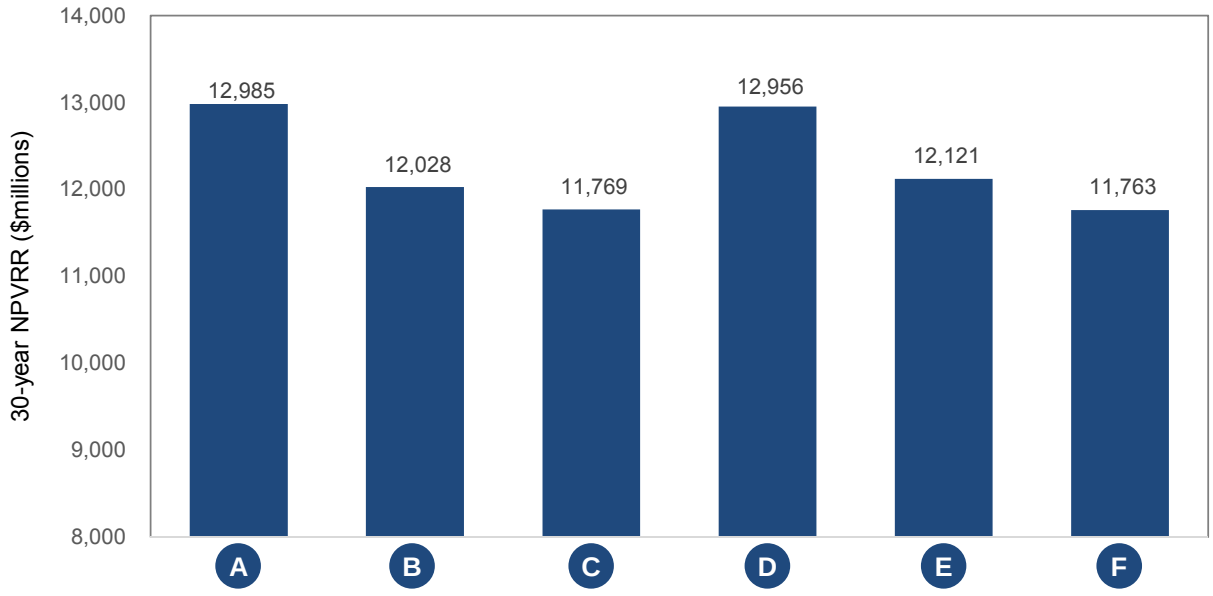
Criteria	Description
Cost to Customer	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Base scenario deterministic results)
Cost Certainty	• Certainty that revenue requirement falls within the most likely range of distribution of outcomes (75% certainty that cost will be at or below this level) • Metric: 75th percentile of cost to customer
Cost Risk	• Risk of extreme, high-cost outcomes • Metric: 95th percentile of cost to customer
Fuel Security	• Power plants with reduced exposure to short-term fuel supply and/or deliverability issues (e.g., ability to store fuel on-site and/or requires no fuel) • Metric: Percentage of capacity sourced from resources other than natural gas (2025 ICAP MW sourced from non-gas resources)
Environmental	• Annual carbon emissions from the generation portfolio • Metric: Total annual carbon emissions (2030 metric tons of CO_2) from the generation portfolio
Employees	• Net impact on NiSource jobs • Metric: Approximate number of permanent NiSource jobs added
Local Economy	• Property tax amount from entire portfolio • Metric: 30-year NPV of estimated modeled property taxes from the entire portfolio

9.2.5 Evaluation of Replacement Portfolios – Results

Base Case Cost Results

The six replacement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail.) to estimate revenue requirements for each over time. The assessment was first performed across the Base Case set of market assumptions and inputs in order to calculate baseline projections of the NPVRR over the thirty-year planning horizon. Under the Base Case market conditions, Replacement Portfolio F (long-duration renewables) was the least cost option, with Replacement Portfolio C (short-duration renewables) only $6 million higher on an NPVRR basis. The portfolios with only natural gas and other fossil resource additions (Replacement Portfolios A and D) are highest cost, while portfolios with a mix of gas and renewable additions (Replacement Portfolios B and E) have a cost premium of between $250 and $350 million when compared to Portfolio F. Figure 9-20 summarizes the results for the each replacement portfolio under Base Case conditions.

Figure 9-20: Cost to Customer Impacts – Replacement Portfolios



Scenario Cost Results

In addition to the analysis under Base Case conditions, NIPSCO also evaluated each replacement portfolio against each scenario described earlier in Section 8. The NPVRR for each replacement portfolio across each scenario is summarized in Figure 9-21, with additional details regarding the scenario results described below.

Figure 9-21: Cost to Customer across All Scenarios – Replacement Portfolios (30-year NPVRR – millions of $)

Retirement Portfolio	Base	Aggressive Env Reg	Challenged Econ	Booming Econ/ Abund Nat Gas
A	12,985	14,476	9,496	12,167
B	12,028	12,948	8,985	11,699
C	11,769	12,675	8,740	11,475
D	12,956	14,426	9,463	12,097
E	12,121	12,970	9,102	11,756
F	11,763	12,424	8,905	11,585

Under the Aggressive Environmental Regulation scenario, higher carbon prices and higher natural gas prices drive higher portfolio costs overall, but more so for the portfolios with significant natural gas capacity additions (Portfolios A and D). Meanwhile, the renewable dominant portfolios (Portfolios C and F) see change in costs to a lesser degree, given that most costs associated with the renewable resource additions are fixed in nature. For example, the NPVRR for Portfolio D increases by nearly $1.5 billion versus the Base Case, while the NPVRR for Portfolio F increases by less than $700 million. In addition, the shorter-duration portfolios with

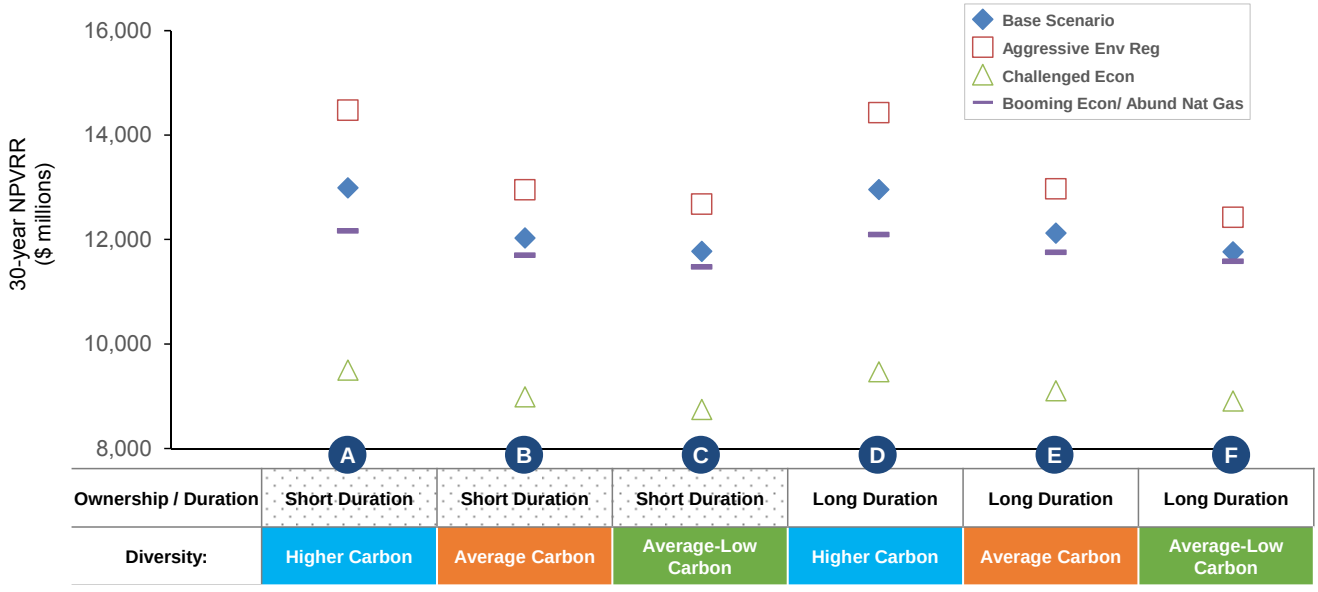
more exposure to the market perform relatively worse under the Aggressive Environmental Regulation scenario due to the fact that market prices are significantly higher. While Portfolios F and C are nearly identical in cost in the Base Case, Portfolio F has an NPVRR that is $250 million lower than Portfolio C's in this scenario.

Under the Challenged Economy scenario, all portfolio costs decline due to no carbon price and lower gas and power prices. Larger NPVRR declines are observed for the portfolios that include more natural gas capacity, but the renewable-only portfolios are still lowest cost. Furthermore, given that market prices are low and given that NIPSCO load is lower, the short-duration renewable concept (Portfolio C) performs best in this scenario, since its market exposure is significantly reduced. In fact, Portfolio C has a lower NPVRR than Portfolio F by about $160 million.

Under the Booming Economy & Abundant Natural Gas scenario, low natural gas prices improve the relative position of the portfolios with more natural gas capacity, as fuel costs are lower and natural gas combined cycle dispatch is higher. For example, the NPVRR of Portfolio D (long-duration natural gas) declines by about $860 million relative to the Base Case in this scenario, while the NPVRR of Portfolio F (long-duration renewables) declines by only about $180 million. However, although Portfolios D and E are much closer in Cost to Portfolio F, the all-renewables options are still the least expensive alternative. Portfolio C is slightly lower cost overall, due to lower market prices reducing its MISO market exposure relative to Portfolio F.

Overall, while the relative economics of fossil and renewable resource replacement options are impacted by changes in carbon prices, natural gas prices, and MISO market power prices, the lowest-cost replacement option is always dominated by renewable resources. When market prices are low and when NIPSCO load is low, a shorter-duration renewable strategy is lower cost, while a longer-duration renewable portfolio performs best in the Base Case and when market prices are higher. These results are summarized for each portfolio and each scenario in Figure 9-22.

Figure 9-22: NPVRR Summary across All Scenarios – Replacement Portfolios

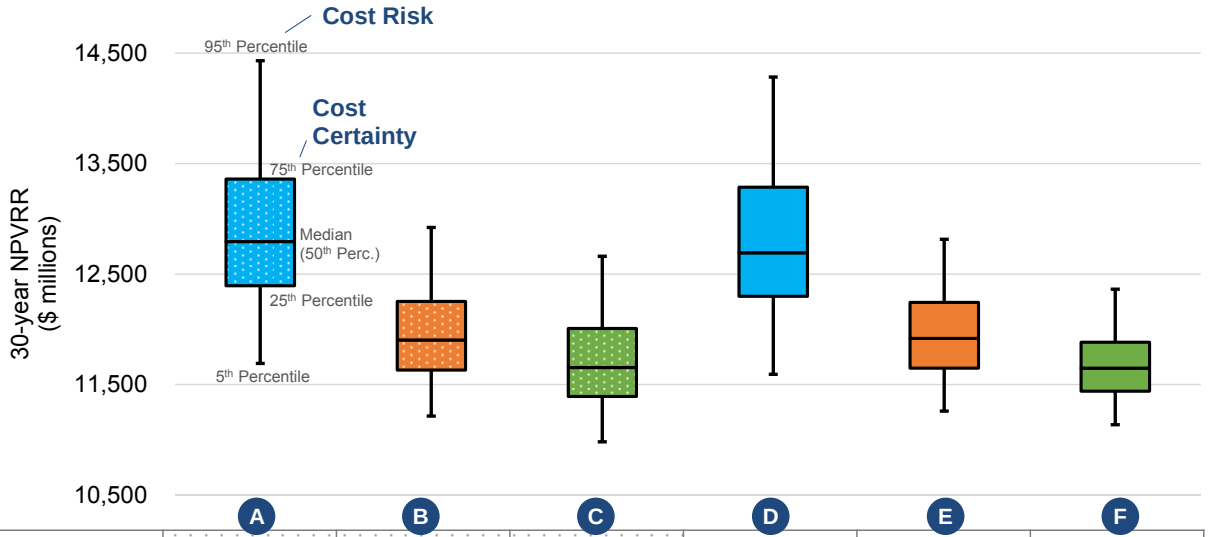


Stochastic Analysis Results

In addition to assessing each retirement portfolio against each market scenario, NIPSCO has also evaluated the replacement options against the full stochastic distribution of potential market outcomes, as described earlier in this Section. As in the retirement analysis, the stochastic assessment is used to further evaluate the risk of each of the portfolios against a broad range of commodity price conditions for natural gas and power prices and against the potential for market price volatility on a granular daily or hourly basis.

Figure 9-23 presents a summary of the stochastic results for each of the replacement portfolios. Overall, although the introduction of stochastic price volatility impacts the natural gas and renewable resource elements in each portfolio differently, Portfolio F (long-duration renewables) has the lowest median cost, and also the lowest cost at the 75th and 95th percentiles.

Figure 9-23: Summary of Stochastic Results – Replacement Portfolios



Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Delta from Lowest Median Cost	$1,147 9.8%	$254 2.2%	$6 0.1%	$1,044 9.0%	$271 2.3%	$0 0.0%
Delta from Lowest Cost Certainty	$1,477 12.4%	$371 3.1%	$124 1.0%	$1,403 11.8%	$362 3.0%	$0 0.0%
Delta from Lowest Cost Risk	$2,067 16.7%	$558 4.5%	$297 2.4%	$1,920 15.5%	$452 3.7%	$0 0.0%

On average, the median difference in NPVRR between the renewable-only portfolios and those that have some natural gas capacity goes down, meaning that natural gas options look relatively better in the stochastics when compared to their performance in deterministic Base Case.

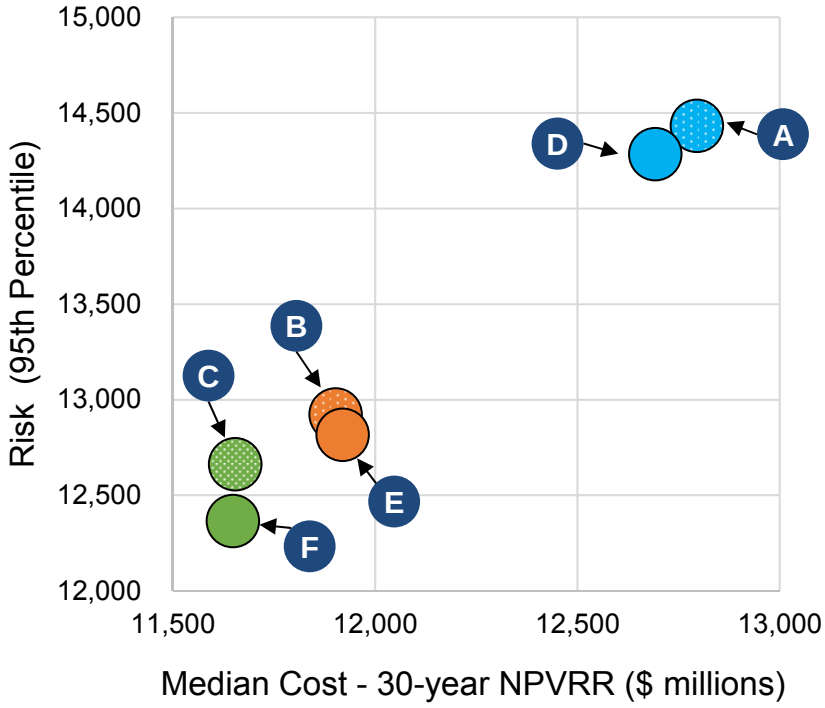
This is because natural gas plants can take advantage of potential low gas price outcomes and can flexibly dispatch in response to changing prices in a volatile market, while renewable costs and dispatch are generally fixed. However, this small improvement in NPVRR for natural gas portfolios across the stochastic distribution does not outweigh the overall cost benefits associated with incorporating fixed price renewable assets into the portfolio.

Although more favorable market conditions for gas resources are incorporated into the stochastic assessment, as more natural gas capacity is added to the portfolio, costs and risks increase. This is due to the fact that natural gas capacity is more exposed to gas price volatility on the upside, which impacts both dispatch and the costs of operation. Although gas-dominant portfolios perform better when gas prices are low, they become heavily exposed to conditions with higher gas and carbon prices, resulting in significantly higher portfolio costs than those options that include more renewables. Portfolio F (long-duration renewables) has a cost certainty value that is around $1.4 billion lower than that of Portfolio D (long-duration CCGT) and $360 million lower than that of Portfolio E (long-duration mix), and a cost risk value that is around $1.9 billion lower than Portfolio D and $450 million lower than Portfolio E.

The longer-duration renewable portfolio (F) also performs better on the risk metrics than the shorter-duration renewable portfolio (C). This is due to the fact that Portfolio C includes 400 MW of MISO market purchases, resulting in higher costs under conditions with higher carbon, fuel, and power prices. This drives the width of Portfolio C's distribution higher. Although Portfolio F and Portfolio C have nearly identical NPVRRs at the median cost level, Portfolio F is about $125 million lower in cost at the 75th percentile and nearly $300 million lower in cost at the 95th percentile.

Another way to examine the cost and risk performance is to plot the median cost expectation against the cost projection at the 95th percentile. This is done in Figure 9-24, which shows that higher costs are generally associated with higher risks, as measured through the 95th percentile outcome. At the 95th percentile, portfolios with more natural gas capacity are exposed to the risk of higher gas prices and higher carbon prices, as well as potentially reduced dispatch in the market. More fixed-price renewable resources generally result in lower tail risk overall. The difference in risk profile between Portfolios C and F is also evident in this figure. Although both portfolios have nearly the same median cost (x-axis), F has significantly lower 95th percentile risk (y-axis).

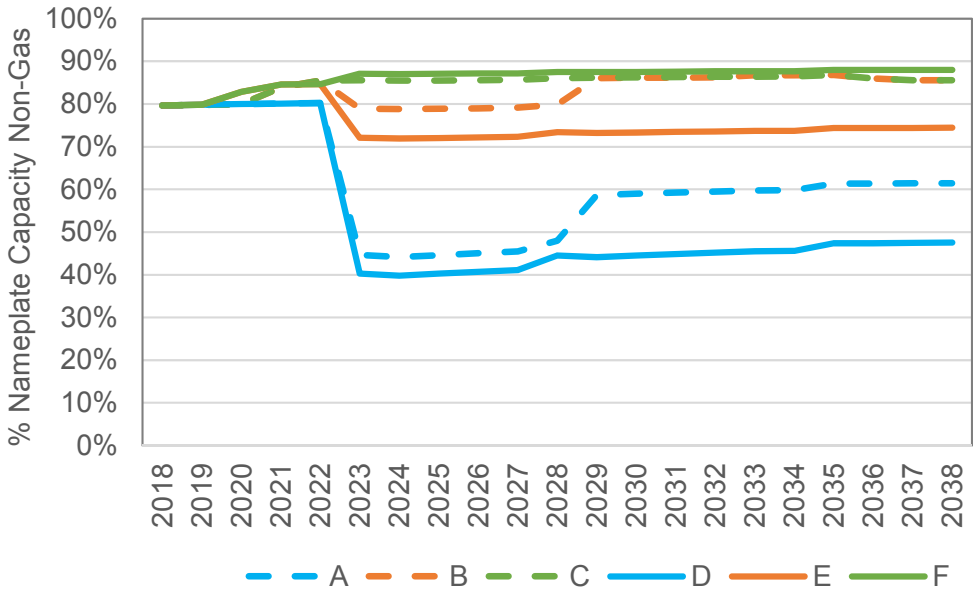
Figure 9-24: Summary Cost and Tail Risk – Replacement Portfolios



Additional Scorecard Metric Results

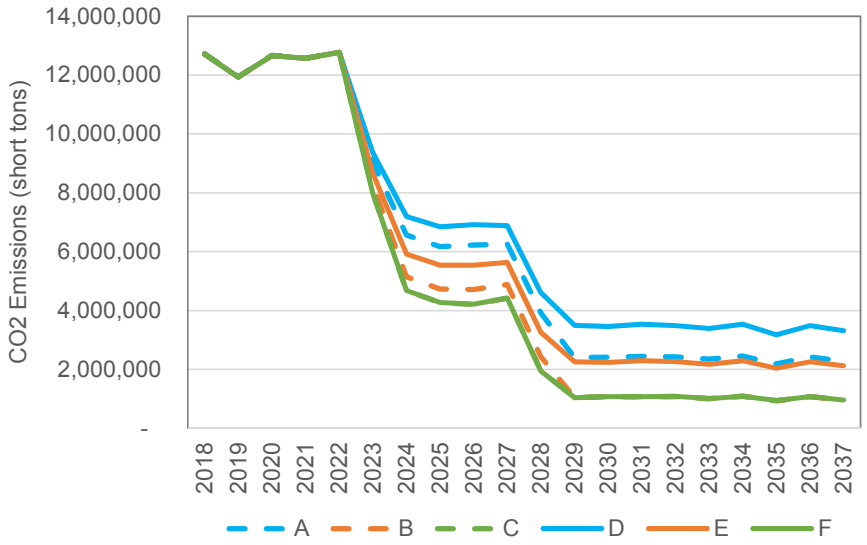
NIPSCO has identified fuel security as an important metric in its integrated scorecard assessment. Fuel security has been defined as the percentage of total nameplate capacity that is sourced from non-natural gas resources. A summary projection of this metric over time for each of the six replacement portfolios is shown in Figure 9-25. As is shown, after the potential retirement of coal capacity in 2023, Portfolios A and D would have less than 50% of their capacity comprised of non-gas resources, while Portfolios C and F would be closer to 90% for this metric. For purposes of the scorecard, 2025 is used as the benchmark year.

Figure 9-25: Percent of Nameplate Capacity that is Non-Gas for Replacement Portfolios



As an environmental stewardship benchmark, NIPSCO has identified CO2 emissions has an important scorecard metric. While all replacement portfolios would expect to realize significant CO2 emission reductions with the retirement of coal capacity in 2023 and 2028, differences in long term emissions are dependent on whether the resource replacements are renewable or natural gas-fired. Figure 9-26 summarizes the projected CO2 emissions over time for all six replacement portfolios, showing that the renewable-only options are lower over the long-term.

Figure 9-26: Projected CO2 Emissions over Time for Replacement Portfolios



Scorecard Summary

Figure 9-27 presents a summary of all scorecard metrics for each of the six replacement portfolios. This includes the cost metrics associated with the Base Case NPVRR and the risk metrics associated with the stochastic analysis, as well as the impacts of each option on fuel security, carbon emissions, NIPSCO employees, and the local economy.

Figure 9-27: Replacement Portfolio Scorecard

Preferred Replacement Path

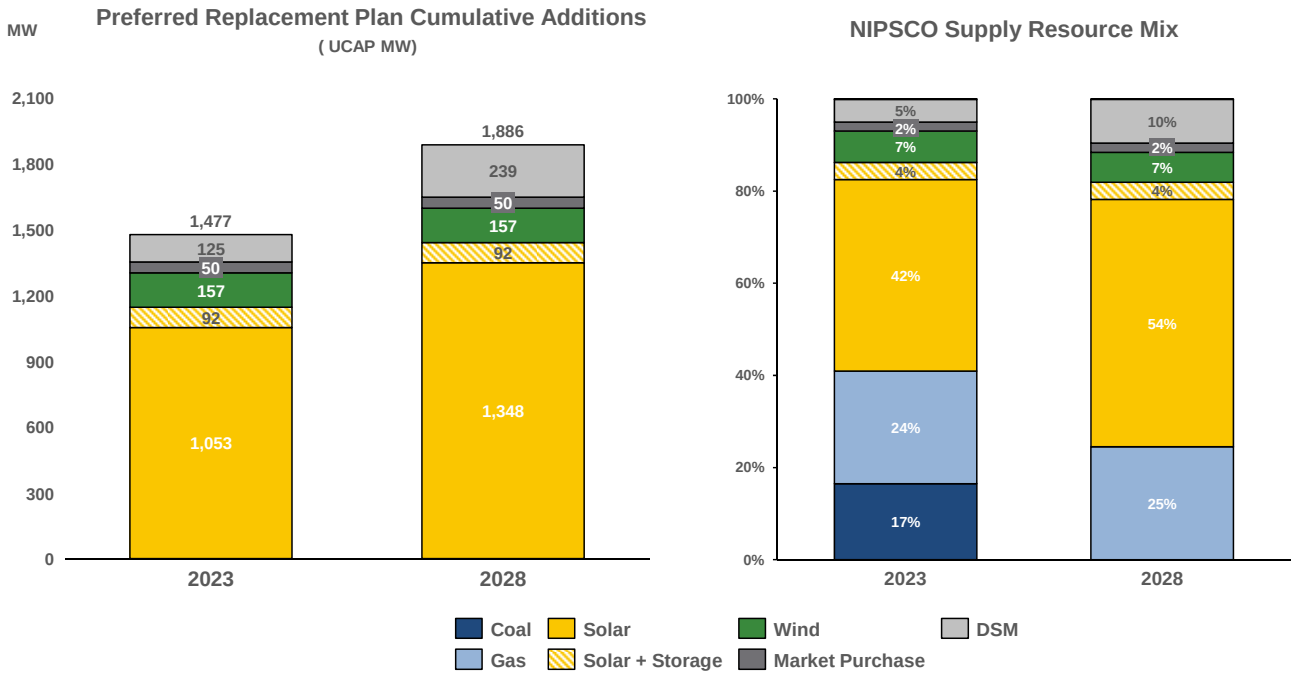
	A	B	C	D	E	F
Ownership / Duration	Short Duration	Short Duration	Short Duration	Long Duration	Long Duration	Long Duration
Diversity:	Higher Carbon	Average Carbon	Average-Low Carbon	Higher Carbon	Average Carbon	Average-Low Carbon
Cost to Customer delta from least	$12,985 $1,222 10.4%	$12,028 $265 2.2%	$11,769 $6 0.1%	$12,956 $1,192 10.1%	$12,121 $357 3.0%	$11,763 $0 0.0%
Cost Certainty delta from least	$13,360 $1,477 12.4%	$12,254 $371 3.1%	$12,007 $124 1.0%	$13,286 $1,403 11.8%	$12,245 $362 3.0%	$11,883 $0 0.0%
Cost Risk delta from least	$14,431 $2,067 16.7%	$12,922 $558 4.5%	$12,661 $297 2.4%	$14,284 $1,920 15.5%	$12,815 $452 3.7%	$12,364 $0 0.0%
Fuel Security % non-gas capacity	45%	79%	86%	40%	72%	87%
Environmental 2030 CO_2 emissions 2005 baseline = 18.2M	2.18M	0.97M	0.97M	3.13M	2.03M	0.97M
Employees	0	0	0	<30	<30	<30
Local Economy	← Dependent on project selection and location; currently under evaluation →					

9.3 Preferred Replacement Portfolio

The replacement scorecard shown in Figure 9-27 shows that replacement portfolios with renewables are more cost effective than portfolios without renewables. Additionally, portfolios with more renewables provide greater amounts of CO2 emissions reduction and provide the greatest amount of fuel security.

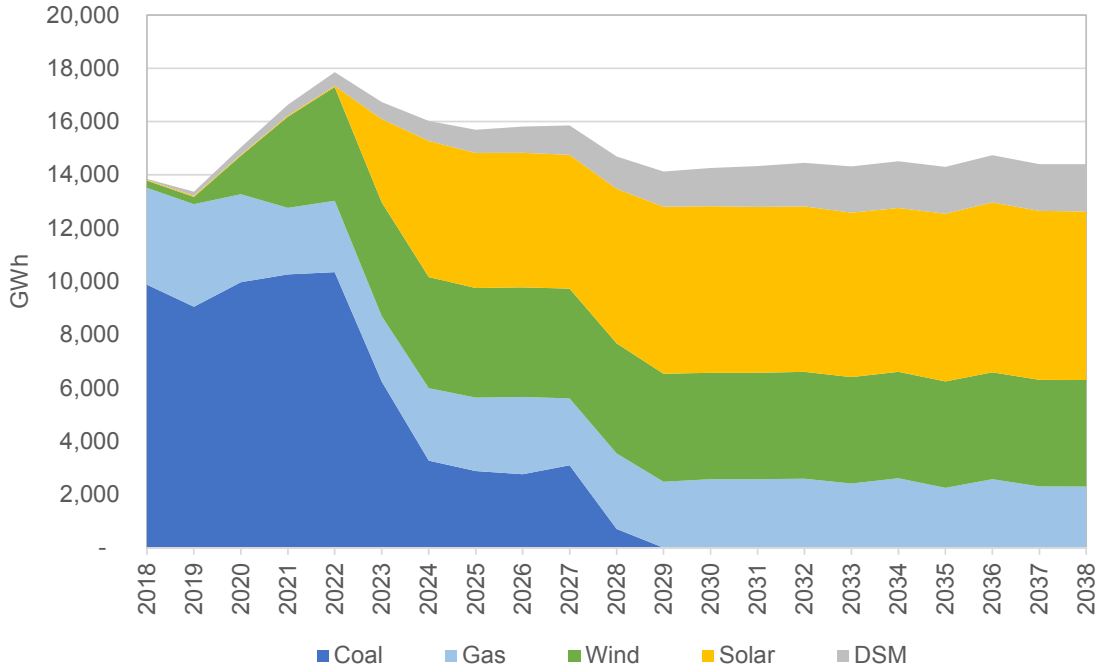
NIPSCO has selected replacement Portfolio F as the preferred plan. This portfolio calls for the addition of a mix of wind, solar, battery storage, market purchases and DSM resources over time. Figure 9-29 shows the NIPSCO preferred plan *incremental* additions and NIPSCO's overall projected capacity supply mix at the end of 2023 and 2028.

Figure 9-28: Preferred Plan Capacity Mix over Time



Over the twenty-year planning horizon, NIPSCO's generation mix is projected to shift significantly from coal to renewables. As shown in Figure 9-29, renewable generation is expected to increase with the acquisition of wind resources between 2020 and 2022 and solar resources thereafter. During this time period, coal generation is expected to decline to zero, while gas generation is projected to be relatively stable. Under this portfolio, NIPSCO will be supplied primarily by renewable resources (wind and solar) over the long-term, with meaningful natural gas and DSM contributions. Market purchases would be expected to meet the remainder of the requirements, but are dependent on renewable operations and the details of future resource decisions that are be made by NIPSCO in the coming years.

Figure 9-29: Preferred Portfolio Energy Mix

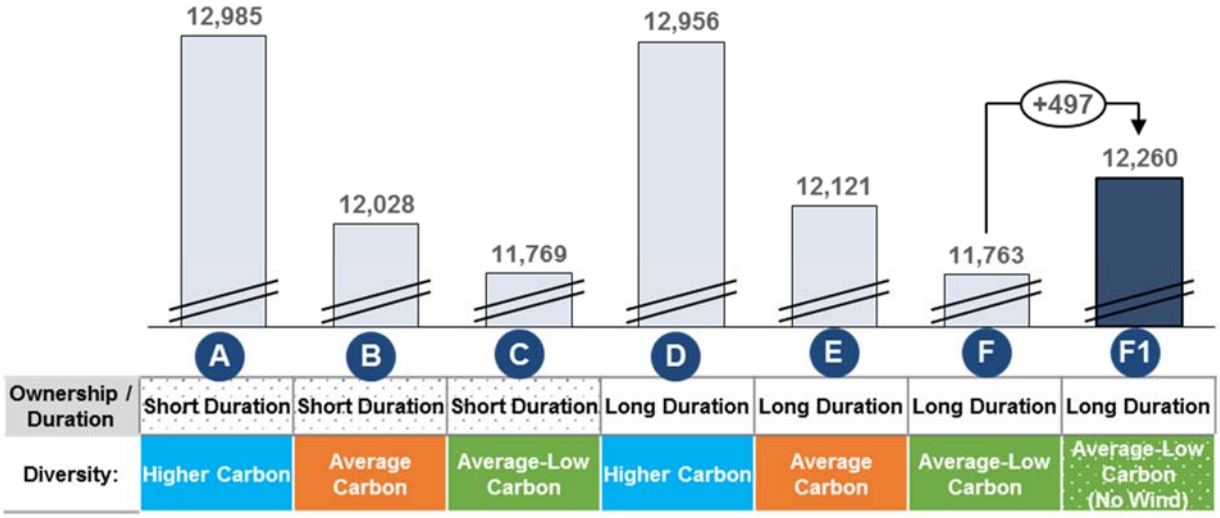


9.3.1 Procuring Wind in 2020

As discussed in Section 4.10.2, tax incentives currently available for renewable energy resources are currently in the midst of a phase out, and projects need to begin construction by a certain date and be in service by a certain date in order to receive the benefits. For wind resources to qualify for 100% of the production tax credit (PTC), projects need to be placed in service by the end of 2020. Solar resources are eligible to receive the investment tax credit (ITC), but do not need to enter into service until the end of 2023 to qualify.

NIPSCO has found that wind resources provide significant value to the portfolio from a cost perspective, and that procuring wind resources in 2020 to realize the full benefits of tax credits is important to achieve the lowest portfolio costs for customers. In order to evaluate the impact of the best-performing All-Source RFP wind resources on the costs of the portfolio, NIPSCO evaluated a variation of Portfolio F that relies solely on solar and solar plus storage resources in place of wind. This portfolio is nearly $500 million more expensive than Portfolio F on a 30-year NPVRR basis, as shown in Figure 9-30. This is due to the fact that the alternative portfolio removes the lowest-cost resources (wind) and replaces them with higher-cost solar resources and a larger amount of higher-cost market purchases.

Figure 9-30: Base Case Replacement Cost NPVRR with No Wind Portfolio



9.3.2 Preferred Plan Summary

From a customer perspective, NIPSCO's preferred plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply is available to meet future customer needs. NIPSCO also carefully planned and considered the impacts to its employees, the environment, system reliability and impacts on the local economy as the plans were developed. It is important to remember that the integrated resource plan is a snapshot in time and while it establishes a direction for NIPSCO, it is subject to change as the operating environment changes. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

The major components of the NIPSCO supply strategy for the next 20 years are expected to:

- Lead to a lower cost, cleaner, diverse and flexible portfolio by accelerating the retirement of over 75% of NIPSCO's current coal capacity by the end of 2023 and 100% by 2028
- Continue the Company's commitment to energy efficiency and demand response by executing the current filed DSM plan
- Replace retired coal generation resources with lower cost renewables, including wind, solar and battery storage
- Identify and implement required reliability and transmission upgrades resulting from retirement of the units

- Reduce customer and Company exposure to customer load, market and technology risks by intentionally allocating a portion of the portfolio to shorter duration supply;
- Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services
- Continue to comply with NERC and EPA standards and regulations

9.3.3 Financial Impact

Figure 9-31 shows NIPSCO's financial impact of the preferred plan over the planning period. The 30-year NPVRR is broken down into operating and capital costs. The operating costs include the fixed and variable costs associated with both existing units and future resources, as well as contract costs and net market purchases. The capital costs include all capital related costs for existing units and costs related to the acquisition of new resources in the preferred portfolio. These costs include depreciation expenses, capital charge, and taxes. In order to present a levelized net present value rate summary, the total energy forecast for NIPSCO is also discounted over the 30-year period at the same rate.

Figure 9-31: Financial Impact Summary

Financial Impact Summary	
Operating Costs ($000)	7,357,588
Capital Costs ($000)	4,405,775
Total Revenue Requirement ($000)	11,763,363
Total Energy Requirement (GWh)	203,994
Cents/kWh	5.77

Note that Total Energy Requirement is the discounted value of 30 years of energy forecasts, rather than a total sum. This is done to allow for the cents per kWh summary to be reflective of a levelized net present value calculation.

NIPSCO expects that existing cash balances, cash generated from operating activities and funding through inter-company loan arrangements with its parent company will meet anticipated operating expenses and capital expenditures associated with NIPSCO's short term action plan.

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from a number of sources including: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; (v) new equity capital and (vi) tax equity financing. NiSource, Inc. procures external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB at Fitch and Baa2 at Moody's. NIPSCO intends to fulfill its commitment in Cause No. 44688, in regard to electric related projects,

to "finance, in aggregate, any project, or set of projects in an approved plan, estimated to cost more than $100 million for which it receives a Certificate of Public Convenience and Necessity pursuant to Ind. Code Chapters 8-1-8.4, 8-1-8.5, 8-1-8.7, 8-1-8.8, or 8-1-39 with at least 60% debt capital.

9.3.4 Capacity Resource Planning With Non Dispatchable Resources

Reliable system planning fundamentally requires having enough resources available to meet customer needs at all times. As discussed in Section 4.8, the NIPSCO plans supply resources to meet its peak demand coincident with MISO system peak demand plus the required reserve margin. NIPSCO recognizes that system planning with renewable resources is more complex than with dispatchable resources and that assumptions based on today's market constructs may ultimately change. NIPSCO believes the plan outlined in the IRP is a 'low regrets' path that provides flexibility to adjust to these potential changes while managing customer cost.

Renewable resource capacity credit assumptions used in the IRP depend on the resource. The 2018 IRP modeling uses resource capacity credit roughly based on current MISO rules and are fixed over the planning horizon. For new MISO Load Resource Zone ("LRZ") 6 wind resources, the IRP modeling uses a fixed 15.6% capacity credit which is based on MISO effective load-carrying capability ("ELCC") from Planning Year 2017. ELCC is a measure of the additional load that the system can supply with an additional generator; it is ultimately a derating factor applied to the nameplate capacity of a resource in order to determine how many megawatts can be counted towards meeting a the local resource adequacy requirements of a load serving entity like NIPSCO.

For new LRZ 6 solar resources, the IRP modeling uses a fixed 50% capacity credit assumption. This assumption is based in part on current MISO methodology which sets annual UCAP based on the 3-year historical output for hours ending 15, 16, and 17 EST. Solar resources without historical data currently receive the 50% class average. NIPSCO uses this placeholder value set by MISO for 1st year operations throughout the entire modeling horizon. NIPSCO understands that MISO intends to move to an ELCC methodology for solar similar to the one used for wind when sufficient data is available.

For new LRZ 6 storage resources, the IRP modeling assumes 4 hour storage required to firm renewables (i.e. 4MWh storage creates 1MW capacity). NIPSCO understands that MISO is currently working through the stakeholder process for storage credit in response to FERC Order 841. Recent work points towards a 5% EFORd assumption and capacity credit based on 4-hour duration.

Although not modeled, renewable capacity credit is likely to change over time. NIPSCO's IRP modeling uses a UCAP assumption and renewable project size is "grossed up" to account for capacity credit. A renewable generator's contribution to meeting peak load is dynamic and depends on multiple factors including:

- Renewable generation profile –when is the unit producing energy?
- Load profile –when do customers demand energy?

- Renewable penetration levels –how much of the system is comprised of renewables?

- ISO-specific policies / methodologies

Capacity credit value and methodology is not fixed and may change. Current capacity credit methodology in MISO matches unit availability with peak load hours during the summer to arrive at a capacity credit.

However, MISO is exploring a Resource Availability and Need ("RAN") methodology that expands resource adequacy from a single summer peak view to look at seasonal needs with greater emphasis on the ability of resources to provide energy all year around. Initial solar capacity credit of 50% will likely change with Effective Load Carrying Capability analysis; both wind and solar capacity credit will change over time with increased renewable penetration levels. MISO has identified a number of available levers to mitigate reductions in resource availability including: resource diversity; geographic diversity; southwest-facing solar; solar tracking; energy storage; demand control and energy efficiency[15].

Notably, the 2018 NIPSCO IRP Preferred Plan portfolio includes many of these mitigation levers, including resource diversity through coal, natural gas, wind, solar and energy storage; geographic diversity with current and planned resources spread across and beyond NIPSCO's electric footprint; demand control; energy efficiency. Furthermore, NIPSCO will consider southwest facing solar and solar tracking in its planned procurement. NIPSCO will continue to monitor how the market evolves and incorporate it into future planning

If capacity credit rules or methodologies change, NIPSCO's IRP path can be cost-effectively scaled to adjust. If additional capacity is required, NIPSCO's modeling, based on RFP data, shows that procuring additional renewable resources is the lowest cost option. As discussed in Section 9.2, the optimization model economically selects a renewable (or renewable + storage) resource over alternatives. By not committing to any single, large asset for the majority of UCAP needs, NIPSCO can flexibly adapt as rules and technologies change.

Preferred Plan Provides Opportunities to Track Drivers that are Difficult to Quantify Today

Congestion and nodal price risk is one such driver. Energy delivery to the grid is critical to realize benefits from renewables. As part of the selection process for replacement resources identified through the RFP, NIPSCO plans to evaluate system delivery risks (market congestion impacts) associated with each project. For projects shortlisted, NIPSCO will conduct economic planning studies based on transmission congestion and variable fuel cost adjusted for purchase costs and sales revenues using the MISO Transmission Expansion Plan (MTEP) model under the Accelerated Fleet Change planning future.[16] This future assumes 26 GW of coal and natural gas retirements, 22 GW of new wind, and 14 GW of new solar in MISO by 2027. The studies will help

[15] MISO "Renewable Integration Impact Assessment". June 5, 2018. Available at https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

[16] MISO MTEP18 Futures Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results. Available at https://cdn.misoenergy.org/MTEP18%20Futures%20Summary111488.pdf

identify potential system issues with delivering the energy from multiple wind and solar installations throughout Indiana under normal and contingent operating conditions.

Forecasting is not an exact science and NIPSCO recognizes that the current analysis may not capture all potential future states of the world and is committed to tracking market evolutions and will update and incorporate into future IRPs as appropriate. Examples of potential changes include MISO evolution on ancillary services, renewable resource availability/ capacity credit forecasts, seasonal constructs, etc.

As discussed in Section 9.4, NIPSCO's short-term action plan does not commit to immediately filling the entire 2023 capacity gap but leaves room to evaluate market and technology changes on a dynamic basis.

9.4 Short-Term Action Plan

NIPSCO's short term action plan covering the period 2019 to 2022 is focused mainly on initiating the planning process for the retirement of the Schahfer 14,15,17,18 units and beginning the procurement of replacement resources. In this period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire the Schahfer coal units by the end of 2023. NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements of the units.

NIPSCO will select replacement resources identified through the 2018 All-Source RFP evaluation process, prioritizing resources with expiring federal tax incentives to achieve lowest customer cost. For the projects selected, NIPSCO will pursue the required approvals from the commission to acquire those projects. To fill any short term capacity needs during this period, NIPSCO will rely on MISO market purchases or short term PPA(s). NIPSCO will also continue to implement the filed DSM plan for 2019 to 2021

Lastly, NIPSCO will conduct a subsequent All-Source RFP solicitation to identify preferred resources to fill the remainder of the 2023 capacity need. Figure 9-32 summarizes the short term actions for the 2018 NIPSCO IRP.

Figure 9-32: Short-Term Action Plan Summary

Initiate retirement of Schahfer units 14,15,17,18 by making required notifications to MISO, NERC and other organizations
Identify and implement required reliability and transmission upgrades resulting from retirement of the units
Select replacement projects identified from the 2018 All-Source RFP evaluation process, prioritizing resources that have expiring federal tax incentives to achieve lowest customer cost
File CPCN(s) and other necessary approvals for selected replacement projects
Procure short-term capacity as needed from the MISO market or through short-term PPA
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
Conduct a subsequent All-Source RFP to identify preferred resources to fill remainder of 2023 capacity need (likely renewables and storage)
Continue implementation of filed DSM Plan for 2019 to 2021
Comply with NERC, EPA and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

9.4.1 Procurement of Preferred Resources

NIPSCO recognizes that the amount of projects that need to be acquired to support its preferred replacement plan will require much time, effort and planning. NIPSCO will utilize a multi-phase approach for acquiring those resources. As discussed in the Short Term Action Plan, in the early phases, NIPSCO will look to primarily acquire tax advantaged wind projects, with solar and solar plus storage targeted for later phases. NIPSCO will use the early phases to build the organization capabilities, repeatable processes and procedures to support later procurement phases for the need identified. NIPSCO will also seek to engage with counterparties from the 2018 all source RFP that have extensive demonstrated development, construction and operational experience with wind, solar and storage projects. Lastly, NIPSCO will look to find process efficiencies by standardizing terms and conditions in agreements with counterparties and standardizing construction oversight procedures across all projects.

9.5 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This IRP quantifies changes associated with the emerging energy market place to best accommodate risks associated with customer cost and service. No longer is it

possible to view the world in terms of choosing a simple least cost option; it is now necessary to think it terms of minimizing future environmental impacts and maximizing resource diversification all the while ensuring affordable service to customers.

The IRP process and document are ever evolving and no filed document is ever up-to-date with the world as it stands the day after filing. Rather than trying to model our future world with exact precision, this IRP seeks to utilize a broad set of scenarios assumptions in combination with advanced risk treatment using stochastics to understand and develop resource plans and portfolios that perform best under multiple potential futures.

Section 10. Customer Engagement

10.1 Enhancing Customer Engagement

NIPSCO is focused on enhancing how it serves and interacts with its customers. Whether upgrading the energy infrastructure to make sure it's prepared to meet future needs, providing more convenient options to connect with the Company in-person, online or via telephone or expanding energy efficiency programs, customers are the central focus.

10.1.1 Leveraging Stakeholder Feedback

NIPSCO relies on customer feedback to uncover service improvement opportunities. Those feedback mechanisms include the J.D. Power Customer Satisfaction Surveys, MSR Group Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's call center, as well as the IURC's Consumer Affairs Division. The Company also researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the industry. This data is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and added programs and other offerings that have been instituted in recent years.

For example, recent J.D. Power Electric Customer Satisfaction survey results have highlighted the need to expand how NIPSCO communicates with customers during power outages. As a result, the Company launched NIPSCO Alerts, which enables customers to receive updates regarding power outages, including estimated restoration time via text, email, or telephone. As part of this, NIPSCO also added the option for customers to text to report a power outage. With this new offering, NIPSCO customers can now choose the option that is most convenient for them – telephone, online (desktop and mobile) and text. These enhancements were part of why NIPSCO was recently awarded with Chartwell's top award for 2018 Outage Communications Best Practices among all utilities nationally.

10.1.2 NIPSCO's Customer Workshop Series

NIPSCO recently kicked off the 7th season of its Customer Workshop Series in partnership with Purdue University. Since 2011, hundreds of NIPSCO Transmission and C&I customers from all over northern Indiana have attended the various workshops. With topics ranging from technical (Understanding HVAC, Fundamentals of Compressed Air, Energy Savings 101, etc.) to interpersonal (Six Sigma, Managing Time & Stress, Becoming a Leader, etc.), customers are able to pick which workshops are valuable to their business and reserve openings for themselves and/or their colleagues.

Attendees are able to interact with industry experts, representatives from the NIPSCO Major Account team, as well as their peers at other companies, learning best practices and voicing their current challenges and solutions in an open, classroom setting. Each season, customers are surveyed and feedback is used to improve the subsequent season. Changes for the 2018 season included additional workshops in the South Bend area, as well as a class geared towards navigating generational changes in the workplace.

10.1.3 New Business Department

The New Business Department was formed in July of 2015 to add value for customers and stakeholders by providing a focus on new business activities for all customers (residential, and C&I). The goals include:

- Continuous improvement of the new business process "from first call to install"
- Single source accountability for policy maintenance
- Enhancing relationships with builder/developer community
- Improving metrics to inform on efficiency and effectiveness
- Supporting capital budget methodology to increase clarity
- Managing growth programs including Electric Vehicle, Feed-In Tariff, Green Power, Compressed Natural Gas

The New Business Department has responsibility for any customer that requests new service, upgrade of service, retirement of service, or relocation of service. NIPSCO's new business representatives are specifically trained in the details of these transactions and provide a resource for customer issues. Since its inception, the New Business Department has undertaken initiatives to:

- Create a single Site Readiness policy for NIPSCO
- Provide automated emails to customers with project status updates
- Revise key performance indicators to better inform on execution levels
- Simplify agreements for all customer classes
- Establish new accounting codes to provide clarity into new service costs

The New Business Department expanded in 2016 and now includes external, customer facing representatives and internal support to assist customers with their new service connections. The New Business Department continues its efforts to evaluate the new business process to determine opportunities for increased efficiency and improved customer service. An end-to-end process map has been completed, which has helped to identify additional areas of opportunity.

10.1.4 Customer Feedback

Customer feedback is essential in NIPSCO's development of customer support and service offerings to provide for an exceptional customer experience. NIPSCO utilizes an on-line group of customers to provide feedback on project offerings and channel options. NIPSCO utilized this on-line group, along with an additional in-person focus group, in the redesign of its customer bill that

launched in the spring of 2016. NIPSCO also surveys customers to determine customer satisfaction with the call center and interactions with field personnel, as well as with on-line experiences such as mobile, integrated voice response and web. Customer surveys are also used to capture specific customer issues and to gain immediate feedback on the quality of NIPSCO's customer service. NIPSCO uses the results of these surveys, as well as the information obtained through the J.D. Power Customer Satisfaction Surveys, to identify potential ways to improve the overall customer experience including training and development for customer service representatives and field personnel.

In addition to the J.D. Power Customer Satisfaction Surveys, NIPSCO also relies on customer feedback obtained through MSR Group Surveys, online customer panels, comments and complaints that are emailed or called into NIPSCO's call center, as well as the Commission's Consumer Affairs Division to discover service improvement opportunities. NIPSCO also researches best practices that have been demonstrated by those within the utility sector, as well as those outside of the utility industry. Customer feedback is the primary driver behind many of the operational changes, improvements in customer communications, enhancements to services and additional programs and other offerings that have been instituted in recent years.

10.1.5 Community Partnerships - Community Advisory Panels

Another avenue used by NIPSCO to engage with its customers and stakeholders is the use of Community Advisory Panels ("CAPs"), which serve as a forum to discuss new company initiatives and programs as well as to educate and facilitate feedback regarding service and other NIPSCO-related matters in their communities. NIPSCO has five regions across the Company's footprint for the CAPs. CAPs are comprised of individual customers as well as local government and community leaders representing a diverse, broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues. This year, as part of the development of the IRP, the CAPs were asked to design a portfolio to meet NIPSCO's electricity needs. The activity led to a great deal of discussion around the best portfolio and provided insight for NIPSCO and CAP members.

10.2 Customer Programs

10.2.1 Feed-in Tariff – Rate 765

NIPSCO's Renewable Feed-in Tariff ("FIT") Phase I was approved on July 13, 2011 in Cause No. 43922. Implementation began immediately as a three-year pilot program with a 30 MW capacity cap. Phase I offered a rate greater to participants selling electricity than the retail electric rate in the current approved sales tariffs and provided an incentive to encourage development of renewable generating resources. The pilot program was designed to help maximize the development of renewable energy in Indiana, which welcomed biomass, wind, hydro and solar resources. The FIT provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a Renewable Power Purchase Agreement ("RPPA"). Participating customers receive payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- An Interconnection Agreement ("IA") and RPPA are required to reserve capacity or enter the queue.
- The customer is responsible for interconnection fees and installation costs in accordance with the Indiana Administrative Code.
- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with the IA.

Phase I concluded in March of 2015 with a total subscription of 29.7 MW and is summarized in the Table 10-1.

Table 10-1: FIT Phase I In-Service

Technology	Total FIT (kW)
Biomass	14,348
Solar (large)	14,500
Solar (small)	690
Wind (large)	150
Wind (small)	10
New Hydro	0
Total	**29,698**

NIPSCO's FIT Phase II was approved on February 4, 2015 in Cause No. 44393. NIPSCO released Phase II, Allocation I of the FIT program in March of 2015 and Phase II, Allocation II in March of 2017. Phase II allows for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW. Table 10-2 shows the subscription for Phase II as of July, 2018.

Table 10-2: FIT Phase II Project Totals

Technology	In-service (kW)	Queue (kW)	Total FIT (kW)
Micro Solar	110	74	184
Intermediate Solar	3,576	4,380	7,956
Micro Wind	20	0	20
Intermediate Wind	0	1,000	1,000
Biomass	0	0	0
Total	3,706	5,454	9,160

With over 37 MW currently interconnected in the FIT program, as of December 31, 2017, NIPSCO has a total metered generation from customers selling electricity of 473,379,090 kWh.

Table 10-3 shows the annual production and growth by technology segment.

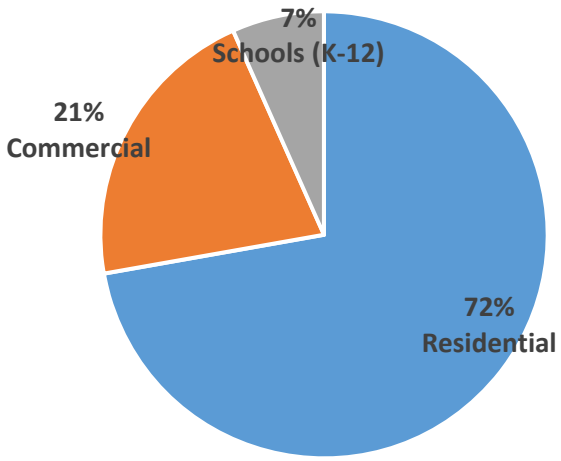
Table 10-3: Annual Production by Technology – Generation (kWh)

Technology	2011	2012	2013	2014	2015	2016	2017	*Total*
Biomass	6,219,791	19,152,432	31,602,728	49,916,700	81,369,723	83,552,339	89,486,440	**361,300,153**
Large Solar	-	433,758	15,789,457	21,665,115	22,436,103	22,696,839	24,391,349	**107,412,621**
Small Solar	-	118,895	471,806	718,758	818,332	825,066	848,789	**3,801,646**
Large Wind	-	-	90,113	165,880	217,949	165,593	167,807	**807,342**
Small Wind	-	3,588	15,721	12,051	9,462	8,019	8,487	**57,328**
Total	**6,219,791**	**19,708,673**	**47,969,825**	**72,478,504**	**104,851,569**	**107,247,856**	**114,902,872**	**473,379,090**

10.2.2 Net Metering – Rider 780

NIPSCO's Net Metering Rider allows customers to install renewable energy generation to offset all or part of their own electricity requirements. Net metering is the measurement of the difference between the electricity that is supplied by NIPSCO and the electricity that is supplied back to NIPSCO by an eligible net metering customer. Production is measured on a kWh basis. To be eligible, a customer must be in good standing and operating a solar, wind, biomass or hydro generating facility that has a nameplate capacity less than or equal to 1 MW. NIPSCO follows the rules and guidelines set forth in the Indiana Administrative Code with respect to Net Metering and the interconnection process. Customers with a fully executed Net Metering Agreement and Interconnection Agreement receive a credit for each kWh provided to NIPSCO above their own usage requirement. NIPSCO's Net Metering program capacity cap is limited to 45 MW and total subscription is as of December 31, 2017 was 10.69 MW. The total measured generation by the Net Metering customers for 2017 was 3,667,721 kWh. The current classification of NIPSCO's 270 Net Metering customers is shown in Figure 10-1.

Figure 10-1: Classification of Net Metering Customers



10.2.3 Electric Vehicle Programs (Phase I and Phase II) – Rider 785

10.2.3.1 NIPSCO IN-Charge Electric Vehicle Program – At Home (Phase I)

NIPSCO's IN-Charge Electric Vehicle ("EV") Pilot Program was approved on February 1, 2012 in Cause No. 44016 through January 31, 2016. NIPSCO launched its IN-Charge Electric Vehicle Program - At Home on April 2, 2012. On October 29, 2014, the Commission approved NIPSCO's 30-day filing to extend its EV Program an additional two years through January 31, 2017. Under the extended EV Program, the incentive of up to $1,650 per customer continued for a period through January 31, 2017 or until such time as the funds were depleted, which occurred earlier. As of June 30, 2016, 250 customers had received program incentives, exhausting the funds available for customer incentives. On January 11, 2017, in Cause No 44828, the Commission approved NIPSCO's request for a modification of its EV Program to provide that participants of record as of January 31, 2017 would be subject to an energy charge of $070894 per kilowatt hour for all kilowatt hours used per month in the PEV Off-Peak Hours, plus all applicable Riders for a period of 23 months. This program expires on December 31, 2018.

As of January 31, 2018, NIPSCO had received 382 customer enrollment requests. Estimates for installation costs, including the cost of a home EV charger, ranged from $667 to $6,325 with an average of $2,062. The average incentive amount used by customers with completed installations was $1,629.

The Bureau of Motor Vehicle registrations that show registrations in counties that NIPSCO has electric service in are as follows:

Table 10-4: NIPSCO's Electric Vehicle Customer Request Breakdown

Row Labels	2014	2015	2016	2017
BENTON	1	1	1	3
DEKALB	1	4	18	18
ELKHART	33	45	63	78
FULTON	4	5	5	4
JASPER	4	7	11	18
KOSCIUSKO	12	17	22	32
LAKE	116	154	185	250
LAPORTE	17	30	40	62
MARSHALL	7	8	9	14
NEWTON	2	2	2	7
PORTER	68	84	107	140
PULASKI		1	2	4
SAINT JOSEPH	50	71	87	148
STARKE	1	3	3	5
STEUBEN	3	6	10	18
WHITE	2	5	5	7
Grand Total	**321**	**443**	**570**	**808**

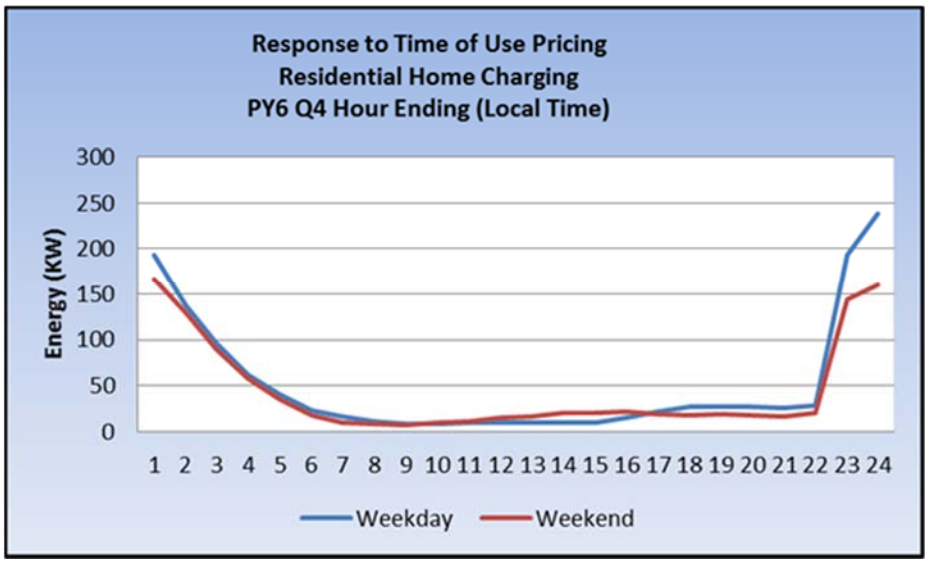
On average, EV customers that were a part of NIPSCO's pilot program used approximately 220 kWh per month to charge their electric vehicle. The actual amount of consumption will vary by individual customer. Customer vehicle type will impact the consumption significantly as well as the demand on the grid. A Tesla Model S charging demand is 10 kW, while a Chevrolet Volt charging demand is only 3.3 kW. The Nissan Leaf charging demand ranges from 3.3 kW to 6.6 kW depending on the options installed in the car. To put demand in perspective, an average size residential home has approximately 33 kW in connected load of which, on average, 18 kW might be on during coincidental peak time. For comparison, typical residential demand breakdown by appliance is listed below:

- Water Heater – 4.5 kW
- Range / Oven – 8.0 kW
- Central Air Conditioner – 6.0 kW
- Clothes Dryer – 5.0 kW
- Dishwasher – 2.0 kW
- Lighting, Fans, Appliances, Other – 7.5 kW

NIPSCO's Rate Case Order indicates that its typical residential electric customer used 698 kWh per month on average during the weather normalized test year. The average EV consumption during the pilot period was approximately 220 kWh or approximately 31 percent of the average home consumption. The type of vehicle purchased and the number of miles driven by the customer will directly impact the average consumption of the vehicle for each individual customer.

NIPSCO found that the "free" energy and discounted energy during the off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior during the pilot. The typical usage by hour over the recent three month period analyzed (November 2017 through January 2018) is shown in Figure 10-2. The vast majority of the time, EV residential customers began their charging session at 10 p.m. when the energy discounted period began and their vehicles were fully charged by 6 a.m. when the energy discounted period ended. As predicted, the total energy consumption was higher during the work week, when owners typically drove their vehicles more than they did on weekends. The analysis indicates that time of use rates do have an impact on pushing 80% of EV loads to more preferred off-peak time for utilities.

Figure 10-2: Response to Time of Use Pricing



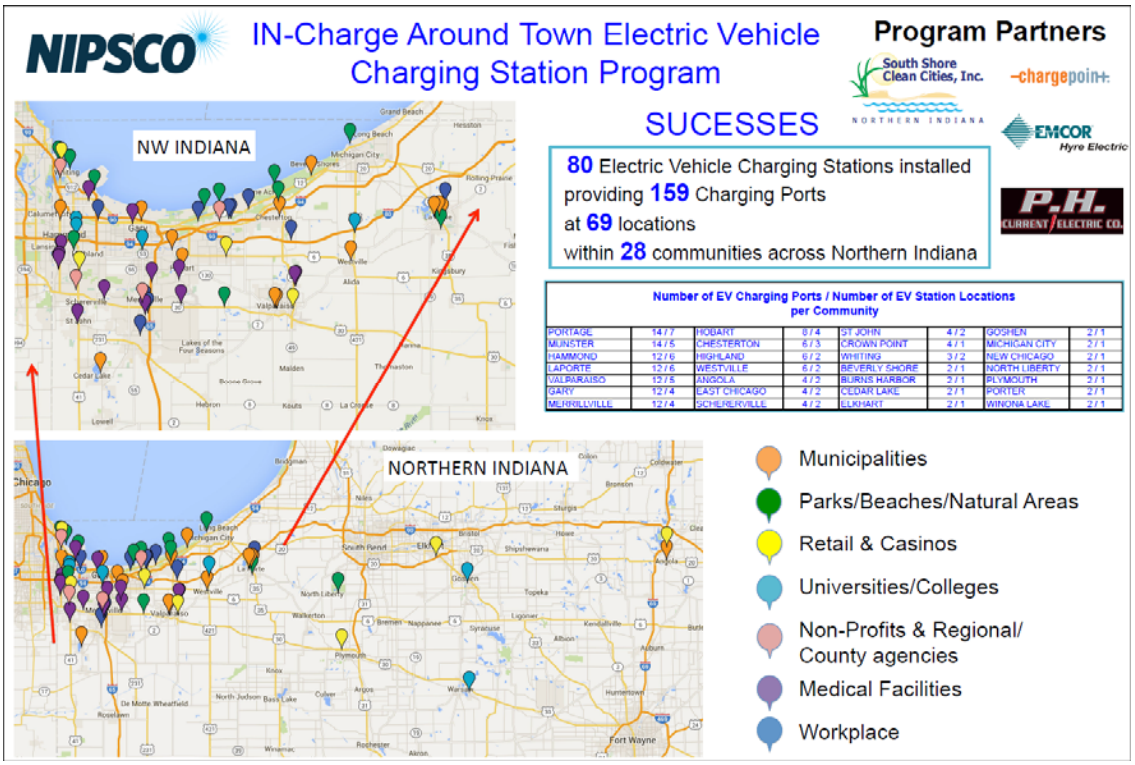
10.2.4 NIPSCO IN-Charge EV Program – Around Town (Phase II)

NIPSCO partnered with South Shore Clean Cities to expand opportunities for alternative fuel, through the launch of a public charging station incentive program in February 2014. The NIPSCO IN-Charge EV Program – Around Town made it easier and more affordable for businesses and organizations to install public charging infrastructure. The In-Charge – Around Town program was available to commercial / industrial electric customers across northern Indiana and was offered until program funds were exhausted in June 2016.

For every unit of electricity used by IN-Charge Around Town charging stations during the program, NIPSCO bought an equivalent amount of renewable energy certificates ("RECs") – the environmental attributes associated with electricity that is generated from renewable sources, such as wind power.

As of June 30, 2016, NIPSCO had installed 80 public charging stations providing 159 charging ports at 69 locations. Figure 10-3 shows a map of the station locations and application status:

Figure 10-3: Station Locations and Application Status



10.2.5 Green Power Program – Rate 760

NIPSCO's Green Power Rider ("GPR") program was approved on December 19, 2012 in Cause No. 44198 through December 31, 2014. NIPSCO's request for extension of its GPR Program, with certain modifications, and as a component of NIPSCO's approved tariff on a non-pilot basis, was approved on December 30, 2014 in Cause No. 44520. The GPR Program is a voluntary program that allows customers to designate a portion or all of their monthly electric usage to be attributable to power generated by renewable energy sources. Customers can enroll online or by calling NIPSCO. .

Green Power is energy generated from renewable and/or environmentally-friendly sources or a combination of both, which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of Green Power include: solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green Power includes the purchase of RECs from the sources described above. For the GPR Program, NIPSCO's residential electric customers can designate 25%, 50% or 100% of their total electricity usage to be attributable to Green Power. In addition to those options, NIPSCO's C&I customers also have the option to designate 5% or 10% of their total electricity usage to be attributable to Green Power. As of December 31, 2017, 1,191 customers were participating in the GPR Program. Figure 10-4 shows the breakdown among residential customers as of December 31, 2017.

Figure 10-4: Residential Customer Count

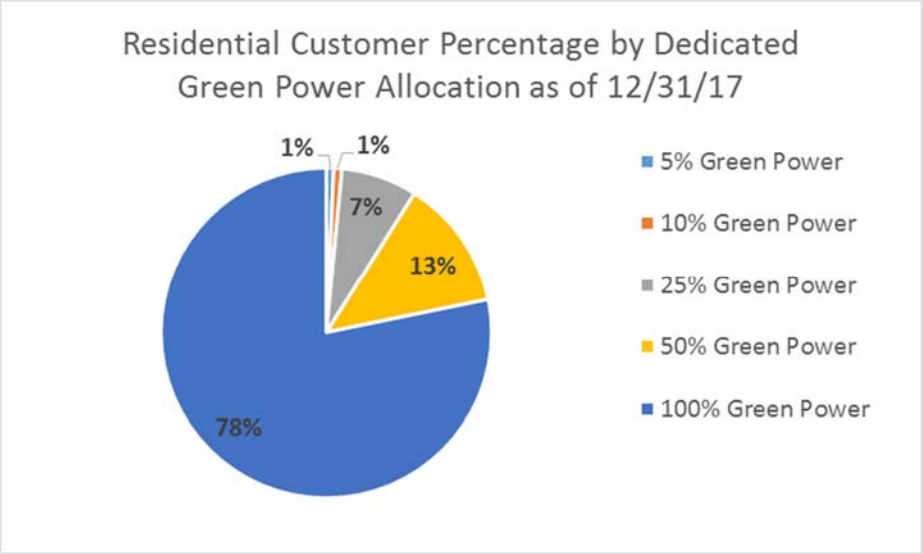
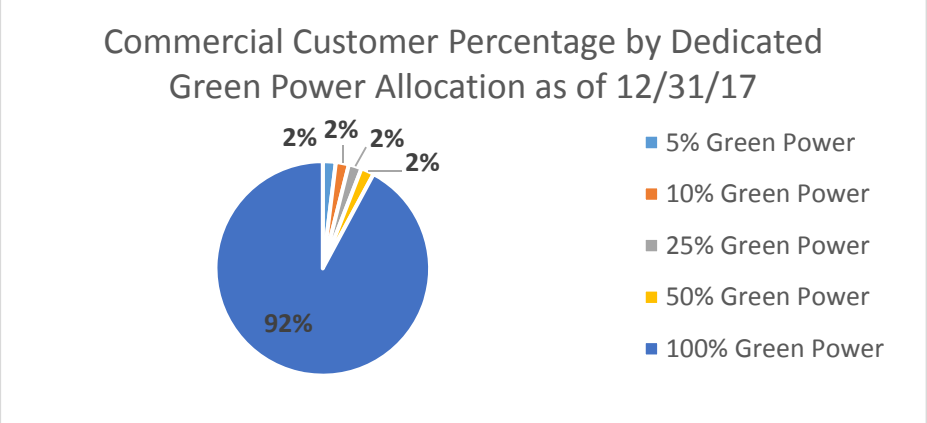


Figure 10-5 shows the breakdown of commercial and industrial customers as of December 31, 2017.

Figure 10-5: Commercial Customer Count



NIPSCO's GPR Program for the period of January 1 through December 31, 2017 accounted for 18,274,702 kWh energy consumption designated as Green Power. Residential customers accounted for 6,973,682 kWh of energy consumption and commercial and industrial customers accounted for 11,301,020 kWh of energy consumption of designated Green Power. For both residential and commercial customers, the majority of the GPR Program enrollments designate 100% of their energy as Green Power. Table 10-5 shows the energy consumption designated as Green Power for participating customers by rate for the period January 1 through December 31, 2017.

Table 10-5: 2017 Green Power Customers by Rate (kWh)

Rate	Participation %	17-Jan	17-Feb	17-Mar	17-Apr	17-May	17-Jun	17-Jul	17-Aug	17-Sep	17-Oct	17-Nov	17-Dec	TOTAL
760	100%	986	856	796	808	644	669	639	620	770	771	904	722	9,185
711	5%	455	364	294	256	219	305	387	390	320	293	241	267	3791
	10%	833	689	594	581	616	886	986	941	745	665	625	600	8,761
	25%	13,075	12,096	11,807	10,064	9,510	14,579	17,815	17,464	14,349	12,998	10,762	11,936	156,455
	50%	48,352	39,945	37,771	37,629	33,844	51,781	62,997	61,220	49,347	44,746	38,478	41,564	547,674
	100%	574,872	483,575	431,576	427,760	372,190	540,691	677,110	673,250	570,611	519,354	465,081	520,931	6,257,001
721	5%	-	-	-	-	-	173	183	174	143	149	115	109	1,046
	10%	1,959	1,515	1,651	1,667	1,681	1,968	1,720	1,888	1,696	1,728	1,496	1,408	20,377
	25%	182	126	169	213	146	223	264	275	177	116	88	96	2,075
	50%	718	569	629	639	961	1,013	1,413	1,451	960	602	382	470	9,807
	100%	91,908	80,847	73,865	65,371	59,997	58,862	65,804	72,766	72,342	72,219	70,681	78,300	862,962
723	5%	3,360	-	-	-	-	-	-	-	-	-	-	-	3,360
	100%	50,800	54,040	52,280	40,640	47,320	46,000	42,280	49,520	49,280	43,960	48,600	44,640	569,360
724	100%	363,168	408,176	465,600	450,080	471,808	530,784	523,024	532,336	412,832	445,424	394,208	388,000	5,385,440
726	100%	337,152	341,632	354,160	356,064	397,232	453,792	421,904	418,400	398,128	370,656	299,568	288,720	4,437,408
TOTAL		1,487,820	1,424,430	1,431,192	1,391,772	1,396,168	1,701,726	1,816,526	1,830,695	1,571,700	1,513,681	1,331,229	1,377,763	18,274,702

Participating customers are billed under their current applicable rate, with a separate line item showing the premium to participate in the GPR Program. This premium is calculated by multiplying the GPR Rate by the kWhs the customer specifies to be subject to the GPR. Table 10-6 shows the Green Power premiums applicable during the period January 1, 2017 through December 31, 2018.

Table 10-6: Green Power Premiums

January 2017 through December 2017	January 2018 through June 2018	July 2018 through June 2019
$0.001640	$0.002940	$0.001805

10.3 Corporate Development and Community Support

10.3.1 Supporting Economic Growth

NIPSCO partners with community leaders and state, regional, and local economic development organizations to attract and support the expansion of new and existing businesses and to help create more jobs across the NIPSCO's service territory. In addition to being one of the largest employers in the region, NIPSCO spends $1.1 million in economic development efforts each year, which has resulted in 67 new businesses or expansions and 7,500 local jobs in the last 10 years.

NIPSCO's Rider 777 – Economic Development Rider ("EDR") offers discounts on existing tariff services for qualifying projects that bring new jobs and investment from outside its

service territory. When coupled with local and state incentives, a powerful package is created with often positive results.

Even with the continued growth, NIPSCO's transmission and distribution system is designed to provide all customers with reliable energy services, and NIPSCO's resource plans focus on maintaining and developing resources in NIPSCO's service territory. Additionally, the investments NIPSCO is making to modernize and upgrade its energy infrastructure continue to have a positive, direct impact on local businesses.

10.3.2 Supplier Diversity

Cultivating a diverse pipeline of suppliers helps innovate ideas and processes, gain a competitive advantage and benefit NIPSCO's communities. NIPSCO has created a supplier diversity program that strengthens and widens the playing field for qualified suppliers that are typically underutilized in the supply chain of a large corporation.

In 2017, NIPSCO's direct supplier spend in Indiana was $155 million, and the direct supplier spend with diverse Indiana businesses was $40 million.

10.3.3 Workforce Development

NIPSCO continues to lead efforts and partnerships focused on workforce development – both for the current and future workforce generations. Some of the highlights include:

- **Ivy Tech Partnership for Energy Industry Training Program:** Program began in 2009 and provides training in electric-line, power plant technology and gas technology areas. NIPSCO has hired more than 50 students from the program and graduates are guaranteed an interview opportunity. Additionally, NIPSCO provides instructors for these training classes and recently provided a full-scale electric distribution system for training purposes built within the Ivy Tech Valparaiso campus energy technology lab – the only such facility in an educational setting in Indiana.

- **NIPSCO Energy Academy:** Started in 2014, the NIPSCO Energy Academy program is a partnership designed to prepare area students for high-demand jobs in the electronics, energy and utility industries. It is the first initiative of its kind in Indiana, and it will serve students from Michigan City High School, LaPorte High School, New Prairie High School, South Central High School, LaCrosse High School and Westville High School. Participants have entered the Ivy Tech program and are in the Apprentice Program at the International Brotherhood of Electrical Workers (IBEW), with more than 100 students that have gone through the program.

- **IN-Power Youth Mentoring Program:** IN 2010, NIPSCO introduced the IN-POWER Youth Mentoring Program – a unique mentoring program for local high school students that takes a holistic approach to developing a more highly skilled future workforce in the energy sector. The program was expanded with IN-

POWER STEM PLUS, designed to give 7th and 8th grade students a firsthand experience on gas and electric safety, while teaching them about the various aspects of science, technology, engineering and math needed in the energy sector. NIPSCO employees and American Association of Blacks in Energy (AABE) Indiana members serve as mentors and instructors. Participants receive college credits, unique mentoring and internships among other opportunities.

- **Junior Achievement Support:** NIPSCO provides annual support for classroom business education programs through both contributions and volunteer instructors across NIPSCO's service area. For the last several years, NIPSCO has supported a "JA Day" in a local Hammond school.

- **City of Gary Summer of Opportunity Job Program:** The Summer of Opportunity places youth in meaningful work opportunities throughout the City of Gary, with Lunch & Learn workshops featuring local professionals with every other session focusing on financial literacy. Local youth staff six summer program sites that offer summer meals and learning. Mayor Karen Freeman-Wilson, NIPSCO, Gary Youth Services Bureau, Urban League of NWI and the Gary Chamber of Commerce have partnered to create a set of supports that enable strong transitions from school year to school year and from high school to college and career**.**

- **Girl Scouts Engineering Day:** For more than 5 years, NIPSCO has hosted more than 125 girls from kindergarten to fourth grade for the annual Introduce a Girl to Engineering Day. The girls come from local Girl Scout troops along with some young relatives of NIPSCO and NiSource employees. The four hour event is part of the company's efforts to help build the next generation of female leaders, support local communities and provide opportunities for local students interested in Stem related careers**.** The event was organized by the employee resource group Developing and Advancing Women at NiSource (DAWN).

10.3.4 Corporate Citizenship

NIPSCO believes that reinvesting in the communities where its employees live and work will enhance the quality of life for everyone. Each year, NIPSCO and its employees donate time, money, and other resources to hundreds of local philanthropic programs and organizations across its 30-county service area, focusing on:

- Basic Human Needs
- Education
- Public Safety & Emergency Response
- Environmental Stewardship

- Economic Development

Through these programs and partnerships, NIPSCO is working hard with its communities to build a brighter future for years to come. In 2017, NIPSCO and the NiSource Charitable Foundation contributed more than $1.78 million to local organizations throughout its service territory.

A highlight of those effort is NIPSCO's annual Charity of Choice campaign, where employees select one nonprofit organization or an area of need to support. Fundraisers, volunteerism and other activities are planned throughout a summer-long, employee-led campaign. Recent benefactors and causes selected by employees have included autism, veterans, Boys and Girls Clubs, the American Heart Association, the American Red Cross and more.

10.3.5 Volunteerism

NIPSCO employees have a passion for volunteering and giving back to their local communities. Through a program called "Dollars for Doers," cultivated by NiSource, employees translate their community service into financial support for organizations they care about most. The program contributes up to $500 per employee to an organization in return for volunteer time. In 2017, NIPSCO employees contributed 5,535 volunteer hours, equating to $110,700 donated to charities of their choice. Additionally, NIPSCO employees volunteer their personal time and resources with more than 100 local nonprofit boards, associations and other local community efforts each year.

List of Appendices

Appendix A	Public Advisory Meetings
Exhibit 1	Public Advisory Meeting 1
Exhibit 2	Public Advisory Meeting 2
Exhibit 3	Public Advisory Meeting 3
Exhibit 4	Technical Webinar
Exhibit 5	Public Advisory Meeting 4
Exhibit 6	Public Advisory Meeting 5
Appendix B	DSM Reports
Exhibit 1	2016 Market Potential Study
Exhibit 2	DSM Savings Update
Appendix C	Overview of Aurora Portfolio Model
Confidential Appendix D	Hourly Load Shapes and Duration Curve, Seasonal Load Shapes, Scenarios and Sensitivities, Scenario Planning Variable Breadth and Diversity, Sensitivity Modeling Results, NIPSCO Unit Retirement Analysis, Scenarios and Sensitivity Results
Confidential Appendix E	Sargent & Lundy Engineering Study Technical Assessment
Confidential Appendix F	NIPSCO FERC Form 715

Section 11. Compliance with Proposed Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(d) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents: (1) The integrated resource plan.	Submitted via email and hand delivery on October 31, 2018
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.	Confidential Appendix D
(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) the IRP public advisory process; and (vi) any additional details the commission staff may request. (B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	Executive Summary
(e) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following: (1) The name and address of each known entity considered by the utility to be an interested party. (2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information: (A) A general description of the subject matter of the submitted IRP. (B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 90 days of the IRP submittal.	Transmittal Letter

Rule	Section(s)
An interested party includes any business, organization, or customer that participated in the utility's previous public advisory process. A utility is not required to separately notify all of its customers. (3) A statement that the utility has served a copy of the documents submitted under subsection (d) above on the office of the consumer counselor.	
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) A municipally owned utility; (2) A cooperatively owned utility; and (3) A utility submitting an IRP under subsection 2(b) of this rule. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the commission, and its staff. (d) The utility retains full responsibility for the content of its IRP.	N/A
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable energy and non-energy benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and its rationale. (2) The utility is encouraged to hold additional meetings as appropriate. (3) The schedule for meetings shall be determined by the utility and shall:	Section 2.1, Appendix A

Rule	Section(s)
(A) be consistent with its internal IRP development schedule; and (B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP. (4) The utility or its designee shall: (A) chair the participation process (B) schedule meetings; and (C) develop and publish to its website agendas and relevant material for those meetings at least seven calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen calendar days following each meeting; (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility. (6) The utility shall take reasonable steps to notify its customers; the commission; and interested parties of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	
(a) The commission or its staff may host an annual technical conference to facilitate: (1) identifying contemporary issues; (2) identifying best practices to manage contemporary issues; and (3) instituting a standardized IRP format. (b) The agenda of the technical conference shall be set by the commission staff. Utilities and interested parties may request commission staff include specific contemporary issues and presenters. (c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed. The utility shall address the designated contemporary issues in its next IRP. In addition, prior to its next IRP the utility shall provide to interested parties either a discussion of the impacts of such issues on its IRP or describe how it has taken the contemporary issues into account.	N/A
(d) A utility shall address new issues raised in a contemporary issues technical conference if the contemporary issues technical conference occurred at least one (1) year prior to the submittal date of a utility's IRP.	Section 2.2.1
170 IAC 4-7-4: Integrated Resource Plan Contents	
An IRP must include the following:	

Rule	Section(s)
(1) At least a 20 year future period for a predicted or forecasted analysis.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.	Section 3.2 Section 3.3 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.8 Section 3.8 Section 3.9 Section 3.10 Section 3.11
(3) At least three alternative forecast scenarios of peak demand and energy usage in compliance with subsection 5(b) of this rule.	Section 3.11 Section 3.12
(4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.	Section 4.3 Section 4.4 Section 4.5 Section 5.1
(5) A description of possible alternative methods of meeting future demand for electric service in compliance with subsection 6(b) of this rule.	Section 5.1 Section 5.4
(6) The resource screening analysis and resource summary table required in subsection 7(a) of this rule.	Section 4.9 Confidential Appendix F
(7) The information and calculation of tests required for potential resources in compliance with subsections 7(b)-7(e) of this rule.	Confidential Appendix B
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.	Section 8.1 Section 8.3 Section 8.4 Section 8.5 Section 9.2 Section 9.3Appendix F
(9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(b) of this rule.	Section 9.2 Section 9.3
(10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.	Section 1.1 Section 9.4
(11) A discussion of the inputs; methods; and definitions used by the utility in the IRP.	Section 2 Section 3.2 Section 4.4 Section 4.9

Rule	Section(s)
	Section 5.1 Section 5.2 Section 5.5 Section 5.6 Section 7.3 Section 8.1 Section 8.2 Section 8.4 Section 9.2 Section 9.3Appendices A through D and Confidential Appendices J
(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 9(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of any adjustments made to the data. The data must be submitted with the IRP in a manipulable format.	Appendix D
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Section 3.2.1 See Note 1
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Section 3.2
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	See Note 2

Rule	Section(s)
(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 3.2 Section 5.2
(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.	Section 9 Section 6.2 Section 10.2.1 Section 10.2.2
(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Appendix A Appendix C
(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 4.1
(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.	Section 7.4
(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 7.3 Section 8.2.3
(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan.	Section 9.3 Section .2.3
(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources that are certain. Existing laws or policies continuing throughout at least some portion of the planning horizon with a high	Section 9.3

Rule	Section(s)
probability of expiration or repeal must be eliminated or altered when applicable. (C) Not include future resources, laws, or policies unless the utility receives stakeholder input on the inclusion and it meets the following conditions: (i) Future resources have obtained regulatory approvals. (ii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	
(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 9.3
(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) the limits of the utility's transmission use; (ii) the utility's assessment practices developed through experience and study; and (iii) operating restrictions and limitations particular to the utility.	Confidential Appendix F
(27) A list and description of the contemporary methods utilized by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	Section 2.2 Section 3.2 Section 8.1 Section 8.3 Section 8.4 Section 9.3 Appendix B Appendix C

Rule	Section(s)
(28) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Section 5.2 Appendix B
(29) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically in a manipulable format. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Section 3.1 Appendix C
(30) A summary of the utility's most recent public advisory process, including: (A) Key issues discussed. (B) How the utility responded to the issues (C) A description of how stakeholder input was used in developing the IRP.	Section 2.1 Appendix A
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 4.9 Section 5 Appendix B Confidential Appendix E
170 IAC 4-7-5: Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Section 3 Appendix C,
(2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.	Section 3.3 Section 3.4 Section 3.5

Rule	Section(s)
	Section 3.6 Section 3.7 Section 3.11
(3) Actual and weather normalized energy and demand levels.	Section 3.11
(4) A discussion of methods and processes used to weather normalize.	Section 3.10
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Section 3.11 Section 3.12
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes, rate classes, or both. (C) Firm wholesale power sales.	Section 3.13
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2
(8) Justification for the selected forecasting methodology.	Section 3
(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data, such as described in subdivision 4(10) of this rule.	No Response Needed
(b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices, including competition. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 3.12
(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process.	Section 3.2
170 IAC 4-7-6: Resource Assessment	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information:	Section **Error! Reference source not found.** Section 4.5

Rule	Section(s)
(1) The net dependable generating capacity of the system and each generating unit.	
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.9 Section 4.10 Section 9.1
(3) A fuel price forecast by generating unit.	Section 8.1.2
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	Section 4.4.1 Section 4.4.2 Section 4.4.3
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	Section 5.4 Section 6.1.6 Section 6.1.7 Section 6.1.8
(6) A discussion of DSM programs and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Section 3.2 Section 5.1 Section 5.6 Appendix B
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Innovative rate design as a resource in meeting future electric service requirements.	Section 5.2
(2) Demand-side resources, including Demand response programs, and Energy efficiency programs. For a demand-side resource identified in the IRP, the utility shall, include the following:	Section 5.2 Section 5.5 Appendix B

Rule	Section(s)
(A) A description of the program considered. (B) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to programs under consideration such as project life and seasonal operation. (C) The customer class or end-use, or both, affected by the program. (D) A participant bill impact projection and participation incentive to be provided in the program. (E) A projection of the program costs to be borne by the participant. (F) Estimated annual and lifetime energy (kWh) and demand (kW) savings per participant for each program. (G) The estimated program penetration rate and the basis of the estimate. (H) The estimated impact of a DSM program on the utility's load, generating capacity, and transmission and distribution requirements. (I) whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	See Note 3
(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including: (i) Size (MW). (ii) Utilized technology and fuel type. (iii) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Section 4.4 Section 4.5 Section 4.9
(4) transmission facilities as a resource including new projects, upgrades to transmission facilities, efficiency improvements, and smart grid technology.	Section 6.1.7 Section 6.1.8 Section 6.2
In analyzing transmission resources, the utility shall include the following: (A) A description of the timing, types of expansion, and alternative options considered.	Section 6.1.7 Section 6.1.8 Section 6.2
(B) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.7 Section 6.1.8

Rule	Section(s)
(C) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 6.1.3
(D) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Section 6.1.3
170 IAC 4-7-7: Selection of Resources	
(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 4.9 Section 5.3 Section 5.4
(b) The following information must be provided for a resource selected for further analysis: (1) A description of significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge. (2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan and the commission analysis to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	Confidential Appendix E
(c) For each DSM program analyzed under this section, the IRP must include one (1) or more of the following tests to evaluate the cost-effectiveness of the program. (1) Participant cost test. (2) Ratepayer impact measure. (3) Utility cost test. (4) Total resource cost test. (5) Other reasonable tests accepted by the commission.	Section 5.5 Appendix B
(d) A utility is not required to calculate a test result in a specific format.	N/A

Rule	Section(s)
(e) For each program in subsection (c), a utility must calculate the net present value of the program's impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the interest rate used in the net present value calculation.	Section 5.5 Appendix B
(f) For a test performed under subsection (c), an IRP must: (1) specify the components of the benefit and the cost for the test; and (2) identify the equation used to calculate the result.	Appendix B
(g) If a reasonable cost-effectiveness analysis for a program cannot be performed using the tests in subsection (c), because it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	N/A
(h) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios. In selecting the candidate resource portfolios, the utility shall consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Section 8.3
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential futures. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s). (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2 Appendix D
(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Section 9.3
(2) Identification of the variables used.	Section 9.3

Rule	Section(s)
(3) Identification of the standards of reliability.	Section 9.3
(4) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.3
(5) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 9.2.3
(6) An analysis showing the preferred resource portfolio utilizes, to the extent practical, all economical supply-side resources and demand-side resources as sources of new supply.	Section 9.3
(7) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten years of the planning period.	Section 5.3 Appendix B
(8) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Section 9.3.3 Confidential Appendix E
(9) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (x) operating costs; (v) construction costs; (vi) resource performance;	Section 9.3

Rule	Section(s)
(vii) load requirements; (viii) wholesale electricity and transmission prices; (ix) RTO requirements; and (x) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(10) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including the following changes: (A) The demand for electric service. (B) The cost of a new supply-side resources or demand-side resources.. (C) Regulatory compliance requirements and costs. (D) Changes in wholesale market conditions. (E) Changes in fuel costs. (F) Changes in environmental compliance costs. (G) Changes in technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Section 9.3
(11) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 2.2
170 IAC 4-7-9: Short Term Action Plan	
(a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. (b) The short term action plan must include, but is not limited to, the following: (1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio.	Section 1.1 Section 9.4

Rule	Section(s)
(B) The criteria for measuring progress toward the objective. (2) Identification of energy efficiency goals for implementation of energy efficiency that can be produced by reasonably achievable, cost effective plans developed in accordance with 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives. (3) The implementation schedule for the preferred resource portfolio. (4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	
Note 1: NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumption patterns by DSM program. The savings associated with DSM programs are gauged and claimed based on various technical resource manuals ("TRMs"), including the Indiana TRM, and the DSM programs are evaluated by program year by a third party EM&V administrator. NIPSCO will continue to consider its options. NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumptions patterns by end use.	
Note 2: As part of its DSM functions, DSM programs are evaluated by program year by a third party EM&V administrator. As part of the EM&V process, the administrator surveys a sample of customers who have and have not participated in NIPSCO's DSM program. NIPSCO is currently conducting a MPS that will include primary data. In addition, NIPSCO has previously completed lighting and market effect studies. NIPSCO is considering using customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns as part of its updated MPS.	
Note 3: Customer bill impacts are calculated directly utilizing the customer rate and the savings of each measure/participant. Appropriate escalators and discount rates are used to determine the NPV of these savings and then Aggregated across all measures/participants. Incentives are also included in the cost benefit analysis as an input on a per participant/measure basis. Appropriate escalators and discount rates are applied and the NPV calculated.	

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 72
NIPSCO 2021 IRP



Northern Indiana Public Service Company LLC

2021
Integrated Resource Plan

November 15, 2021





NIPSCO

2021 INTEGRATED RESOURCE PLAN

SUMMARY



NIPSCO®
A NiSource Company

NIPSCO.com


479,000 NORTHERN INDIANA
HOMES AND BUSINESSES IN
20 COUNTIES DEPEND ON NIPSCO
EACH DAY FOR SAFE, RELIABLE
AND AFFORDABLE ENERGY

BACKGROUND

Three years after announcing our electric generation transition plan, branded “Your Energy, Your Future,” NIPSCO is proud to serve Northern Indiana families and businesses with safe and reliable energy every day. Our company’s customer-centric “Your Energy, Your Future” initiative includes the electric generation transition plan at NIPSCO, and is our balanced approach to deliver lower-cost, sustainable and reliable energy for future generations. NIPSCO presents this plan to the Indiana Utility Regulatory Commission (IURC) every three years.

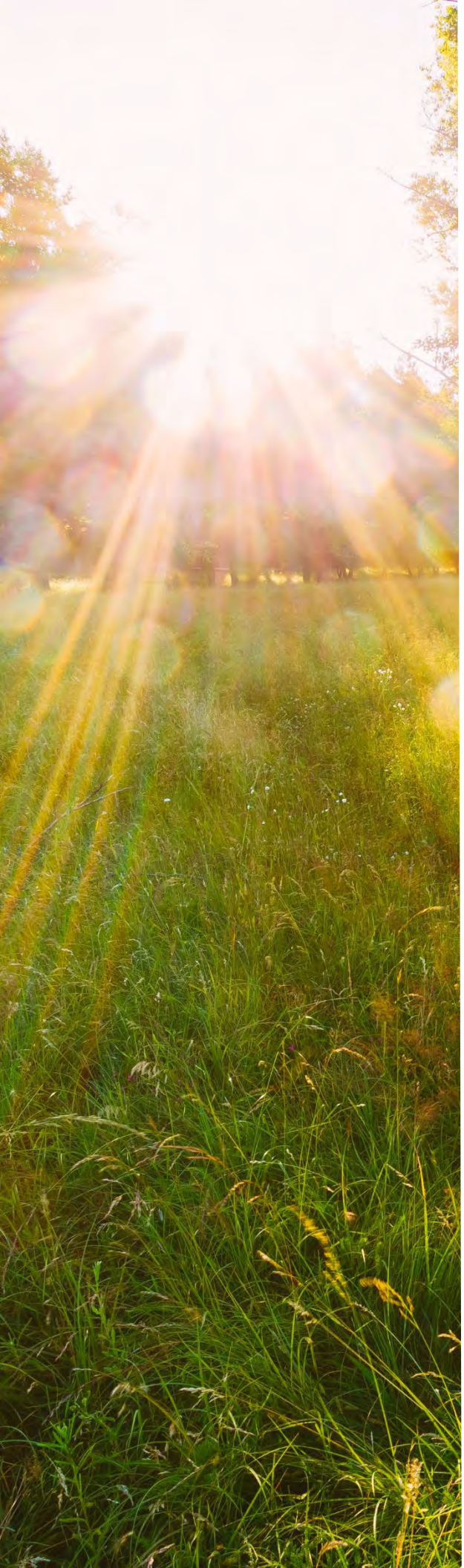
Since NIPSCO introduced our plan in 2018, we debuted two operating wind farms and have begun transitioning our employees to new roles after the retirement of two coal-fired units at R.M. Schahfer Generating Station in Wheatfield, Indiana. We look forward to soon adding 12 more renewable projects that are currently in development and projected to be operational by the end of 2023.

As we evolve alongside our communities and the changing energy landscape, we use a forward-looking analysis framework to create an Integrated Resource Plan (IRP), which establishes a road map for near-term electric portfolio decisions and our long-term vision. Our process involves a comprehensive analysis of our future energy mix, informed by valuable input from numerous stakeholders including customers, regulators, and local community leaders.

NIPSCO’s industry-leading plan creates a vision for the future that keeps our customers’ best interests at the forefront. It is consistent with our goal to transition to the best cost and cleaner electric supply mix while maintaining reliability, diversity and flexibility for the technology and market changes on the horizon.

YOUR ENERGY YOUR FUTURE





ABOUT THE 2021 INTEGRATED RESOURCE PLAN

Our IRP charts a path to best meet the energy needs of our customers for the next 20 years, and it is updated every three years. The 2021 plan reflects the dynamic changes taking place in the electric industry, the changing needs and behaviors of our customers, and the subsequent evolving policy and market rules.

Our 2021 IRP captures this evolving environment and creates a highly flexible plan that achieves the following:

- Refines the window to retire all remaining coal-fired generation to between 2026 and 2028, with our largest plant retired by 2023
- Retires aging gas peaker units between 2025 and 2028
- Replaces retired generation resources with a diverse, flexible, and scalable mix of incremental resources, including short-term contracted capacity resources, expanded demand side management programs, solar, large battery energy storage, and new gas peaking resources
- Explores potential hydrogen generation pilots and emerging energy storage technologies on the path toward further decarbonization of the generation portfolio
- Continues on the trajectory of reducing carbon emissions* from generation by 90% (from a 2005 baseline) by 2030 identified in the 2018 IRP and illuminates the pathway for further emissions reductions

* NIPSCO may sell in the future and has previously sold the Renewable Energy Credits from renewable generation to a third party.

NIPSCO IS INTEGRATED INTO THE BROADER ENERGY MARKETPLACE

NIPSCO's service territory and resources are part of the Midcontinent Independent System Operator (MISO) power market, specifically located within Local Resource Zone 6 (LRZ6), covering Indiana and parts of Kentucky. Independent System Operators (ISOs) like MISO perform the following key roles:

- Ensure the reliability of the electric system by complying with Federal Energy Regulatory Commission (FERC) Orders and North American Electric Reliability Corporation (NERC) Reliability Standards
- Oversee markets for energy, capacity, ancillary services, and transmission rights
- Direct the daily operation of the electric system, including plant dispatch

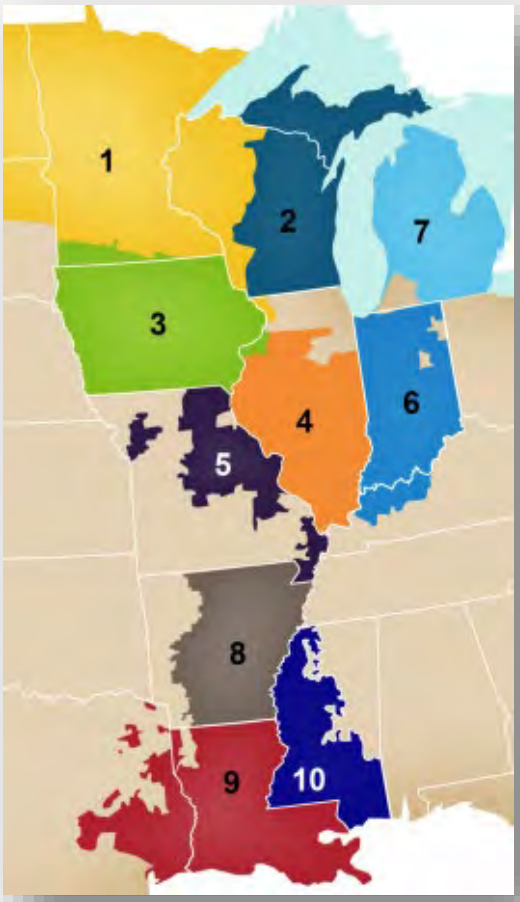
Therefore, as a member of MISO, NIPSCO is not independently responsible for system reliability and market operations. However, NIPSCO must offer its resources into the market, respond to MISO signals and instructions, and comply with a dynamic set of market rules and standards. In addition, as a Transmission Operator (TOP), NIPSCO is responsible for directly complying with a variety of NERC standards associated with reliability.

The MISO market is currently in the midst of significant change, meaning that NIPSCO must navigate its own portfolio decisions while recognizing this dynamic external environment. These MISO changes include:

- A system-wide transition away from coal and towards more intermittent renewable resources
- The emergence of new technologies with operating profiles that are very different from traditional generation resources like coal and natural gas
- The evolution of market rules to accommodate these changes, such as:
    - Evaluating the use of seasonal reserve margin targets
    - Development of new methods of calculating capacity credit for intermittent resources
    - Establishment of participation models for storage resources

Given the uncertainties associated with future MISO market changes, it is critical that NIPSCO ensure resource planning decisions are flexible enough to adapt over time.

MISO FOOTPRINT



GENERATION CAPACITY
- 184,287 MW (market)
- 198,933 MW (reliability)

TRANSMISSION LINES
- 65,800 miles

STATES/PROVINCES
- 15 U.S. States
- 1 Canadian Province

MISOENERGY.ORG

NIPSCO's 2021 INTEGRATED RESOURCE PLAN APPROACH

Resource planning is a complex undertaking, one that must address the inherent uncertainties and risks that exist in the evolving electric industry landscape. In the 2021 IRP, several key planning themes shaped the way NIPSCO approached the development of its preferred plan and the supporting analysis. These included a focus on:

- **Long-Term Planning With Intermittent Resources**, particularly associated with understanding the system reliability implications of a portfolio that will have significant intermittent resources
- **Carbon Emissions and Environmental Policy Trends**, including assessment of diverse portfolio options in the context of increased policy conversations that push for 100% decarbonization of the power sector by the middle of the next decade
- **Flexibility & Adaptability of the Portfolio** to meet evolving MISO rules and state and federal energy and environmental policy changes

Using in-depth data, modeling and risk-based analysis provided by internal and external subject matter experts, NIPSCO's IRP projects future energy and capacity needs and evaluates available options to meet those needs.

The 2021 IRP also introduced an enhanced evaluation of the reliability of NIPSCO's portfolio to better understand the implications of a resource mix with significant intermittent resources, particularly in light of the MISO market evolution and NIPSCO's operational responsibilities. NIPSCO's expanded analysis incorporated both economic and non-economic assessments of reliability.

NIPSCO's 2021 IRP is based on the best available information at the time this IRP is filed. Changes that affect our plan may arise, which is why it's important for us to remain flexible and adaptable as we continually evaluate current market conditions, the evolution of technology—particularly energy storage and hydrogen-based technology —and demand side resources, as well as changing laws and environmental regulations.



ENGAGING CUSTOMER AND PUBLIC STAKEHOLDERS

Indiana's energy future is everyone's concern. That's why any discussion of resource planning for the future must bring all stakeholders into the conversation. We engaged stakeholder groups and individuals in a variety of ways throughout the entirety of the planning process.

NIPSCO initiated stakeholder advisory outreach for its 2021 IRP in March when we hosted a virtual public meeting and launched a web page for interested stakeholders to follow the progress. Given the ongoing COVID-19 pandemic, public stakeholder meetings and stakeholder interactions were entirely virtual during this planning cycle. Four additional virtual public meetings followed in May, July, September and October. NIPSCO also hosted a virtual technical webinar to discuss the reliability assessments. Each of these public stakeholder meetings had over 100 registered participants and garnered a high level of stakeholder participation. Members of our executive leadership team and several of our subject matter experts attended each meeting to hear feedback and answer questions.

Throughout the IRP process, stakeholders were also invited to meet with us on a one-on-one basis to discuss key concerns and perspectives. NIPSCO met with several stakeholders in virtual one-on-one settings and exchanged written correspondence with several others. Each interaction provided a forum for discussion and feedback related to the many components of the IRP. Valuable discussions arose in several key areas, including load forecasting calculations, energy efficiency program analysis, generation portfolio modeling techniques, and reliability assessment considerations.

Stakeholder feedback gained throughout the process was used to inform and improve the final plan. A summary of the meeting materials, including presentations and stakeholder questions, is available at **NIPSCO.com/IRP**.





FORECASTING FUTURE CUSTOMER DEMAND

Projecting customers' energy needs is a key component of the IRP process, and several enhancements to the development of the demand forecast were implemented in the 2021 IRP. For the first time, the IRP demand forecast incorporates an Industrial Service Structure tariff, known as Rate 831, and its subsequent impact on large industrial customer load. Approved in 2019, this new industrial service structure tariff gives certain large industrial customers the option to procure most of their energy and capacity needs on their own.

Leveraging NIPSCO's load forecasting tools, we developed monthly net energy and peak load projections to evaluate seasonal energy peak periods throughout the plan horizon. This was done through an econometric analysis of customer count, energy usage per customer, and customer class-level load factor data, along with detailed analysis of the impact of changes in customer behavior on load requirements.

New to 2021, NIPSCO forecasted the impact of customer owned distributed energy resources (DER) and Electric Vehicles (EV) on load across a range of adoption scenarios. NIPSCO's final forecasts combined the baseline econometric load projections with the DER and EV analysis across planning scenarios to capture a range of future load growth outcomes.

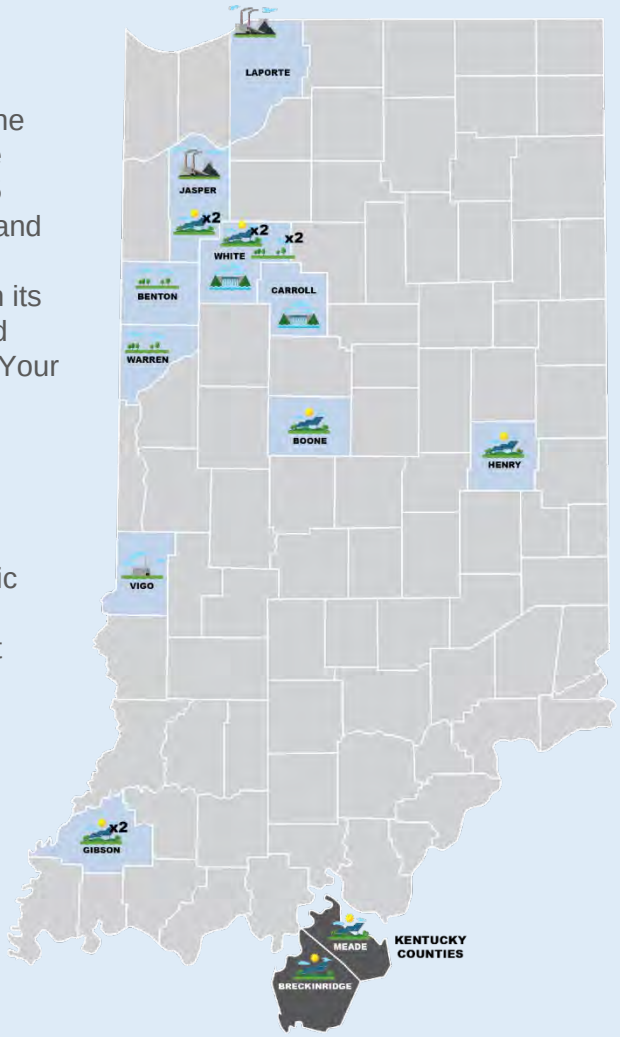
LOAD FORECAST HIGHLIGHTS

PEAK LOAD	NIPSCO's 2021 IRP load forecast expects near-term **summer peaks** to be around **2,300 MW** and **winter peaks** to be around **1,600 MW** Peak load expectations are over **600 MW lower** than those from the 2018 IRP due to a new industrial service tariff, although interruptible demand response supply resources from industrial customers are also down.
EVs	The load forecast includes a range of **electric vehicle penetration** scenarios, representing between approximately **10 to 80 MW of peak load** impact and **up to 8% of total sales** over the long-term
DERs	The load forecast scenarios suggest that **customer-owned distributed energy resources** have the potential to reduce summer peak loads between **40 to 160 MW** over the long-term.

CURRENT SUPPLY

NIPSCO's resource portfolio is in the midst of a transition. Since the 2018 IRP, NIPSCO has proceeded with retirement activities at the R.M. Schahfer Generating Station. Schahfer Coal Units 14 and 15 were retired in 2021, while the remaining Schahfer Coal Units 17 and 18 are on track to retire by the end of 2023. To replace the retired capacity at Schahfer, the company continues to make progress on its 14 approved renewable energy projects, including wind, solar, and solar plus battery storage resources, as part of our "Your Energy, Your Future" transition plan. Two of these wind projects were placed in service in 2020 and the remaining 12 projects are expected to be completed throughout 2022 and 2023.

Additionally, NIPSCO's resource portfolio is composed of its last remaining coal-fired plant (Michigan City Unit 12), two hydroelectric plants (Norway and Oakdale), a natural gas-fired combined cycle (Sugar Creek), two older vintage natural gas-fired peaking units at Schahfer (Units 16A and 16B), two older vintage wind contracts (Barton, Buffalo Ridge), and demand-side resources (DSM).



NEW GENERATION FACILITIES

PROJECT	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102MW	WHITE	COMPLETE
JORDAN CREEK WIND*	400MW	BENTON WARREN	COMPLETE
INDIANA CROSSROADS WIND	300MW	WHITE	2021
DUNNS BRIDGE SOLAR I	265MW	JASPER	2022
BRICKYARD SOLAR*	200MW	BOONE	2022
GREENSBORO SOLAR*	100MW +30MW BATTERY	HENRY	2022
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2022
GREEN RIVER SOLAR*	200MW	BRECKINRIDGE & MEADE (KENTUCKY)	2023
DUNNS BRIDGE SOLAR II	435MW +75MW BATTERY	JASPER	2023
CAVALRY SOLAR	200MW +60MW BATTERY	WHITE	2023
GIBSON SOLAR*	280MW	GIBSON	2023
FAIRBANKS SOLAR	250MW	SULLIVAN	2023
INDIANA CROSSROADS II WIND*	204 MW	WHITE	2023
ELLIOT SOLAR	200 MW	GIBSON	2023

* Projects are Power Purchase Agreements (PPAs)

PLANNED RENEWABLE RESOURCES EXPECTED TO ADD 3,330MW INSTALLED CAPACITY

ADDITIONAL $5B CAPITAL INVESTMENTS, MUCH OF WHICH STAYS IN THE INDIANA ECONOMY

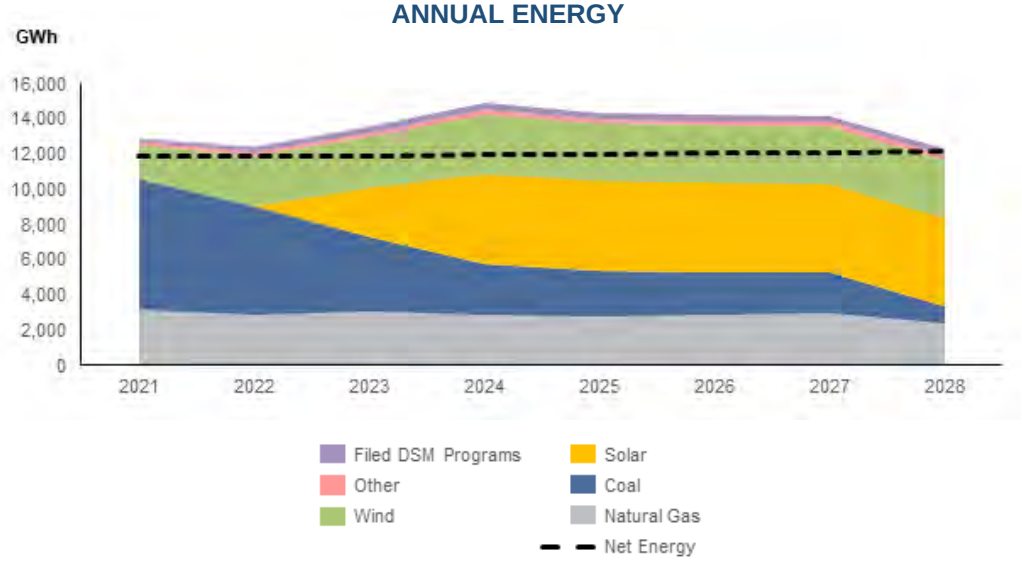
CURRENT FACILITIES

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2026-2028	469MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2021/2023	1,780MW	COAL	JASPER
R.M. SCHAHFER RETIRING 2025-2028	155MW	NATURAL GAS	JASPER
SUGAR CREEK	535MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2MW	WATER	WHITE
OAKDALE HYDRO	9.2MW	WATER	CARROLL

CURRENT SUPPLY CONT.

As NIPSCO looks beyond the implementation of its short-term action plan from the 2018 IRP, it is clear that evolving market dynamics require attention not only to annual supply and demand of capacity and energy, but also energy adequacy on an hourly basis, as illustrated below. Thus, the 2021 IRP was structured to ensure a full assessment of the type of resources needed to respond to evolving market conditions and future portfolio retirements.

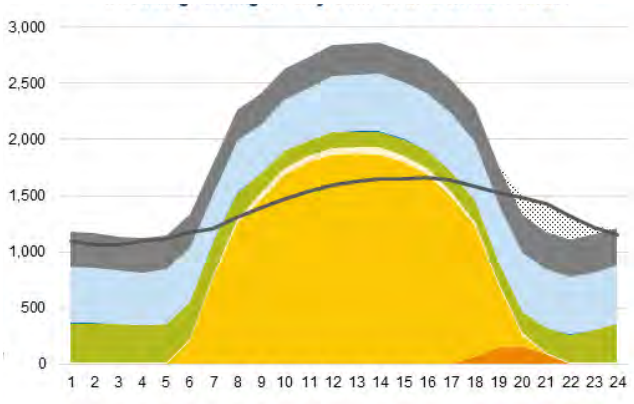
ANNUAL ENERGY



NIPSCO is well positioned to produce more energy than needed on an annual basis, driven by the energy value and dispatch advantage of wind and solar resources entering the portfolio.

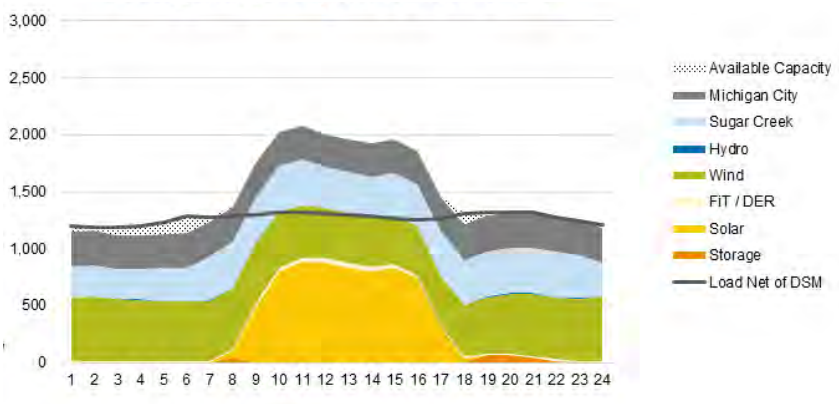
AVERAGE SUMMER DAY AFTER SCHAHFER COAL RETIREMENT

INCLUDING MICHIGAN CITY UNIT12 AND UNITS 16A AND 16B



AVERAGE WINTER DAY AFTER SCHAHFER COAL RETIREMENT

INCLUDING MICHIGAN CITY UNIT12 AND UNITS 16A AND 16B



Across a 24-hour day, there are hours where renewable resources are not available, particularly overnight for solar. As NIPSCO looks forward to the retirement of its Michigan City coal plant and vintage peakers at Schahfer, replacement resources will need to provide availability when renewable output is low to minimize market exposure.

ANALYZING FUTURE SUPPLY OPTIONS – RFP

NIPSCO conducted three separate Requests for Proposals (RFP) events covering all-sources to help inform the 2021 IRP planning process and to gain information on available, actionable projects with real costs from the marketplace. All energy technology companies were eligible to participate, and for the 2021 RFP, NIPSCO received 182 proposals— representing 78 individual projects with more than 15 gigawatts (GW) of installed capacity (ICAP). In concert with the core IRP analysis, RFP screening criteria included energy source availability, technical feasibility, commercial availability, economic attractiveness and environmental compatibility.

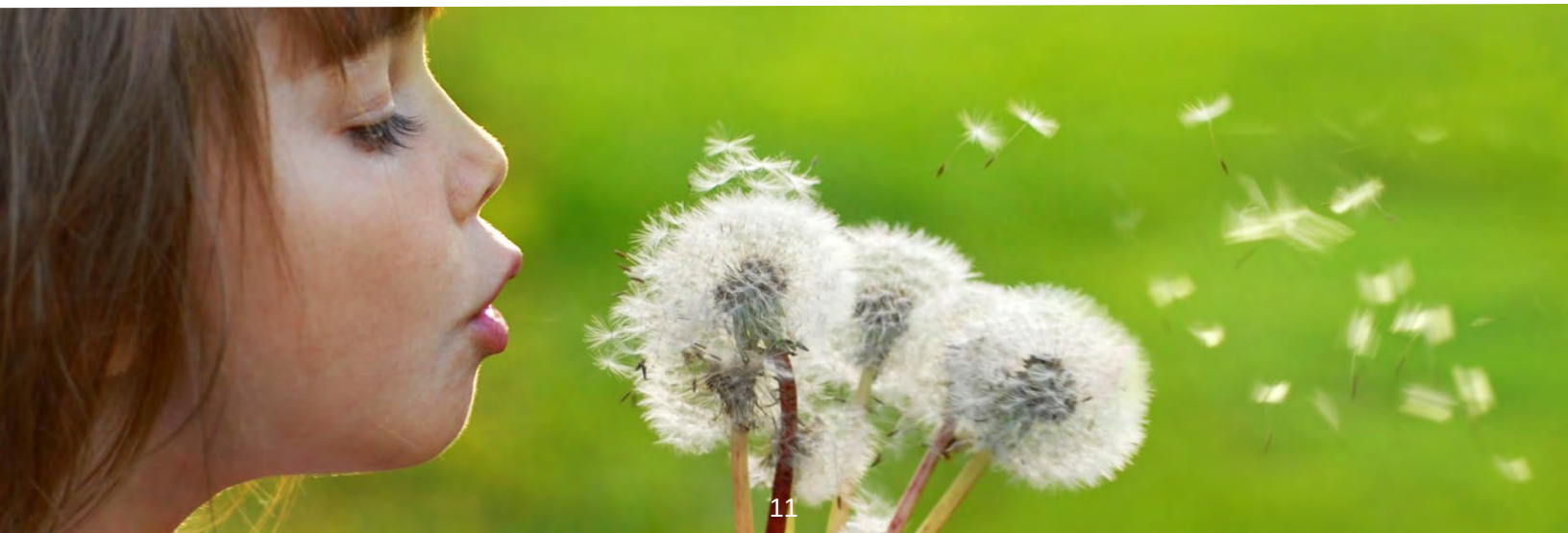
DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY

DSM programs and energy efficiency measures have been an integral part of the NIPSCO supply mix. Promoting energy efficiency is not only good for customers, but it can play an important role in helping ensure that we can meet future energy needs. Consequently, the assessment of DSM and energy efficiency programs is a core component of the IRP process. NIPSCO offers a variety of programs to help residential and business customers save energy. The programs are tailored to customers and designed to help ensure energy savings.

Since 2010, NIPSCO customers have saved more than 1.3 million megawatt hours of electricity by participating in the range of energy efficiency programs offered by NIPSCO. Technologies continue to change, and it's important that we constantly evaluate our offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings. The 2021 IRP included a robust assessment of future DSM programs through a Market Potential Study and rigorous portfolio analysis of the various options.

ENHANCED RELIABILITY ASSESSMENT

The ongoing energy transition is requiring the considerations of system reliability impacts within the resource planning process as new resources like solar, wind and storage have different operational characteristics from traditional thermal resources like coal and natural gas. NIPSCO has incorporated several expanded elements and enhancements to the core IRP economic analysis to capture resource planning and power markets operating with more intermittent resources. NIPSCO engaged a third-party expert to perform a reliability assessment to better understand the ability of potential replacement resources to support the continued reliable operation of the system. The assessment involved series of system analyses to quantify the performance of potential replacement resources against an independently developed set of reliability criteria and measures. The results of the assessment were incorporated into the analysis to inform portfolio evaluation and the Preferred Plan.



KEY ANALYTICAL ELEMENTS OF THE 2021 IRP

NIPSCO's 2021 IRP is the result of a year-long, multi-disciplinary analytical exercise that incorporates the following major elements:

SCENARIO ANALYSIS	Scenario analysis to evaluate four integrated, but divergent future states-of-the-world for commodity prices, load growth, carbon regulation, other environmental policy drivers, and the evolution of the MISO power market
ROBUST RISK ANALYSIS	Robust risk analysis to assess uncertainty in gas and power prices and, new to the 2021 IRP, hourly wind and solar output
MULTI-PHASED PORTFOLIO ANALYSIS	A multi-phased portfolio development process that identified a wide range of future plans with different existing fleet retirement dates, various levels of carbon emissions reductions, and a range of dispatchability characteristics
ENHANCED RELIABILITY ASSESSMENT	An advanced assessment of reliability, which evaluated a range of economic and technical reliability components, including ancillary services, blackstart, and other operational considerations



PREFERRED PORTFOLIO AND NEXT STEPS

Consistent with previous analyses, NIPSCO's 2021 IRP has determined that early retirement of coal is still cost-effective for customers. Accordingly, NIPSCO has refined the retirement timing of Michigan City Generating Station Unit 12 to occur between 2026 and 2028. The precise timing of the retirement will be influenced by system reliability impacts, federal/state regulatory policy direction, MISO market rules evolution and securing the replacement resources.

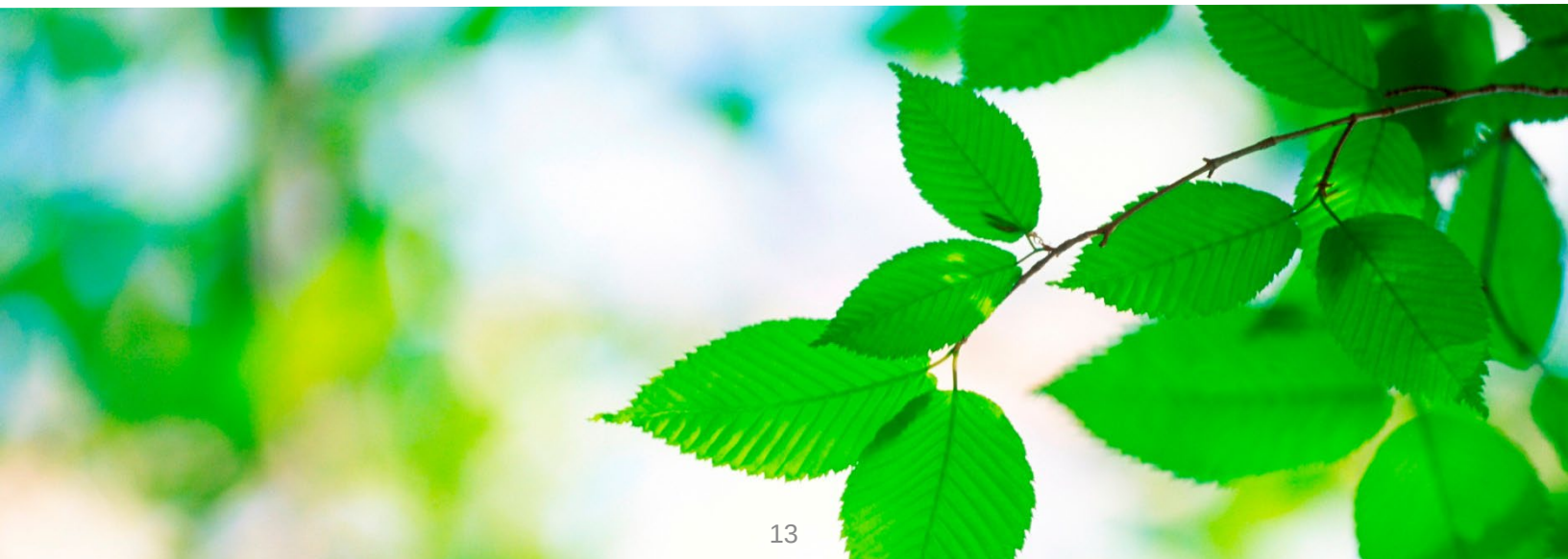
NIPSCO operates two vintage gas peaking units – Units 16A and 16B – at the Schahfer Generating Station. Given the operational condition and age of the units, the analysis pointed to retiring 16A and 16B between 2025 and 2028.

The flexibility in the retirement timing of the peaking units along with Michigan City 12 allows NIPSCO to optimize the decision. NIPSCO will pursue cost-effective resources that cover the capacity needs for both facilities, although the units do not have to retire at the same time.

To replace the retiring resources, NIPSCO has identified a preferred pathway that balances all of NIPSCO's major planning objectives, while preserving flexibility in an environment of market, technology, and policy uncertainty. In the near-term, replacement options include a diverse, flexible, and scalable mix of incremental resources, including DSM resources, distributed energy resources, solar, stand-alone energy storage, and upgrades to existing facilities at the Sugar Creek Generating Station. The plan also calls for a natural gas peaking unit to replace existing vintage gas peaking units at Schahfer and support system reliability and resiliency, as well as upgrades to the transmission system to enhance the electric generation transition.

Over the longer term, additional solar and wind capacity may be added if environmental policy makes it more economic than competing resources, and additional storage capacity may be added as further technology, policy, and reliability diligence is performed. New peaking capacity may be hydrogen-enabled as options are explored further. Hydrogen pilot projects and long-term hydrogen conversion pathways may be explored for Sugar Creek as policy and technology evolves.

NIPSCO'S 2021 IRP AFFIRMS THE COMPANY'S CUSTOMER-CENTRIC "YOUR ENERGY, YOU FUTURE" ELECTRIC GENERATION TRANSITION TO LOWER-COST AND RELIABLE ENERGY FOR OUR CUSTOMERS IN THE YEARS TO COME.



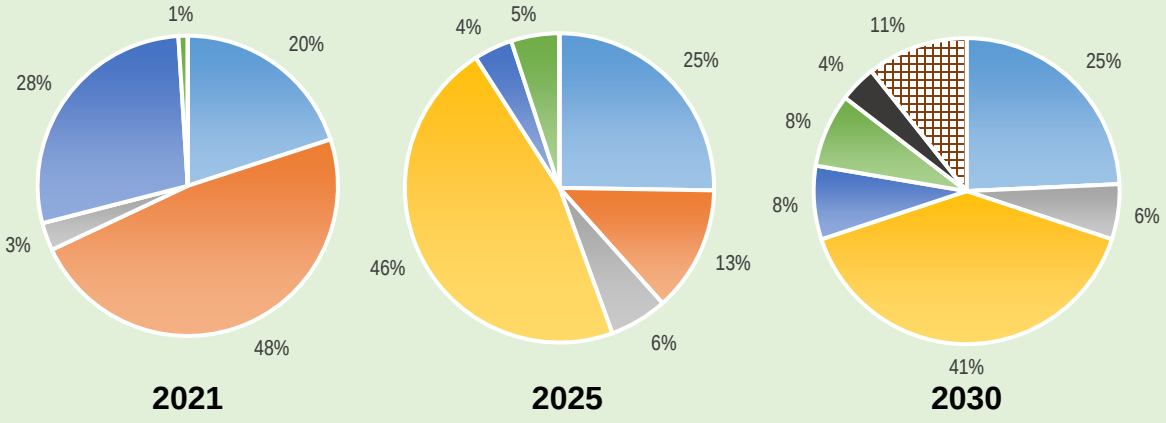
PREFERRED PORTFOLIO AND NEXT STEPS CONT.

This pathway does not alter the company's previously stated goal of a 90% reduction in carbon emissions (from a 2005 baseline) by 2030.

NIPSCO's 2021 IRP outlines refinements to the timeline of our future generation plans, and it enables flexibility to adapt to evolving technologies, policies and market rules while providing additional time for research and further refinement to our long-term energy strategy – NIPSCO will continue to update its future energy strategy in the next IRP. This 2021 IRP affirms the company's customer-centric "Your Energy, Your Future" electric generation transition to lower-cost and reliable energy for our customers in the years to come. Learn more about the "Your Energy, Your Future" plans at NIPSCO.com/future. More information about NIPSCO's electric supply strategies and the IRP process can be found at NIPSCO.com/IRP.

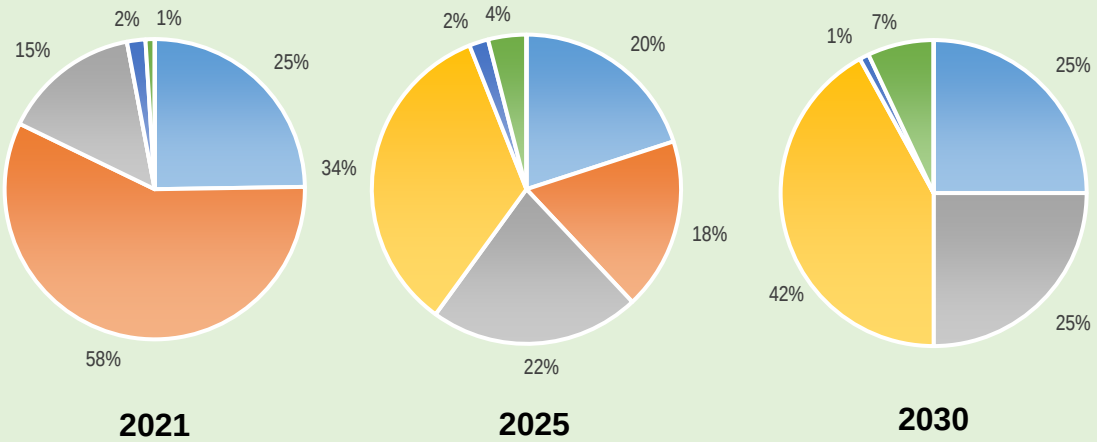
NIPSCO PROJECTED CAPACITY MIX Projected Unforced Capacity (UCAP)

NIPSCO's summer capacity mix transitions away from coal towards a more diverse mix of resources, with the flexibility to pivot to peaking gas or storage and add more solar and wind over the long term. New peaking capacity may be hydrogen-enabled as further diligence is performed.



NIPSCO ENERGY MIX

NIPSCO's energy mix transitions away from coal towards a portfolio that is predominantly renewable. Flexibility in the plan allows for even more solar and wind additions over time, depending on the balance of new gas and storage resources and evolving policy and market rules changes.



Natural Gas
Coal
Wind
Solar + Storage
Other*
DSM
New Storage
New Gas or New Storage

* Includes Hydro, DER, FIT and Thermal Contracts

ACTION PLAN

	NEAR TERM ACTIONS (2022-2025)	MID-TERM ACTION (2026-2028)
RETIRE	• Schahfer Units 17 and 18 (by 2023)	• Michigan City Unit 12 • Schahfer Units 16A and 16B
PREPARE	• MC12-related transmission projects • Further diligence to optimize quantities and resource types • Secure approvals for replacement projects	• Full implementation of Transmission projects • Secure approvals for replacement projects • Optimize quantities/resource types
REPLACE	• ~3,000MW of wind/solar projects approved by the IURC • Currently approved DSM plan and future approved DSM plan • NIPSCO Owned DER (up to 10MW) • Short term Capacity Contracts (150MW) • Storage (135-370MW*)	• Sugar Creek Uprate (30-53MW) • Solar (100-250MW) • Storage (135-370MW*) • Gas Peaking (up to 300MW) • Hydrogen Electrolyzer Pilot (20MW**)
ONGOING		
MONITOR	• Actively monitor changing federal/state policy, MISO market rules and technology advancements	

* Exact Storage ICAP MW to be optimized
**Assumes Green Hydrogen; Quantities to be optimized



Table of Contents

Section 1. Integrated Resource Plan 1

1.1 Short Term Action Plan 1

1.2 Plan Summary 3

1.3 Emerging Issues 4

1.3.1 Market Rules Uncertainty 4

1.3.2 Policy Uncertainty 5

1.3.3 Technology Uncertainty 5

Section 2. Planning for the Future 6

2.1 IRP Public Advisory Process 6

2.1.1 Stakeholder Meeting 1 6

2.1.2 Stakeholder Meeting 2 7

2.1.3 Stakeholder Meeting 3 7

2.1.4 Stakeholder Meeting 4 8

2.1.5 Technical Webinar 8

2.1.6 Stakeholder Meeting 5 8

2.1.7 One-on-one Stakeholder Meetings 9

2.2 IRP Planning Process 9

2.2.1 Contemporary Issues 10

2.2.2 2018 IRP Feedback and 2021 Process Improvement Efforts 11

2.2.3 Equitable Transition 12

2.3 Resource Planning Approach 12

Section 3. Energy and Demand Forecast 25

3.1 Introduction and Major Highlights of the Forecast 25

3.2 Forecasting Methodology Overview 25

3.3 Base Customer Count, Electric Energy, and Peak Demand Forecast 26

3.3.1 Data Gathering, Weather Normalization, and Econometric Modeling 26

3.3.2 New Industrial Service Structure 30

3.3.3 Customer Count Forecast 30

3.3.4 Sales per Customer and Total Electric Sales Forecast 32

3.3.5 Peak Load Forecast Development 32
3.4 Electric Vehicles 34
3.4.1 Methodology Overview 34
3.4.2 Core Data Source Inputs 34
3.4.3 Light Duty Vehicles 36
3.4.4 Transit Vehicles 41
3.4.5 Medium Duty Vehicles 42
3.4.6 Heavy Duty Vehicles 43
3.4.7 Electric Vehicle Forecast Results 43
3.5 Distributed Energy Resources 46
3.5.1 PenDER Model Description 46
3.5.2 Key Input Assumptions 47
3.5.3 DER Forecast Results 50
3.6 Scenario Analysis 52
3.6.1 Economic Variables 53
3.6.2 Electric Vehicles 53
3.6.3 Distributed Energy Resources 53
3.6.4 Other Electrification 54
3.6.5 Industrial Load Risk 54
3.6.6 Scenario Results 54
3.7 Detailed Forecast Results 56
Section 4. Supply-Side Resources 67
4.1 Existing Resources 67
4.1.1 Michigan City 68
4.1.2 Schahfer 68
4.1.3 Sugar Creek 69
4.1.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources) 70
4.1.5 NIPSCO Wind Purchase Power Agreements and Joint Venture 71
4.1.6 Total Resource Summary 72
4.2 Fuel, Energy, and Capacity Procurement Strategy for Existing Resources 74
4.2.1 Coal Procurement and Inventory Management Practices 74
4.2.2 Natural Gas Procurement and Management 78

4.2.3 Electric Generation Gas Supply Request for Proposal Process 78
4.3 Planned Resource Summary 79
4.3.1 Planned Wind Resources 79
4.3.2 Planned Solar and Solar + Storage Resources 80
4.4 MISO Wholesale Electricity Market 84
4.4.1 Operations Management and Dispatch Implications 84
4.5 Resource Adequacy and Current Supply-Demand Balance 84
4.6 Future Resource Options.....85
4.6.1 Request for Proposal 85
4.6.2 Incorporation of the RFP Results into the IRP 88
4.6.3 Tranche Development 89
4.6.4 Renewable Resource Tax Incentives and Tax Equity Partnership ...91
4.6.5 Sugar Creek Uprate Opportunity 93
4.6.6 Distributed Energy Resources.....93
4.6.7 Emerging Technologies 96
4.6.8 Carbon Capture, Utilization, and Storage 107
4.6.9 Small Modular Reactors 111
Section 5. Demand-Side Resources.....112
5.1 Existing Resources.....112
5.1.1 Existing Energy Efficiency Resources.....112
5.1.2 Existing Demand Response Resources 120
5.2 DSM MPS 121
5.2.1 DSM MPS – Purpose and Key Objectives 121
5.2.2 Impact of Opt-out Customers.....121
5.2.3 Modeling Framework.....121
5.2.4 Key Assumptions That Impact Energy Efficiency Potential 122
5.2.5 Energy Efficiency Measures & Potential.....124
5.2.6 DR Potential.....131
5.3 Future Resource Options.....133
5.3.1 Energy Efficiency Bundles 133
5.3.2 DR Bundles.....140
5.4 Consistency between IRP and Energy Efficiency Plans.....141

Section 6. Transmission and Distribution System....144
6.1 Transmission System Planning....144
6.1.1 Transmission System Planning Criteria and Guidelines....144
6.1.2 North American Electric Reliability Corporation....144
6.1.3 Midcontinent Independent System Operator, Inc. 145
6.1.4 Market Participants....146
6.1.5 Customer Driven Development Projects....146
6.1.6 NIPSCO Transmission System Capital Projects....146
6.1.7 Electric Infrastructure Modernization Plan....147
6.2 Distribution System Planning....148
6.2.1 Evolving Technologies and System Capabilities....151
Section 7. Environmental Considerations....152
7.1 Environmental Sustainability....152
7.2 Environmental Compliance Plan Development....153
7.3 Environmental Regulations....154
7.3.1 Solid Waste Management....154
7.3.2 Clean Water Act....154
7.3.3 Effluent Limitations Guidelines....154
7.3.4 Clean Air Act....154
7.3.5 Emission Allowance Inventory and Procurement....155
7.4 Climate-Related Considerations....156
Section 8. Managing Risk and Uncertainty....157
8.1 Introduction & Process Overview....157
8.2 Reference Case Market Drivers and Assumptions....158
8.2.1 Natural Gas Prices....158
8.2.2 Coal Prices....166
8.2.3 Carbon Policy and Prices....168
8.2.4 MISO Energy and Capacity Prices....170
8.3 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment....176
8.4 IRP Scenarios....178
8.4.1 Scenario Overview....178
8.4.2 Status Quo Extended Scenario....179

8.4.3 Aggressive Environmental Regulation Scenario 182
8.4.4 Economy-Wide Decarbonization Scenario....185
8.4.5 Scenario Comparisons 188
8.5 Stochastic Input Development 198
8.5.1 Input Data Development....199
8.5.2 Statistical and Fundamental Analysis 200
8.5.1 Final Stochastic Input Development....205
Section 9. Portfolio Analysis....207
9.1 Existing Fleet Analysis 207
9.1.1 Process Overview....207
9.1.2 Existing Fleet Analysis Methodology....208
9.1.3 Identification of Existing Fleet Portfolios....208
9.1.4 Existing Fleet Cost Assumptions....209
9.1.5 Identification of Least-Cost Replacement Capacity 210
9.1.6 Evaluation of Each Existing Fleet Portfolio – Scorecard Metrics ..212
9.1.7 Evaluation of Each Existing Fleet Portfolio – Results....214
9.1.8 Existing Fleet Analysis Scorecard Summary....218
9.1.9 Preferred Existing Fleet Portfolio 219
9.2 Replacement Analysis....221
9.2.1 Process Overview....221
9.2.2 Identification of Replacement Resource Concepts 222
9.2.3 Development of Specific Replacement Portfolios....223
9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics....227
9.2.5 Evaluation of Replacement Portfolios – Core Analysis Results....229
9.2.6 Sub-Hourly Modeling with Ancillary Services 237
9.2.7 Non-Economic Reliability Assessment 246
9.3 Preferred Replacement Portfolio....257
9.3.1 Preferred Portfolio Summary....259
9.3.2 Financial Impact....260
9.3.3 Developments That Will Shape NIPSCO's Preferred Portfolio Implementation 261
9.4 Short-Term Action Plan....264
9.5 Conclusion 265

Section 10. Customer Engagement 266
10.1 Enhancing Customer Engagement 268
10.1.1 Leveraging Customer and Stakeholder Feedback 268
10.1.2 Customer Education – Your Energy, Your Future 269
10.1.3 NIPSCO's Customer Workshop Series 270
10.2 Community Partnerships 270
10.2.1 Community Advisory Panels 270
10.2.2 Partners For Clean Air 271
10.3 Customer Programs 271
10.3.1 Feed-in Tariff 271
10.3.2 Net Metering 273
10.3.3 Green Power Rider Program 274
10.3.4 Transportation Decarbonization: DC Fast charging stations & IDEM Grant 276
10.3.5 Advanced Metering Infrastructure 277
10.4 Corporate Development and Community Support 277
10.4.1 Supporting Economic Growth 277
10.4.2 Supplier Diversity 277
10.4.3 Workforce Development 278
10.4.4 Corporate Citizenship 279
10.4.5 Volunteerism 280
Section 11. Compliance with Proposed Rule 281

ACRONYMS AND ABBREVIATIONS

A

AC	Air Conditioning
ACE	Affordable Clean Energy
ACP	Alternative Compliance Payment
ACS	American Community Survey 2019
AEO	Annual Energy Outlook (from EIA)
AER	Aggressive Environmental Regulation Scenario
ASHP	Air Source Heat Pumps
AMI	Advanced Metering Infrastructure
A/S	Ancillary Services
ATC	Around-the-Clock

B

BEV	Battery Electric Vehicles
BNEF	Bloomberg New Energy Finance
BPM	Business Practice Manual

C

C&I	Commercial and Industrial
CAA	Clean Air Act – EPA issued initial rules in 1970
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CapEx	Capital Expenditures
CAP	Community Advisory Panel
CAPP	Central Appalachia
CATF	Clean Air Task Force
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCUS	Carbon capture, utilization, and storage
CDD	Cooling Degree Days
CEPP	Clean Electricity Performance Program
CF	Capacity Factor
CO2	Carbon Dioxide
Company	Northern Indiana Public Service Company LLC
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity

CRA	Charles River Associates (IRP Consultant)
CT	Combustion Turbine
CWA	Clean Water Act

D

DA	Distribution Automation
DER	Distributed Energy Resource
DG	Distributed Generation
DG Statute	Indiana Code Ch. 8-1-40
DOE	U.S. Department of Energy
DR	Demand Response
DRR1	Demand Resource Type 1
DSM	Demand-Side Management
DSM Statute	Ind. Code § 8-1-8.5-10

E

EDG	Excess Distributed Generation
EDR	Emergency Demand Response
EE	Energy Efficiency
EIA	Energy Information Administration of the U.S. Department of Energy
EISA	Energy Independence and Security Act of 2009
ELCC	Effective Load Carrying Capability
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ESOP	Energy Storage Operations
ESP	Electrostatic Precipitator
ESR	Electric Storage Resources
EV	Electric Vehicles
EWD	Economy-Wide Decarbonization Scenario

F

FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

G

GDS	GDS Associates, Inc.
GDS Team	GDS and Demand Side Analytics

GHG	Green House Gas
GPCM	Gas Pipeline Competition Model
GPR	Green Power Rider

H

H2	Hydrogen
HDD	Heating Degree Days
HDV	Heavy-Duty Vehicle
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HSPF	Heating Seasonal Performance Factor
HVAC	Heating, Ventilation, and Air Conditioning

I

IA	Interconnection Agreement
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gas Combined Cycle
ILB	Illinois Basin
IMEP	Interregional Market Efficiency Project
IQW	Income Qualified Weatherization
IRP	Integrated Resource Planning
IRP Rule	170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC/Commission	Indiana Utility Regulatory Commission

K

kWh	Kilowatt hour

J

JA	Junior Achievement
JOA	Joint Operating Agreement

L

LCOE	Levelized Cost of Electricity/Energy

LCOH	Levelized Cost of Hydrogen
LDV	Light-Duty Passenger Vehicle
LED	Light Emitting Diode
LLF	Line Loss Factors
LMR	Load Modifying Resource
LMP	Locational Marginal Pricing
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LRZ 6	MISO Load Resource Zone 6

M

MAP	Maximum Achievable Potential
MDV	Medium-Duty Vehicle
MFDI	Multi Family Direct Install
Michigan City	Michigan City Generating Station
Michigan City 12	Michigan City Unit 12
MISO	Midcontinent Independent System Operator, Inc.
MOSEP	CRA's Moment Simulation Energy Price
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Planning
MW	Megawatt

N

NAAQS	National Ambient Air Quality Standard – EPA issued rules January 2013
NAPP	Northern Appalachian
NBV	Net Book Value
NDC	Net Demonstrated Capacity
NERC	North American Electric Reliability Corporation (formerly Council)
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGF	CRA's Natural Gas Fundamentals Market Model
NIPSCO	Northern Indiana Public Service Company LLC
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value of Revenue Requirements
NSRDB	National Solar Radiation Database
NREL	National Renewable Energy Laboratory
NTG	Net To Gross
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance
OFA	Over-Fire Air
OSB	Energy Efficiency Oversight Board
OUCC	Indiana Office of Utility Consumer Counselor

P

PEM	Proton Exchange Membrane
PenDER	CRA's DER Penetration Model
PEV	Plug-In Electric Vehicle
PGC	Potential Gas Committee
PHEV	Plug-In Hybrid Electric Vehicle
Pilot Program	IN-Charge Electric Vehicle Pilot Program
PJM	PJM LLC (Regional Transmission Organization)
PPA	Purchase Power Agreement
PRB	Powder River Basin
PTC	Production Tax Credit
PV	Photovoltaic

Q

Quanta Technology	Quanta Technology, LLC

R

RAN	Resource Availability and Need
RAP	Realistic Achievable Potential
RCx	Retro-Commissioning
REC	Renewable Energy Credit
Ref	Reference Case Scenario
RFP/2021 RFPs	Request for Proposals/2021 RFP Events
RIIA	Renewable Integration Impact Assessment
RIM	Rate Payer Impact Measure
RPPA	Renewable Purchase Power Agreement
RTO	Regional Transmission Organization (Independent System Operator)

S

SAIFI	System Average Interruption Frequency Index (Reliability-see also SAIDI and CAIDI)
SAM	System Advisor Model
SBDI	Small Business Direct Install
SCADA	Supervisory Control and Data Acquisition

SCED	Security-Constrained Economic Dispatch
Schahfer	R.M. Schahfer Generating Station
Schahfer 16 A/B	Schahfer Units 16A and 16B
SCUC	Security-Constrained Unit Commitment
SEER	Seasonal Energy Efficiency Ratio
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SQE	Status Quo Extended Scenario
STEM	Science, technology, engineering, and math
Sugar Creek	Sugar Creek Generating Station

T

T&D	Transmission and Distribution
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
TRC	TRC Companies, Inc.
TRM	Technical Resource Manual

U

UCAP	Unforced Capacity (the amount of Installed Capacity that is actually available)
UCT	Utility Cost Test
Urban League	Urban League of Northwest Indiana

V

VOM	Variable Operations and Maintenance Costs

W

WACC	Weighted Average Cost of Capital

Section 1. Integrated Resource Plan

1.1 Short Term Action Plan

Northern Indiana Public Service Company LLC has developed a short-term action plan in this 2021 IRP that ensures NIPSCO can confidently provide the least cost, cleanest supply portfolio available while maintaining reliability, diversity and flexibility during a time of transition within NIPSCO's own resource portfolio and dynamic change in the overall energy industry.

As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2023 and continue activities associated with the implementation of transmission system reliability upgrades. NIPSCO will continue to complete and place in service wind, solar, and solar plus storage replacement resources previously approved by the Commission for the scheduled 2023 retirement of all coal units at Schahfer.

Beyond the activities associated with the retirement of the Schahfer coal units, NIPSCO's short-term action plan focuses on maintaining flexibility for retirement of additional units and replacement with new resources. Consistent with previous analyses, early retirement of coal units is still cost-effective for customers, and NIPSCO has refined the retirement timing of Michigan City to occur between 2026 and 2028. Additionally, NIPSCO's two vintage gas peaking units (Schahfer 16A/B) will also retire between 2025 and 2028. Flexibility in timing allows NIPSCO to optimize the retirement dates of Michigan City and Schahfer 16A/B, pursuing cost-effective resources that fulfill emerging capacity needs.

The robust response to the 2021 RFPs (discussed in more detail in Section 4) indicates that there is a diverse set of resources and projects to meet NIPSCO supply needs over the near term. NIPSCO will select replacement projects/bids through the 2021 RFPs evaluation process, prioritizing capacity-advantaged resources that address our reliability requirements, including thermal contracts, storage, and gas peaking resources. NIPSCO will also engage with bidders on emerging technology resources, such as long-duration energy storage and hydrogen technologies, to pursue pilots and inform how such technologies can be deployed by NIPSCO to achieve further decarbonization of the generation portfolio over the long term. Additionally, NIPSCO will further study strategically-sited NIPSCO-owned DER opportunities with the potential to defer substation and other distribution system investment (discussed further in Section 4).

NIPSCO will make the necessary regulatory filings with the Commission and continue to monitor federal and state policy, MISO market trends, and emerging technologies, while staying actively engaged with project developers and asset owners to maintain flexibility and optionality. If necessary, NIPSCO may conduct future RFPs to identify preferred resources to replace Michigan City 12 and Schahfer 16A/B.

NIPSCO will continue the implementation of its current DSM plan through 2023.[1] NIPSCO will also continue to comply with existing environmental regulations and all NERC compliance standards and requirements. Lastly NIPSCO will continue to invest and modernize its electric infrastructure to maintain the safe and reliable delivery of electricity to its customers

As described in greater detail in Section 9, the action items included in NIPSCO's short-term action plan include those listed in Table 1-1.

Table 1-1: 2021 IRP Short-Term Action Plan

Complete and place in service 12 remaining renewable facilities approved by the IURC
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by 2023
Refine the retirement of Michigan City 12 to be between 2026 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate
Monitor the operating condition of the Schahfer 16A/B and plan for their retirement between 2025 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate, including preserving the optionality to use existing interconnection rights at the site through the MISO generator replacement process
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Confirm Sugar Creek uprate options in more detail with the plant's turbine manufacturer and schedule the uprate in accordance with the plant's maintenance cycles
Identify candidate DER projects as part of NIPSCO's distribution planning activities and consistent with planning-level assumptions developed in the IRP; implement identified projects after additional project-specific diligence
Continue implementation of filed DSM Plan for 2022 through 2023
Select replacement projects identified from the 2021 RFPs, initially prioritizing thermal PPA and solar resources
Perform deeper diligence on gas peaker and storage projects from the 2021 RFPs, selecting projects that conform to the preferred portfolio's requirements as NIPSCO tracks MISO guidelines, Commission requirements, and system reliability needs
As needed, conduct a subsequent RFP(s) to identify additional resources that may be available with attributes that are consistent with those required to implement the preferred portfolio

[1] On September 1, 2021, the IURC issued an Order in Cause No. 45456 approving NIPSCO's proposed Electric DSM Program for the period of 2022-2023.

Explore potential pilot projects from the RFP associated with emerging technologies, such as long duration storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
Procure short-term capacity as needed from the MISO market or through short-term bilateral capacity transactions
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape
Perform additional reliability analysis within the NIPSCO system as needed to ensure evolving portfolio meets all reliability needs and requirements
Comply with NERC, EPA, and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

1.2 Plan Summary

NIPSCO's preferred portfolio pathway preserves flexibility and our ability to adapt to expected changes in environmental regulations, federal and state energy policy, and other market forces, while providing additional time for further research, refinement and confirmation of our long-term energy plans. The plan was developed to ensure that a reliable, compliant, flexible, diverse and affordable supply will continue to be available to meet future customer needs. NIPSCO carefully planned and considered the impacts to its employees, the environment and the local economy of the communities NIPSCO serves (property tax, supplier spend, employee base) as the plans were developed.

This preferred plan was developed through substantial quantitative and qualitative analyses that capture the ever evolving energy landscape to allow NIPSCO to remain flexible in a time of uncertainty. NIPSCO completed an analysis to evaluate the retirement timing of its remaining existing generating fleet relative to viable alternatives (See Section 9). NIPSCO utilized the 2021 RFP solicitations to identify the best combination of supply- and demand-side resources to meet its capacity needs.

The 2021 RFPs provided NIPSCO insight into the most relevant types of resources available to meet customer needs and their prices (*See* Section 4). NIPSCO performed both the existing fleet and replacement analyses using robust scenario and risk-based (stochastic) analyses that capture the flexibility and adaptability of the portfolio among changing market rules; carbon emissions and regulations/incentives in an uncertain policy future; and system reliability implications of a portfolio with significant intermittent resources. NIPSCO also performed an enhanced reliability assessment to understand the reliability implications of potential resource

additions to the NIPSCO portfolio and incorporated the results into the final scoring to create the optimal plan.

It is important to note that the IRP is a snapshot in time, and while it establishes a direction for NIPSCO, it is subject to change as the energy landscape continues to evolve. NIPSCO will continue to engage its stakeholders and be transparent in its decisions following submission of this 2021 IRP.

NIPSCO's supply strategy for the next 20 years is expected to:

- Phase out 100% of its coal emissions by the 2026-2028 time period based on the ultimate retirement timing date for Michigan City;
- Replace retired generation resources with a diverse, flexible, and scalable mix of incremental resources, including short-term capacity contracts, solar, large energy storage, and gas peaking resources;
- Seek to advance NIPSCO's knowledge and understanding of future hydrogen pilots and other emerging storage technologies identified as potential pathways toward further decarbonization of the generation portfolio in the long term;
- Remain on the CO2 emission reduction pathway identified in the 2018 IRP, with the opportunity to further reduce emissions based on technology advances; and
- Continue the Company's commitment to energy efficiency and demand response by executing DSM plans.

1.3 Emerging Issues

NIPSCO's preferred plan follows a diverse and flexible supply strategy, with a mix of market purchases and different low variable cost generation resources, to provide the best balanced mitigation against marker rules, policy, and technology uncertainty.

1.3.1 Market Rules Uncertainty

At the outset of its 2021 IRP process, NIPSCO identified several regulatory developments at the MISO level that could impact portfolio performance. While MISO has advanced policy development and proposed tariff revisions in many areas over the last year, several areas of uncertainty remain, requiring NIPSCO to ensure portfolio decisions are flexible enough to adapt to the changing market rules environment. These include:

- Ongoing activities associated with RAN framework and the pending implementation of a seasonal capacity construct;
- MISO's transition to an ELCC methodology to assess capacity credit for wind and solar resources over time and by season;

- MISO's ongoing RIIA study, which may highlight new emerging reliability issues and potential market design responses;

- MISO's implementation of market rules associated with FERC Order 841, which requires ISOs and RTOs to establish a participation model for storage resources in energy, capacity, and ancillary services markets.

1.3.2 Policy Uncertainty

As of the time of the development of NIPSCO's 2021 IRP preferred portfolio, federal policymakers were debating significant changes to energy and environmental policy, and debates on such policy topics will continue at the federal and state level. Major policy uncertainties that could impact the ultimate direction of NIPSCO's preferred plan include:

- The potential implementation of a stand-alone storage ITC;

- The potential implementation of a hydrogen PTC or other federal incentives for hydrogen development;

- The potential implementation of a carbon tax, clean energy standard or CEPP that could impact the relative economics of different generating resource types.

1.3.3 Technology Uncertainty

As the power sector continues to navigate a period of significant change, NIPSCO expects that technology evolution will be rapid, requiring regular review of the supply-side resource marketplace and flexibility in the preferred portfolio. Going forward, NIPSCO expects power sector technology evolution to continue to impact both short-term procurement activities and long-term resource decisions. In particular, NIPSCO will continue to monitor the following:

- Stand-alone storage resource costs, efficiencies, and operational parameters, such as cycle limits, depth of discharge specifications, and ongoing expenses;

- Grid-forming inverter technology that could provide reliability benefits, such as blackstart, fast frequency response, and inertial response, to NIPSCO's system as it becomes more inverter-based;

- Hydrogen production developments, particularly associated with electrolysis of water with clean electricity sources ("green hydrogen") and the costs and capabilities of turbines and other thermal resources to burn hydrogen or blend hydrogen with natural gas;

- CCUS costs and sequestration opportunities, particularly associated with the Sugar Creek facility;

- Long-duration storage technologies, including gravity storage, and their associated costs, efficiencies, and other value drivers; and

- Other technologies that may emerge over the long term, including small modular reactors and other nuclear technology.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2021 IRP stakeholder process focused on continuing to increase transparency around its planning process and enhance public involvement through extensive stakeholder interactions. At each stakeholder meeting, NIPSCO provided information on the processes and assumptions involved in the development of the IRP and solicited relevant input for consideration. Furthermore, to facilitate stakeholder outreach and ongoing communications, NIPSCO maintained a web page on its website with current information about the IRP. NIPSCO posted all meeting agendas, presentations, meeting notes and other relevant documents to the web page.

As part of the IRP process NIPSCO conducted an RFP solicitation to identify the most viable capacity resources currently available in the market place to best meet customer needs. NIPSCO sought input from stakeholders regarding the approach and design of the All-Source RFP to ensure a robust and transparent process that yielded the desired results.

Stakeholders were invited to meet with NIPSCO throughout the IRP process to discuss key issues, concerns and perspectives. NIPSCO extended an invitation to participate in the stakeholder process to the Commissioners and Commission staff, the OUCC and stakeholders that participated in previous IRP public advisory processes. NIPSCO's executive leadership and its subject matter experts attended each public advisory meeting. In the section that follows, NIPSCO provides an overview of its stakeholder process. A more comprehensive accounting of stakeholder meetings, presentations and meeting notes is included in Appendix A.

As part of the 2021 IRP process, NIPSCO hosted five virtual public advisory meetings plus one virtual technical webinar, which was focused on the additional reliability analysis that NIPSCO introduced in this IRP. For all meetings, NIPSCO posted an open invitation on its website for any party wishing to register.

In addition to the public advisory meetings, NIPSCO participated in a number of one-on-one meetings with individual stakeholders to address specific concerns and issues that were raised as a result of information presented and discussed at the public advisory meetings. NIPSCO also corresponded with individual stakeholders on a variety of issues throughout the process.

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held virtually on March 19, 2021. In this first meeting, NIPSCO set the stage for the 2021 IRP. An update on the progress of the 2018 Short Term Action Plan and the ongoing generation transition plan was discussed. NIPSCO then outlined

the fundamental pillars of NIPSCO's long-term resource planning strategy, which includes producing a plan that is reliable, compliant, flexible, diverse, and affordable. Process improvements from the 2018 IRP were then discussed in detail, including the approach to reliability. NIPSCO then walked through the resource planning approach for 2021, which is structurally similar to the 2018 process with changes and enhancements.

NIPSCO provided an in depth discussion on key assumptions used in the 2021 IRP, including commodity prices and the load forecast, which included impacts from EVs and DERs. NIPSCO then walked through the treatment of uncertainty and introduced scenario concepts. Finally, NIPSCO concluded with the stakeholder advisory meeting road map and indicated a RFP would be conducted in conjunction with the 2021 IRP. The meeting presentation (including the agenda), notes (including questions/responses), and registered participants for Meeting 1 are included in Appendix A.

2.1.2 Stakeholder Meeting 2

NIPSCO's second stakeholder meeting was held virtually on May 20, 2021. In this second meeting, NIPSCO provided an overview of the resource planning process and provided an update on NIPSCO's response to stakeholder feedback received since the first meeting. NIPSCO then provided an overview of the major considerations that are taken into account while performing a long-term planning exercise with intermittent resources. NIPSCO outlined the MISO functions and various roles, then introduced major regulatory changes related to MISO market operations since the 2018 IRP. NIPSCO then provided an overview of NIPSCO's environmental impact targets, outlined the environmental controls present on NIPSCO's generation fleet, and summarized how the 2018 IRP's preferred portfolio addressed specific environmental compliance requirements.

NIPSCO then provided an overview of how the 2021 IRP will perform both scenario and stochastic analysis. The four planning scenarios were re-introduced and each of the key variables drivers within each scenario was expanded on in depth. NIPSCO then provided a summary of the major stochastic variable inputs, including a detailed discussion on how renewable generation uncertainty would be incorporated in the 2021 IRP.

NIPSCO also provided an overview of NIPSCO's RFP, including specifics of each bid event, the range of capacity being requested, duration expectations, and other details. The evaluation criteria, logistics, and timing were also discussed. The meeting presentation (including the agenda), stakeholder presentations, notes (including questions / responses), and registered participants for Meeting 2 are included in Appendix A.

2.1.3 Stakeholder Meeting 3

NIPSCO's third stakeholder meeting was held virtually on July 13, 2021. In this third stakeholder meeting, NIPSCO provided an overview of the resource planning process and progress since the second stakeholder meeting. NIPSCO then shared an in-depth overview of DSM resource modeling, methodology, and how these resources are considered in the IRP. NIPSCO also introduced supply-side DER options being considered in the IRP. NIPSCO then provided an

overview of the 2021 RFP Results. NIPSCO and the RFP manager, CRA, provided an overview of the proposals received and a summary of the pricing. NIPSCO also explained how the RFP results would be integrated into the IRP analysis and important next steps for both the IRP and RFP processes. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 3 are included in Appendix A.

2.1.4 Stakeholder Meeting 4

NIPSCO's fourth stakeholder meeting was held virtually on September 21, 2021. In this fourth meeting, NIPSCO reviewed the overall IRP process and reminded stakeholders of the various inputs and assumptions discussed during previous meetings, including key planning themes, NIPSCO's integrated scorecard, scenario and stochastic inputs, and supply and demand resource options. NIPSCO then provided an overview of its supply-demand balance and its portfolio energy position on an annual and hourly basis, followed by a detailed review of the preliminary findings from the portfolio modeling.

NIPSCO explained the rationale for conducting a two-stage portfolio analysis and reviewed detailed results for the existing fleet and replacement analyses. These results included portfolio optimization outcomes, revenue requirement projections, scenario cost ranges, stochastic analysis results, and other major metrics on NIPSCO's integrated scorecard associated with environmental sustainability, reliability, and social and economic impacts. NIPSCO also reviewed preliminary findings from its sub-hourly ancillary services analysis and outlined the key elements of the ongoing technical reliability assessment. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 4 are included in Appendix A.

2.1.5 Technical Webinar

NIPSCO held a technical webinar on October 12, 2021. The technical webinar focused on the enhanced reliability considerations in the 2021 IRP, providing a forum for stakeholder questions. NIPSCO reviewed its approach to reliability in this IRP, which considers both the economic and non-economic aspects of reliability. During the meeting, NIPSCO and CRA presented the economic analysis of sub-hourly energy and ancillary services value, and Quanta Technology reviewed the non-economic reliability assessment performed for all replacement portfolios. NIPSCO, CRA, and Quanta Technology responded to stakeholder questions. The presentation (including the agenda), notes (including questions / responses), and registered participants for the Technical Webinar are included in Appendix A.

2.1.6 Stakeholder Meeting 5

NIPSCO's fifth stakeholder meeting was held virtually on October 21, 2021. In this fifth meeting, NIPSCO reviewed the public advisory process, resource planning activities, existing fleet and replacement analyses, and the reliability assessment presented in the October 12th Technical Webinar. NIPSCO also responded to stakeholder feedback related to DSM topics and alternative customer cost summaries. NIPSCO then reviewed its preferred resource plan and preliminary action plan and responded to stakeholder questions and feedback. The meeting presentation

(including the agenda), notes (including questions / responses), and registered participants for Meeting 5 are included in Appendix A.

2.1.7 One-on-one Stakeholder Meetings

NIPSCO held a number of one-on-one meetings with its stakeholders throughout the public advisory process. Generally, the meetings related to either (1) clarifications, (2) additional information regarding the RFP solicitation, or (3) providing additional data. Information relating to the stakeholder requests can be found in the presentation included in Appendix A (Slides 48 through 52) and Appendix A(Slides 11 through 23).

NIPSCO's 2021 IRP is the result of analysis performed by NIPSCO that includes consideration of stakeholder input. NIPSCO has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. NIPSCO appreciates the participation of its stakeholders, including the Commission staff, the OUCC, NIPSCO's largest industrial customers and community action groups, all of which participated extensively throughout the IRP development process. NIPSCO's stakeholders and Commission staff provided valuable feedback throughout the process, which has been considered and incorporated as applicable. The written feedback NIPSCO received, as well as the Company's responses, is included in Appendix A. Despite best efforts to address and resolve all input from stakeholders, there were instances wherein NIPSCO still incorporated, for example, methodologies that were not supported by all stakeholders.

2.2 IRP Planning Process

NIPSCO's 2021 IRP is in compliance with the Commission's IRP Rule. A matrix showing NIPSCO's compliance with each section of the IRP Rule (providing a reference to the appropriate Section(s) of the IRP) is included in Section 11: Compliance with Proposed Rule.

Long term resource planning requires addressing risks and uncertainties and for NIPSCO, the first step in this process is to identify objectives and metrics. Next NIPSCO develops market perspectives for key variables such as customer demand and commodity prices. This involves the creation of distinct thematic "states-of-the-world" that represent potential future operating environments for NIPSCO. Then NIPSCO constructs integrated resource portfolio strategies and performs detailed modeling and analysis to evaluate the performance of various resource portfolios across a range of potential futures as well as a distribution of key stochastic variables. NIPSCO's goal is to develop a resource plan that is reliable, compliant with all regulations, diverse, flexible and affordable for customers with careful consideration of all stakeholder viewpoints.

The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs. The short-term strategic plan identifies the steps NIPSCO will take over the next three years to implement the long-term strategic plan.

NIPSCO recognizes future economic and environmental changes are difficult to accurately predict. While the 2021 IRP addresses a wide range of plausible market conditions and portfolio

strategies, new information is evaluated and incorporated as it becomes available as part of NIPSCO's commitment to continuous planning.

NIPSCO's IRP team included experts from key areas of NIPSCO and its affiliate NiSource Corporate Services Company. The following energy consultants also provided input:

GDS 1850 Parkway Place, Suite800 Marietta, GA 30067	Developed DSM measures inputs for a long-term DSM forecast
CRA 200 Clarendon Street Boston, MA 02116	Provided fundamental long term commodity price forecasts and performed portfolio modeling and analysis. A separate division of CRA provided assistance in administering the All-Source RFP and evaluating the responses.
Demand Side Analytics 691 John Wesley Dobbs Ave NE Suite V3 Atlanta, GA 30312	Provided assistance with analyzing demand response measures and opportunities
Quanta Technology 4020 Westchase Blvd., Suite 300 Raleigh, NC 27607	Provided technical reliability assessment of replacement portfolio options

2.2.1 Contemporary Issues

NIPSCO also participated in the Commission's IRP Contemporary Issues Technical Conferences that occurred since NIPSCO completed its last IRP. Dates and topics discussed included:

Date	Topics
April 15, 2019	• Load shapes and planning • Utilizing data bases • Long-term planning and procurement • Integration of DERs • NIPSCO's IRP/RFP and preliminary lessons learned • Life cycle analysis of GHG emissions and resource planning
August 25, 2020	• Benefits of RTOs • Resource adequacy • Implications of changing resource mix • Transmission planning • DERs
September 24, 2020	• Renewable integration models • All-source competitive solicitation • Grid-interactive efficient buildings

	• Time and locational value of EE
June 8, 2021	• EE and load forecasting
July 15, 2021	• Development and use of MPSs • EE Oversight Boards
August 19, 2021	• Development of EE bundles selected in the IRP optimization process and into utility program offerings

To the extent the information applicable and appropriate, NIPSCO included the items discussed during the technical conference in its analysis.

2.2.2 2018 IRP Feedback and 2021 Process Improvement Efforts

NIPSCO strives to continuously improve all aspects of its resource planning process and, for the 2021 IRP, NIPSCO reviewed the major feedback it received throughout the 2018 IRP process and implemented key improvements. The process improvements in the 2021 IRP were designed to enhance the robustness of the load forecast, improve upon established advanced risk modeling techniques, and remain flexible to MISO market rule changes.

Table 2-1 summarizes the major areas of feedback received on NIPSCO's 2018 IRP and the improvements that were included in the 2021 IRP process.

Table 2-1: Process Improvement

Category	2018 IRP Feedback	2021 Improvement Plan
Load Forecast	• Load forecast relies too heavily on historic methods and professional judgment. Little consideration for evaluating efficacy of current methods or new approaches • Electric Vehicle (EV) penetration not considered • Distributed Energy Resources (DERs) not evaluated sufficiently in load forecast or energy efficiency evaluation process	• Overall load forecasting process and methodology improvement, including explicit incorporation of: ○ DER modeling ○ EV modeling ○ Energy Efficiency
Scenarios and Sensitivities	• Clearer scenario narratives and solicit feedback earlier from stakeholders • Ensure coverage of technology and load uncertainty	• Broader scenario ranges and earlier data exchange with stakeholders • Scenario ranges include technology (including impact of tax credit) and load (economic, industrial, DER, EV) uncertainty
Risk Analysis	• Risk analysis focused on higher cost risk, but ignores lower cost opportunities • Reliability risk not quantified sufficiently	• Additional reliability and operational flexibility metrics to be included in NIPSCO's scorecard • Additional lower cost opportunity metric to be included in NIPSCO's scorecard • Incorporation of renewable generation output risk, correlated with power price risk in stochastic analysis
Market Rule Changes	• Significant burden on NIPSCO to monitor market rules changes, particularly seasonal reserve margin	• Tracking of MISO's Renewable Integration Impact Assessment ("RIIA") initiative findings and expected market responses central to IRP framework • Evaluation of preferred plan's ability to meet both the summer and winter peak • Incorporation of range of Effective Load Carrying Capability ("ELCC") trajectories over time, particularly for solar

2.2.3 Equitable Transition

As the resource mix and generation technologies in the industry continue to transition, the topic of equity or "just transition" to ensure all customers and communities are included has surfaced as a core issue to address. The vision of an equitable transition is one that improves universal access to energy to customers and communities, ensures inclusion of all stakeholders in strategy/decision-making, and ensures a fair division of costs and benefits.

NIPSCO recognizes the importance of equity and a "just transition" for NIPSCO's customers and communities as the generation portfolio evolves. In 2018, as part of the selection of projects to replace the retiring Schahfer coal units, NIPSCO indicated a strong preference for projects that were located in the communities the Company serves, and if that was not possible, within the State of Indiana. Thirteen of the 14 projects we selected are within the State of Indiana, and the construction and ongoing operations of the plants will deliver enduring economic benefits to those communities and the state. Of note, the Dunn's Bridge I and II projects will be located in Jasper County where the Schahfer plant is located and will contribute significantly to the property tax base for that community for years to come. Furthermore, as part of the 2019 and 2021 RFP solicitations, NIPSCO incorporated proposal-specific benefit and risk factors outlined in the evaluation criteria, which included, but were not limited to, impacts on local communities that NIPSCO serves, minority- or women-owned business enterprises, and the enterprise's supplier diversity spending. Incorporating these factors into the bidding process was another step forward for integrating equity considerations into the IRP.

In the 2021 IRP Stakeholder process, the topic of equity considerations was discussed, including a recommendation that NIPSCO consider the addition of an equity metric as part of its scorecard. NIPSCO welcomed this discussion and is always interested in engaging broadly with stakeholders on this important topic. NIPSCO recognizes that measuring equity in the energy transition is a complex process and is taking steps to further expand its knowledge and understanding of different ways and approaches to evaluate this issue. NIPSCO and NiSource employees are participating in the Equity in a Clean Energy Economy Collaborative, which brings together diverse stakeholders to create new approaches and tools to ensure equity in a clean energy economy for at-risk customers and communities. NIPSCO looks forward to engaging in a state-wide dialogue with the Commission, other utilities, and interested stakeholders on the topic of equity in future IRP Contemporary Issues Technical Conferences and other forums. NIPSCO will continue to examine future resource decisions within the context of broader issues like equity and where possible will seek to develop metrics and measures to better assess the impact of those decisions.

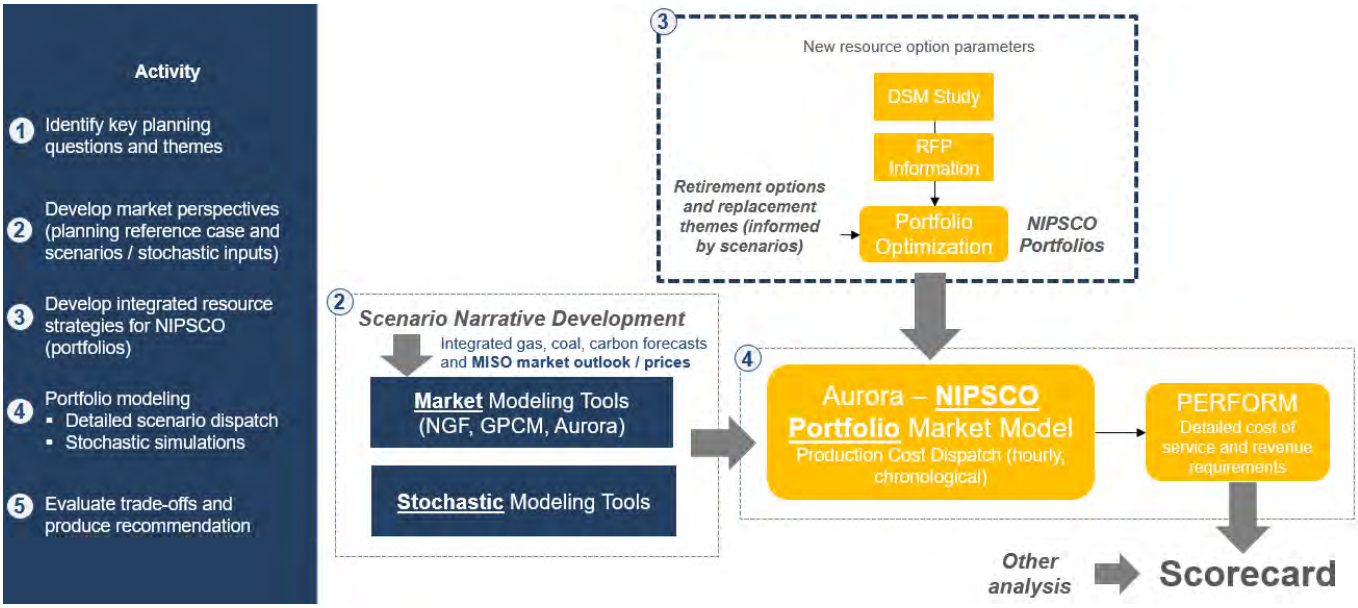
2.3 Resource Planning Approach

Consistent with the principles set out in Section 1.1, the 2021 IRP identifies a preferred portfolio plan for NIPSCO over a 20-30 year[2] planning horizon that seeks to deliver reliable,

[2] Note that fundamental market modeling and portfolio dispatch is performed over a 20-year period, and NIPSCO performs a 10-year end effects analysis in the financial modeling framework to arrive at 30-year NPVRR estimates. The end effects analysis grows variable costs at the rate of inflation, but specifically accounts for full rate base accounting and incorporates the impacts of contract expirations during the end effects period.

compliant, flexible, diverse and affordable electric service to its customers. NIPSCO's 2021 IRP was performed according to the detailed planning approach process that is outlined in Figure 2-1 and described in more detail below. While structurally similar to the 2018 IRP process, the 2021 approach has incorporated new approaches and process enhancements in order to respond to feedback that was received, as noted above.

Figure 2-1: Overall Integrated Resource Planning Approach



Step 1: Identify Key Planning Questions and Themes

The first step in NIPSCO's planning approach was to identify key planning questions and themes to guide the overall analysis framework. These key questions and themes influence all other elements of the IRP process, including the structuring of market perspectives, the identification of potential resource strategies, and the definition of objectives and metrics against which to evaluate future portfolios in NIPSCO's integrated scorecard framework. The major themes of the 2021 IRP are described in more detail below.

Retirement Timing for Existing Gas and Coal Units

NIPSCO's 2016 and 2018 IRPs explicitly evaluated the retirement timing of NIPSCO's coal fleet, with detailed evaluations of different retirement date permutations across all units. With all Schahfer coal units now planned for retirement by 2023, NIPSCO's 2021 IRP has been structured to evaluate various retirement pathways for the remaining thermal assets in the portfolio: the coal-fired Michigan City Unit 12, the natural gas-fired Schahfer 16A/B peaking units, and the natural gas-fired Sugar Creek combined cycle. As in past IRPs, NIPSCO's analysis framework has been structured to fully evaluate different retirement dates along with the corresponding

impacts associated with ongoing costs and new replacement options. This provides a transparent means of assessing key portfolio evolution strategies over both the short-term and the long-term.

Reliability

The ongoing energy transition is transforming the way that resource planners need to think about the role of reliability in an IRP process, and a power market with more intermittent resources requires ongoing enhancements to modeling approaches and new performance metrics for portfolio evaluation. As a member of MISO, NIPSCO is not independently responsible for all elements of reliability, but must be prepared to meet changing market rules and standards. MISO has been studying the impacts of growing intermittent generation penetration in the market for the last several years through the RIIA[3] initiative, which lays out the key emerging elements of reliability and serves as a useful framework for resource planning. The RIIA report defined three major focus areas for reliability, which are summarized along with other factors in Figure 2-2.

Figure 2-2: Reliability Elements from MISO's Renewable Integration Impact Assessment

	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition:	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
Forward Planning Horizon:	Year-ahead	Day-ahead	Real-time or Emergency
Reliability Factors:	Reserve margin, ELCC and energy duration	Dispatchability, energy market risk exposure	Real Time Balancing System
IRP Modeling Approach:	Portfolio development constraints, with ELCC and seasonal accounting	Hourly dispatch analysis, including stochastic risk	Ancillary services analysis (regulation, reserves), with sub-hourly granularity; additional technical reliability assessment

Consistent with the reliability elements identified by MISO, NIPSCO's 2021 IRP has incorporated the following elements and enhancements:

- An expanded view of resource adequacy to assess seasonal (summer and winter) planning reserve margins and to evaluate changing ELCC credit for resources over time;
- A broadened stochastic uncertainty analyses to incorporate hourly renewable generation uncertainty and its expected relationship with hourly MISO power prices;

[3] MISO published a summary report in February, 2021, which can be accessed here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

- A sub-hourly ancillary services analysis to assess the potential value for fast response resources such as CTs and energy storage and solar plus storage in the energy, regulation, and reserves markets over time;

- An additional technical reliability assessment to evaluate resources and portfolios against key reliability standards and metrics that are unable to be quantified in the IRP's core economic analysis; and

- Incorporation of new scorecard metrics that develop reliability scores and assess broader perspectives of tail risk.

Flexibility and Adaptability of the Portfolio

A key element of NIPSCO's 2018 IRP was *flexibility*. The preferred plan specifically incorporated expectations that NIPSCO would regularly evaluate new resource options, track technology change, and adapt to market rules and policy evolution. And NIPSCO's implementation of its short-term action plan did exactly that by; (i) conducting an additional set of RFPs to secure additional projects beyond those selected in 2018; (ii) adjusting NIPSCO's procurement strategy to integrate storage into certain solar projects; and (iii) evolving the analytical tools used in IRP studies to incorporate broader risks and market considerations in the 2020 portfolio analysis and now in this 2021 IRP.

The 2021 IRP has been structured around these same principles in the following ways:

- NIPSCO identified key regulatory developments early in the planning process to ensure market scenarios and portfolios were constructed to be flexible to imminent changes. These included:

    - MISO's RAN framework and the pending implementation of a seasonal capacity construct;

    - In 2021, the Indiana General Assembly passed House Enrolled Act 1520, a three-year Forward Looking Resource Adequacy Requirement

    - MISO's transition to an ELCC methodology to assess capacity credit for wind and solar resources over time and by season;

    - FERC Order 2222, which enables DERs to participate fully in wholesale markets; and

    - FERC Order 841, which requires ISOs such as MISO to establish a participation model for electric storage resources in energy, capacity, and ancillary services markets.

- NIPSCO conducted RFP events to solicit actionable resource offers of all types and duration and specifically requested information on emerging technologies to understand likely technology trends in the coming decade;

- NIPSCO deployed a portfolio construction process that did not rely solely on least cost optimization, but assessed a wide range of strategies to understand tradeoffs and identify the attractiveness of different pathways under different states-of-the-world for commodity prices, environmental policy, and MISO market evolution.

Carbon Emissions and Environmental Policy

NIPSCO's 2018 IRP laid out a plan to significantly reduce carbon emissions by 2030 through the retirement of its coal fleet and replacement with predominantly renewable resources. Meanwhile, federal energy and environmental policy proposals have outlined several means of achieving ambitious carbon emission reductions from the power sector through a number of mechanisms, including extension of tax credits, a clean energy standard, and programs to provide grants or impose penalties on utilities based on their future clean energy expansion plans. Given NIPSCO's desire to use the 2021 IRP to assess a range of environmental policy futures and a range of potential portfolio strategies, the following considerations have been made:

- Expansion of NIPSCO's IRP planning scenarios to incorporate a range of environmental policy outcomes, including two distinct net-zero emission constructs: one based on the implementation of a carbon tax or cap-and-trade mechanism and one based on the implementation of a series of policy incentives and clean energy standard mechanisms.

- Development of net-zero portfolio concepts for NIPSCO that incorporate long-term options to retire or retrofit all fossil resources in the portfolio.

Scorecard Definition

With these key planning questions and themes identified, NIPSCO worked to define a series of scorecard objectives and indicators against which to measure portfolio options. The scorecard is a means of reporting key metrics for different portfolio options to transparently review tradeoffs and relative performance. It does not produce a single score or ranking of portfolios, but serves as a tool to facilitate decision-making

For its 2021 IRP scorecard, NIPSCO identified five major planning objectives and multiple metrics within nine key indicator categories, as summarized in Figure 2-3. The objectives include Affordability; Rate Stability; Environmental Sustainability; Reliable, Flexible, and Resilient Supply; and Positive Social and Economic Impacts. These are similar to those used in the 2018 IRP, with the following key modifications:

- Based on stakeholder feedback, the Rate Stability objective was expanded to assess different measures of cost risk and a new measure for lower cost opportunity.

- The reliability-focused objective was refined to incorporate new measures of technical reliability and an additional review of economic opportunities in the sub-hourly ancillary services markets.

Figure 2-3: Key Scorecard Objectives and Indicators

Objective	Indicator
Affordability	Cost to Customer
Rate Stability	Cost Certainty
	Cost Risk
	Lower Cost Opportunity
Environmental Sustainability	Carbon Emissions
Reliable, Flexible, and Resilient Supply	Reliability
	Resource Optionality
Positive Social & Economic Impacts	Employees
	Local Economy

Step 2: Develop Market Perspectives

Prior to performing any portfolio-specific analysis, NIPSCO developed perspectives on key *external* market drivers and other major planning assumptions. This involved the use of several market models and forecasting approaches in order to arrive at a Reference Case set of inputs and a set of scenarios against which to evaluate resource options. The elements involved in this step are described in more detail below.

Key Market Forecast Inputs

Market and commodity price forecasts are important drivers for NIPSCO's IRP, since they influence the variable costs of operation for many resources, the dispatch of certain power plants, and NIPSCO's interaction with the MISO market. CRA produced commodity price forecasts for major inputs, including natural gas prices, coal prices, emission allowance prices, and power prices (energy and capacity) for the Reference Case and three alternative integrated market scenarios. For certain inputs, CRA relied on support from NIPSCO's subject matter experts for details or assumptions that are specific to NIPSCO's current operating fleet. For example, for coal pricing, delivered coal contract details and expected coal transportation rates were provided by NIPSCO's Fuel Supply group in order to conform to near-term price expectations for the existing fleet of

plants. Long-term fundamental forecasts were blended in over time. Figure 2-4 presents a summary of the source and reference information for each of the major market inputs.

Figure 2-4: Major Market Input Sources

Major Input	Source	Section Reference for More Detail
Natural Gas Prices	CRA forecasts and NIPSCO operations team	8 (fundamental forecasts, including scenarios and stochastic inputs) 4 (current gas procurement strategies)
Coal Prices	CRA forecasts and NIPSCO fuel supply group	8 4 (coal procurement and current contracts/ transportation arrangements)
Emission Prices and Environmental Regulation	CRA forecasts and NIPSCO environmental group	8
MISO Power Prices	CRA forecasts	8
MISO Capacity Prices	CRA forecasts	8

CRA relied on the following models to perform this work:

- CRA's NGF model, which provides a bottom-up forecast of North American gas production and prices with a focus on shale gas supply and other unconventional resources. Key NGF outputs include a long-term price forecast for domestic natural gas, as well as breakeven costs and production data for major gas basins across the United States. NGF is a national model, useful for macroeconomic scenarios. CRA also licenses the GPCM for regional basis analysis.

- The Aurora model, which CRA licenses, performs regional long-term capacity expansion analysis and produces hourly MISO market prices at a zonal level based on a fundamental dispatch of the market. Market inputs for the Aurora model include fuel prices, emission prices, regional load forecasts, existing resource parameters and announced regional capacity additions and retirements, and costs and operational parameters for new technology resource options. CRA also deploys a capacity market model, which produces an internally consistent capacity price outlook based on MISO market rules.

- Gas and power price stochastic inputs were developed with CRA's MOSEP mode. The tool's Monte Carlo engine simulates price deviations around expected paths based on historical volatility and gas-power correlation to yield hundreds of iterations of daily and hourly price paths. CRA also integrated hourly renewable output uncertainty into the process, based on historical weather data. The details of the stochastic development process are discussed in more detail in Section 8.

Environmental Planning Inputs

For the 2021 IRP, the joint NIPSCO-CRA team developed a range of potential environmental policy input assumptions across market scenarios, given significant uncertainty regarding the outcome of ongoing policy debates at the federal level. These environmental planning inputs included a range of tax credit extension, CO2 pricing, and clean energy target assumptions. NIPSCO's environmental group provided perspective on the policy ranges and the likely impacts for NIPSCO's fleet. A comprehensive review of key environmental planning drivers is provided in Section 7.

Energy and Demand Forecast

For the 2021 IRP, CRA developed an independent load forecast for NIPSCO's energy sales and expected future summer and winter peaks. Although independent, CRA coordinated with NIPSCO's load forecast experts to review data and discuss modeling approaches. The 2021 IRP explicitly included a robust accounting of the impacts of historical DSM, as well as quantitative scenario-based projections of EV and customer-owned DER penetration and their impacts on NIPSCO's load growth outlook. Scenario variables also included economic growth, industrial load uncertainty, and broader market-wide electrification. All methods, assumptions and detailed forecast results are provided in Section 3.

Existing NIPSCO Portfolio Parameters

NIPSCO's IRP models incorporate all elements of the existing portfolio. NIPSCO's generation operations and planning groups provided the following characteristics for the existing set of resources: capacity, heat rates, emission rates, other operational characteristics of fossil-fired resources, variable O&M costs, fixed O&M costs, forced outage rates, maintenance schedules, must run schedules for coal units, energy and capacity contracts, feed-in-tariff contracts, existing DSM data, and renewable shapes. Certain details regarding the existing fleet are provided in Section 4.

New Resource Parameters

NIPSCO relied on multiple sources for major input assumptions associated with new resource options. DSM resource options and costs were developed by GDS, as described in Section 5. Supply-side resource options were developed according to the 2021 RFPs. The 2021 RFPs provided real-world cost information and resource operational characteristics, including capacities, heat rates, and expected capacity factors for renewable resources. Section 4 describes this process in more detail, along with a review of emerging technologies that may be viable over the long-term for NIPSCO and across the broader MISO market. In addition, for the first time in 2021, NIPSCO also introduced DER resource options, inclusive of potential cost savings associated with distribution system investment deferrals. Details of this process are also described in Section 4.

Planning Reserve Margin Target

NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy. The MISO UCAP planning protocol was used to determine the planning reserve margin target to use in the 2021 IRP update, and NIPSCO set its target to 9.4%, as per current MISO standards. This target is based on NIPSCO's coincident peak in MISO. For winter planning reserve margin purposes, NIPSCO also assumed a 9.4% target, although formal rules and seasonal reserve margin standards have yet to be defined for MISO's forthcoming seasonal resource adequacy construct.

Financial Assumptions

Several financial assumptions are relevant to projecting annual revenue requirements, such as the expected return on equity and debt, tax rates, and the discount rate used when calculating the NPV. A summary of the major financial assumptions used in the 2021 IRP is provided in Figure 2-5.

Figure 2-5: Major Financial Assumptions

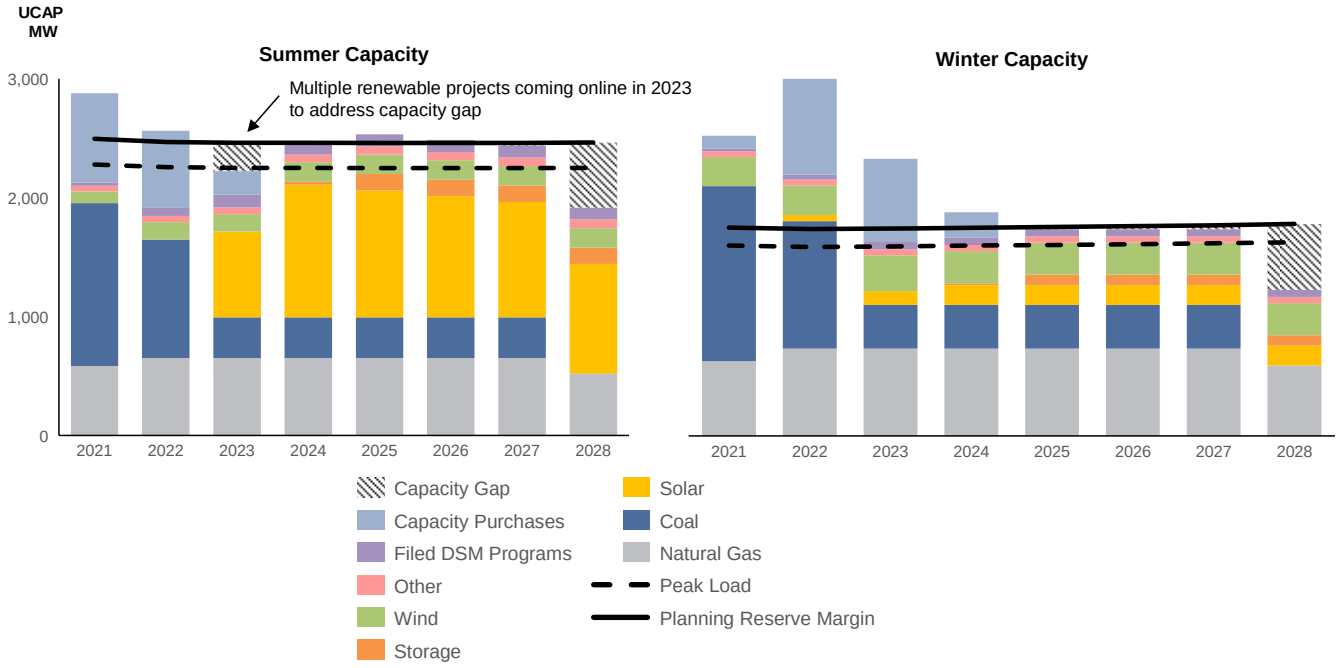
Financial Assumption	Value
Cost of Equity	9.90%
Cost of Debt	4.97%
Equity %	57.11%
Debt %	42.89%
After-Tax Weighted Average Cost of Capital	7.26%
Federal Income Tax Rate	21.00%
State Income Tax Rate	4.90%
Blended Income Tax Rate	24.87%
Property Tax Rate	2.16%
Discount Rate	7.26%
Allowance for Funds Used During Construction%	7.44%
Blended Depreciation Rate for Existing Assets	3.88%

Step 3: Develop Integrated Resource Strategies

The third major step in the 2021 IRP process was to develop resource strategies or portfolios for further evaluation. Foundational to this step was establishing NIPSCO's starting supply-demand position and energy balance, inclusive of the actions taken since the 2018 IRP. NIPSCO is currently in the midst of retiring its coal-fired Schahfer units and replacing them primarily with wind, solar, and storage resources.[4] As shown in Figure 2-6, these new resources will support NIPSCO in maintaining sufficient capacity reserves to meet peak load obligations plus the assumed MISO 9.4% planning reserve margin, until additional resource retirements are made.[5]

While winter loads are considerably lower than summer demand, the lower capacity credit for solar resources in the winter results in comparable reserve margin positions across seasons. While NIPSCO currently expects to meet reserve margin requirements from a planning perspective, it is important to note that uncertainty in load growth, planning reserve margin targets, and seasonal capacity accreditation for renewable resources requires flexibility in future resource procurement.

Figure 2-6: Starting Supply-Demand Balance by Season



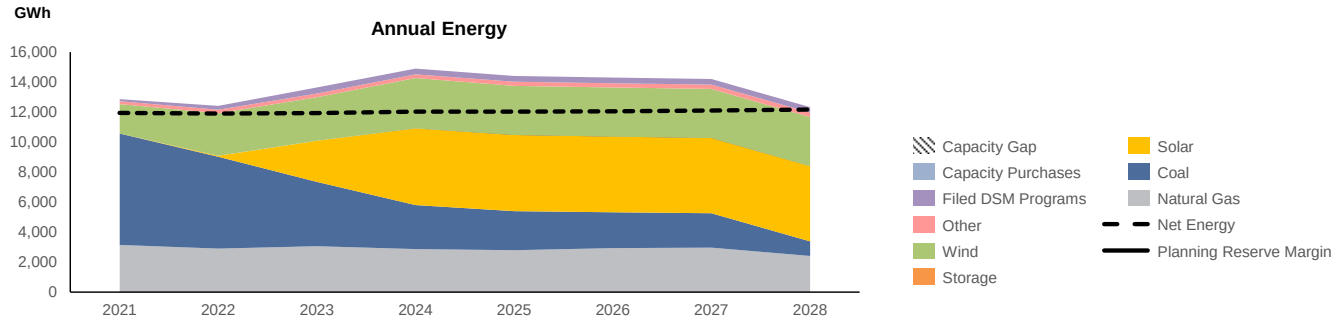
From an energy perspective, the portfolio is expected to be in balance in the near-term on an annual basis, with a growing net long position anticipated into the middle of the next decade,

[4] Note that capacity credit for new resources may not be accounted for until the calendar year after they enter operation due to seasonal accreditation rules. In addition, the capacity credit for some storage resources is not reflected until 2025 (after a full year of operations) due to pairing configuration with solar resources.

[5] Note that the graphic shows planned retirements of the Michigan City 12 coal unit and the Schahfer 16AB natural gas-fired units in 2028. This 2021 IRP evaluated these retirement decisions in further detail, as discussed in Section 9.

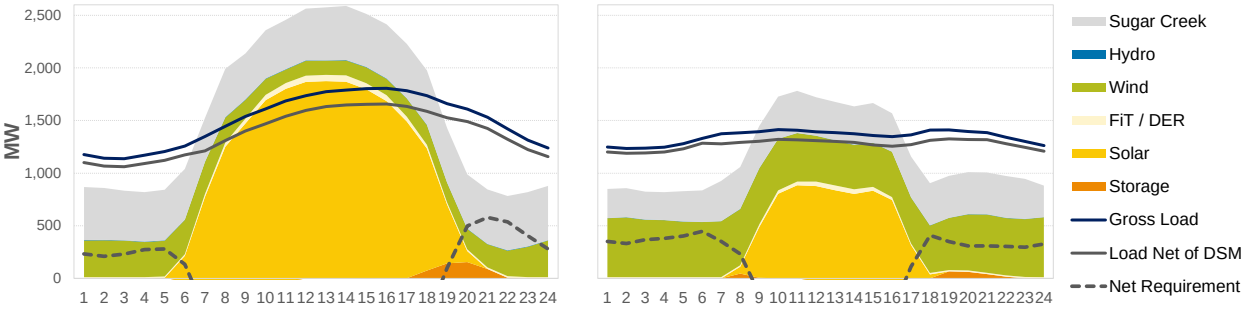
driven by the energy value and dispatch advantage of the wind and solar resources entering the portfolio. This is illustrated in Figure 2-7. However, the tight capacity position may create hourly gaps, particularly in the winter mornings and evenings when solar resources ramp down.

Figure 2-7: Starting Annual Net Energy Balance



These hourly energy gaps are shown for an average future summer day and an average future winter day *after the retirement of Michigan City 12 and Schahfer 16A/B* in Figure 2-8. As illustrated in these graphics, there are hours of the day where renewable resources are not available, notably overnight for solar resources. Furthermore, solar resources may experience steep production declines in the evening hours. Currently, NIPSCO's Sugar Creek, Schahfer 16A/B, and Michigan City 12 units are available during all hours of the day when called upon, and when economic, NIPSCO can purchase from the MISO market. However, as Michigan City 12 and Schahfer 16A/B retire, the portfolio will require new resources to be available to mitigate against specific hourly energy exposure, even as the portfolio has enough total energy to meet requirements on an annual basis.

Figure 2-8: Hourly Projected Energy Balance – Average Summer and Winter Day



With this foundational starting point, the 2021 IRP's portfolio development process relied on multiple inputs and approaches, which are described in more detail in Section 4 (Supply Side Resource Options), Section 5 (Demand Side Resource Options), and Section 9 (Portfolio

Analysis). In the context of the major themes identified in step one and the starting supply-demand balance noted above, NIPSCO believes that the dynamic planning environment requires an advanced two-stage portfolio development approach to first assess the existing fleet and to then evaluate replacement options, rather than a traditional approach that relies solely on the deployment of single least cost optimization runs. While portfolio optimization analysis for both supply side and demand side resources with the Aurora model's portfolio optimization tool was a critical part of the portfolio development process, NIPSCO's approach to portfolio construction does not rely solely on this one framework. This is due to three major considerations:

- Retirement analyses are difficult to perform in standard least cost optimization planning models, since capital and maintenance budgets vary based on expected end-of-life date. Most optimization frameworks are not set up to dynamically adjust current and future budgets in a single optimization pass, so NIPSCO evaluates the economic implications of various retirement concepts independently, with least cost optimization techniques used to identify replacement resource options for each existing fleet pathways.

- Least cost is not the only metric in NIPSCO's integrated scorecard, so determining portfolios solely through least cost optimization runs could fail to evaluate portfolios that are lower risk or provide other valuable attributes for customers (including environmental sustainability, reliability, or positive social and economic impacts). For example, in the 2021 IRP, NIPSCO has explicitly evaluated the costs of net zero carbon emission concepts and has assessed a range of different replacement themes with different reliability attributes. Such portfolios would not be feasibly identified or evaluated through single-round optimization runs.

- The approach supports transparency of results. If NIPSCO were to rely solely on optimized portfolios, it would be difficult to evaluate how much higher cost other options might be, leaving stakeholders a limited set of outputs to review, particularly if unable to perform optimization simulations on their own. Overall, NIPSCO's approach in this 2021 IRP has allowed for the evaluation of 17 different portfolio concepts to transparently present the landscape of future options.

Step 4: Portfolio Modeling

After detailed portfolios were constructed, each of them was evaluated in CRA's suite of resource planning tools, namely Aurora and a utility financial model known as PERFORM. The Aurora model performs an hourly, chronological dispatch of NIPSCO's portfolio within the MISO power market, accounting for all variable costs of operation, all contracts or PPAs, and all economic purchases and sales with the surrounding market. Aurora produces projections of asset-level dispatch and the total variable costs associated with serving load. It also produces estimates for other key metrics, such as carbon dioxide emissions over time and capacity and generation by fuel type. CRA also deployed its ESOP model to evaluate sub-hourly energy and ancillary services value, as described in more detail in Section 8.

The Aurora output is then used by CRA's PERFORM model to build a full annual revenue requirement, inclusive of capital investments, fixed operating and maintenance costs, and financial accounting of depreciation, taxes, and utility return on investment. The PERFORM model produces annual and net present value estimates of revenue requirements. The full set of portfolio modeling is undertaken for all portfolio options for the Reference Case, each individual integrated market scenario, and a full stochastic distribution of potential outcomes associated with select commodity prices and hourly renewable generation.

Step 5: Evaluate Tradeoffs and Produce Recommendations

The final step in NIPSCO's IRP process is to evaluate the various portfolios with an integrated scorecard and produce recommendations for a preferred plan. As discussed in Step 1, NIPSCO identified several planning objectives for its scorecard. In this step, metrics were recorded against all key planning criteria, and tradeoffs were evaluated. Ultimately, NIPSCO management is responsible for selecting the preferred portfolio based on an assessment of all options and scorecard metrics. This process and the preferred portfolio selection is described in Section 9.

Section 3. Energy and Demand Forecast

3.1 Introduction and Major Highlights of the Forecast

This section provides an overview of NIPSCO's load forecast. For the 2021 IRP, NIPSCO expanded its relationship with CRA to produce a load forecast by customer class, including residential, commercial, small industrial and large industrial customers.[6] This entailed an econometric core load forecast, plus projections for EV and DER penetration throughout the service territory. Major highlights of the forecast include:

- NIPSCO's energy sales are projected to grow at a CAGR of approximately 0.2% over the next 20 years. Summer peak load is projected to *decline* at a CAGR of 0.2%, while winter peak load is projected to *increase* at a CAGR of 0.2%.

- Residential and commercial customer counts are projected to grow at CAGRs of 0.5% and 0.8%, respectively, with the small industrial customer count projected to grow at a rate of 0.3% per year. Residential and commercial sales are projected to grow at slower rates than customer counts, while small industrial and large firm industrial sales are projected to decline.

- EV growth has the potential to add between approximately 150 to 1,000 GWh to the sales forecast and between 10 and 80 MW to peak load.

- Customer-owned DERs have the potential to reduce the sales forecast by approximately 125 to 450 GWh, while reducing summer peak load by between approximately 40 and 160 MW and winter peak load by up to 100 MW.

- NIPSCO's scenario analysis provides a broad range of potential load growth outcomes based on uncertainty regarding future economic growth, EV and DER penetration, other electrification, and potential industrial load migration.

3.2 Forecasting Methodology Overview

For the 2021 IRP, NIPSCO has made several enhancements to its load forecasting methodology, which are discussed in detail in this section. The overall load forecasting methodology includes five key steps, which are illustrated in Figure 3-1 and described as follows:

- **Data Gathering**: Compilation of historical data, including historical energy consumption and number of customers by class, historical demand side management program impacts, Moody's macroeconomic variables (such as state-level data on number of households, employment, and personal income), and

[6] Additionally, railroad, street lighting, public authority and company use energy forecasts are incorporated in the total energy forecast. However, the load forecast for these customer classes has been projected using a simple moving average assumption based on historical data, rather than a regression estimation method.

weather variables (heating and cooling degree days based on historical temperature and humidity).

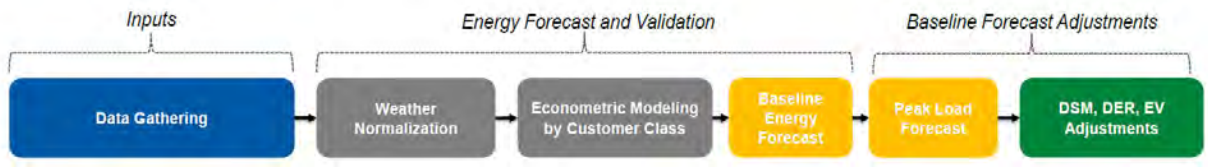
- **Weather Normalization:** Development of weather-normalized energy sales by class (kWh/customer) for the historical period, *excluding* historical DSM program impacts.

- **Econometric Modeling by Customer Class:** Testing of all economic and demographic "driver" variables in a dynamic regression system, and performance of post-estimation tests on econometric models' specification and forecasting performance (for example, Systemic Mean Absolute Percentage Errors).

- **Baseline Energy and Peak Load Forecast Development:** Development of baseline customer count and energy forecasts for each NIPSCO customer rate class, *excluding* historical DSM, and development of accompanying peak load forecasts using the energy forecast and load factors by customer rate class.

- **Adjustments:** Adjustments to the load forecast to incorporate existing and planned *known* DSM programs, projections for electric vehicle and distributed energy resource penetration ranges, as well as additional factors in the scenario analysis, including other electrification and industrial load loss.

Figure 3-1: Summary of NIPSCO Load Forecasting Methodology



3.3 Base Customer Count, Electric Energy, and Peak Demand Forecast

3.3.1 Data Gathering, Weather Normalization, and Econometric Modeling

NIPSCO developed *baseline* forecasts for customer count and energy usage per customer separately, employing an econometric analysis of monthly historical customer class data. First, NIPSCO collected historical data by customer class on the number of customers and energy consumption at a monthly level from 2010 through 2020,[7] macroeconomic and demographic

[7] It is important to note that NIPSCO's baseline load forecast takes out all historical DSM and EE savings from historical electric energy consumption prior to the econometric analysis.

indicators for the region from Moody's Analytics,[8] weather data (heating and cooling degree days based on historical temperature and humidity) from the National Oceanic and Atmospheric Administration, and information regarding NIPSCO's historical DSM and EE program savings.

After constructing datasets for each customer class, NIPSCO developed econometric regression models for forecasting the number of customers for each customer class, controlling for key drivers. These key variables are regional economic and demographic factors, including household counts (for residential and commercial) and employment in the manufacturing sector (for industrial) and dummy variables that control for seasonal and annual impacts. Specifically, the following variables were used in the development of the customer count model:

- The number of households is the key variable used to forecast residential and commercial customer count.[9]
- For the small industrial sector forecast, regional historical employment in the manufacturing sector is used as the key variable.[10]
- Finally, dummy variables control for factors that cannot be controlled with any other variable in regression equations that is not associated with regional economic or demographic factors, such as monthly seasonality.

A representation of the estimated regression model for the customer count forecast is presented in Equation 3-1.

Equation 3-1: Regression Equation for Customer Count Forecast

$$C_{it} = b_o + b_1 X_{it} + b_{jt}\theta_t + \pi_{it}$$

Where

i=customer class (residential, commercial and small industrial)

t= month

b_o= constant term

C_{it} = number of customers in a given customer class i in month t

X_{it}= Macroeconomic variable (e.g., number of households for residential and commercial classes in a given month i)

[8] Note that the final IRP load forecast was based on economic data from Moody's as of April, 2021. NIPSCO presented preliminary load forecasts based on earlier vintage Moody's data in its first public stakeholder meeting in March, 2021. Therefore, very minor differences in customer count and load growth rates are present in the final numbers relative to the preliminary data that was initially reviewed in the first stakeholder meeting.

[9] The expected coefficient on the number of households variable is positive for both residential and commercial customer classes suggesting that an increase in the number of households is associated with an increase in the number of residential and commercial customers in NIPSCO territory.

[10] The expected coefficient on the manufacturing employment variable is positive for the small industrial customer class, suggesting that an increase in employment in manufacturing is associated with an increase in the number of small industrial customer count in NIPSCO territory.

$b_1, b_2, .. b_j$ = Estimated coefficients (slopes) for each variable included in the regression model.

$b_{jt}\theta_t$= time dummies

π_{it} = random error term

Similarly, NIPSCO developed econometric regression models for predicting energy sales[11] for each customer class that would control for key drivers for energy consumption including weather and regional economic and demographic drivers. Specifically, key variables for the residential, commercial and small industrial class regression equations included the average class-specific monthly retail rate, heating and cooling degree days, real personal income (for residential), employment in the manufacturing sector (for commercial and small industrial), and dummy variables that control for seasonal impacts on energy consumption. The following variables were used in the development of the electric energy sales per customer model:

- The average retail rate controls for the impact of the cost of electric energy on the amount of electricity consumption in each customer class.[12]

- Heating and cooling degree day variables control for the impact of weather on electricity consumption. Particularly, residential and commercial sectors are responsive to outside temperature because a significant portion of electricity consumption is used for air conditioning, and to a lesser extent space heating, for these two customer classes.[13]

- Demographic variables (i.e., real personal income and employment in the manufacturing sector) control for the impact of regional economic factors on electricity consumption.[14]

- Dummy variables control for factors that cannot be controlled with any other variable in regression equations such as monthly seasonality that is not associated with weather.

[11] The electric energy forecast is predicted for energy consumption per customer, which is the ratio of total energy consumption by total number of customers in a specific customer class in a given month (i.e., residential energy use per customer (MWh/customer) is calculated as total residential energy consumption (MWh) in a given month divided by the total number of residential customers in that month).

[12] The expected coefficient on the average monthly retail rate variable is negative, suggesting that an increase in average retail rate is associated with a lower amount of electricity consumption.

[13] The expected coefficients on heating degree days and cooling degree days suggest that (i) an increase in the number of heating degree days is associated with higher electricity consumption, specifically due to space heating; and (ii) an increase in the number of cooling degree days is associated with higher electricity consumption, specifically due to space cooling.

[14] The expected coefficient on real personal income and employment in the manufacturing class is positive, suggesting that (i) an increase in regional real personal income is associated with higher electric energy consumption due to an increase in wealth (e.g., larger homes, increase in number of home appliances); and (ii) an increase in employment is associated with higher electric energy consumption due to an increase in commercial and industrial economic activity.

A representation of the estimated regression model for the usage per customer forecast is presented in Equation 3-2.

Equation 3-2: Regression Equation for Usage per Customer Forecast

$$D_{it} = a_o + a_1 P_{it}^e + a_2 X_{it} + a_3 Weather_{it} + a_{jt}\theta_t + \varepsilon_{it}$$

Where

i=customer class (residential, commercial and small industrial)

t= month

a_o= constant term

D_{it}= electric energy usage per customer in a given customer class i in a given month

P_{it}^e= average retail electricity rate in a given customer class i in a given month

X_{it}= Macroeconomic variable (e.g., real personal income for residential class in a given month)

$Weather_t$= variables included to control for weather such as heating and cooling degree days

$a_{jt}\theta_t$= time dummies that control for seasonality in demand.

ε_{it}= random error term

$a_1, a_2, a_3, \ldots a_j$ = Estimated coefficients (slopes) for each variable included in the regression model.

Figure 3-2 summarizes the key variables included in both the energy per customer and customer count load forecast equations for residential, commercial and small industrial customer classes.

Figure 3-2: Econometric Model Parameters for Core Load Forecast

	Residential	Commercial	Small Industrial
Customer Count Forecast	*Number of households*, seasonal and annual dummies	*Number of households*, seasonal and annual dummies	*Manufacturing employment*, seasonal and annual dummies
Baseline Sales per Customer Forecast	*Real personal income*, average retail rate, HDD, CDD, seasonal monthly dummies	*Manufacturing employment*, average retail rate, HDD, CDD, seasonal monthly dummies	*Manufacturing employment*, average retail rate, HDD, CDD, seasonal monthly dummies

After estimating regression equations for each customer class, a number of statistical tests were performed to validate the regression equations specifications and forecast errors. CRA selected the presented model based on R-squared, adjusted R-squared, Root Mean Squared Error and Mean Absolute Percentage Error. Stata software was then used to construct the load forecast data for each customer class.

3.3.2 New Industrial Service Structure

The 2021 IRP incorporates NIPSCO's new industrial service tariff, known as Rate 831, and its subsequent impact on industrial load. This new industrial service tariff was included in the settlement agreement in Cause No. 45159, approved by the Commission in 2019 and it gives certain large industrial customers the option to secure their own energy and capacity needs. For IRP planning purposes, NIPSCO's load forecast for the large industrial customer class includes Rate 832, Rate 833, and Rate 831 (Tier 1 energy only) customers.[15]

3.3.3 Customer Count Forecast

Historical customer count data indicates that approximately 87% of NIPSCO customers are residential class with a historical CAGR of 0.4% between 2010 and 2019. The commercial class makes up about 12% of NIPSCO customers, and the small industrial class makes up about 0.4% of NIPSCO customers. The CAGR between 2010 and 2019 for commercial and small industrial is 0.6% and *minus* 1.4%, respectively.

Figure 3-3 presents NIPSCO's projected customer count for the Residential class, and Figure 3-4 presents NIPSCO's projected customer count for the Commercial and Small Industrial customer classes (green line for commercial and blue line for small industrial).

The CAGR is also calculated for each customer class projection between 2021 and 2040 in order to provide an understanding on the future growth trends for NIPSCO's customer count growth trends. NIPSCO's forecast projects residential and commercial CAGRs of 0.5% and 0.8%, respectively. The small industrial customer class growth rate is projected to be slower, at 0.3% through 2040.

[15] Note that hourly historical meter data for each individual industrial customer is analyzed when developing the load forecast for the large industrial customer class that NIPSCO services. The energy consumption of industrial customers under Tiers 2 and 3 on Rate 831 is excluded from the load forecast because this load is not served by NIPSCO.

Figure 3-3: NIPSCO Residential Customer Count Forecast

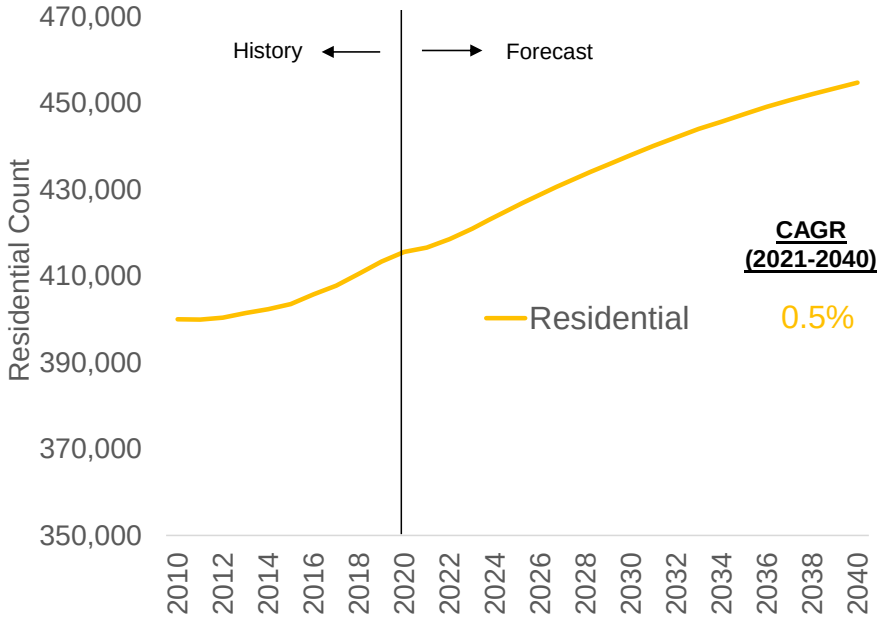
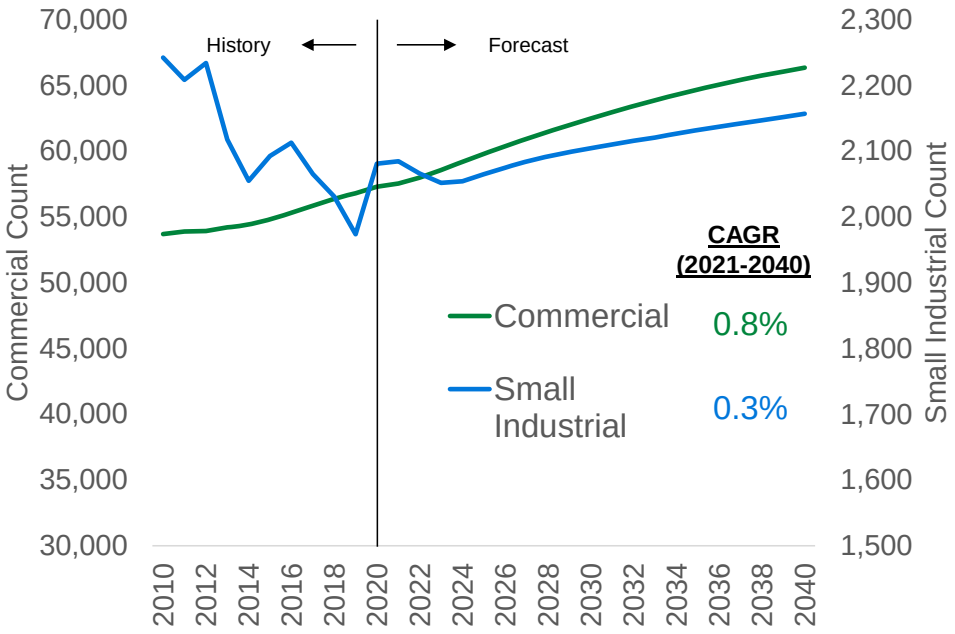


Figure 3-4: NIPSCO Commercial and Small Industrial Customer Count Forecast

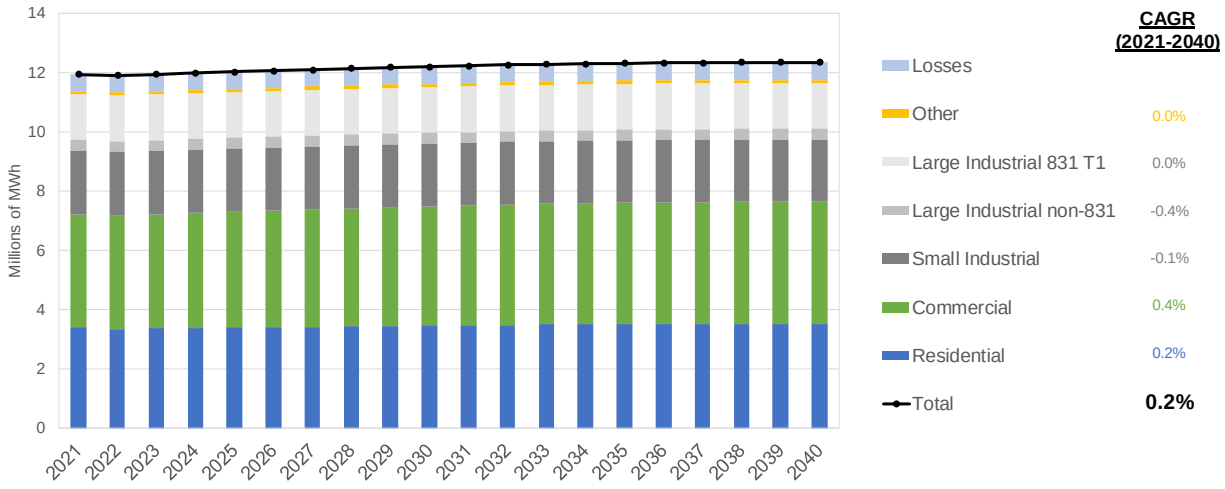


3.3.4 Sales per Customer and Total Electric Sales Forecast

To obtain the total monthly energy sales forecast for each class between 2021 and 2040, the energy sales per customer forecast is multiplied by the customer count forecast. The residential and commercial sectors make up almost half of total NIPSCO electric energy sales, followed by the Small Industrial customer class. Historical energy sales data shows that approximately 22% of NIPSCO electric energy sales are from the residential class. The commercial class makes up about 25% of NIPSCO electric energy sales, and the small industrial class makes up about 14% of NIPSCO electric energy sales. Note that electric energy sales for the Large Industrial customer class only include customers under the new tariff structure that are served by NIPSCO.

Figure 3-5 presents NIPSCO's projected electric energy sales forecast by customer class and total NIPSCO energy sales through 2040.[16] The CAGR for residential customers is projected to be 0.2%, and the CAGR for commercial energy sales is projected to be 0.4%, while the CAGR for the small industrial class is projected to be -0.1% between 2021 and 2041.

Figure 3-5: NIPSCO Electric Sales Forecast by Customer Class



3.3.5 Peak Load Forecast Development

After developing the baseline energy forecasts, NIPSCO developed peak load forecasts on a monthly basis. Applying monthly peak load factors and developing specific monthly peak load projections are improvements for the 2021 IRP, enabling NIPSCO to compare seasonal peak load differences, particularly the summer and winter peaks.

NIPSCO's historical sample meter data was used to develop the monthly peak load factors for the residential, commercial and small industrial customer classes, as presented in Figure 3-6. Based on the sample data, peak load factors are lowest during summer months including June, July

[16]Note that "Other" includes Railroad, Street Lighting, Public Authority, and Company Use. Note that losses are calculated monthly to arrive at net energy for load that must be served by generation. Losses are approximately 5% on an annual basis.

and August and higher during winter months including January, February and December. The formula used to develop load factors is summarized in Equation 3-3.

Equation 3-3: Load Factor Calculation

$$Load\ Factor = \left(\frac{Usage\ (kWh)}{\left(Demand\ kW\ *\ 24 \frac{hr}{day} * X \frac{days}{mo} \right)} \right)$$

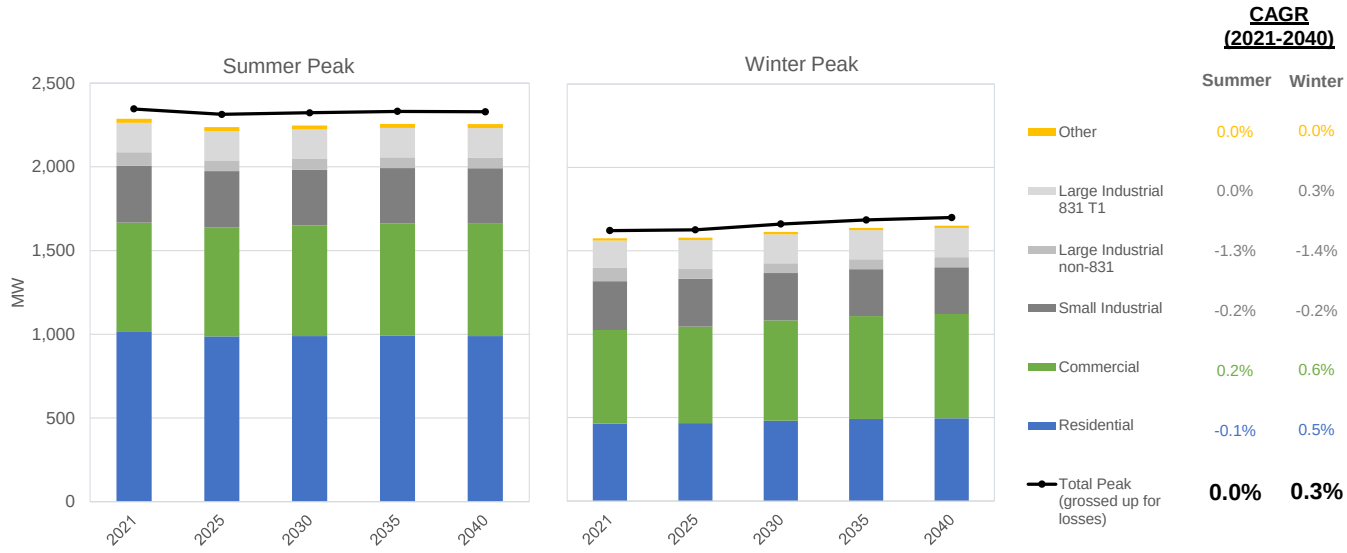
Figure 3-6: Calculated Peak Load Factors by Customer Class

Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	84%	84%	85%	73%	62%	55%	50%	50%	55%	67%	84%	84%
Commercial	79%	79%	72%	81%	67%	79%	74%	74%	79%	82%	79%	79%
Small Industrial	88%	88%	82%	87%	82%	81%	76%	76%	81%	87%	88%	88%

Note that in summarizing the annual system peak, NIPSCO calculated the highest sum of monthly peaks, not the sum of the highest monthlies for each class (i.e., a coincident peak), allowing for the development of summer and winter peak load forecasts by customer class, which are presented in Figure 3-7. While summer peak load is projected to stay stable through 2040, the winter peak is projected to grow at 0.3%.[17] This is consistent with historical trends that indicate that peak load in the winter months has been growing faster than summer months historically.

[17] Note that these growth rates refer to the baseline econometric analysis and do not reflect NIPSCO's final load forecast, which includes additional adjustments discussed in more detail below.

Figure 3-7: NIPSCO Peak Load Forecast by Customer Class



3.4 Electric Vehicles

3.4.1 Methodology Overview

NIPSCO developed a range of potential EV penetration rates based on existing data regarding EV counts in NIPSCO counties and a top-down forward outlook based on third-party projections. NIPSCO-specific and external information about electricity charging usage and hourly charging patterns was then used to estimate the impact on NIPSCO sales and peak load requirements for each of the four market scenarios.

The EV fleet was broken down into four classes of vehicle fleets, which were independently forecasted:

- LDVs
- Transit vehicles, such as buses and shuttle vans
- MDVs
- HDVs

3.4.2 Core Data Source Inputs

3.4.2.1 Starting Vehicle Count Estimates

NIPSCO developed estimates of the starting values for vehicle counts within the four major categories from the following major sources:

- LDVs: NIPSCO EV customer database

- Transit/MDV/HDV: National Transit Database, with estimates for the total vehicle counts in NIPSCO's territory

3.4.2.2 Vehicle Count Growth Rate Projections

To develop future projections for EV growth, NIPSCO largely relied on the EV forecasts for MISO LRZ 6 from the 2021 MTEP process. NIPSCO deduced EV sales CAGR from the three MTEP Futures scenarios and mapped them to Low, Medium, and High scenarios. These assumptions are provided in Table 3-1. NIPSCO also used public information from Bloomberg New Energy Finance for the heavy-duty vehicle sector.

Table 3-1: Electric Vehicle Sales CAGR by Scenario

	2020-2024	2025-2029	2030-2034	2035-2040
Low	33%	15%	11%	11%
Med	49%	21%	16%	15%
High	59%	30%	21%	15%

To determine the energy impact of the EV fleet, NIPSCO relied on a range of sources by vehicle class as documented in Table 3-2:

- For LDVs, the electricity demand per mile was determined from the 2019 EPA Automotive Trends Report for common vehicle model types: 0.28 kWh/mi for BEV and 0.075 kWh/mi for PHEV (assuming around one-third of the time PHEVs charge from the electric grid).

- For transit vehicles, MDVs, and HDVs, NREL, DOE, and specific vehicle data sources were used to estimate electricity demand per mile over time.

- Efficiency improvements over time were assumed, driven by a variety of factors, such as vehicle light-weighting, improvements in passenger driving behavior to maximize fuel economy, and others. A generic long-term improvement rate in kWh/mi efficiency was assumed at 0.5% per year, with faster near-term efficiency improvement in the Medium and High scenarios.[18]

[18] Electric Power Research Institute. Environmental Assessment of a Full Electric Transportation Portfolio Volume 1 Background, Methodology, and Best Practices. September 2015. 3002006875. https://www.eenews.net/assets/2015/09/18/document_cw_01.pdf. Based on U.S. Energy Information Administration Annual Energy Outlook, 2013

Table 3-2: Electric Vehicle Energy Usage Assumptions Summary

		LDVs	Transit Vehicles	MDVs	HDVs
Avg. Miles per Day		40	77[2]	66[4]	250[4]
Retirement Age		15 years	8 years[3]	8 years[3]	15 years[3]
BEV % of Total EVs	**Low**	42% -> 75%	42% -> 75%	42% -> 75%	-
	Med	42% -> 75%	42% -> 75%	42% -> 75%	-
	High	42% -> 90%	42% -> 100%	42% -> 90%	20% -> 40%
Fuel Economy (2021 vintage)	**BEV**	0.28 kWh/mi[1]	2.18 kWh/mi[2]	0.51 kWh/mi[5]	2.00 kWh/mi[4]
	PHEV	0.075 kWh/mi[1]	1.17 kWh/mi[2]	0.33 kWh/mi[5]	0.83 kWh/mi[4]

(1) EPA (2019) Automotive Trends Report 2019.

(2) NREL (2016). "NREL Evaluates Performance of Fast-Charge Electric Buses." https://www.nrel.gov/docs/fy16osti/67057.pdf

(3) National Transit Database 2019 Vehicles.

(4) DOE (2019). "Medium- and Heavy-Duty Vehicle Electrification: An Assessment of Technology and Knowledge Gaps."

(5) Based on Rivian 1-T and N-Gen Workhorse models.

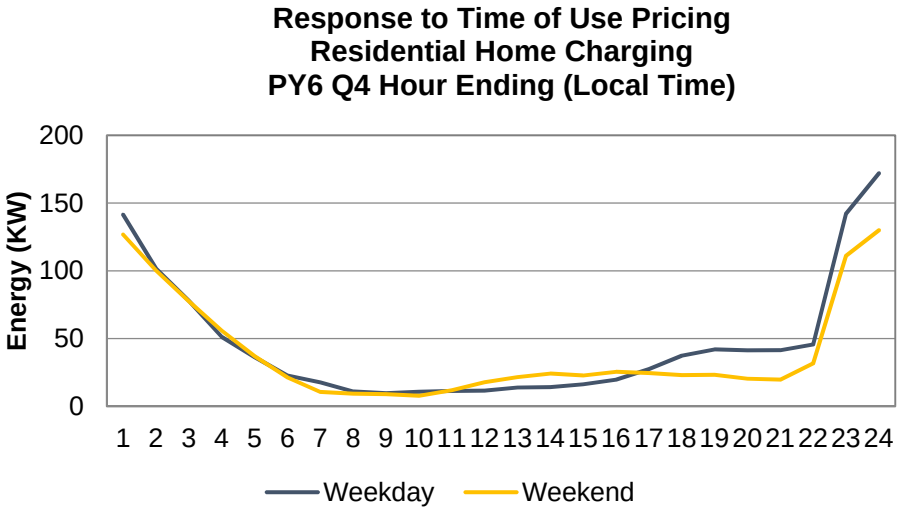
3.4.3 Light Duty Vehicles

3.4.3.1 Historical Service Territory Data: NIPSCO's IN-Charge Program

On February 1, 2012, the Commission issued a Final Order in Cause No. 44016 approving NIPSCO's Pilot Program through January 31, 2015 on February 1, 2012. On October 29, the Commission approved NIPSCO's 30-day filing to extend its EV program an additional two years through January 31, 2017. On January 11, 2017, the Commission issued a Final Order in Cause No. 44828 approving NIPSCO's request for modification of its EV Program to provide that participants of record as of January 31, 2017 would be subject to an energy charge of $0.070894 per kilowatt hour for all kilowatt hours used per month in the PEV Off-Peak Hours, plus all applicable Riders for a period of 23 months.

As of 2019, NIPSCO received 382 customer enrollments in the Pilot Program. From customer enrollment data, the typical customer drove 40 miles per day, with the time of use charging shape depicted below. The typical BEV model was a Tesla Model S, and typical PHEV models were Chevy Volt and Nissan Leaf. The data on customer charging patterns, usage, and fuel economy informed the inputs for the light-duty vehicles modeling. NIPSCO found that the discounted energy during off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior, as shown in Figure 3-8.

Figure 3-8: NIPSCO Time of Use Residential Home Charging Shape



3.4.3.2 Fleet Growth Forecast

As per the Indiana Bureau of Motor Vehicles, there were 1,262 electric vehicles registered in NIPSCO counties in 2018, of which 693 were PHEV, 499 BEVs, and the remainder various other vehicle types (i.e. motorcycles, utility EV). LDV numbers by County are provided in Table 3-3.

Using this starting number of EV registrations in NIPSCO counties, the annual sales of light duty vehicles were forecasted to grow according to the MTEP Futures-informed CAGRs shown in Table 3-1. To reflect increasing acceptance of BEV models, the mix of BEV-to-PHEV is trended over time to 75% BEVs of total EVs in the Low and Medium scenarios and 90% in the High scenario.

The replacement of older, less efficient vehicles is assumed to naturally occur as vehicles age and owners adopt new vehicle models. To reflect this process of stock turnover, an average car lifetime of 15 years was assumed. The combination of new BEV and PHEV sales per year, as well as the retirement of the existing stock, resulted in fleet-wide projections for BEVs and PHEVs.

Table 3-3: Light Duty Vehicles in NIPSCO Counties (LDV Registrations)

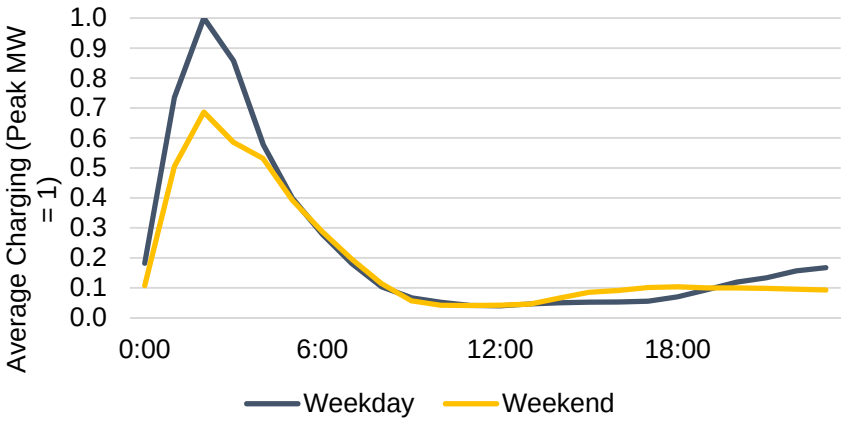
County	2014	2015	2016	2017	2018
BENTON	1	1	1	3	2
DEKALB	1	4	18	18	37
ELKHART	33	45	63	78	134
FULTON	4	5	5	4	9
JASPER	4	7	11	18	22
KOSCIUSKO	12	17	22	32	57
LAKE	116	154	185	250	344
LAPORTE	17	30	40	62	79
MARSHALL	7	8	9	14	40
NEWTON	2	2	2	7	11
PORTER	68	84	107	140	226
PULASKI		1	2	4	6
SAINT JOSEPH	50	71	87	148	229
STARKE	1	3	3	5	22
STEUBEN	3	6	10	18	32
WHITE	2	5	5	7	12
Total	321	443	570	808	1262

3.4.3.3 Peak Demand Impact

NIPSCO applied two EV charging shapes to the forecast scenarios to capture a variety of potential influences on charging behavior, such as rate design, public charging infrastructure availability and incentives, technology improvements in fast-charging, and smart charging infrastructure. The Low EV Penetration scenario charging shape, shown in Figure 3-9 was based on time-of-use data from NIPSCO's IN-Charge program, although shifted a few hours to exhibit price responsiveness consistent with the Aurora forecasted power prices.[19] NIPSCO found that the discounted energy during off-peak times of 10 p.m. to 6 a.m. (local time) had a significant impact on charging behavior.

[19] NIPSCO made this change in response to stakeholder feedback arising from the First Stakeholder Meeting on March 19, 2021, as described in the May 20, 2021 Stakeholder Meeting materials.

Figure 3-9: Low EV Penetration Charging Shape



The High EV Penetration scenario charging shape, shown in Figure 3-10, was based on data from the DOE's EV Project,[20] which utilized data from over 10,000 charging systems in 18 regions across the US. The time-of-day charging demand for all EV Project regions was reviewed from this report, including a variety of residential Level 2, public Level 2, and DC fast-charging stations.

Figure 3-10 High EV Penetration Charging Shape

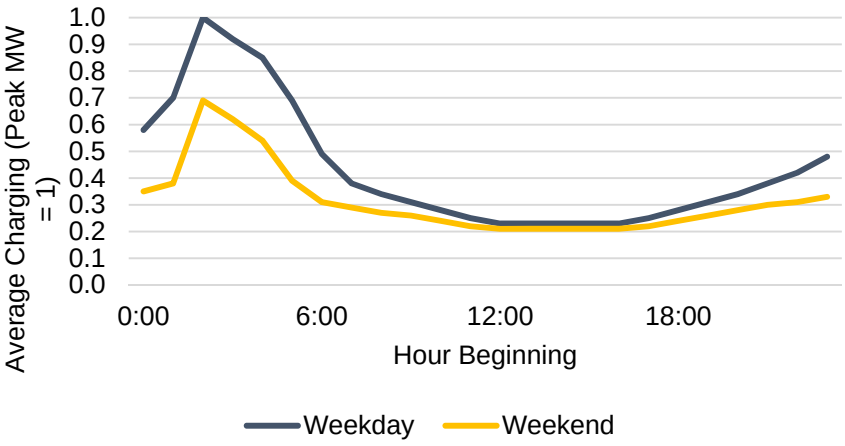
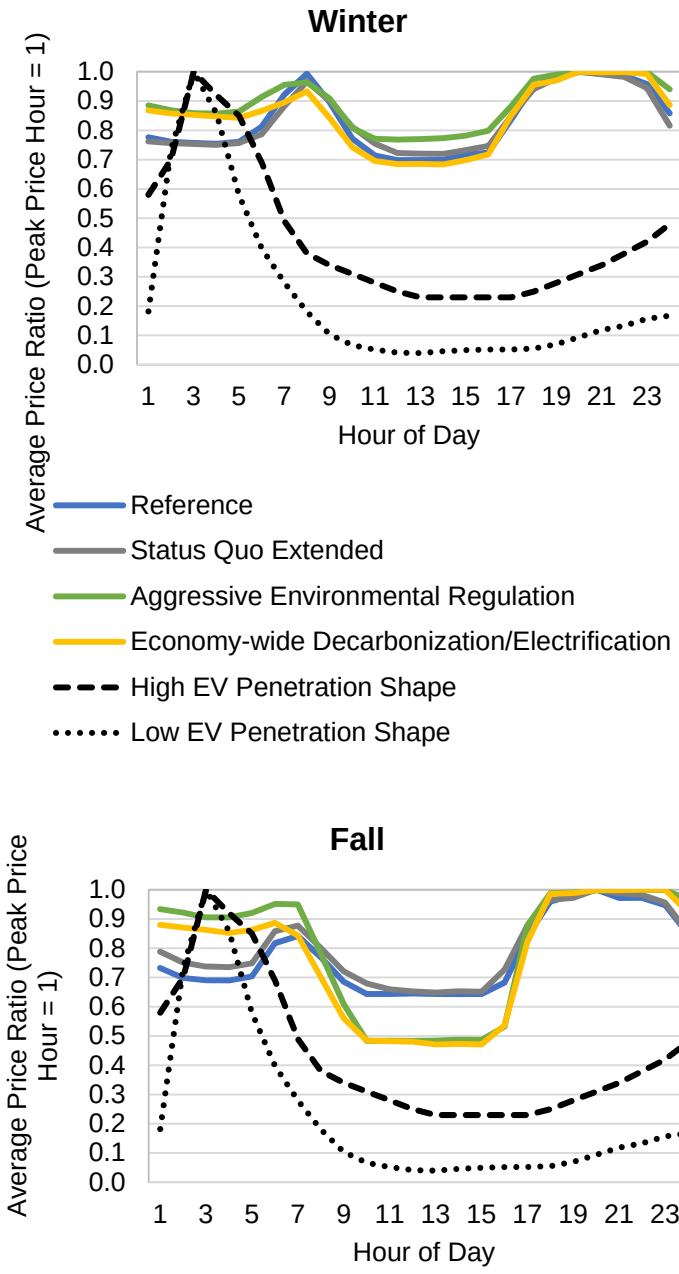
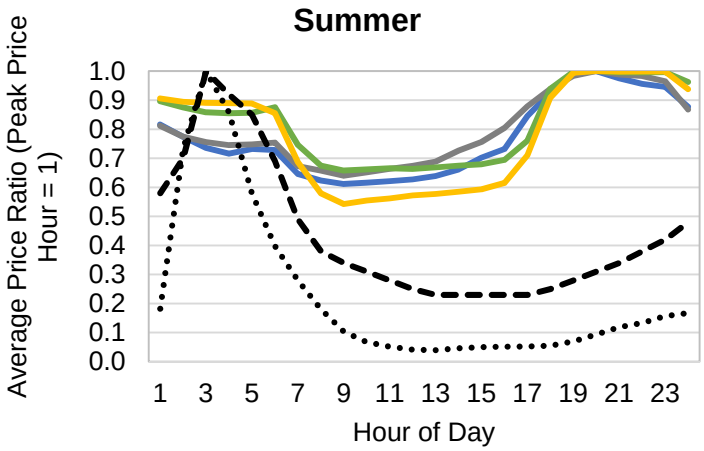


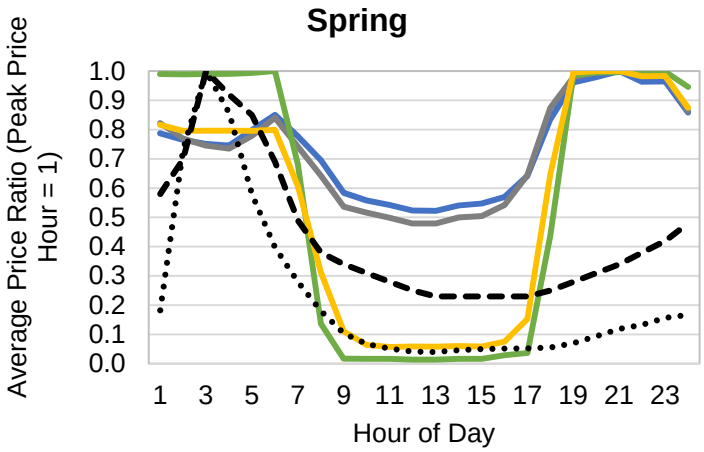
Figure 3-11 provides a view of the charging profiles versus expected hourly price shapes, displaying how charging behavior was assumed largely during the overnight periods.

[20] Schey, S., Scoffield, D., Smart, J. (2014) "A First Look at the Impact of Electric Vehicle Charging on the Electric Grid in The EV Project." *EVS26 International Battery, Hybrid and Fuel Cell Electric Vehicle Symposium.* https://www.energy.gov/sites/prod/files/2014/02/f8/evs26_charging_demand_manuscript.pdf

Figure 3-11: EV Charging Shapes vs. Normalized Hourly Power Prices by NIPSCO Scenario







3.4.4 Transit Vehicles

The same approach to estimating fleet wide vehicle numbers, energy and peak demand impacts was applied to the transit vehicle sector, which includes buses, cutaway vans, and shuttles. However, unlike with the light-duty vehicle category, limited data is available on the adoption of electric transit vehicles within NIPSCO's service territory. To estimate the total number of transit vehicles in NIPSCO counties, data was developed from the 2019 National Transit Database, the Federal Transit Administration's repository of data on financial, operating, and asset conditions of American transit systems. Filtering on those metropolitan areas in NIPSCO counties, there were approximately 263 transit vehicles registered in NIPSCO counties. Assuming a number of these vehicles are electric in proportion to the light-duty vehicle fleet (~0.2% of light-duty vehicles were some form of BEV/PHEV), a forecast of electric transit vehicles was developed using the MTEP Futures'-implied CAGRs. For the High scenario, the assumption of a 100% electric transit fleet is assumed, given the nature of several municipalities' stated goals.

The operating assumptions for transit vehicles are provided in Table 3-3. From the National Transit Database, an average lifetime of eight years was determined. This data point is consistent with the idea that higher utilization leads to shorter lifetimes, when compared to the 15-year lifespan of passenger light-duty vehicles. The number of miles driven per year and electric usage in kWh/mi were taken from an NREL study on Fast-Charge Electric Buses.[21]

Assuming passenger transportation patterns are identical between using a car versus public transport, the same EV charging patterns as shown in Figure 3-9 and Figure 3-10 were applied for the transit vehicle category.

3.4.5 Medium Duty Vehicles

Medium-duty vehicles include city delivery vans, walk-in vans, and other large commercial vehicles within the Class 2-6 classification by the Federal Highway Administration. Given there is limited data on electrified MDVs, available data on the Indiana fleet of MDV/HDV Registrations was used to determine the total number of MDVs in NIPSCO counties. Around 19,600 MDVs were calculated, from which a proportion (0.23% electric, based on the LDV Registrations dataset) led to approximate starting numbers for the electric MDV forecast.

According to NIPSCO NIPSCO's New Business department, a large order of several hundred delivery vans for a large fleet operator is expected to come online in the territory in early-through-mid 2020s. Therefore, this delivery fleet of 700 vehicles was assumed in the MDV forecast, with online dates of 2022-2030. As a result, the near-term growth rates in MDVs appears higher than the MTEP Futures-inspired CAGRs, as shown in Table 3-4 versus Table 3-1. Other relevant forecasting assumptions are outlined in Table 3-2.

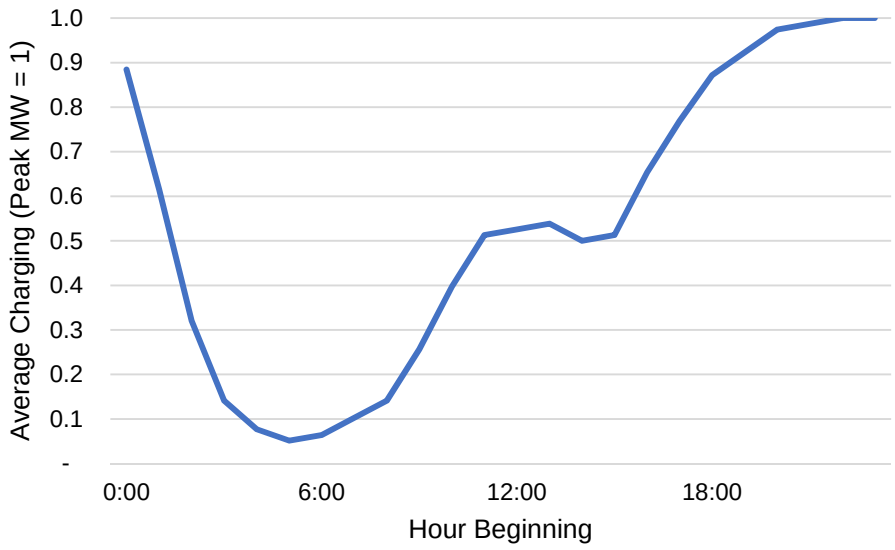
Table 3-4: MDV and HDV Electric Vehicle Sales' CAGR by Scenario

	2020-2024	2025-2029	2030-2034	2035-2040
Low – MDV	50%	23%	15%	11%
Med – MDV	72%	30%	16%	15%
High – MDV	79%	30%	21%	15%
High – HDV	5%	33%	20%	20%

Commercial vehicles might be expected to charge more frequently than LDVs, given their higher energy density requirements and potential for optimization of their logistics. The charging shape for MDVs and HDVs (discussed in the next section) is taken from the charging pattern from an NREL field study conducted in 2016 and illustrated in Figure 3-12.[22]

[21] NREL (2016). "NREL Evaluates Performance of Fast-Charge Electric Buses." https://www.nrel.gov/docs/fy16osti/67057.pdf
[22] NREL (2016). "Field Evaluation of Medium-Duty Plug-In Electric Delivery Trucks." https://www.nrel.gov/docs/fy17osti/66382.pdft

Figure 3-12: MDV/HDV Charging Pattern



3.4.6 Heavy Duty Vehicles

Heavy-duty vehicles, classified by the Federal Highway Administration as Class 7-8 vehicles, include semi-trucks utilized in the industrial sector, highway trucks for ground freight, and other large vehicles. Given the significant energy density required to haul heavy cargo and batteries' relatively lower energy density than liquid fuels, electric trucking is unlikely without significant technology improvement. For this reason, a forecast was developed only for the High scenario.

As with the MDV forecast, starting numbers of total HDVs in NIPSCO's territory were taken from the database of medium- and heavy-duty vehicles in NIPSCO counties. To reflect relatively slower advancement of the enabling technology, near-term growth in HDVs is minimal, whereas stronger annual sales growth rates are projected in the 2025+ time frame.

The charging profile as illustrated in Figure 3-12 is similarly applied to the HDV sector in order to estimate peak demand impact. Other relevant forecasting assumptions are outlined in Table 3-2.

3.4.7 Electric Vehicle Forecast Results

3.4.7.1 Vehicle Count Projections

Figure 3-13 presents the LDV vehicle count forecast. Across scenarios, assuming that customers replace their cars on average after a 15-year life, and assuming that the average car

ownership is 1.5 vehicles per household[23], EVs represent 10%, 39%, and 97% of new vehicle sales by 2040 for the Low, Medium, and High scenarios. Considering the retirement and replacement of older vehicles, EVs represent 7%, 19%, and 48% of total vehicle stock by 2040 for the Low, Medium, and High scenarios.

Figure 3-13: LDV Vehicle Count Forecast

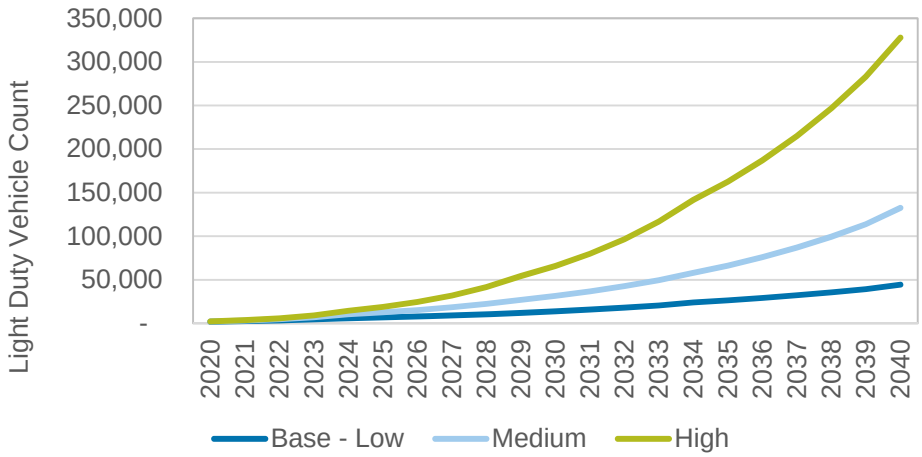
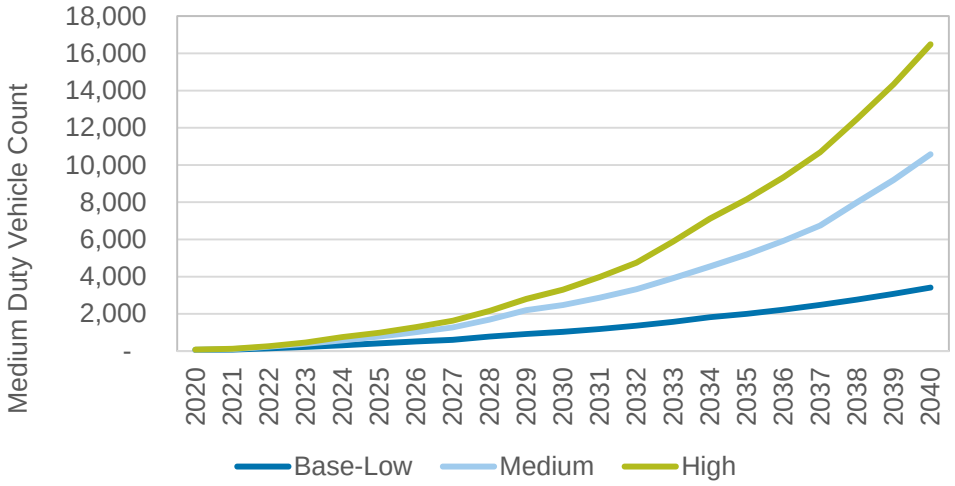


Figure 3-14 presents the MDV vehicle count forecast. Assuming that commercial vehicles are replaced after an 8-year life, and total commercial vehicles grow proportionally to the commercial customer class, EVs represent 12%, 49%, and 77% of new vehicle sales by 2040 for the Low, Medium, and High scenarios respectively. Considering the retirement and replacement of older vehicles, EVs represent 15%, 46%, and 72% of total vehicle stock by 2040 for the Low, Medium, and High scenarios.[24]

[23] Representative of sampling of cities throughout Indiana from the U.S. Census Bureau's American Community Survey: Compiled and accessed through Governing.com.

[24] Note that the total stock % is higher than new sales % in the Low case, due to the annual growth trajectory and relatively short assumed lifespan of vehicles.

Figure 3-14: MDV Vehicle Count Forecast

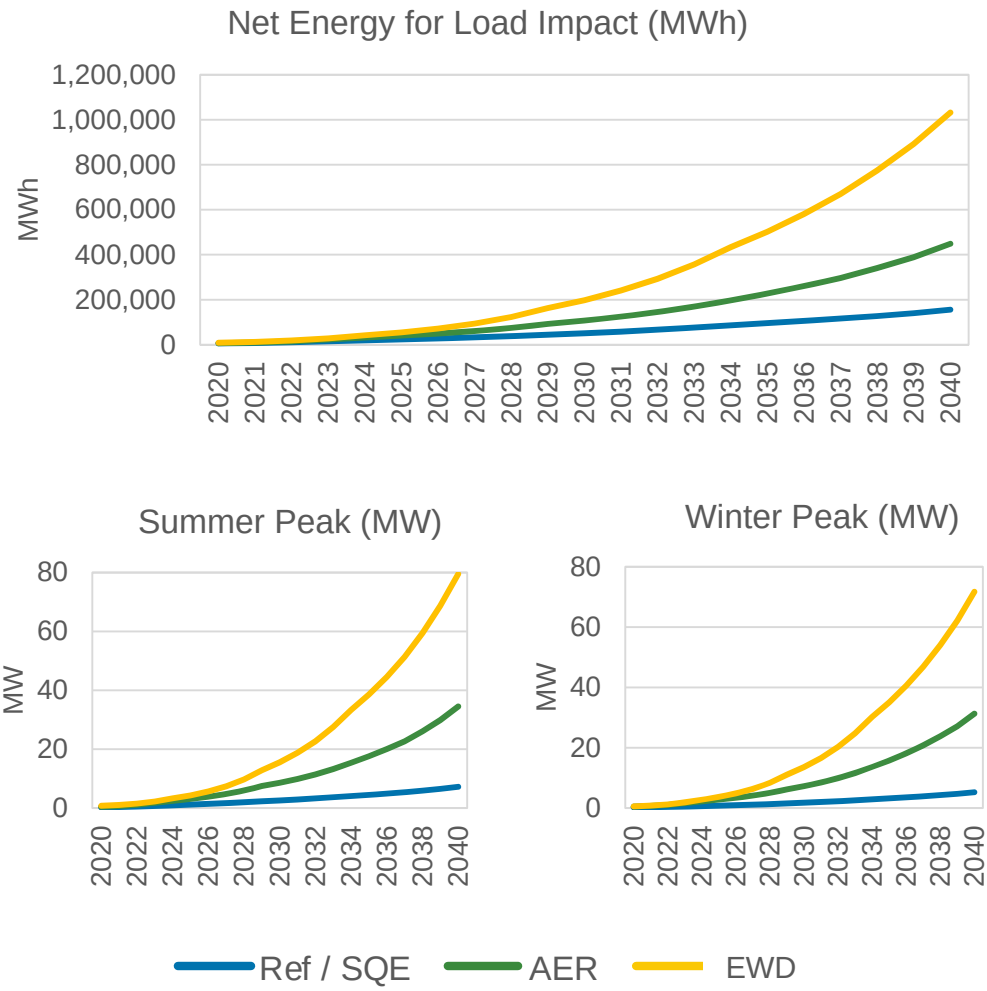


3.4.7.2 Sales and Peak Load Impact Projections

The overall impact of electric vehicle growth on NIPSCO's sales and summer and winter peak load forecasts across scenarios is summarized in Figure 3-15.[25] The LDV forecast is the primary driver of the overall forecast levels and range, contributing over 120 GWh in the low scenario and over 800 GWh in the high scenario by 2040. The MDV contribution is expected to range from approximately 25 to 120 GWh. Transit electrification is projected to be far less impactful than LDV and MDV growth. Transit vehicles represent an additional 1.8 GWh in the Low scenario; 2 GWh in the Medium scenario and 10 GWh in the High scenario by 2040. The HDV forecast for the High scenario represents an additional 74 GWh of energy impact and 10 MW of peak demand in 2040. Nonetheless, this represents around 18% of total HDV sales and 8% of the total HDV stock, assuming a 15-year life. This finding is aligned with industry sources that suggest a minor penetration of electrified HDVs.

[25] Note that the net energy for load and peak load impacts include a 5% gross-up for losses. Ref = Reference; SQE = Status Quo Extended; AER = Aggressive Environmental Regulation; EWD = Economy-Wide Decarbonization

Figure 3-15: Total EV Energy and Peak Load Impacts by Scenario



3.5 Distributed Energy Resources

Customer-owned DERs are expected to grow throughout NIPSCO's territory, and this can potentially have a significant impact NIPSCO's net sales and peak demand requirements. To estimate a range of impacts for DER penetration in the 2021 IRP, NIPSCO deployed CRA's agent-based PenDER model, customized and calibrated to NIPSCO's existing database of DER customers. As solar PV resources (with or without storage) are expected to be the most widespread DER resource type, NIPSCO's DER study focused exclusively on solar and storage technologies, excluding wind, biomass, and other resources. In addition, the study focused on two main customer groups likely to adopt DER: residential and commercial.

3.5.1 PenDER Model Description

PenDER is an agent-based model developed by CRA that simulates the adoption decisions and interactions via social networks of thousands of autonomous agents to provide granular

forecasting of DER adoption. Techno-economic variables and demographic characteristics of the simulated agents contribute to an individual agent's probability to adopt DER based on an economic review of retail rate expectations, the costs of installing DER, and potential financial incentives.

The techno-economic variables deployed in the PenDER modeling for NIPSCO's 2021 IRP include:

- The capital cost of a solar PV system, inclusive of expected ITC benefits
- Solar capacity factor and solar system lifetime expectations
- Retail rates (for net metering) and wholesale rates projections
- Assumptions for customer discount rate
- Demographic data from the ACS for NIPSCO counties to estimate agents' household incomes

The combination of the techno-economic variables and agent income levels are then used to develop a calculation of payback period and household budget in order to assess the probability of DER adoption through a calibrated logit probability function.

While economics plays an important role in the decision to install DER, the personal propensity and communal influences to adopt new technology also play a role, as described through the Bass diffusion model of technology forecasting.[26] Therefore, the simulated agents are randomly assigned a "Bass innovation index," representing their personal propensity on a scale of early adopters to laggards of new technology. Relationships between agents are modeled through "social networks," with an average size of 13 agents belonging to one network. As more agents in one's network adopt DER, the more likely a given agent will also adopt.

Ultimately, an agent's decision to adopt DER is influenced by the combination of techno-economic factors (through payback period and household budget) as well as personal and communal influences (through personal preferences and network effects).

3.5.2 Key Input Assumptions

The techno-economic input assumptions for PenDER used in NIPSCO's 2021 IRP are summarized in Table 3-5 and Table 3-6 and as follows:

- **Solar System Characteristics**: Data from the Net Metering program enrollment provided information regarding the average size of DER solar systems currently installed on NIPSCO's system, which was approximately 8 kW for residential

[26] See Bass, F (1969). "A New Product Growth for Model Consumer Durables." *Management Science*. 15 (5): 215-227

customers and 100 kW for commercial customers. NIPSCO approximated CFs for the DER systems based on NREL data and assumed a 25-year life for solar projects.

- **Capital Cost and Tax Credit Inputs:** Assumptions regarding capital cost projections, capacity factor, and lifetime for solar PV were taken from NREL's Annual Technology Baseline for the Advanced, Moderate, and Conservative cases for both residential and commercial solar PV technologies.[27] Assumptions regarding extensions to the federal ITC were consistent with those defined across NIPSCO's four core planning scenarios.

- **Retail Rate Growth**: Retail rate growth is uncertain and dependent on NIPSCO's generation plan, commodity prices, regulatory policy, transmission and distribution system cost drivers, and several other factors. NIPSCO developed a range of real retail rate growth rates with broad alignment to NIPSCO's four core planning scenarios.

- **Net Metering / Excess Distributed Generation:** NIPSCO's Net Metering and Excess Distributed Generation programs are governed by Indiana Code Ch. 8-1-40 and the Commission's Rules and General Administrative Orders. The DG Statute establishes the methodology under which NIPSCO procures electricity supplied by customers with qualifying distributed generation resources and offsets the cost of the electricity supplied to such customers. The DG Statute requires that an electricity supplier's net metering tariff remain available until the earlier of the following: "(1) January 1 of the first calendar year after the calendar year in which the aggregate amount of net metering facility nameplate capacity under the electricity supplier's net metering tariff equals at least one and one-half percent (1.5%) of the most recent summer peak load of the electricity supplier [or] (2) July 1, 2022." As of January 1, 2021, the aggregate amount of net metering facility nameplate capacity under NIPSCO's net metering tariff exceeded 1.5% of its most recent summer peak load (the statutory threshold) and NIPSCO filed Cause No. 45505 to gain Commission approval for an Excess Distributed Generation Rider which is still pending approval. The total net metering capacity (based off 2020 summer peak) is around 45 MW. Since the NIPSCO proposed Excess Distributed Generation Rider filing is still pending approval, PenDER simulated various future scenarios under various energy metering incentive programs. In two scenarios – SQE and Ref – the statuary net metering cap was enforced, after which DER is compensated at wholesale power prices times a 1.25 multiplier. In the AER and EWD scenarios, net metering is extended through 2040. These policy scenarios were designed to assess a broad range of potential DER penetration outcomes.

[27] NREL (National Renewable Energy Laboratory). 2020. 2020 Annual Technology Baseline. Golden, CO.

Table 3-5: DER Capital Cost, ITC, and Incentives by Scenario

	Status Quo Extended	Reference Case	Aggressive Environmental Regulation	Economy-Wide Decarbonization
	SQE	**Ref**	**AER**	**EWD**
Capital Cost	High	Med	Low	Low
ITC	Current Policy	Two-year extension	Five-year extension	Ten-year extension
Retail Rates Real Growth Rate	-0.25%	0.00%	1.0%	-0.04%
Energy Metering Incentive Programs	Net Metering Cap, then wholesale	Net Metering Cap, then wholesale	Net Metering Extended through 2040	Net Metering Extended through 2040

- **Solar System Characteristics:** Data from the Net Metering program enrollment provided information regarding the average size of DER solar systems currently installed on NIPSCO's system, which was approximately 8 kW for residential customers and 100 kW for commercial customers. NIPSCO approximated CF for the DER systems based on NREL data and assumed a 25-year life for solar projects.

- **Financial Inputs**: Assumptions regarding the financing of PV systems, namely the WACC, were developed based on the rationale that the WACC for residential and commercial customers would be at a premium to the financing costs for utility-scale solar. NIPSCO also has assumed that small customers (i.e. residential) have higher financing costs than larger-scale customers with better access to capital.

Table 3-6: Residential and Commercial Project Parameter Assumptions

	Residential	Commercial
Average PV Size	8 kW	100 kW
Solar CF	15-16%	15-16%
Solar Lifetime	25 years	25 years
Inflation	2%	2%
Real After-Tax WACC	7.70%	6.00%

- **Household Income**: The household income distributions were determined from the ACS for NIPSCO counties. The ACS is a nationwide survey that collects and produces information on demographic, housing, economic, and social characteristics of the nation's population every year. Household income is defined as the "pretax cash income of the householder and all other people 15 years and

older in the household, whether or not they are related to the householder."[28] Agents in the PenDER model were assigned a household income level to preserve consistency with the distribution of income levels in NIPSCO's service territory from the ACS.

- **Storage Integration**: Initial DER modeling did not account for behavioral change that might maximize DER resource capacity credit. However, after receiving stakeholder comments, NIPSCO incorporated an assumed integration of DER storage resources over time. By storing solar energy during the day and discharging energy during peak hours, distributed storage could reduce peak demands and increase the net effective capacity contribution for such resources. For modeling purposes, NIPSCO assumed that by 2040, solar output would be supported by storage in the following manner: 5% of total installed solar capacity would be matched by storage in the Reference scenario, 25% in the Aggressive Environmental Regulation scenario, and 33% in the EWD scenario.

- **Bass Innovation Index Parameters:** By using NIPSCO's customer adoption numbers from 2012 through 2019 from the Net Metering program, PenDER's bass innovation index parameters were calibrated to match historical adoption decisions (using historic retail rates and solar PV capital costs).

3.5.3 DER Forecast Results

Using all of the input assumptions outlined above, NIPSCO deployed the PenDER model to estimate a range of DER penetration levels across the four major planning scenarios. Projections for cumulative customer-owned DER installations and associated storage additions are shown in Figure 3-16, with the resulting cumulative energy impacts summarized in Figure 3-17.[29] (AER), and 40% (EWD and Electrification). The cumulative peak summer impact from DER is shown in Figure 3-18.

[28] Guzman, G. (September 2020). "Household Income: 2019". *American Community Survey*. https://www.census.gov/content/dam/Census/library/publications/2020/acs/acsbr20-03.pdf

[29] Note that this graphic displays energy projections at the customer meter. For purposes of inclusion in the IRP load forecast modeling, NIPSCO grossed up the energy impact by 5% to incorporate line losses.

Figure 3-16: Projected Cumulative Customer-Owned DER Installations

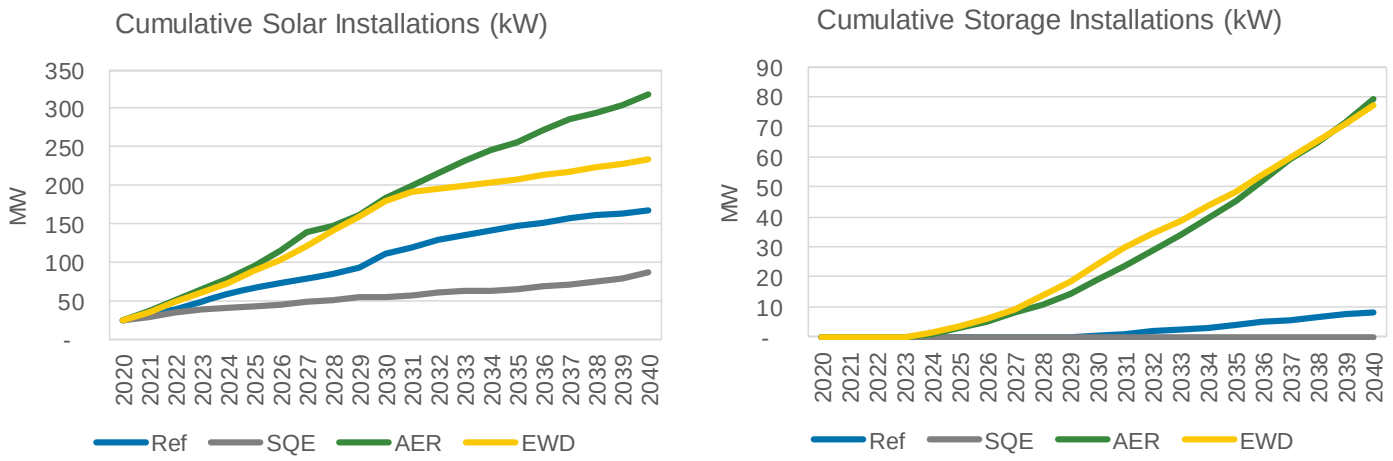
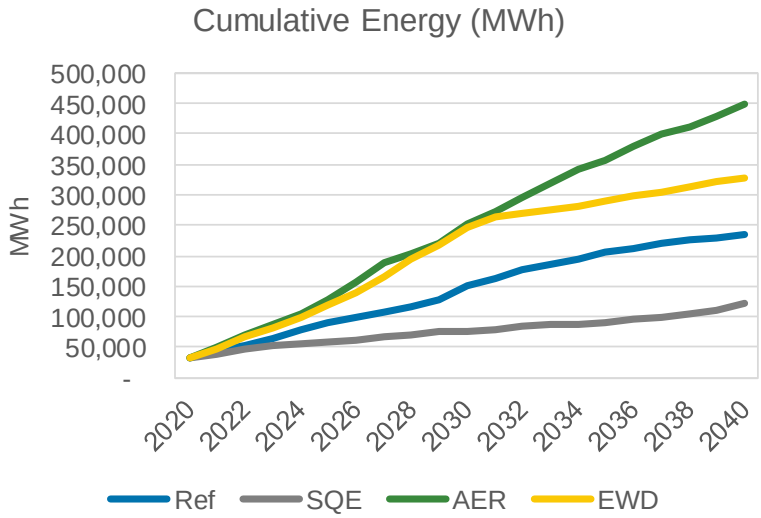


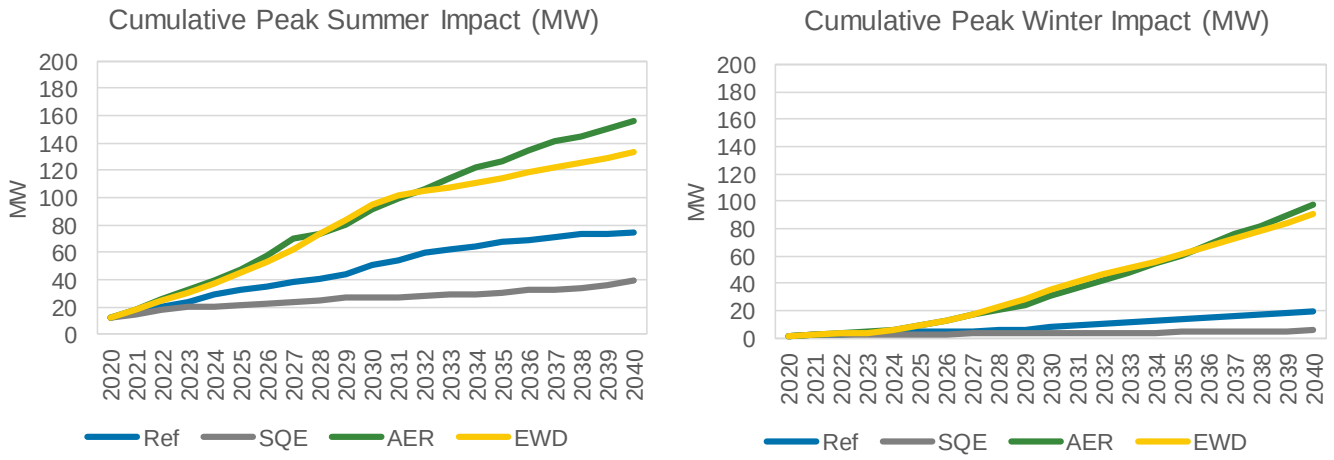
Figure 3-17: Projected Cumulative Customer-Owned DER Energy Impact



For peak accounting, NIPSCO evaluated expected contributions for solar and storage resources based on MISO's RIIA studies[30] and the fundamental expectations for market evolution across the four planning scenarios. The resulting contributions to both summer and winter peak periods are shown in Figure 3-18.

[30] See in particular, Figure RA-18 for Distributed PV in the MISO RIIA Summary Report, https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Figure 3-18: Customer DER Cumulative Peak Summer and Winter Impact



3.6 Scenario Analysis

NIPSCO combined the base econometric modeling analysis with the EV and DER analysis across all four planning scenarios to develop a range of future load growth outcomes, as outlined in Table 3-7. The remainder of this section outlines the key drivers of scenario uncertainty and provides a summary of the forecasts.

Table 3-7: Scenario Drivers Summary

Scenario Name	Economic Growth	EV Penetration	DER Penetration	Other Electrification	NIPSCO Industrial Load
Reference Case	**Base** *Moody's Baseline forecast*	**Low** *Current trends persist (MTEP Future I)*	**Base** *Baseline expectations for continued growth, which is exponential in areas*		
Status Quo Extended	**Low** *Moody's 90th percentile downside: COVID impacts linger; consumer spending lags stimulus amounts, unemployment grows again*	**Low** *Current trends persist; economics continue to favor ICE (MTEP Future I)*	**Low** *Lower electric rates decelerate penetration trends*		**Low** *Additional industrial load migration – down to 70 MW firm 831*
Aggressive Environmental Regulation	**Base** *Moody's Baseline forecast*	**Mid** *Customers respond to cost increases in gasoline, and EV growth rates increase (MTEP Future II)*	**High** *Higher electric rates and lower technology costs accelerate penetration trends*		
Economy-Wide Decarbonization	**High** *Moody's 10th percentile upside: vaccine facilitates faster re-openings, fiscal stimulus boosts economy more than expected*	**High** *Policy, technology, behavioral change drive towards high EV scenario (MTEP Future III)*	**High** *Technology-driven increase, as solar costs decline and policies facilitate installations*	**High** *MTEP Future III for R/C/I HVAC, appliances, processes*	

3.6.1 Economic Variables

NIPSCO relied on Moody's macroeconomic data for forecasts of the econometric variables described in Section 3.3.1. NIPSCO used the Moody's Baseline forecast for the Reference Case as of April 2021, and deployed the 10th percentile upside scenario for the high case (mapped to the EWD scenario) and the 90th percentile downside scenario for the low case (mapped to the SQE scenario).

As per Moody's documentation,[31] "by definition the probability that the economy will perform better than this projection is equal to 50%, the same as the probability that it will perform worse" under the Baseline forecast. The economic variables are then flexed up and down in the alternative scenarios. Under the 10th percentile upside scenario, Moody's assumes:

- Effective vaccine implementation allows businesses to reopen sooner, driving consumer and business confidence higher than the baseline;
- Fiscal stimulus boosts the economy more than expected, consumers return to higher levels of spending, and unemployment falls; and
- Although inflation and long-term interest rates rise more than in the baseline, the stock market continues to rise.

Under the 90th percentile downside scenario, Moody's assumes:

- COVID-19 incidences rise and concerns build regarding whether enough people will agree to be vaccinated, causing businesses to reopen more slowly than expected;
- Consumer confidence erodes, reducing spending and causing the economy to fall back into recession; and
- Unemployment rises and the stock market falls significantly.

3.6.2 Electric Vehicles

NIPSCO developed a range of EV penetration scenarios with resulting impacts on the load forecast, as described in Section 3.4 and mapped to the scenarios as summarized in Table 3-7.

3.6.3 Distributed Energy Resources

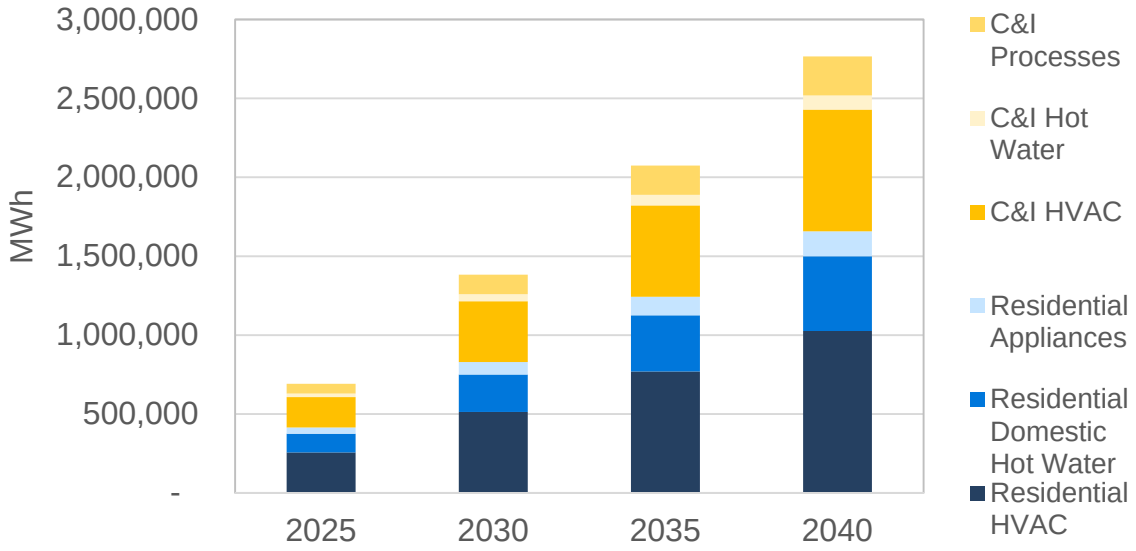
NIPSCO developed a range of DER penetration scenarios with resulting impacts on the load forecast, as described in Section 3.5 and mapped to the scenarios as summarized in Table 3-7.

[31] All scenario narrative documentation is adopted from Moody's Analytics' U.S. Macroeconomic Outlook Baseline and Alternative Scenarios: April, 2021.

3.6.4 Other Electrification

For the EWD scenario, NIPSCO incorporated additional electrification impacts according to the electrification study developed by AEG for MISO's MTEP 2021 process. This study incorporated potential electrification of residential and commercial/industrial heating, hot water, appliances, and processes. NIPSCO adopted the projections for LRZ 6 to its service territory and added loads as summarized in Figure 3-19. As many of the electrification impacts have larger demand impacts in the winter than summer, the peak profile was also impacted.

Figure 3-19: Electrification Impact on NIPSCO Energy Sales



3.6.5 Industrial Load Risk

For the Status Quo Extended scenario, NIPSCO incorporated the potential for additional industrial load migration to the new industrial rate service structure. The scenario incorporated a reduction of firm industrial load in Rate 831 down to 70 MW.

3.6.6 Scenario Results

Figure 3-20 presents a summary of the total net energy for load forecast across the four planning scenarios. The Reference Case and AER scenarios expect net sales to grow on a CAGR of just below 0.2% per year. They both rely on the same underlying economic forecast and EV (increase in net load) and DER (decrease in net load) growth tend to offset each other. The high EV and other electrification impacts drive the CAGR in the EWD scenario above 1.4% over the study period, while lower economic growth and industrial load loss assumptions result in negative growth in the SQE scenario.

Figure 3-20: Total Net Energy for Load Forecast across Scenarios

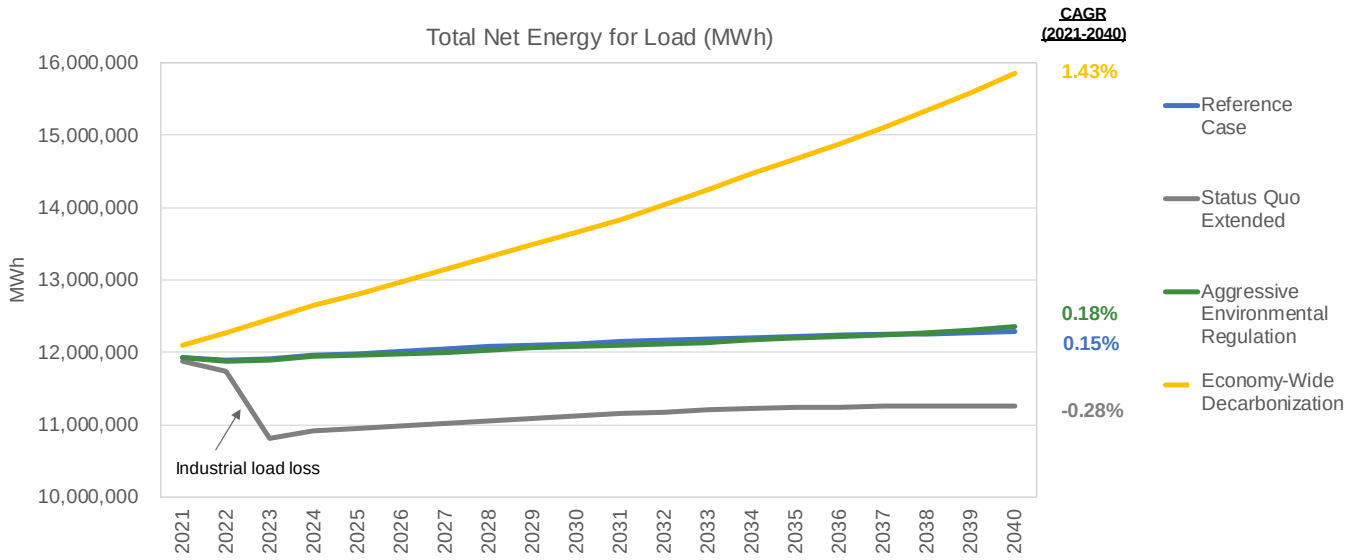
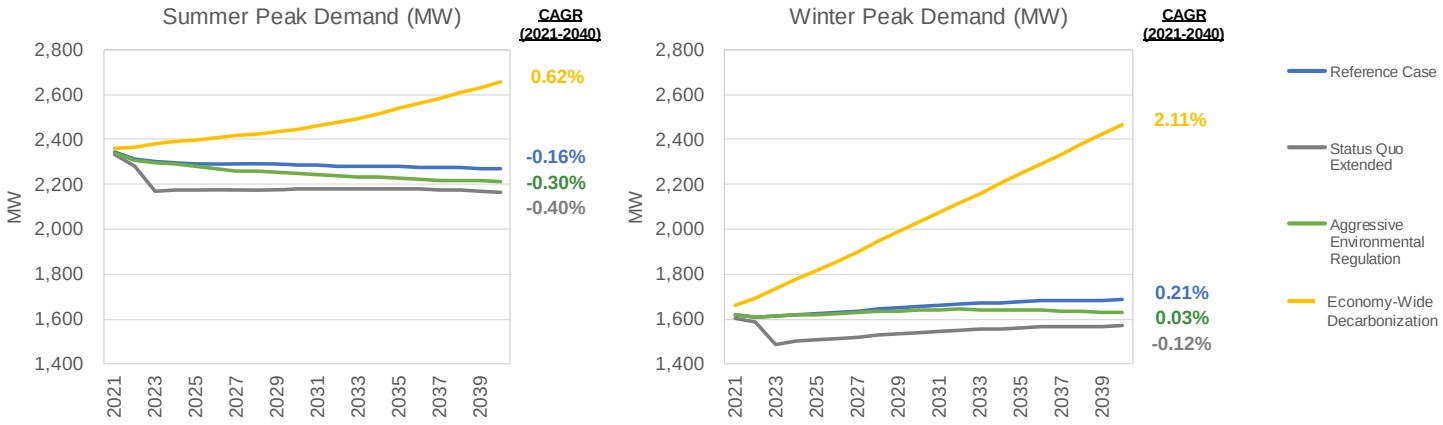


Figure 3-21 summarizes the all-in peak load forecasts for both the summer and winter seasons across scenarios. Peak load is generally expected to grow at a slower rate than sales, particularly in the summer time period, with three out of the four cases exhibiting negative CAGRs. In the winter, the expected peak growth rates are projected to be higher, with a CAGR above 2% in the EWD scenario as a result of electrification impacts that are concentrated in the heating season.

Figure 3-21: Summer and Winter Peak Load Forecasts across Scenarios



3.7 Detailed Forecast Results

The remainder of this section provides detailed annual sales and peak demand forecasts by customer class for the Reference Case and by category across all four scenarios.

Table 3-8: Customer Count Forecast by Major Customer Segment – Reference Case

Year	Residential	Commercial	Small Industrial
2021	416,604	57,530	2,028
2022	418,557	57,981	2,006
2023	420,987	58,542	2,005
2024	423,685	59,165	2,013
2025	426,348	59,781	2,027
2026	428,891	60,368	2,040
2027	431,304	60,925	2,050
2028	433,590	61,453	2,059
2029	435,819	61,968	2,067
2030	438,007	62,474	2,075
2031	440,110	62,959	2,082
2032	442,122	63,424	2,088
2033	444,036	63,866	2,094
2034	445,767	64,266	2,100
2035	447,491	64,664	2,105
2036	449,164	65,051	2,111
2037	450,689	65,403	2,116
2038	452,086	65,726	2,121
2039	453,429	66,036	2,125
2040	454,746	66,340	2,130
2021-2040 CAGR	**0.5%**	**0.8%**	**0.3%**

Table 3-9: Electric Sales Forecast (Inclusive of Historical Energy Efficiency Programs Only) – Reference Case

Year	Residential	Commercial	Small Industrial	Large Industrial non-831	Large Industrial 831 T1	Other*	Losses	Total MWh
2021	3,395,795	3,800,474	2,159,154	381,929	1,527,600	110,200	564,935	11,940,087
2022	3,358,783	3,820,236	2,154,978	352,212	1,541,760	110,393	564,051	11,902,413
2023	3,370,774	3,845,252	2,152,399	352,227	1,541,760	110,323	565,493	11,938,227
2024	3,388,242	3,873,709	2,150,579	353,194	1,542,000	110,346	567,560	11,985,631
2025	3,398,391	3,900,840	2,149,084	352,245	1,541,760	110,346	569,150	12,021,815
2026	3,409,746	3,926,110	2,147,191	352,250	1,541,760	110,356	570,761	12,058,173
2027	3,423,005	3,949,461	2,144,979	352,255	1,541,760	110,364	572,369	12,094,192
2028	3,438,589	3,970,855	2,142,568	353,217	1,542,000	110,373	574,046	12,131,648
2029	3,453,761	3,991,285	2,140,029	352,265	1,541,760	110,382	575,566	12,165,047
2030	3,467,788	4,010,980	2,137,384	352,269	1,541,760	110,391	577,041	12,197,613
2031	3,480,116	4,029,325	2,134,661	352,274	1,541,760	110,399	578,368	12,226,902
2032	3,490,838	4,046,170	2,131,872	353,237	1,542,000	110,406	579,589	12,254,112
2033	3,499,537	4,061,487	2,129,048	352,284	1,541,760	110,413	580,548	12,275,076
2034	3,506,036	4,073,853	2,126,171	352,287	1,541,760	110,419	581,300	12,291,826
2035	3,511,925	4,086,001	2,123,240	352,289	1,541,760	110,425	582,012	12,307,652
2036	3,516,488	4,097,337	2,120,292	353,247	1,542,000	110,430	582,667	12,322,461
2037	3,519,122	4,106,322	2,117,313	352,291	1,541,760	110,435	583,021	12,330,264
2038	3,519,797	4,113,349	2,114,328	352,290	1,541,760	110,439	583,232	12,335,196
2039	3,519,584	4,119,474	2,111,314	352,289	1,541,760	110,443	583,355	12,338,219
2040	3,519,047	4,125,105	2,108,251	353,239	1,542,000	110,447	583,483	12,341,572
2021-2040 CAGR	**0.2%**	**0.4%**	**-0.1%**	**-0.4%**	**0.0%**	**0.0%**	**0.2%**	**0.2%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-10: Peak Load Forecast (Inclusive of Historical Energy Efficiency Programs Only) – Reference Case

Year	Residential	Commercial	Small Industrial	Large Industrial non-831	Large Industrial 831 T1	Other*	Total MW	System Wide Peak (Grossed Up for Losses)
2021	1,017	649	340	82	176	24	2,287	2,346
2022	997	648	337	64	176	24	2,245	2,321
2023	992	649	336	64	176	24	2,240	2,316
2024	991	650	335	64	176	24	2,240	2,315
2025	987	652	335	64	176	24	2,238	2,313
2026	986	654	334	64	176	24	2,238	2,313
2027	985	656	333	64	176	24	2,239	2,314
2028	986	658	333	64	176	24	2,241	2,317
2029	988	660	332	64	176	24	2,244	2,319
2030	989	662	332	64	176	24	2,247	2,322
2031	990	664	332	64	176	24	2,249	2,325
2032	991	666	331	64	176	24	2,252	2,328
2033	992	667	331	64	176	24	2,254	2,329
2034	992	669	330	64	176	24	2,255	2,330
2035	992	670	330	64	176	24	2,256	2,331
2036	992	672	329	64	176	24	2,257	2,332
2037	992	673	329	64	176	24	2,257	2,332
2038	991	673	328	64	176	24	2,257	2,331
2039	990	674	328	64	176	24	2,256	2,330
2040	989	675	327	64	176	24	2,255	2,329
2021-2040 CAGR	**-0.1%**	**0.2%**	**-0.2%**	**-1.3%**	**0.0%**	**0.0%**	**-0.1%**	**0.0%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-11: Reference Case Electric Sales Forecast with Adjustments

	MWh Sales			
	Base Load	EV Load	DERs*	All-In
2021	11,940,087	7,239	(13,054)	11,934,273
2022	11,902,413	10,211	(22,511)	11,890,112
2023	11,938,227	14,183	(34,542)	11,917,868
2024	11,985,631	19,342	(50,631)	11,954,342
2025	12,021,815	23,188	(63,186)	11,981,817
2026	12,058,173	27,507	(71,638)	12,014,041
2027	12,094,192	32,099	(80,448)	12,045,843
2028	12,131,648	37,512	(89,686)	12,079,475
2029	12,165,047	43,655	(101,544)	12,107,158
2030	12,197,613	50,140	(126,379)	12,121,374
2031	12,226,902	57,416	(138,4790	12,145,839
2032	12,254,112	65,701	(154,566)	12,165,247
2033	12,275,076	74,924	(163,677)	12,186,324
2034	12,291,826	86,776	(172,783)	12,205,819
2035	12,307,652	95,740	(182,511)	12,220,881
2036	12,322,461	105,290	(188,733)	12,239,018
2037	12,330,264	115,709	(197,911)	12,248,062
2038	12,335,196	127,374	(204,913)	12,257,657
2039	12,338,219	139,840	(208,010)	12,270,049
2040	12,341,572	155,423	(214,101)	12,282,894
2021-2040 CAGR	**0.2%**	**17.5%**	**15.9%**	**0.2%**

*DERs are reductions to the load served by NIPSCO.

Table 3-12: Reference Case Peak Demand Forecast with Adjustments

	Summer Peak (MW)				Winter Peak (MW)			
	Base Load	EV Load	DERs*	All-In	Base Load	EV Load	DERs*	All-In
2021	2,346	0	(5)	2,341	1,622	0	(1)	1,621
2022	2,321	0	(8)	2,313	1,611	0	(1)	1,610
2023	2,316	1	(13)	2,304	1,614	0	(2)	1,612
2024	2,315	1	(18)	2,298	1,622	1	(2)	1,620
2025	2,313	1	(22)	2,292	1,626	1	(3)	1,624
2026	2,313	1	(25)	2,290	1,633	1	(3)	1,630
2027	2,314	2	(27)	2,289	1,640	1	(4)	1,637
2028	2,317	2	(30)	2,289	1,650	1	(4)	1,647
2029	2,319	2	(33)	2,289	1,654	1	(5)	1,651
2030	2,322	3	(41)	2,284	1,661	2	(6)	1,656
2031	2,325	3	(45)	2,283	1,667	2	(8)	1,662
2032	2,328	3	(50)	2,281	1,676	2	(9)	1,669
2033	2,329	4	(53)	2,281	1,678	2	(10)	1,670
2034	2,330	4	(55)	2,279	1,682	3	(11)	1,673
2035	2,331	4	(58)	2,278	1,686	3	(13)	1,676
2036	2,332	5	(60)	2,277	1,692	4	(14)	1,682
2037	2,332	5	(62)	2,275	1,692	4	(15)	1,681
2038	2,331	6	(64)	2,273	1,694	4	(16)	1,682
2039	2,330	6	(65)	2,272	1,695	5	(17)	1,683
2040	2,329	7	(66)	2,270	1,699	5	(18)	1,686
2021-2040 CAGR	**0.0%**	**18.6%**	**14.8%**	**-0.2%**	**0.2%**	**17.3%**	**19.4%**	**0.2%**

*DERs are reductions to the load served by NIPSCO.

Table 3-13: SQE Electric Sales Forecast with Adjustments

	MWh Sales			
	Base Load	EV Load	DERs*	All-In
2021	11,882,769	7,239	(8,236)	11,881,772
2022	11,738,319	10,211	(15,906)	11,732,624
2023	10,826,820	14,183	(22,246)	10,818,757
2024	10,912,600	19,342	(25,380)	10,906,562
2025	10,953,440	23,188	(27,900)	10,948,728
2026	10,995,558	27,507	(31,901)	10,991,164
2027	11,030,105	32,099	(36,777)	11,025,427
2028	11,062,811	37,512	(40,947)	11,059,377
2029	11,091,495	43,655	(45,904)	11,089,245
2030	11,119,554	50,140	(48,002)	11,121,692
2031	11,144,181	57,416	(49,616)	11,151,981
2032	11,167,627	65,701	(54,992)	11,178,337
2033	11,182,358	74,924	(58,036)	11,199,247
2034	11,192,656	86,776	(60,095)	11,219,336
2035	11,201,372	95,740	(63,549)	11,233,563
2036	11,209,985	105,290	(69,477)	11,245,797
2037	11,211,709	115,709	(72,598)	11,254,820
2038	11,210,581	127,374	(77,193)	11,260,762
2039	11,206,908	139,840	(83,400)	11,263,348
2040	11,202,183	155,423	(96,983)	11,260,623
2021-2040 CAGR	**-0.3%**	**17.5%**	**13.9%**	**-0.3%**

*DERs are reductions to the load served by NIPSCO.

Table 3-14: SQE Peak Demand Forecast with Adjustments

	Summer Peak (MW)				Winter Peak (MW)			
	Base Load	EV Load	DERs*	All-In	Base Load	EV Load	DERs*	All-In
2021	2,338	0	(3)	2,335	1,606	0	(0)	1,606
2022	2,284	0	(6)	2,279	1,588	0	(1)	1,588
2023	2,174	1	(8)	2,167	1,490	0	(1)	1,489
2024	2,182	1	(9)	2,174	1,503	1	(1)	1,502
2025	2,182	1	(10)	2,173	1,507	1	(1)	1,506
2026	2,184	1	(11)	2,174	1,514	1	(1)	1,513
2027	2,185	2	(12)	2,174	1,520	1	(2)	1,520
2028	2,187	2	(14)	2,175	1,529	1	(2)	1,529
2029	2,189	2	(15)	2,176	1,533	1	(2)	1,533
2030	2,191	3	(16)	2,178	1,539	2	(2)	1,539
2031	2,193	3	(16)	2,180	1,545	2	(2)	1,544
2032	2,195	3	(17)	2,180	1,552	2	(3)	1,552
2033	2,195	4	(18)	2,181	1,554	2	(3)	1,554
2034	2,195	4	(19)	2,180	1,557	3	(3)	1,557
2035	2,194	4	(19)	2,180	1,560	3	(3)	1,560
2036	2,194	5	(21)	2,178	1,565	4	(3)	1,565
2037	2,193	5	(22)	2,176	1,564	4	(3)	1,564
2038	2,191	6	(23)	2,174	1,565	4	(3)	1,566
2039	2,188	6	(25)	2,170	1,565	5	(4)	1,566
2040	2,186	7	(29)	2,164	1,568	5	(4)	1,569
2021-2040 CAGR	**-0.4%**	**18.6%**	**12.6%**	**-0.4%**	**-0.1%**	**17.3%**	**13.5%**	**-0.1%**

*DERs are reductions to the load served by NIPSCO.

Table 3-15: AER Electric Sales Forecast with Adjustments

	MWh Sales			
	Base Load	EV Load	DERs*	All-In
2021	11,940,087	8,848	(18,353)	11,930,582
2022	11,902,413	14,117	(39,460)	11,877,069
2023	11,938,227	21,643	(58,513)	11,901,358
2024	11,985,631	32,279	(78,351)	11,939,558
2025	12,021,815	39,750	(101,219)	11,960,346
2026	12,058,173	49,150	(130,630)	11,976,693
2027	12,094,192	60,357	(166,489)	11,988,060
2028	12,131,648	74,624	(179,303)	12,026,969
2029	12,165,047	92,524	(198,380)	12,059,191
2030	12,197,613	107,422	(231,625)	12,073,410
2031	12,226,902	124,827	(255,225)	12,096,504
2032	12,254,112	145,101	(279,276)	12,119,936
2033	12,275,076	169,022	(302,984)	12,141,114
2034	12,291,826	197,883	(326,113)	12,163,596
2035	12,307,652	227,408	(341,534)	12,193,525
2036	12,322,461	260,245	(366,863)	12,215,843
2037	12,330,264	296,570	(388,403)	12,238,432
2038	12,335,196	340,450	(400,873)	12,274,772
2039	12,338,219	388,899	(418,854)	12,308,264
2040	12,341,572	448,747	(439,145)	12,351,174
2021-2040 CAGR	**0.2%**	**23.0%**	**18.2%**	**0.2%**

*DERs are reductions to the load served by NIPSCO.

Table 3-16: AER Peak Demand Forecast with Adjustments

	Summer Peak (MW)				Winter Peak (MW)			
	Base Load	EV Load	DERs*	All-In	Base Load	EV Load	DERs*	All-In
2021	2,346	1	(7)	2,340	1,622	1	(1)	1,621
2022	2,321	1	(14)	2,308	1,611	1	(2)	1,610
2023	2,316	2	(21)	2,296	1,614	2	(3)	1,612
2024	2,315	2	(29)	2,289	1,622	2	(5)	1,619
2025	2,313	3	(37)	2,280	1,626	3	(8)	1,621
2026	2,313	4	(47)	2,269	1,633	3	(11)	1,625
2027	2,314	5	(60)	2,258	1,640	4	(16)	1,628
2028	2,317	6	(65)	2,258	1,650	5	(20)	1,635
2029	2,319	7	(71)	2,255	1,654	6	(24)	1,637
2030	2,322	9	(83)	2,248	1,661	7	(30)	1,638
2031	2,325	10	(91)	2,244	1,667	8	(36)	1,640
2032	2,328	11	(100)	2,239	1,676	10	(42)	1,643
2033	2,329	13	(108)	2,235	1,678	12	(49)	1,640
2034	2,330	15	(115)	2,230	1,682	14	(56)	1,640
2035	2,331	18	(120)	2,229	1,686	16	(62)	1,639
2036	2,332	20	(129)	2,223	1,692	18	(70)	1,640
2037	2,332	23	(136)	2,219	1,692	21	(78)	1,634
2038	2,331	26	(140)	2,218	1,694	24	(85)	1,633
2039	2,330	30	(145)	2,215	1,695	27	(93)	1,630
2040	2,329	34	(152)	2,212	1,699	31	(101)	1,629
2021-2040 CAGR	**0.0%**	**23.5%**	**17.8%**	**-0.3%**	**0.2%**	**22.5%**	**28.3%**	**0.0%**

*DERs are reductions to the load served by NIPSCO.

Table 3-17: EWD Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	Other Electrification	DERs*	All-In
2021	11,959,772	11,797	138,288	(16,823)	12,093,034
2022	12,009,527	18,051	276,575	(36,768)	12,267,385
2023	12,073,746	27,243	414,863	(53,629)	12,462,223
2024	12,120,588	41,410	553,150	(70,244)	12,644,904
2025	12,156,297	54,220	691,438	(93,435)	12,808,519
2026	12,191,556	71,300	829,726	(114,783)	12,977,798
2027	12,225,301	93,545	968,013	(140,008)	13,146,853
2028	12,254,438	123,199	1,106,301	(170,374)	13,313,564
2029	12,279,724	162,557	1,244,588	(196,880)	13,489,991
2030	12,302,917	197,831	1,382,876	(225,617)	13,658,008
2031	12,323,055	240,823	1,521,164	(244,397)	13,840,644
2032	12,337,897	292,523	1,659,451	(251,846)	14,038,025
2033	12,349,912	356,629	1,797,739	(256,836)	14,247,444
2034	12,358,681	433,600	1,936,027	(263,625)	14,464,683
2035	12,366,646	502,271	2,074,314	(271,449)	14,671,782
2036	12,373,769	580,771	2,212,602	(280,740)	14,886,402
2037	12,374,300	670,186	2,350,889	(288,030)	15,107,346
2038	12,372,805	774,588	2,489,177	(296,379)	15,340,190
2039	12,369,171	892,267	2,627,465	(304,262)	15,584,640
2040	12,364,591	1,031,805	2,765,752	(313,157)	15,848,992
2021-2040 CAGR	**0.2%**	**26.5%**	**17.1%**	**16.6%**	**1.4%**

*DERs are reductions to the load served by NIPSCO.

Table 3-18: EWD Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	Other Electrification	DERs*	All-In	Base Load	EV Load	Other Electrification	DERs*	All-In
2021	2,349	1	17	(6)	2,361	1,626	1	34	(1)	1,660
2022	2,344	1	34	(14)	2,367	1,626	1	68	(2)	1,693
2023	2,345	2	51	(20)	2,379	1,633	2	102	(3)	1,734
2024	2,344	3	69	(26)	2,390	1,641	3	137	(5)	1,776
2025	2,342	4	86	(35)	2,397	1,611	4	206	(8)	1,813
2026	2,342	6	103	(43)	2,407	1,617	5	247	(12)	1,857
2027	2,342	7	120	(53)	2,417	1,623	6	288	(16)	1,902
2028	2,342	10	137	(65)	2,425	1,629	8	330	(22)	1,945
2029	2,343	13	154	(75)	2,435	1,635	11	371	(28)	1,988
2030	2,344	15	172	(87)	2,444	1,640	14	412	(36)	2,030
2031	2,345	19	189	(95)	2,458	1,645	17	453	(42)	2,073
2032	2,345	23	206	(98)	2,475	1,649	20	494	(47)	2,116
2033	2,345	28	223	(101)	2,494	1,653	25	536	(52)	2,161
2034	2,280	33	305	(104)	2,515	1,656	30	577	(57)	2,206
2035	2,279	39	327	(108)	2,537	1,659	35	618	(62)	2,249
2036	2,278	45	349	(112)	2,560	1,661	41	659	(68)	2,292
2037	2,277	51	371	(116)	2,583	1,663	47	700	(74)	2,336
2038	2,275	59	393	(120)	2,607	1,664	54	741	(80)	2,379
2039	2,272	69	415	(123)	2,632	1,665	62	783	(87)	2,423
2040	2,269	79	436	(128)	2,658	1,665	72	824	(93)	2,467
2021-2040 CAGR	**-0.2%**	**26.0%**	**18.6%**	**17.3%**	**0.6%**	**0.1%**	**27.0%**	**18.2%**	**28.3%**	**2.1%**

*DERs are reductions to the load served by NIPSCO.

Section 4. Supply-Side Resources

NIPSCO's generation fleet is in the midst of a transition as with much of the electric industry. NIPSCO is committed to make every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest cost reasonably possible. Consistent with this objective and as set forth in the 2018 IRP, NIPSCO continues to execute on the generation plan to retire coal generation and replace it with a mix of renewable resources. NIPSCO's supply-side resources are comprised of the existing coal and natural gas units, renewable generation currently in-service and planned to be in-service, and a mix of future resource options.

4.1 Existing Resources

NIPSCO has a variety of generation resources to meet its customers' forecast capacity and energy needs. Not only do these resources need to meet the principles set out in Section 1, they must operate within MISO, the Regional Transmission Organization, and subject to NERC standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization Reliability standards approved by FERC. In NIPSCO's case, its Regional Reliability Organization is ReliabilityFirst.

NIPSCO-owned generating resources consist of coal, natural gas and hydro units. Additionally NIPSCO meets it customer needs with 4 wind purchase power agreements. The total NDC of the existing resources is 2,491 MW across multiple generation sites, including Schahfer (Units 16A, 16B, 17 and 18), Michigan City (Unit 12), Sugar Creek and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). Of the total capacity, 48% is from coal-fired units, 28% is from natural gas-fired units and 24% is from wind and hydroelectric generation units. Table 4-1 provides a summary of the current generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity

Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	877
Sugar Creek		NG	535
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	600
NIPSCO			2,491

NG=Natural Gas

4.1.1 Michigan City

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. It has one base-load unit, Unit 12 and is equipped with SCR and OFA systems to reduce NO_x emissions. A new FGD system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-2.

Table 4-2 Michigan City Generating Station

	Unit 12
NET Output	
Min (MW)	315
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	Coal
Turbine	General Electric
Frame	G2
In-Service	1974
Environmental Controls	FGD, SCR, OFA

4.1.2 Schahfer

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. It is the largest of NIPSCO's generating stations. There are two coal-fired base-load units and two gas-fired simple cycle peaking units that came

on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce SO2 emissions and SCR, SNCR, LNB, and OFA systems to reduce NO_x emissions. As part of the Company's CAIR Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. The individual unit characteristics of Schahfer are provided in Table 4-3.[32]

Table 4-3 : Schahfer

	Unit 17	Unit 18	Unit 16A	Unit 16B
Net Output				
Min (MW)	125	125	------	------
Max (MW)	361	361	78	77
Boiler	Combustion Engineering	Combustion Engineering	-----	-----
Burners	6 Pulverizers	6 Pulverizers	-----	-----
Main Fuel	Coal	Coal	Gas	Gas
Turbine	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB243	BB243	D501	D501
In-Service	1983	1986	1979	1979
Environmental Controls	FGD, LNB, OFA	FGD, LNB, OFA	-----	-----

4.1.3 Sugar Creek

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired CTs and CCGTs were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is its newest thermal electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two generators and one steam turbine generator are operated in the CCGT mode and environmental control technologies include SCR to reduce NO_x, and dry low NO_x combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 4-4.

[32] Units 14 and 15 were retired effective October 1, 2021.

Table 4-4: Sugar Creek

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	120	120	120
Max (MW)	156	157	222
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA	7FA	D11
In-Service	2002	2002	2003
Environmental Controls	SCR, DLN	SCR, DLN	---

4.1.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources)

Norway Hydro is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has four generating units capable of producing up to 7.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 4-5.

Table 4-5: Norway Hydro

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydro is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has three generating units capable of producing up to 9.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 4-6.

Table 4-6: Oakdale Hydro

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

4.1.5 NIPSCO Wind Purchase Power Agreements and Joint Venture

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 4-7.

Table 4-7: Barton Wind PPA

	Barton PPA
NET Output	
Per Unit (MW)	2
Number of Units	25
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County, South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 4-8.

Table 4-8: Buffalo Ridge Wind PPA

	Buffalo Ridge PPA
NET Output	
Per Unit (MW)	2
Number of Units	24
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Jordan Creek, which will operate and maintain the facilities. Jordan Creek, located in Benton and Warren counties, Indiana, near Williamsport, Indiana, went into commercial operation in December 2020. The individual unit characteristics of Jordan Creek are provided in Table 4-9.

Table 4-9: Jordan Creek Wind PPA

	Jordan Creek PPA		
NET Output			
Per Unit (MW)	2.8	2.3	2.5
Number of Units	131	14	1
Total Output (MW)	369	32	2.5
In-Service	2020		
Main Fuel	Wind		

The Rosewater wind project, developed and constructed by EDP Renewables North America LLC, is located in White County, Indiana and went into commercial operation in December 2020. EDP Renewables and NIPSCO entered into a joint venture and ownership agreement for the Rosewater project. The individual unit characteristics of Rosewater are provided in Table 4-10.

Table 4-10: Rosewater Wind JV

	Rosewater JV
NET Output	
Per Unit (MW)	4
Number of Units	25
Total Output (MW)	100
In-Service	2020
Main Fuel	Wind

4.1.6 Total Resource Summary

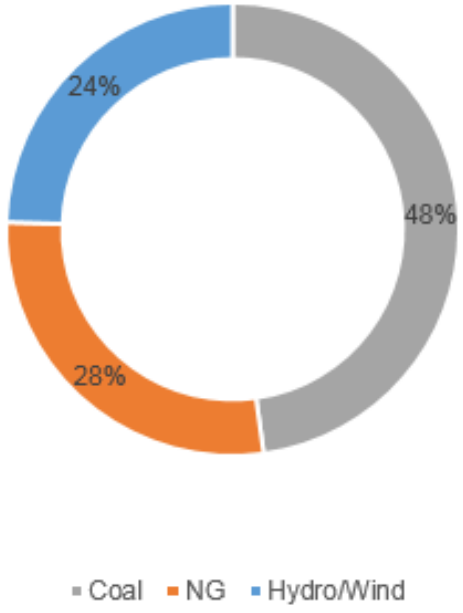
Table 4-11 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-1 illustrates NIPSCO's existing resources by fuel type.

Table 4-11: Existing Generating Units

Resource	Unit	Fuel	Capacity NDC (MW)	Year In Service
Michigan City	12	Coal	469	1974
Schahfer	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
		Subtotal	877	
Sugar Creek		NG	535	2002
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind	Barton	Wind	50	2009
	Buffalo Ridge		50	2009
	Rosewater		100	2020
	Jordan Creek		400	2020
		Subtotal	600	
NIPSCO			2,491	

NG=Natural Gas

Figure 4-1: Existing Resources Net Demonstrated Capacity



4.2 Fuel, Energy, and Capacity Procurement Strategy for Existing Resources[33]

As NIPSCO operates as a public utility providing electric service to customers, the procurement of fuel, energy, and capacity at the lowest reasonably possible cost is the foundation of NIPSCO's strategy. NIPSCO's Fuel Supply team ensures all fuel, energy, and capacity supply meets Indiana Code § 8-1-2-42(d).

4.2.1 Coal Procurement and Inventory Management Practices

4.2.1.1 Coal Supply Strategy

NIPSCO employs a multifaceted strategy to guide coal procurement activities associated with the fuel supply requirements for its coal-fired units. The goal of this strategy is to maximize reliability while maintaining customer affordability. Key elements include: (1) procuring coal supply from sources that minimize the delivered cost of coal, O&M costs, environmental costs, inventory costs and other financial impacts ("total cost of ownership"); (2) hedging customers' price exposure with forward purchases to protect against price volatility; (3) supporting environmental compliance; (4) maintaining reliable inventory levels; (5) ensuring reliability of coal supply and delivery; and (6) maximizing operational flexibility and reliability by procuring coal types that can be used in more than one unit whenever possible.

4.2.1.2 Coal Procurement

NIPSCO maintains a five-year baseline coal forecast that is used to create a strategy that drives its fuel procurement plan. The forecast is used to estimate coal and related coal transportation procurement requirements needed to maintain reliable and economic coal inventory levels. The strategy and fuel procurement plan are highly dynamic and are updated on a periodic basis in response to energy market conditions. Over the past several years, environmental regulations, a significant influx of highly variable renewable generation (e.g. wind and solar), low natural gas prices, and energy efficiency and other demand side initiatives have made coal-fired generation the marginal supply source. Consequently, this has created an environment with highly variable and nearly unpredictable coal purchase requirements. Therefore, NIPSCO's fuel procurement plans must remain as flexible as possible while still maintaining supply reliability. Obtaining volume flexibility can be challenging since coal suppliers and transportation providers typically require firm volume commitments.

[33] Due to the timing of the IRP, this section was written during the summer of 2021 and the forecast is based on the market at that time. During the latter part of the third quarter, and into the fourth quarter, the coal and natural gas markets have become volatile and prices have increased. The IRP is an imperfect snapshot in time and the changes in these markets are indicative of that. At the time of submission of the IRP, it is unknown how long current trends will continue or if the markets will return to previous levels. As always, NIPSCO will continue to monitor the markets and make adjustments as necessary.

4.2.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Over the last decade, energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower production costs and highly efficient natural gas extraction processes (horizontal drilling and fracking) have kept natural gas a competitive fuel when used in high efficiency, CCGT units. In addition, increases in wet gas production to gather petroleum liquids further increase natural gas supply when oil prices rise. These market dynamics displaced a significant amount of coal-fired electric generation and have kept coal prices relatively low. Decreased coal demand and higher mining costs driven by government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies over the last few years. The restructuring of coal companies' debt and other costs through the bankruptcy process has allowed some of these coal companies to continue coal production in this competitive environment. Class I railroads have also realized that their rates must be rationalized to allow coal to compete in this environment. Supply has been reduced and any significant increase in demand could result in coal price volatility. However, several factors may limit the upside for coal prices. The first factor is the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal-fired electric generation. A second factor is the continuation of coal-fired generation retirements which will continue to reduce coal demand in the long run. Lastly, the increased competitiveness of natural gas generation and renewables will also limit demand for coal if coal prices spike in the long run.

The competitive energy market has also driven a shift in coal supply regions. Specifically, the relatively high cost to produce coal in the Central Appalachian regions and low coal prices have resulted in declining coal production and this has increased market share of the lower cost ILB region. Even with its higher sulfur content, ILB coal has become an export resource, and its use has increased domestically as utilities have installed FGDs to meet tighter SO2 limits and other emission standards. Some utilities in the southeast are now using ILB coal that replaced higher cost Columbian and Central Appalachia coal.

The PRB in Wyoming and Montana is the largest coal producing basin in the United States. PRB coal has a lower heat content than coals mined in other basins; however, some utilities have units designed to efficiently utilize lower cost PRB coal and over the last 20 years, a number of utilities retrofitted older coal units to use PRB coal in a blend with either Central Appalachian, ILB, or NAPP coals to reduce their overall fuel costs and lower SO2 emissions. Asian demand for PRB coal has also grown as Japan and China have built new, high efficiency coal units and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand.

In general, most export tonnage originates from Central Appalachian and NAPP coal regions for metallurgical and steam coal markets abroad. Coal suppliers rely on international markets to offset losses in domestic markets; however, the pressure to reduce coal use worldwide will likely reduce international demand in the long run as well.

Overall, these fundamentals are bearish for long-term coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices and incorporate in its procurement strategies.

4.2.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Domestic demand for coal has continued to trend lower over the last several years; therefore, prices have remained relatively low and stable. NAPP coal and ILB coal market pricing over the last several years has been relatively flat. Pricing for PRB coal has remained low over the last several years and is close to the marginal cost of production.

Domestic and international coal prices have increased during 2021 as the economic recovery from the 2020 pandemic has caused a surge in demand. Export dynamics can drive pricing modestly higher for some coal types (e.g. NAPP and ILB) when global demand increases as well; however, the long-term trends for both demand and pricing are bearish.

4.2.1.5 Coal and Issues of Environmental Compliance

Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to evolve in a manner that meets current and future environmental requirements.

4.2.1.6 Maintenance of Coal Inventory Levels

NIPSCO has an ongoing strategy to maintain stable coal inventories and reviews inventory targets levels annually. NIPSCO may make adjustments in anticipation of changes in supply availability relative to demand, transportation constraints, and unit consumption. NIPSCO may modify target inventory levels on a unit-by-unit basis depending on the unit consumption, delivery rates, reliability of coal supply, and station coal handling operations. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates and variability in delivery performance generally require higher levels of inventory to insure reasonably adequate reliability.

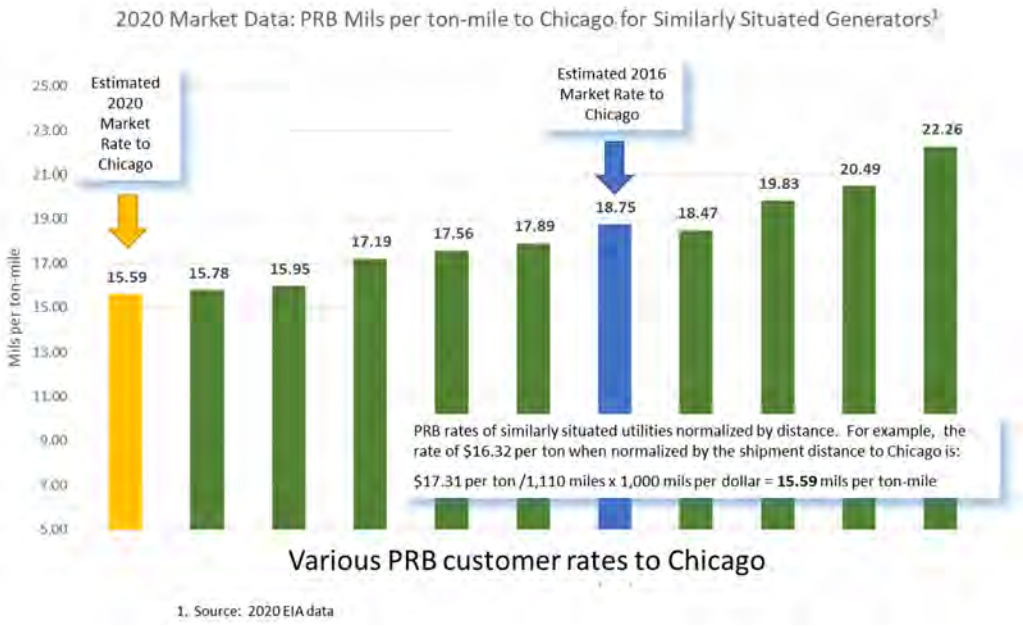
4.2.1.7 Forecast of Coal Delivery and Transportation Pricing

To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts that consider current and future coal supply commitments. All fuel procurement options are compared on a delivered cost basis, which includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have been somewhat stable from the various supply regions. Railroads typically make investment in infrastructure and equipment to support anticipated shipment rates. The cyclical nature of the railroad business can create short term transportation constraints and can impact NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years. The decline in coal demand has made it difficult for railroads to invest in coal infrastructure and this may lead to transportation constraints if there is a significant increase in overall coal demand.

Transportation rates have declined over the last four years given the competition in the energy markets. Railroads have been willing to rationalize rail rates, as shown in the market assessment plots below, in order to remain competitive in the energy market. Figure 4-2 highlights the estimated reduction in PRB coal transportation rates since 2016. This pricing trend has improved the competitiveness of NIPSCO's coal-fired generation to a certain extent.

Figure 4-2: PRB Customer Rates



4.2.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options from various supply regions for most of its coal transportation moves, and is further disadvantaged due to its geographical location. Not only are rail transportation options limited, other transport modes (trucking, barging and lake vessels) are not economically or logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one Class I railroad. All coal deliveries by this railroad to Schahfer have been transported under agreements with escalating transportation rates plus a fuel surcharge indexed to oil prices. Beginning in 2017, NIPSCO and this railroad worked to develop a creative, market-based indexed agreement that lowered rates to improve the station's competitiveness in the market. A second indexed rate agreement has also been recently adopted with another railroad. As

stated above, energy markets have forced a rationalization of coal pricing and associated transportation costs. NIPSCO expects this dynamic to continue for the foreseeable future.

As a result of these changes in the energy markets and agreement structures, NIPSCO's PRB and ILB coal transportation rates though 2020 have reduced by nearly 25%-50% since 2017. Fuel surcharges continue to fluctuate with the changes in oil prices. Transportation pricing is expected to remain soft as long as energy prices stay low and relatively flat over the next five years. Increases in fuel charges could lead to modest transportation cost increases if oil prices trend higher.

4.2.1.9 Coal Contractual Flexibility, Deliverability and Procurement

Contract terms for coal and coal transportation agreements range between one to five years in duration. Spot coal purchases are made on an as-needed basis to manage inventory fluctuations. Fuel blending strategies can be adjusted to conserve a particular type of coal if supply problems are experienced. In addition, coal suppliers and railroads have been more amenable to providing some volume flexibility including lower minimum volume obligations or elimination of minimum volume obligations entirely. This flexibility has supported NIPSCO's inventory management efforts.

4.2.2 Natural Gas Procurement and Management

NIPSCO currently procures natural gas for its CCGT generating station using a natural gas supply contract with an energy manager that delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on Midwestern Gas Transmission Company interstate pipeline and releases the capacity to the energy manager. The contract has provisions to purchase next day and intraday firm gas supplies to serve the daily needs of the facility. NIPSCO nominates and balances the gas supply needs of the CCGT generating station. A portion of the gas supply for Sugar Creek is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

The coal units and CTs at NIPSCO are located within the NIPSCO natural gas local distribution company service territory. NIPSCO maintains a separate contract for firm delivered natural gas supply and energy management for these units. The contract has provisions to nominate next-day usage based on the expected usage of each generating station. The actual usage is balanced daily and balancing is the responsibility of the energy manager.

4.2.3 Electric Generation Gas Supply Request for Proposal Process

NIPSCO conducts two separate RFPs for the electric generation firm natural gas supply, one for the Sugar Creek facility and a separate one for the coal units and CTs. The RFP process may be done on a seasonal or annual basis depending on the current contract length and supplier agreement. The process includes qualifying potential suppliers, customizing the RFP based on

near-term system needs, and gas supply trends. Suppliers are chosen based on the overall value of the package and ability to serve the needs of the facility. To date, NIPSCO has entered into electric generation gas supply agreements that extend no longer than one year, but is always evaluating the value and benefits of longer term agreements.

4.3 Planned Resource Summary

In addition to its existing resource portfolio, NIPSCO has a number of planned renewable resource projects with expected in-service dates through 2023. The planned projects have been filed with the Commission and are in various stages of development. The projects are summarized in Table 4-12.

Table 4-12: Planned Renewable Projects

Project	Technology	Expected ICAP (MW)	Battery Capacity (MW)	Expected In-Service
Indiana Crossroads	Wind	300	-	2021
Indiana Crossroads II	Wind	200	-	2023
Greensboro	Solar + Storage	100	30	2022
Brickyard	Solar	200	-	2022
Green River	Solar	200	-	2023
Gibson	Solar	280	-	2023
Cavalry	Solar + Storage	200	60	2023
Dunns Bridge I	Solar	265	-	2022
Dunns Bridge II	Solar + Storage	435	75	2023
Indiana Crossroads	Solar	200	-	2022
Elliott	Solar	200	-	2023
Fairbanks	Solar	250	-	2023
Total		2,830	165	

4.3.1 Planned Wind Resources

NIPSCO is in the process of developing two wind projects that are expected to be in service by 2023. The first, Indiana Crossroads, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana and is expected to go into commercial operation by December 2021. The planned unit characteristics of Indiana Crossroads are provided in Table 4-13.

Table 4-13: Indiana Crossroads Wind JV

	Indiana Crossroads Wind JV
Net Output	
Per Unit (MW)	4.2
Number of Units	72
Total Output (MW)	302.4
In-Sevice	2021
Main Fuel	Wind

NIPSCO has entered into a 15-year PPA starting in 2023 with EDP Renewables North America, LLC, in which NIPSCO will purchase the power directly from Indiana Crossroads II Wind, who will operate and maintain the facility. Indiana Crossroads II Wind, located in White County, Indiana, is expected to go into commercial operation by December 2023. The planned unit characteristics of Indiana Crossroads II Wind are provided in Table 4-14.

Table 4-14: Indiana Crossroads II Wind PPA

	Indiana Crossroads II Wind PPA	
Net Output		
Per Unit (MW)	4.2	5.6
Number of Units	6	32
Total Output (MW)	25.2	179.2
In-Sevice	2023	
Main Fuel	Wind	

4.3.2 Planned Solar and Solar + Storage Resources

NIPSCO has 10 planned solar projects, three of which include additional battery storage, that are expected to be in service by 2023.

NIPSCO has entered into a 20-year PPA starting in 2022 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Greensboro, who will operate and maintain the facility. Greensboro, located in Henry County, Indiana, is expected to go into commercial operation by December 2022. The planned unit characteristics of Greensboro are provided in Table 4-15.

Table 4-15: Greensboro Solar + Storage PPA

	Greensboro PPA
Solar Output	
Total Output (MW)	100
Storage Output	
Total Output (MW)	30
Output Period (Hrs.)	3
Discharge Limits (Cycles/Yr.)	100
In-Service	**2022**
Main Fuel	**Solar + Storage**

NIPSCO has entered into a 20-year PPA starting in 2022 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Brickyard, who will operate and maintain the facility. Brickyard, located in Boone County, Indiana, is expected to go into commercial operation by December 2022. The planned unit characteristics of Brickyard are provided in Table 4-16.

Table 4-16: Brickyard Solar PPA

	Brickyard PPA
Solar Output	
Total Output (MW)	200
In-Service	**2022**
Main Fuel	**Solar**

NIPSCO has entered into a 20-year PPA starting in 2023 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Green River, who will operate and maintain the facility. Green River, located in Breckenridge and Meade Counties, Kentucky, is expected to go into commercial operation by June 2023. The planned unit characteristics of Green River are provided in Table 4-17.

Table 4-17: Green River Solar PPA

	Green River PPA
Solar Output	
Total Output (MW)	200
In-Service	**2023**
Main Fuel	**Solar**

NIPSCO has entered into a 22-year PPA starting in 2023 with Arevon Energy, in which NIPSCO will purchase the power directly from Gibson, who will operate and maintain the facility.

Gibson, located in Gibson County, Indiana, is expected to go into commercial operation by June 2023. The planned unit characteristics of Gibson are provided in Table 4-18.

Table 4-18: Gibson Solar PPA

	Gibson PPA
Solar Output	
Total Output (MW)	280
In-Service	**2023**
Main Fuel	**Solar**

The Calvary Solar + Storage project, developed and constructed by NextEra Energy Resources, LLC, is located in White County, Indiana and is expected to go into commercial operation by December 2023. NIPSCO will enter into a joint venture and ownership agreement for the Cavalry project. The planned unit characteristics of Cavalry are provided in Table 4-19.

Table 4-19: Cavalry Solar + Storage JV

	Cavalry JV
Solar Output	
Total Output (MW)	200
Storage Output	
Total Output (MW)	60
Output Period (Hrs.)	3
Discharge Limits (Cycles/Yr.)	100
In-Service	**2023**
Main Fuel	**Solar + Storage**

The Dunns Bridge I Solar project, developed and constructed by NextEra Energy Resources, LLC, is located in Jasper County, Indiana and is expected to go into commercial operation by December 2022. NIPSCO will enter into a joint venture and ownership agreement for the Dunns Bridge I project. The planned unit characteristics of Dunns Bridge I are provided in Table 4-20.

Table 4-20: Dunns Bridge I Solar JV

	Dunns Bridge I JV
Solar Output	
Total Output (MW)	265
In-Service	**2022**
Main Fuel	**Solar**

The Dunns Bridge II Solar + Storage project, developed and constructed by NextEra Energy Resources, LLC, is located in Jasper County, Indiana and is expected to go into commercial

operation by December 2023. NIPSCO will enter into a joint venture and ownership agreement for the Dunns Bridge II project. The planned unit characteristics of Dunns Bridge II are provided in Table 4-21.

Table 4-21: Dunns Bridge II Solar + Storage JV

	Dunns Bridge II JV
Solar Output	
Total Output (MW)	435
Storage Output	
Total Output (MW)	75
Output Period (Hrs.)	3
Discharge Limits (Cycles/Yr.)	100
In-Service	**2023**
Main Fuel	**Solar + Storage**

The Indiana Crossroads Solar project, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana and is expected to go into commercial operation by December 2022. NIPSCO will enter into a joint venture and ownership agreement for the Indiana Crossroads Solar project. The planned unit characteristics of Indiana Crossroads Solar are provided in Table 4-22.

Table 4-22: Indiana Crossroads Solar JV

	Indiana Crossroads Solar JV
Solar Output	
Total Output (MW)	200
In-Service	**2022**
Main Fuel	**Solar**

The Elliott Solar project, developed and constructed by Arevon Energy, is located in Gibson County, Indiana and is expected to go into commercial operation by June 2023. NIPSCO will enter into a joint venture and ownership agreement for the Elliott project. The planned unit characteristics of Elliott are provided in Table 4-23.

Table 4-23: Elliott Solar JV

	Elliott JV
Solar Output	
Total Output (MW)	200
In-Service	**2023**
Main Fuel	**Solar**

The Fairbanks Solar project, developed and constructed by Invenergy Renewables Global, LLC, is located in Sullivan County, Indiana and is expected to go into commercial operation by December 2023. NIPSCO will enter into a joint venture and ownership agreement for the Fairbanks project. The planned unit characteristics of Fairbanks are provided in Table 4-24.

Table 4-24: Fairbanks Solar JV

	Fairbanks JV
Solar Output	
Total Output (MW)	250
In-Service	**2023**
Main Fuel	**Solar**

4.4 MISO Wholesale Electricity Market

MISO supplies an important element to NIPSCO's long term plans. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. In 2021, MISO has members from 15 states and one Canadian province with a generation capacity of 184,000 MW and 65,800 miles of high-voltage transmission. MISO manages one of the world's largest energy and operating markets that includes a Day-Ahead Market, Real-Time Market and Financial Transmission Rights Market.

4.4.1 Operations Management and Dispatch Implications

The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, environmental considerations, and the overall generation mix within MISO may affect the level of future dispatch.

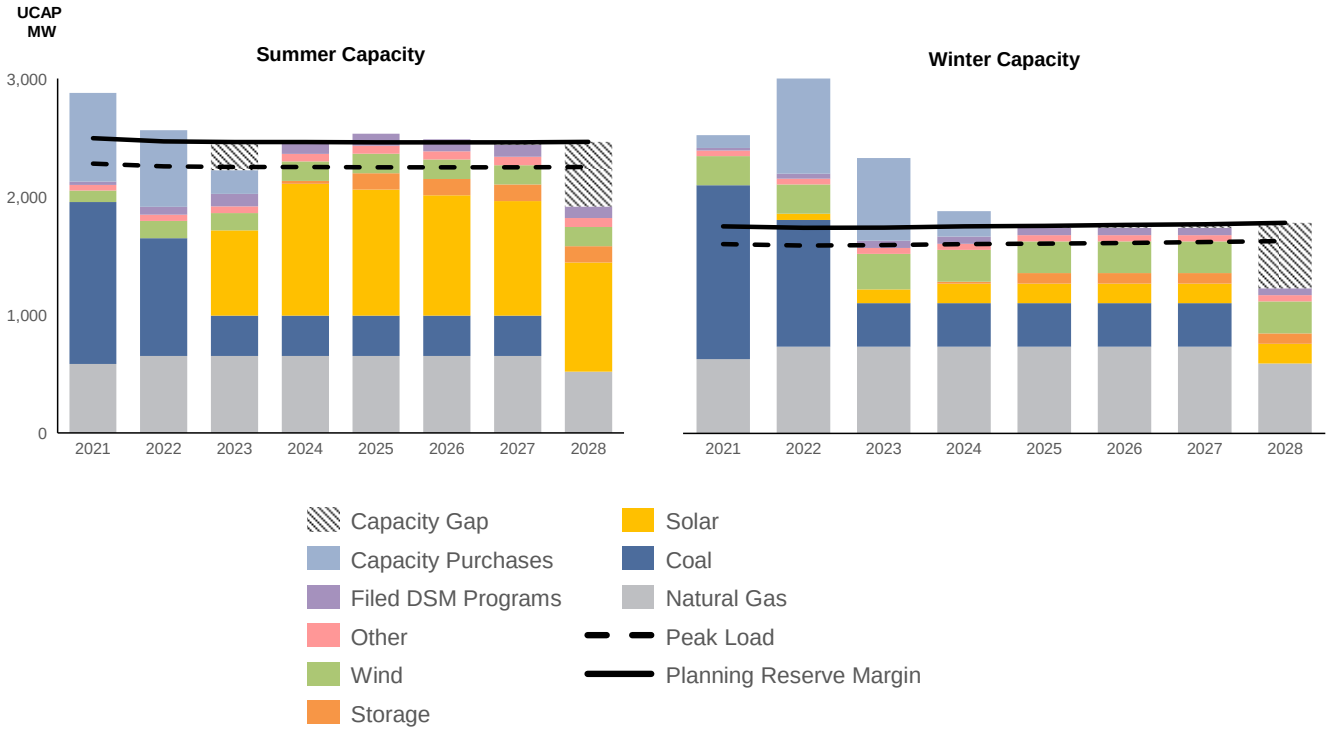
4.5 Resource Adequacy and Current Supply-Demand Balance

Consistent with the principles set out in Section 1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse, and affordable supply. As part of the Resource Adequacy planning process, NIPSCO utilizes the peak demand forecast coincident with the MISO peak demand to determine its capacity requirements. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks, which is typically in the summer. The methodology for calculating the coincident peak demand is described in detail in Section 3.

In addition, as MISO market rules evolve, NIPSCO will need to track resource adequacy compliance in different ways. First, as MISO moves towards a seasonal capacity construct, winter

reserve margin tracking will be required. Second, as renewable resources become a greater share of NIPSCO's portfolio, the seasonal capacity credit or ELCC will likely change over time and will need to be monitored. NIPSCO's assessment of its existing and planned resources against the future needs of its customers for both the summer and winter seasons is shown in Figure 4-3.

Figure 4-3: Resource Adequacy Assessment



4.6 Future Resource Options

As demonstrated in the 2018 IRP, the cost and operational estimates for future resource options modeled in the IRP should reflect the best available market data. In 2021, NIPSCO developed inputs for portfolio modeling based on real bid data that was received in three separate RFP events covering all sources.

4.6.1 Request for Proposal

NIPSCO worked with CRA's Auctions and Competitive Bidding practice during the spring and early summer of 2021 to conduct three separate RFP events covering all-sources. NIPSCO provided the RFP design summary to stakeholders in April 2021 and solicited feedback. During NIPSCO's second Public Advisory meeting, an overview of the RFP design, feedback received during the comment period, and timeline were presented to stakeholders. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the RFP events on May 20, 2021 and closed the window for proposals on June 30, 2021.

The RFPs provided several guidelines to bidders, which are summarized below:

- Technology: The RFPs requested all solutions regardless of technology. Event 1: wind and wind paired with storage, Event 2: solar and solar paired with storage, and Event 3: thermal, stand-alone storage, emerging technologies, and other capacity resources.

- Size: The RFPs defined an overall size range of 400 - 650 MW for the portfolio, but placed no size restrictions on the potential bidders. The RFPs explicitly allowed for resources below 400 MW to offer their solution as a piece of a potential total need. The RFPs also encouraged larger resources to offer their solution for consideration.

- Ownership Arrangements: The RFPs were open to asset purchases (new or existing) and PPAs. However, they required that resources qualify as MISO internal generation (i.e., not pseudo-tied into MISO).

- Duration: The RFPs requested delivery beginning in 2024, 2025, and 2026, but indicated that alternative deliveries would be evaluated. The minimum contractual term and/or estimated useful life was requested to be five years.

- Deliverability: The RFPs required that bidders have physical deliverability utilizing Network Resource Integration Service to MISO LRZ6.

- Participants and Pre-Qualification: The RFPs required counterparties be credit-worthy to ensure an ability to fulfill future resource obligations.

Overall, the RFPs generated a large amount of bidder interest, with 182 total proposals received across a range of deal structures. Within those 182 proposals, NIPSCO received bids for 78 individual projects across five states with over 15 GW of ICAP represented.[34] Many of the proposals offered variations on pricing structure and term length, and the majority of the projects were in various stages of development. A summary of the total number of proposals received by technology type is shown in Figure 4-4.

Figure 4-4: Summary of Number of Proposals Received by Technology Type

Proposal Count by Technology and Transaction Structure

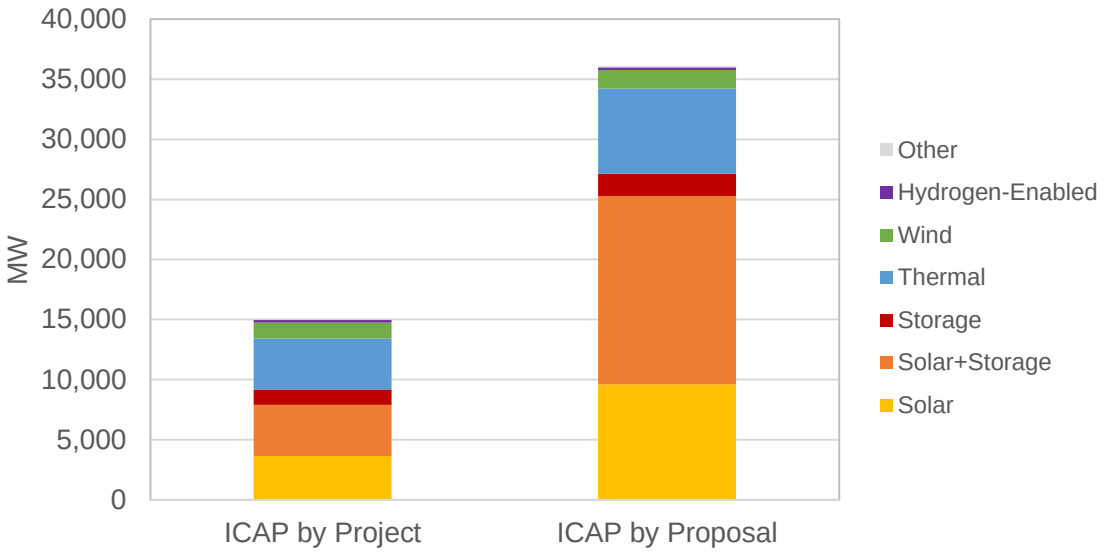
	Solar	Solar + Storage	Storage	Thermal	Wind	Hydrogen Enabled	Other	Total
Asset Sale	1	2	6	4	-	-	-	13
PPA	15	20	8	10	7	2	4	66
Both	37	60	-	2	-	-	4	103
Total	**53**	**82**	**14**	**16**	**7**	**2**	**8**	**182**
States Represented	**IL, IN, KY**	**IL, IN, KY, WI**	**IN, WI**	**IL, IN, KY**	**IL, IN, MO**	**IN**	**MISO**	

On a total MW basis, the 15 GW of ICAP offered represented just under 10 GW of UCAP, providing a sufficiently large set of candidate options for NIPSCO to evaluate for any capacity

[34] CRA received a bid package from one bidder following the formal bid deadline. This bid included 3 proposals for 2 separate storage facility options.

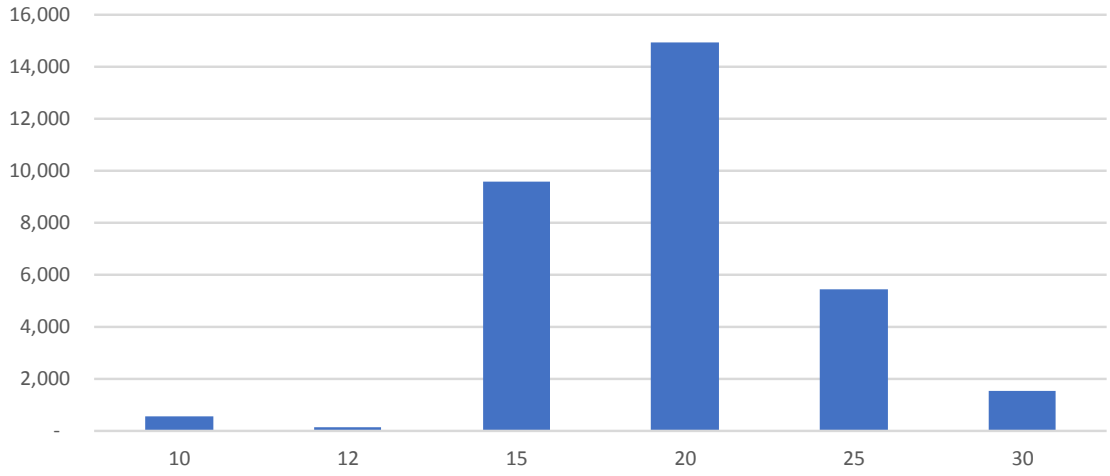
need during the RFP delivery window. Approximately 25% of UCAP was in the form of solar or solar paired with storage. Another 26% were natural gas-fired projects. However, a significant amount of wind and storage resources were also offered. Figure 4-5 shows a summary of total MW offered in response to the RFPs by type.

Figure 4-5: Total MW of Proposals Received by Technology



Most PPA offers were relatively long in duration, with the majority of proposals offering contracts for 15 year terms or longer. Several bidders offered shorter-term options, including a number that provided NIPSCO with options to select from multiple duration possibilities. Figure 4-6 provides a summary of the total ICAP MW offered by duration.

Figure 4-6: Summary of Proposals Received by PPA Duration (ICAP MW)



Most importantly, the responses to the RFPs provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was

relatively consistent with past NIPSCO RFP subject to market adjustments. This indicated that technology change and developer activity in a competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future. A summary of the various proposals by type and by price is provided in Figure 4-7. Note that due to confidentiality considerations, individual project prices cannot be disclosed.

Figure 4-7: Summary of Proposals by Price

Technology	Asset Sale		Power Purchase Agreement			Comments
	$/kW	Count	PPA $/MWh	$/kW-Mo	Count	
Solar	$1,467	38	$41.31	-	52	Many projects were bid as both PPA and Asset Sales as well as several PPA structures
Solar + Storage	$1,719	62	$42.77	$3.86	80	Typical PPA structure for integrated solar and storage includes both a fixed and variable component
Storage	$965	6	-	$12.93	8	
Thermal	$1,075	6	$0.36	$7.95	12	Thermal bids also typically would include pass through costs for startup and fuel
Wind	-	-	$39.63	-	7	
Hydrogen Enabled	-	-	-		2	Hydrogen pricing not reported due to limited bid count and fundamental differences in the bids received
Other	-	4	$21.83	$2.81	8	Other includes a range of structures that may or may not include both energy and capacity

- Average bid prices shown for 'Asset Sale' represent capital costs and exclude on-going fuel, O&M and CapEx (where applicable)
- Figures shown are for representation and do not purport competition between technologies; Separate short-listed assets are created for each RFP event

4.6.2 Incorporation of the RFP Results into the IRP

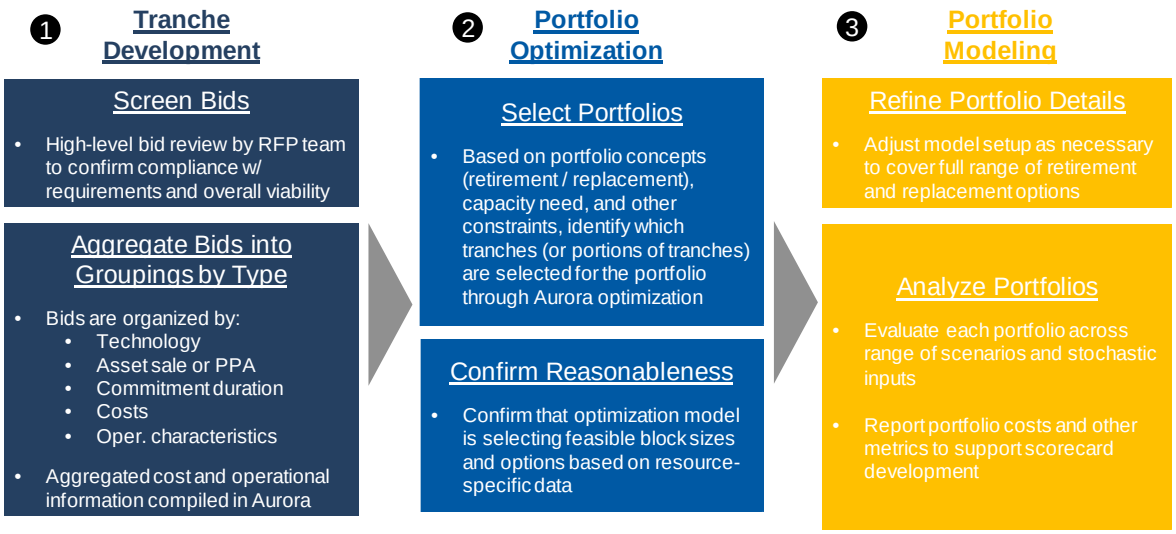
After gathering the bidder data from the RFP, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for RFP-IRP integration, which is outlined in Figure 4-8:

(1) Tranche Development: Screen bids for viability and organize the various bids into groupings or tranches according to technology, whether the bid offered a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics.

(2) Portfolio Optimization: Perform portfolio optimization analysis based on NIPSCO's potential capacity need and other portfolio design constraints, confirming option viability based on feasible block sizes of tranche data from the RFPs.

(3) Portfolio Modeling: Develop and refine comprehensive portfolios with selected tranches from the portfolio optimization step and analyze them across the full set of scenarios and stochastic inputs.

Figure 4-8: Tranche Development and Assessment Process



4.6.3 Tranche Development

It was determined that a tranche approach would be most effective in aggregating the numerous data points from the RFPs into useable IRP information for three main reasons:

- The IRP is intended to select the best resource mix and future portfolio concept rather than select specific assets or projects. While the IRP analysis can now be highly informed by actionable data from the RFPs, it is only meant to develop a planning-level recommended resource strategy. NIPSCO determined that asset-specific selection would require an additional level of diligence, including assessment of development risk, evaluation of locational advantages or disadvantages for specific projects, and review of transmission system impacts, to be conducted outside of the standard IRP process.
- The IRP is a highly transparent and public process that requires sharing of major inputs with stakeholders and the public. There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data.
- The IRP modeling is complex, and resource grouping improves the efficiency of the process. Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set would improve the efficiency of setup and runtime.

When developing tranches, the CRA RFP team first organized resources by technology and then sorted them into categories according to whether they were offered as asset sales or PPAs. Projects were screened by the RFP team to determine conformity with bid requirements, and any non-conforming bids were eliminated. Duplicate projects that were offered multiple times under different structures were consolidated into the lowest-cost option to avoid double-counting.

Beyond the initial organization and screening, the bids were then arranged by commitment duration and finally costs and operational characteristics.

Ultimately, the tranche development process resulted in the production of 19 total tranches. These are summarized by resource type, size, term, and costs for PPA options in Figure 4-9 and for asset sale options in Figure 4-10. As a naming convention, tranches with a "P" represent PPA offers, while those with an "A" represent asset sale offers.

Figure 4-9: Summary of PPA RFP Tranches Used in Modeling

Tranche	ICAP (MW)	Heat Rate (Btu/kWh)	Energy Price ($/MWh)	Capacity Price ($/kW-mo)	First Eligible Start Year**	PPA Term (years)	Escalation Rate
Wind P1	500		$48.37		2025	20	0%
Wind P2 (Non-LRZ 6)	835		$33.28		2024	15	0%
Solar P1	825		$49.73		2024	20	0%
Solar P2	588		$37.50		2024	17	0.9%
Solar + Storage P1	300:150^		$39.00	$7.43	2025	15	0%
Solar + Storage P2	1,135:478^		$44.49	$6.14	2023	20	0%
Storage P1	863			$11.95	2025	19	0.2%
Gas Peaking P1	443	10,244	*	$6.47	2026	20	0%
Gas Peaking P2	193	10,238	*	$8 – $9	2025	20	2.1%
Gas CC P1	1,365	6,627	$0.98*	$8.89	2024	20	0.1%
Other Thermal P1	50	12,500	$2 – $3*	$5 – $6	2024	10	
Other Thermal P2	150			$3 – $4	2026	10	2.0%
Hydrogen P1 – Enabled Peaker	193	10,238	*	$9 – $10	2025	20	
Hydrogen P2 – Electrolyzer Pilot	20			$25 – $30	2026	20	

Notes:
Red-colored price information shown as a range to protect confidentiality when tranches are composed of a limited number of bids.
^Capacity for Solar + Storage tranches is represented in the format of "Solar:Storage."
*Fuel and emission variable costs are additive to the Energy Price and are incorporated in the portfolio modeling for the Gas Peaking P1, Gas Peaking P2, Gas CC P1, Other Thermal P1, and Hydrogen P1 tranches.
**First Eligible Start Year indicates the first year some part of the tranche is expected to be available, although capacity is available to start in subsequent years according to bidder information; this is incorporated in the portfolio modeling.

Figure 4-10: Summary of Asset Sale RFP Tranches Used in Modeling

Tranche	ICAP (MW)	Heat Rate (Btu/kWh)	First Eligible Start Year**	Asset Sale ($/kW)
Solar A1	1,250		2025	$1,282
Solar A2	1,150		2025	$1,603
Solar + Storage A1	901:305^		2024	$1,346
Solar + Storage A2	549:275^		2025	$1,167
Storage A1	406		2025	$984
Gas Peaking A1	369	11,471	2024	$575
Gas CC A1	650	6,540	2026	$1,100 - $1,300

Notes:
Red-colored price information shown as a range to protect confidentiality when tranches are composed of a limited number of bids.

^Capacity for Solar + Storage tranches is represented in the format of "Solar:Storage."
**First Eligible Start Year indicates the first year some part of the tranche is expected to be available, although capacity is available to start in subsequent years according to bidder information; this is incorporated in the portfolio modeling.

4.6.4 Renewable Resource Tax Incentives and Tax Equity Partnership

Federal tax incentives are currently in place for renewable and paired renewable/storage resources. Resources are eligible for a PTC or an investment tax credit ITC. The PTC provides a credit of $25/ MWh[35] for all generation produced by the facility, and the ITC provides a credit as a portion of the total cost of the facility. It is generally advantageous for wind resources to take the PTC, due to their high capacity factors, and solar resources to take the ITC.

The tax incentives are currently in the midst of a phase-out, with the implications on IRP modeling assumptions of current law summarized in Figure 4-11. However, NIPSCO's scenario analysis incorporates different assumptions for extensions over time (see details in Section 8). In order to qualify for the credits, projects need to begin construction by a certain date and be put into service by a certain date. The start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities.[36] The safe harbor for beginning of construction is investment of at least 5% of the total project cost on or before the specified date.

[35] This value is indexed to inflation.
[36] Note that in May 2020 the Internal Revenue Service issued guidance to extend PTC and ITC deadlines in light of potential construction delays and supply chain disruptions associated with the COVID-19 pandemic. In-service date deadlines for 2020 and 2021 PTC projects have been extended by one year, while certain ITC spend schedules were extended by several months. Thus, a wind project safe harbored in 2017 with 80% of the total PTC could potentially still enter into service in 2022. However, given that all RFP wind bids were PPAs, NIPSCO assumes that all tax credit eligibility assumptions are embedded in PPA prices.

Figure 4-11: Current PTC (Wind) and ITC (Solar) Phase-Out Schedule

PTC - Wind

Last Year Project Can Be Placed in Service to Qualify for Continuity Safe Harbor	Credit Percentage
2022	60%
2023	60%
2024	60%
2025	60%
2026+	0%

ITC – Solar and Paired Solar + Storage

Last Year Project Can Be Placed in Service to Maximize ITC	ITC Percentage
2022	30%
2023	30%
2024	26%
2025	26%
2026+	10%

Given the importance of these tax incentives, NIPSCO performed a review of their impact on RFP bids prior to developing final costs for the portfolio modeling. The impact of the tax incentives needed to be treated differently for the different types of RFP bids:

- For PPAs, no adjustments were needed, since tax incentives flow to the developer and are theoretically reflected in PPA pricing; and
- For asset ownership, tax benefits flow to the utility and ultimately to the customer in rates, so adjustments needed to be made.

Without proper structuring, the Internal Revenue Code normalization rules stretch the flow of tax benefits to the customers over the regulatory life of the asset, but an alternative tax equity ownership structure can adjust the flow of benefits. In this arrangement, NIPSCO and a tax equity investor would form a partnership to develop a renewable energy project. The tax equity investor would invest to obtain a specified internal rate of return through the receipt of tax benefits in the form of depreciation, tax credits, and cash for a specified timeframe. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.

In order to properly account for the rate base reduction impact of partnering with a tax equity investor, CRA worked with NIPSCO's tax team to develop relevant financial models consistent with the analysis performed to support prior solar project applications to estimate the breakdown of capital expenditures. Assuming 26% ITC eligibility, the tax equity contribution is estimated to be around 31% of total capital costs once additional tax advantages like accelerated tax depreciation are taken into account, meaning NIPSCO would cover the remaining 69%. This level would decline with a lower ITC percentage.

In the scenarios where NIPSCO assumes the presence of a new storage ITC, similar tax equity capital cost contributions were modeled. Although specific tax equity partnership structures may vary for stand-alone storage resources relative to solar projects as a result of their lack of net energy production, similar reductions in cost would be expected, particularly under a future refundable or direct pay ITC structure in which NIPSCO would be able to directly assume the tax benefit. The expectations of tax equity partner contributions for renewable resources are summarized in Figure 4-12.

Figure 4-12: Capital Cost Adjustments due to Tax Equity Partnership

Resource Type	Tax Equity Capital Cost Contribution
Solar, Solar + Storage, or Stand-alone Storage with 26% ITC	31%
Solar, Solar + Storage, or Stand-alone Storage with 10% ITC	15%

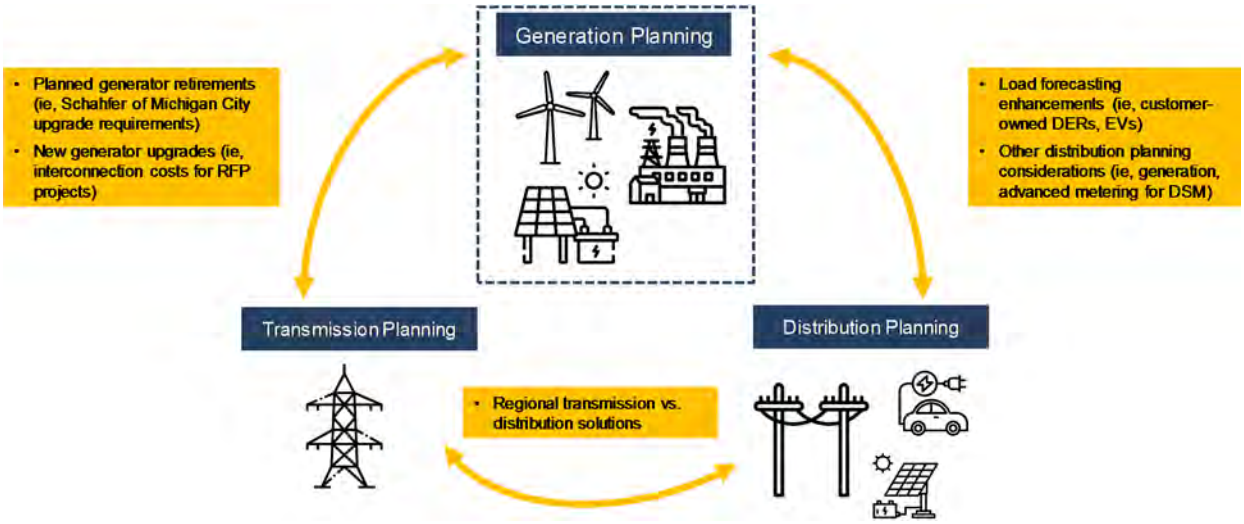
4.6.5 Sugar Creek Uprate Opportunity

NIPSCO operations identified a capital investment opportunity to increase the megawatt range available at the Sugar Creek generating station. The potential project would be an Advanced Gas Path program, which utilizes hot gas path technology to incorporate cooling and sealing enhancements and technology. The program would allow for higher firing temperatures resulting in additional gas turbine output and reduced gas turbine heat rate. The capital project has the potential to increase the MW range of Sugar Creek by 30-53MW for a capital investment range between $13M and $23M (Class 5 estimate). The timing of the project regardless of the level of MW increase would align with a planned outage in the fall of 2026 with the MW available starting in 2027. The 2021 IRP modeled the higher end of the MW range (53MW at an estimated capital investment of $23M). Further engineering due diligence and evaluation will be required prior to implementing such an uprate opportunity at Sugar Creek.

4.6.6 Distributed Energy Resources

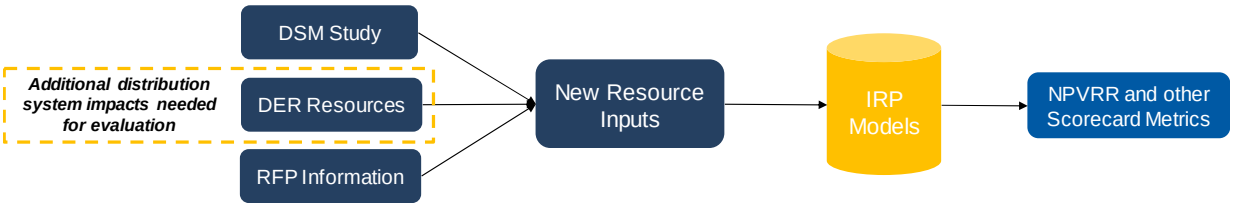
While NIPSCO's IRP has historically been centered on core generation planning questions, the interaction between generation and transmission and distribution planning has been an important consideration. For example, planned generation retirements include estimates of transmission system upgrade requirements, and the economic analysis of new generation additions includes transmission interconnection costs. In addition, NIPSCO's load forecasting process now includes more detail associated with customer-owned DER and electric vehicle penetration, and the DSM study incorporates DR programs reliant on advanced metering infrastructure. These interconnections across generation, transmission, and distribution planning are illustrated in Figure 4-13.

Figure 4-13: Integrated Planning Framework Illustration



In the 2021 IRP, market changes have motivated NIPSCO to explicitly assess DERs as supply-side candidate options. These changes include significant declines in technology costs for solar and storage, making distributed options cost-competitive, and regulatory developments like FERC Order 2222,[37] which will establish new market structures for DER integration. Therefore, in addition to the evaluation of DERs in NIPSCO's load forecast (*See* Section 3), the 2021 IRP is evaluating additional *supply-side* DER options, inclusive of distribution system impacts, against other resource options, as illustrated in Figure 4-14.

Figure 4-14: Process Illustration for DER Integration as a Supply-Side Resource



In order to fully evaluate DER resources, the IRP analysis must incorporate several distinctions between traditional utility-scale options and those sited at the distribution level. There are differences associated with resource costs, impacts on the T&D system, likely storage

[37] FERC Order 2222 "enables DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations." DERs are defined as "any resource located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment." FERC has ordered that "regional grid operators must revise their tariffs to establish DERs as a category of market participant." Although compliance filings were originally due in July 2021, MISO has requested a nine-month extension and has established a cross-functional task force to study the issue.

operational parameters, peak credit accounting, and ancillary services eligibility, as illustrated in Figure 4-15.

Figure 4-15: Distinctions between Utility-Scale and DER Resource Options

	Utility-scale	DER
Costs	• Significant cost data and transparency from RFP bids	• Generally a cost premium to utility-scale, but may depend on specific project
T&D Impacts	• Transmission interconnection costs are incorporated in analysis	• Lowered line losses through T&D system • Strategic siting can defer upgrades on the D system
Storage duration	• ISO rules generally pointing towards 4-hour storage for capacity credit	• Storage duration *can* be shorter and optimized around utility system peaks
Peak planning and pairing with solar	• Higher solar to storage ratios generally preferred, given primary focus on summer peak needs and overall energy value	• Peak requirements may be location/circuit-specific, and lower solar to storage ratios often preferred for capacity value
Ancillary services	• Clear access to wholesale A/S markets	• Current participation options are sometimes unclear, but market rules evolution (i.e. FERC Order 2222) requires tracking

Specific to the potential to defer distribution system investments, NIPSCO's distribution planning team assessed *near-term* (within the next 5 years) system upgrade requirements across the distribution system, with an eye towards how strategically-sited generation alternatives could defer substation and other distribution system investment. As part of this process, the team identified 21 locations on the system that will require capacity improvement investments in the next five years and assessed the following for each location, ultimately identifying eight locations with generation addition opportunities[38]:

- Estimated distribution upgrade project cost at various locations on the system;
- Potential battery storage and paired solar plus storage additions that could defer the distribution upgrade, with consideration given for the availability of nearby land to site capacity; and
- Estimated years of deferral of the distribution upgrade project that could be achieved with the generation addition.

Based on each location's deferred upgrade cost, potential capacity additions, and estimated investment deferral, a NPV of deferred investment on a $/kW basis was developed for each location. NIPSCO and CRA then categorized the projects identified by the distribution planning team into High, Medium, and Low bundles of deferred distribution investment costs to allow for resource selection and economic portfolio analysis, as illustrated in Figure 4-16.

[38] Note that all estimates are based on planning-level information to support IRP analysis. Potential future project execution would require further engineering diligence.

Figure 4-16: DER Bundle Characteristics for IRP Modeling

Deferral Cost Bundle	Resource	Battery Storage MW	Solar MW	Range of Potential NPV of Deferred Investment ($/kW)
High	Solar + Battery	7.0	2.7	**700 – 900**
Mid	Solar + Battery	7.0	9.1	**200 – 300**
Low	Solar + Battery	2.0	2.7	**10 – 100**

From a portfolio modeling perspective, each of these resource options was made available for selection and analysis in the portfolio assessment phase.[39] Given uncertainty in future opportunities on the distribution system and in the regulatory landscape, only near-term opportunities were evaluated. Within the core IRP modeling, a cost premium relative to larger-scale projects from the RFP was assumed,[40] and the NPV of the deferred distribution investment was subtracted from the capital cost of the resource options.

4.6.7 Emerging Technologies

4.6.7.1 Green Hydrogen

The 2021 IRP contemplates multiple deep decarbonization scenarios (*See* Section 8), and NIPSCO recognizes that new, emerging technologies will be needed to achieve emission reduction levels that aim towards a net zero target. One such emerging technology is hydrogen, which may be well-positioned to help decarbonize certain sectors of the economy, including the electricity sector, over the long-term.

The concept of using hydrogen as a source of clean fuel or as a long-duration storage solution has been present in the energy industry for some time. When burned for fuel or consumed in a fuel cell, pure hydrogen emits zero greenhouse gas emissions. In addition, once produced, hydrogen may be stored in existing natural gas infrastructure until it is ready to be burned for fuel in a gas turbine, distributed for residential and commercial heating, or sold to an industrial customer. Due to these characteristics, hydrogen has the potential to be a dispatchable, versatile, zero-emitting alternative to fossil fuels or intermittent resources.

Many obstacles exist to achieving cost-effective, widespread production and consumption of hydrogen in the near term (including cost, lack of availability of transportation and distribution infrastructure, and regulatory uncertainty). However, with sufficiently high carbon emissions prices or natural gas commodity prices, as well as potential technological advancement and federal subsidies for hydrogen, it may become an attractive and versatile fuel option in the long term.

[39] It should be emphasized that the IRP is used to identify the *types of DER projects and characteristics of candidate locations* that may be attractive, with additional project-specific evaluation required in the future.
[40] A cost premium of 20% to utility-scale resource options was incorporated in NIPSCO's analysis, reflective of public sources, such as NREL's Annual Technology Baseline: https://atb.nrel.gov/electricity/2021/data

For the 2021 IRP, NIPSCO considered hydrogen as a possible resource option and developed cost inputs based on RFP responses (through which multiple bidders offered solutions that contemplated the production or use of hydrogen fuel) and independent research and analysis. The research developed a quantitative framework and set of cost assumptions to estimate potential LCOH trajectories to proxy for the expected future market price of hydrogen. NIPSCO then modeled the resulting hydrogen production costs in Aurora as a fuel option for hydrogen-enabled gas turbines and analyzed its dispatch and cost performance in the broader market.

The remainder of this section provides additional context around hydrogen production, a detailed discussion of NIPSCO's LCOH framework and input assumptions, and an analysis of NIPSCO's hydrogen production cost results.

Background on Hydrogen

Hydrogen Production Technology

Hydrogen has the potential to store and deliver zero-emitting energy. However, hydrogen does not typically exist in an isolated form in nature and must be produced from compounds containing it. Today, hydrogen is most commonly produced from thermal processes such as SMR of natural gas, producing what is referred to as "grey" hydrogen (or "blue" hydrogen, if a carbon capture and storage facility is further used to capture and store the carbon emissions from the SMR process). As electrolyzer and renewable prices become more competitive, however, and as existing or expected environmental regulations and targets continue to decrease the use of fossil fuels, renewable energy may instead be used to power the process of water electrolysis to produce "green" or renewable hydrogen. Green hydrogen is made by using zero-emissions electricity to power an electrolyzer, which splits water into hydrogen and oxygen through the electrolysis process, while producing no greenhouse gas emissions.

Green hydrogen is currently more expensive than grey or blue hydrogen, primarily due to low economies of scale, and it is not produced commercially. However, the potential for federal tax incentives for hydrogen production, expectations for significant improvements in system cost components, and continued market evolution toward increased renewable penetration and carbon regulation may make green hydrogen production more attractive in the long term. NIPSCO received multiple bids associated with hydrogen pilot projects or hydrogen enablement in its 2021 RFP, demonstrating that developers are currently actively exploring hydrogen opportunities and validating NIPSCO's effort to assess long-term hydrogen economics within this IRP.

Hydrogen Production Constructs

While green hydrogen is not currently produced at a commercial scale, a "hydrogen economy" could one day develop in one of many forms, each of which would suggest a different modeling approach within a utility resource plan. While these frameworks are speculative, they are useful in helping to define a quantitative approach for analyzing the long-term viability of green hydrogen in the 2021 IRP. NIPSCO considered several hypothetical hydrogen deployment models, as summarized in Figure 4-17.

Figure 4-17 Possible Hydrogen Production Configurations

<table>
<tr><th>Business Model</th><th>Electrolyzer Ownership</th><th>Electricity Ownership</th><th>Gas Plant Ownership</th></tr>
<tr><td rowspan="3">“Islanded”
NIPSCO Ownership Model</td><td rowspan="3">NIPSCO
Capex + fixed costs for electrolyzer, water, storage</td><td>NIPSCO
Capex + fixed costs or PPA for renewable electricity</td><td rowspan="3">NIPSCO
Gas plant retrofit costs</td></tr>
<tr><td>NIPSCO + Market</td></tr>
<tr><td>Market
Grid electricity prices</td></tr>
<tr><td>“Economy”
Purchase H2 for a NIPSCO-owned H2-enabled gas plant</td><td rowspan="2">Third Party
Modeled as a PPA cost for green H2 (inclusive of all production costs)</td><td rowspan="2">Third Party</td></tr>
<tr><td>“Economy”
Purchase green H2-fueled energy through a PPA</td><td>Third Party</td></tr>
</table>

In the near term, the most likely hydrogen “business model” is one in which the utility owns or contracts with all components of the hydrogen production process, including the electrolyzer and electricity sources to produce hydrogen, then consumes the produced hydrogen at its own hydrogen-enabled gas plants to produce electricity during optimal hours. This approach, sometimes referred to as an “islanded” or “closed-system” approach, would be the most appropriate framework in the absence of a functional, widespread hydrogen economy and is consistent with the type of bids offered in response to NIPSCO’s RFP. The hydrogen production cost from the “islanded” approach would include the amortized fixed costs to install and operate the electrolyzer, hydrogen storage facilities, and specific renewable projects used to power the electrolysis process, as well as the variable costs for any grid-sourced electricity and water. Additional costs to transport the hydrogen to the gas plant and to retrofit and operate the plant would also be separate, post-production costs to the utility.

Alternatively, if a functional hydrogen economy is assumed to develop over time, one could extend the “islanded” approach to assume that the utility producer of hydrogen can also optimally sell hydrogen to customers in a broader hydrogen market. For modeling purposes, one could easily imagine the opposite situation, in which the utility simply purchases hydrogen from the market or contracts with third-party green hydrogen producers at a negotiated commodity price to fuel a gas plant. This approach assumes that a suitable transmission and distribution infrastructure builds out over the long term in the hydrogen economy and aims to capture the economics within the assumed hydrogen market as a whole, rather than just the utility-specific

power generation assets that would "feed" the electrolyzer. The assumed market commodity price of hydrogen would be an all-in cost, including the fixed and variable costs of production. NIPSCO used the latter framework as the basis for its long-term economic analysis.

Hydrogen Modeling Input Assumptions Development

Hydrogen Production Cost Components

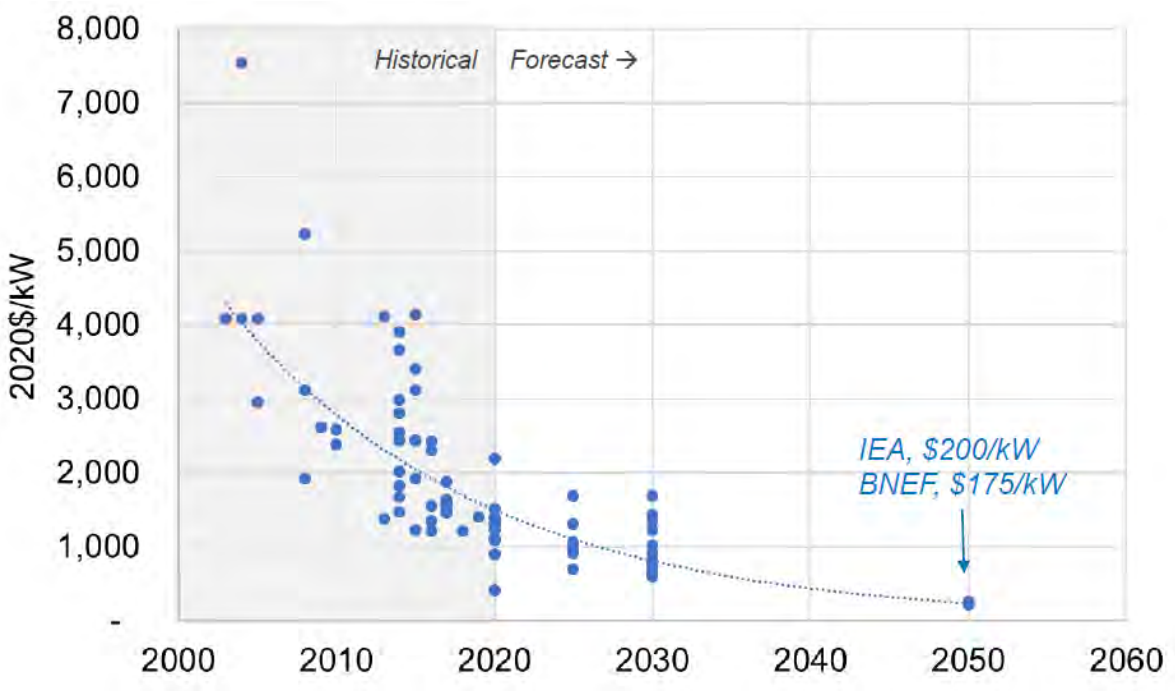
To transparently build up a long-term price trajectory for green hydrogen production, NIPSCO developed a set of input assumptions for each of the cost components. Production costs were assumed to include electrolyzer capital and fixed O&M costs, electricity, and water. All data was drawn from public sources and was adjusted for MISO LRZ 6-specific hydrogen production costs based on local renewable capacity factors and power prices.

Electrolyzer CapEx

Electrolyzer costs are expected to drop significantly over the next twenty years, primarily due to economies of scale and competition from global manufacturers. It is projected that economies of scale will play a noticeable role in lowering overall balance of plant costs, where cost savings between 15-45% can be achieved through increasing annual electrolyzer production. Furthermore, larger electrolyzer systems tend to cost less than smaller systems on a $/kW basis. This $/kW cost difference can range from 33-56%, dependent on future production levels.[41] To develop long-term cost assumptions for electrolyzer capital costs, CRA and NIPSCO conducted a literature review of historical and forecast electrolyzer CapEx estimates. Most data were pulled from a database published by Glenk et al. (2019),[42] which included only original sources of data found in journal articles, industry data, publicly available reports, and interviews with industry sources, and excluded literature that did not provide clear cost estimates or methodologies for producing cost estimates. CRA then developed a potential trajectory for electrolyzer capital costs that achieved long-term estimates recently published by the IEA,[43] BNEF,[44] and Bank of America-Merrill Lynch. The cost estimates for the PEM electrolyzer technology are summarized in Figure 4-18.[45]

[41] Ahmad Mayyas et. al, "Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolyzers" *National Renewable Energy Laboratory* 2019. https://www.nrel.gov/docs/fy19osti/72740.pdf
[42] Gunther Glenk and Stefan Reichelstein. "Economics of converting renewable power to hydrogen." In: Nature Energy 4.3 (2019), pp.216-222.
[43] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen
[44] BNEF. Hydrogen: The Economics of Production from Renewables. 2019.
[45] PEM systems are capable of operating at high pressures, obviating the need for compression.

Figure 4-18 Extrapolated Electrolyzer CapEx Trajectory



As the figure shows, PEM electrolyzer CapEx costs have declined significantly over the last decade. Over the next several decades, cost improvements may be driven by economies of scale of individual electrolyzers, technology advancements, and growth and competition in global electrolyzer manufacturing to achieve capital costs in the $175-200/kW range.

Electrolyzer Fixed O&M

Based on industry research, electrolyzer fixed O&M costs have been typically assumed at 1.5% to 3% of the original electrolyzer CapEx. Electrolyzer fixed O&M was assumed to be 2% of the original capex for NIPSCO's 2021 IRP analysis.

Variable Cost of Water

Based on industry research, NIPSCO assumed variable water costs at $0.08/kg of hydrogen in 2020$.

Electrolyzer Conversion Efficiency

A 100% efficient electrolyzer would be able to produce 0.03 kg hydrogen per kWh. This "ideal" efficiency is scaled down by a conversion efficiency parameter, which varies by

electrolyzer type. For this analysis, conversion efficiencies were based on IEA estimates for modest improvements over time from 60% in 2020 to 74% in 2050 for a PEM electrolyzer.[46]

Storage

The small size and density of hydrogen result in challenges associated with storing the fuel when compared to natural gas. In the gaseous state, hydrogen can be stored in pressurized containers in small volumes.[47] Geological formations such as rock caverns, depleted gas fields, and salt caverns have also been utilized in the United States to store gaseous hydrogen.[48] NIPSCO's service territory has multiple gas storage sites that could be utilized for gaseous hydrogen storage.[49] However, the use of these fields for gaseous hydrogen storage would need to be assessed on a case-by-case basis due to the varying nature of such geological formations.

Liquid hydrogen is another option for hydrogen storage. However, the cost of liquification is often more expensive than the cost of hydrogen itself, ranging from $2.75 to $4.57/kg.[50,51] Conversion and storage of hydrogen as ammonia is also feasible, but currently only makes sense if the ultimate end-product is ammonia.[52]

Given the variable nature of storage prices based upon volume, geological availability, and different sector demands, and the potential for hydrogen storage costs to be covered by existing infrastructure within NIPSCO's service territory, storage pricing has been omitted from the IRP cost estimates.

Variable Cost of Electricity

As explained previously, green hydrogen production requires a source of renewable electricity to power the electrolysis process. The cost of electricity is likely to be the most significant driver of hydrogen production costs, but can be minimized by co-locating renewables with hydrogen production facilities, by using renewable energy that might otherwise be curtailed, and by using an optimal mix of solar, wind, storage, and/or market purchases and sales to achieve higher electrolyzer utilization and achieve the best possible economics for the system.

NIPSCO focused on market power prices, renewable capital cost trajectories, and expected federal tax credits developed for the EWD and AER scenarios (*See* Section 8), which are the two most likely scenarios that might enable economic hydrogen dispatch. For renewable and storage technology CapEx estimates, NIPSCO used capital cost data from NIPSCO's recent RFPs in the near term and data from the NREL Annual Technology Baseline 2020 over the long term, with adjustments for expected technology advancements and federal tax credits that aligned with the

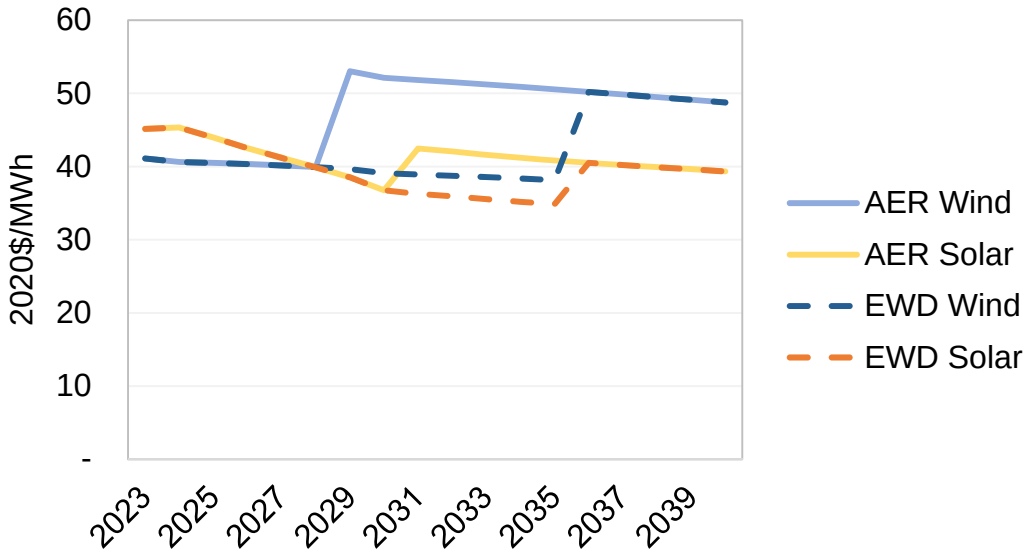
[46] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen
[47] BNEF. Hydrogen Economy Outlook. 2020.
[48] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen
[49] "PDMS Oil and Gas Map." Indiana Geological Survery. Indiana University Bloomington. Accessed August 31, 2021. https://igws.indiana.edu/PDMS/Map/.
[50] Elizabeth Connelly et. al. "Current Status of Hydrogen Liquefaction Costs" *U.S. Department of Energy* 2019.
[51] BNEF. Hydrogen Economy Outlook. 2020.
[52] IEA. The Future of Hydrogen. 2019. https://www.iea.org/reports/the-future-of-hydrogen

IRP scenario narratives (*See* Section 8). For wholesale market power prices, NIPSCO used the EWD and AER scenario power price trajectories developed for the 2021 IRP scenario analysis.[53]

To develop long-term cost of electricity assumptions, NIPSCO determined the LCOE of various configurations of renewable generation, including standalone solar; standalone wind; market electricity purchases; and optimized hybrid combinations of solar, wind, 4-hour battery storage, and market purchases and/or sales.

For the standalone renewable configurations, NIPSCO determined the LCOE of the renewables including amortized capital and fixed operating costs and congestion cost estimates. These estimates are shown in Figure 4-19: S

Figure 4-19: Standalone Wind and Solar LCOE by IRP Scenario



In addition to standalone renewable LCOEs, NIPSCO also considered hybrid configurations to address the possibility that better economics and higher electrolyzer utilization targets could be achieved by combining the hourly production profiles of wind and solar, incorporating battery storage, and/or optimally purchasing electricity from the wholesale power market during the lowest-priced hours.[54] To analyze the economics of such a configuration, NIPSCO developed an optimization tool to determine the least-cost capacity mix of solar, wind, battery storage, and hourly market purchases and sales when assuming a fixed "target" electrolyzer

[53] Section 8 of this report summarizes NIPSCO's MISO market scenario assumptions and modeling outcomes. As noted in that section, new technologies such as hydrogen are likely needed to achieve deep decarbonization. However, the two scenarios have very different power price outcomes based on different assumptions regarding carbon emission regulation.

[54] Without hybrid configurations, devoted standalone solar or standalone wind resources would need to be significantly "overbuilt" above the size of the electrolyzer. Standalone wind would need to be overbuilt to approximately 3 times the size of the electrolyzer to achieve a utilization of 80 percent. The maximum achievable electrolyzer utilization with standalone solar is only 55 percent due to zero nighttime energy from solar plants, and would require overbuilding solar to at least 800 times the size of the electrolyzer. Hourly solar and wind capacity factor data for this analysis was based on data from NIPSCO's planned standalone solar and wind resources.

utilization of 80 percent. The optimization model took as inputs hourly solar and wind generation, hourly battery storage dispatch, capital and fixed costs of the renewables, and hourly wholesale market prices. The optimization model then aimed to minimize capital and fixed costs of the wind, solar, and battery components plus the costs of any market purchases while achieving at least an 80 percent electrolyzer utilization.[55]

Based on the optimization analysis, NIPSCO determined that the least-cost source of electricity to power the electrolyzer and achieve an 80 percent utilization in the EWD case was to purchase all power from the market during optimal hours. In the AER case, the least-cost source of electricity was a mix of optimal hourly market power purchases and solar generation.

For the resulting optimized hybrid renewable configurations, NIPSCO then determined a final hybrid LCOE that included the LCOE of the preferred renewable portfolio and any cost of purchasing wholesale power during optimal hours.

4.6.7.2 Developing Hydrogen Costs for the 2021 IRP

Several bidders in the 2021 RFP discussed the topic of hydrogen production and consumption in electric generating resources, and multiple bidders offered projects associated with either electrolysis-based hydrogen production (in the form of a small-scale pilot program) or enablement of natural gas turbines to burn the fuel. Such bidder interest confirmed the viability of the technology and prompted NIPSCO to develop hydrogen cost projections over time for use in the IRP portfolio modeling. In order to develop cost projections, NIPSCO (i) used bidder-provided information for near-term cost benchmarking associated with *both* hydrogen production and the additional costs required to enable the fuel to be consumed in natural gas turbines and (ii) developed long-term LCOH trajectories based on the information and inputs described above.

Levelized Cost of Hydrogen over Time

NIPSCO's LCOH projections were based on assumptions for the levelized cost of an electrolyzer, the variable costs associated with water, and the LCOE of renewables (potentially combined with optimal hourly net market purchases as discussed above). For IRP portfolio modeling purposes, the hydrogen cost was then included as the fuel component of the dispatch cost for a hydrogen-enabled gas plant, allowing the resource type to compete with other options, including as a fuel alternative (with different fuel and emissions costs) versus natural gas.

Given significant uncertainty regarding the future costs of electrolysis and electricity, support for hydrogen production in the form of a federal subsidy program might be required to achieve cost-competitiveness and achieve significant decarbonization, particularly in the AER and EWD market scenarios. Although at the time of the development of major input assumptions for this IRP no hydrogen subsidy legislation had passed the U.S. Congress, several proposals were under consideration, and NIPSCO has incorporated an assumed $0.50/kg subsidy sensitivity in the AER and EWD scenarios for IRP portfolio modeling.

[55] An alternative approach to the one described here could be to instead optimize the size of the electrolyzer to achieve a sufficiently high utilization to achieve the best possible economics.

NIPSCO's long-term LCOH trajectories, assuming significant continued improvements in electrolyzer capital costs and optimized electricity costs from a hybrid combination of renewable resources and market purchases, are shown in Figure 4-20 for the EWD case and Figure 4-21 for the AER Case. The graphics show costs with and without an assumed $0.50/kg subsidy, which could be in the form of a specific federal policy or other grant or outside investment.

Figure 4-20: Levelized Cost of Hydrogen (2020$/kg) (EWD)

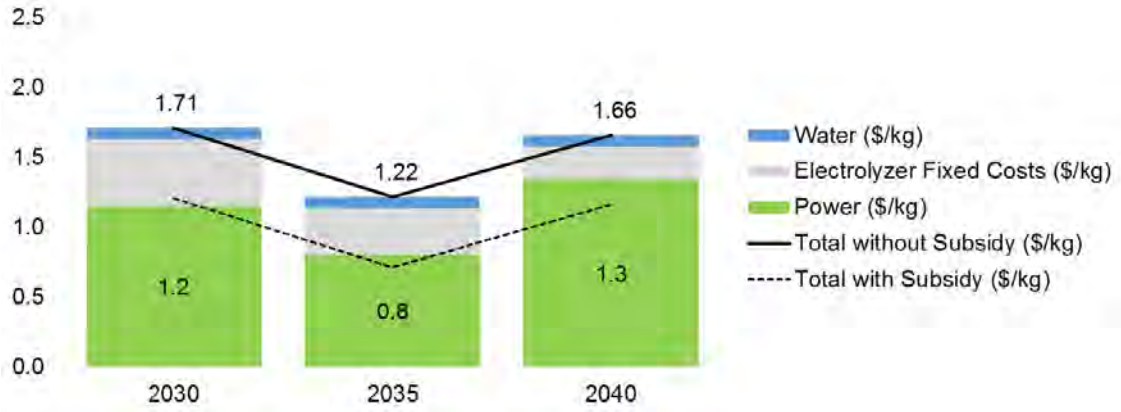
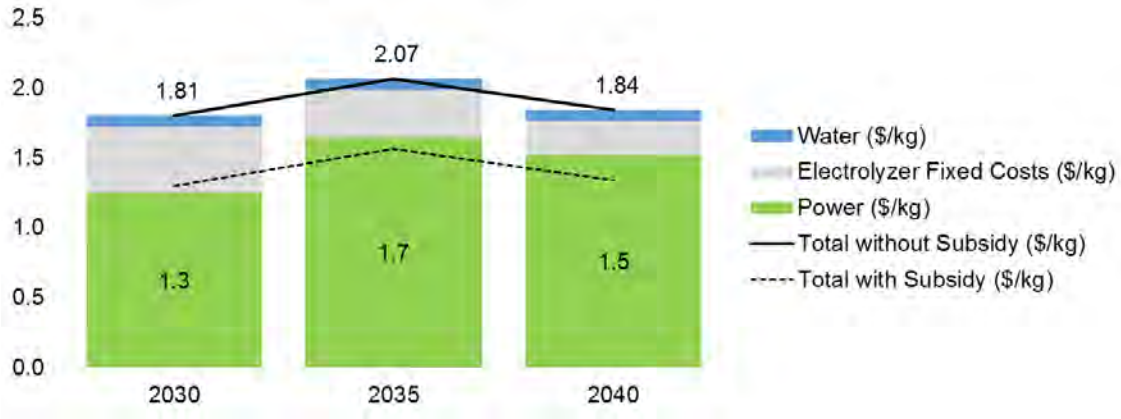


Figure 4-21: Levelized Cost of Hydrogen (2020$/kg) (AER)



As seen in these graphics, electricity costs are expected to make up the majority of long-term hydrogen production costs. EWD electricity costs were projected to be lower through 2035 due to the 10-year investment tax credit and production tax credit extension assumption (*See* Section 8), then to jump up by 2040 when the tax credits were assumed to phase out. AER electricity costs were projected to decline modestly from 2035 to 2040, as the optimized portfolio of renewables/storage was assumed to buy and sell in the MISO power market at times and take advantage of large price swings (selling at high prices and buying at low prices), while maintaining an 80% CF for the electrolyzer. Although the assumed electricity costs are based on fundamental forward scenario modeling, they are reasonably grounded in assumptions around market evolution

and technology advancements associated with decarbonizing futures and produce indicative hydrogen commodity prices for the long term.

A summary of the final near-term RFP and long-term hydrogen costs that were included in the IRP analysis are summarized in Figure 4-22.

Figure 4-22: Summary of Near-Term and Long-Term Hydrogen Costs for 2021 IRP

	Hydrogen P1 H2-Enabled Peaker		Hydrogen P2 + Sugar Creek	
	Near-term	Long-term	Near-term	Long-term
COD Year	2025 (5% H2-Enabled)	2032 (100% H2-Enabled)	2025 (5% H2-Enabled)	2032 (100% H2-Enabled)
Electrolyzer Fixed Costs (2020$/kg)	$1.78 (CRA Trajectory)	$0.47 (CRA Trajectory)	$2.30 (RFP)	$0.47 (CRA Trajectory)
Power (2020$/kg)	Grid Only (Low-Priced Hours)	Optimal Hybrid	Grid Only (Low-Priced Hours)	Optimal Hybrid
Water (2020$/kg)	$0.08			
Possible Subsidy (2020$/kg)	-$0.50			
Additional Portfolio Costs	-	Plant Retrofit Cost (30% CT Capital and FOM)	-	Plant Retrofit Cost (30% of CC Capital and FOM)

Hydrogen Blending in Gas Turbines

To consume hydrogen fuel in natural gas turbines, certain modifications need to be made to the turbines themselves, as well as other infrastructure such as pipelines and emission controls. Multiple bidders to NIPSCO's 2021 RFP either outlined such modifications or proposed specific costs to allow small amounts of hydrogen to be burned in generating facilities. The magnitude of the cost impact is dependent on the amount of hydrogen being consumed in the facility relative to the amount of natural gas (i.e. the blending percentage). While only relatively low hydrogen blends (5-20%) have been used in gas turbine technologies today, a plant can be upgraded to accommodate higher hydrogen blend concentrations as emissions restrictions become more stringent and/or as the hydrogen industry expands. Key operational considerations include:

- Combustor configuration
- Safety and flammability controls
- NO_x controls
- Pipeline upgrades
- On-site hydrogen storage
- Maintenance changes

For purposes of the IRP modeling, NIPSCO used bidder data to develop near-term cost impacts for hydrogen blending at low levels (5%) and public sources and manufacturer data to project the costs required to achieve very high levels of blending (including up to 100% hydrogen consumption) over the long-term. Based on bidder data, a CCGT or combustion turbine CT dispatching on a blend of 5% hydrogen are estimated to have between a zero and 10 percent cost premium for capital and fixed operating costs over a fully natural gas-fired combustion turbine.[56] In the longer-term, thermal plants retrofitted to accommodate pure (100%) hydrogen were assumed to require an additional 30 percent of the original plant capex and operating costs.

Value Stacking Hydrogen Electrolysis

Beyond the value of producing hydrogen fuel for use in thermal generating resources, the use of electrolyzer load as a potential ancillary service in the real time markets is an avenue of research that is currently being explored. Currently, electrolyzers as a grid management tool have been proven on a kW scale to have response times similar to battery systems.[57] While feasibility will still need to be tested on a MW-scale, there may be potential for a fleet of electrolyzers to serve as ancillary load in real time to be ramped up and down in order to provide regulation service and maintain grid frequency.

4.6.7.3 Long-Term Uncertainties with Hydrogen

As an emerging technology, NIPSCO recognizes that the landscape for hydrogen use in the power sector is subject to significant change over the long-term, particularly associated with technology change, federal policy initiatives, and investment in the sector from developers and public authorities. NIPSCO is committed to maintaining flexibility in its future resource decisions and expects to continue tracking the following uncertainties associated with hydrogen deployment:

- Technology advancement associated with electrolyzer capital and operating costs;
- Federal incentives that may develop, including direct subsidies or hydrogen production tax credits that vary based on the source of the electricity used in production;
- Developments in hydrogen transmission, distribution, and storage infrastructure and how they interact with current natural gas infrastructure;
- MISO market dynamics, including the potential for hydrogen production opportunities to develop due to renewable curtailment risk (which could otherwise be diverted to hydrogen production) or local congestion that drives electricity prices very low near certain renewable projects;

[56] While certain RFP bidders indicated that no modifications to existing generating resources would be required to burn low hydrogen percentage blends, others suggested a small cost would be required to address certain on-site infrastructure requirements.
[57] J. Eichman et. al. "Novel Electrolyzer Applications: Providing More Than Just Hydrogen" *NREL* 2014

- Broader carbon emission reduction policies, which could put a price on carbon or incentivize the use of clean energy sources such as hydrogen; and

- The price of natural gas, which remains a competing fuel for hydrogen.

4.6.8 Carbon Capture, Utilization, and Storage

Another emerging technology that may be positioned to support the decarbonization of the electricity sector is CCUS. Broadly, this technology refers to processes that (i) capture and separate CO2 directly from a fossil fuel (such as from coal in an IGCC process) or the flue gas of an electric power plant post-combustion or other point-source emission stream of CO2; (ii) purify, compress, and transport the CO2; and (iii) utilize (such as in an EOR process) or sequester the CO2 underground in saline reservoirs or unused coal seams.

NIPSCO's RFP did not generate any bids related to CCUS, so specific portfolio modeling has not been performed for this technology. However, the MISO market scenario analysis incorporated CCUS technology as a plausible generation resource option under scenarios with significant carbon reduction trajectories (*See* Section 8), and it remains a potentially feasible option for the Sugar Creek combined cycle over the long-term. As a result, NIPSCO plans to continue to assess CCUS technology in the future, particularly as a long-term means of achieving a net zero emission profile. The remainder of this section provides an overview of the technology, potential cost ranges, and federal policy support considerations.

4.6.8.1 CCUS Technology Overview

CCUS is an emissions reduction technology that can be applied to electricity generation processes, such as fossil fuel combustion or gasification. To minimize the costs of transportation and sequestration, a relatively pure stream of CO2 must first be separated from a mixture of gases, such as flue gas or synthetic gas or "syngas" (in the case of an IGCC process). There are multiple technologies available to capture CO2, although the most common application involves chemical absorption via ionic liquid solvent, such as compounds of ethanolamines.[58] In this example, CO2 would be absorbed by the solvent and regenerated as a relatively pure stream at a higher temperature. As a result, a heat source is required and may be provided from redirecting steam from electric generating turbines or by burning natural gas.

The CO2 is then compressed to a high-pressure stream and transported for sequestration. CO2 can be stored underground as a supercritical fluid at temperatures in excess of 88 degrees Fahrenheit and pressures in excess of 1,057 pounds per square inch.[59] The most suitable storage locations include saline formations and oil and gas reservoirs. Retrofitting a power plant for CO2 removal through chemical absorption may include, but not limited to, the installation of absorber-stripper columns, heat exchanger, compression and drying system, and piping.[60] The energy

58 IEA 2021, "About CCUS: Principal Technologies." https://www.iea.org/reports/about-ccus

59 This temperature and pressure define CO2's critical point. NETL Carbon Capture Storage FAQs. https://netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

60 National Energy Technology Laboratory 2013, *Cost and Performance of Retrofitting NGCC Units for Carbon Capture*. DOE/NETL-2018/1896. https://netl.doe.gov/projects/files/CostPerformanceRetrofittingNGCCforCarbonCapture_040119.pdf

penalty associated with the heat source and auxiliary loads (including energy to compress CO2) are typically quoted with CCUS technology parameters.

4.6.8.2 CCUS Cost Estimates

Since the 2021 RFP did not yield any CCUS projects, NIPSCO-specific portfolio analysis of the technology was not performed. However, in order to develop perspective on long-run CCUS costs to be used in the MISO market scenario analysis (*See* Section 8) and to approximate the potential cost and operational impacts of a CCUS retrofit to the existing Sugar Creek combined cycle, CRA and NIPSCO performed a review of third-party estimates. Overall, costs for CCUS projects fall within the following three categories:

- Capturing CO2 at the source of emission and compressing or liquifying it for transport[61];
- Transporting the CO2 via pipeline, ship, or truck, as appropriate; and
- Sequestering the CO2 underground, including costs associated with injection, monitoring, and verification.

To develop planning-level cost estimates for use in the MISO market modeling and to approximate cost ranges for NIPSCO, a range of sources were reviewed, including the EIA Annual AEO, the Global CCS Institute, the NETL, and the CATF.[62] From a high-level perspective, CRA's MISO market analysis suggests that under a scenario with high carbon prices or a significant clean energy standard that aims to achieve deep decarbonization, CCUS can be competitive with other technologies like hydrogen, or new nuclear in 2035 and beyond, depending on plant-specific cost and locational considerations, and transportation infrastructure.

Across scenarios, the economics tended to favor coal CCS in the AER scenario (high gas prices, high carbon price), with more gas CCS projects likely to be economic in the EWD scenario (with lower gas prices and a clean energy standard with accompanying clean energy credit prices).[63] The referenced studies and CRA's MISO market analysis suggest that CCUS is likely to be cost-effective at CO2 prices between $50-150/ton, depending on future costs of fuel, technology advancement, and transportation requirements.

[61] Capital expenditures are largely associated with an absorption tower, energy consumption requirements that are often represented through reductions in power output of the host facility, and compression costs.
[62] Specific sources include the 2021 AEO (https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf), the Global CCS Institute's *Global Costs of Carbon Capture and Storage* study (https://www.globalccsinstitute.com/archive/hub/publications/201688/global-ccs-cost-updatev4.pdf), NETL's *Economics of CCUS* presentation by Tim Fout from November 2020, and CATF's "Estimate of CO2 Capture Performance and Cost Parameters for Gulf Coast Power Fleet Modeling," (https://www.catf.us/wp-content/uploads/2018/12/Estimate_of_CO2_Capture_Performance_and_Cost_Parameters.pdf)
[63] See Section 8 of this report for more detail.

For NIPSCO in particular, the saline aquifer geological features around NIPSCO's natural gas-fired Sugar Creek combined cycle plant may be appropriate for CCUS siting,[64] so CRA and NIPSCO developed planning-level cost and operational estimates associated with a potential future conversion. These include new capital and operating costs that would be associated with a CCUS facility, as well as changes in net plant output and efficiency and are summarized in Figure 4-23. Right now, NIPSCO is aware of four natural gas combined cycle CCUS demonstration projects that are currently under study, with cost estimates expected towards the end of 2021 and into 2022.[65] As these engineering studies are completed and more information is developed, NIPSCO will likely refine the potential cost and operational implications of CCUS deployment at Sugar Creek in future IRPs.

Figure 4-23: Indicative Sugar Creek CCUS Costs and Operational Parameters

Characteristic	Units	Before Retrofit	After Retrofit	*See* Note
Net Capacity to Grid (Winter)	ICAP MW	545	473	1
Net Capacity to Grid (Summer)	ICAP MW	530	460	1
Heat Rate (Winter)	Btu/kWh	6,903	8,091	2
Heat Rate (Summer)	Btu/kWh	6,912	8,103	2
Incremental Installed CapEx	2021$/kW	0	976	3
VOM Costs	2021$/MWh	1.15	1.32	4
Incremental VOM Costs applied to post-retrofit capacity	2021$/MWh	0	1.22	3
Fixed Operations and Maintenance Costs	2021$/kW-yr	23.33	26.86	4
Incremental FOM applied to post-retrofit capacity	2021$/kW-yr	0	22.72	3
CO2 Emission Rate	lbs/MMBtu	118.86	13.7	4,5

Notes: 1: Assumes a 13.16% energy penalty / parasitic load being met by a portion of Sugar Creek to operate CCUS equipment.
2: Assumes a 17.22% heat rate penalty due to carbon capture; gas for compression, and other factors.
3: Based on Global CCS Institute, CATF, and NETL
4: Increased by a factor of 1.15 (i.e., 545 / 473 MW) after retrofit to account for grid MW being lower although capacity still used to power capture equipment.
5: Assumes 90% carbon capture

[64] See the DOE's *Carbon Storage Atlas:* https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf and Great Plains Institute's report titled, "Transport Infrastructure for Carbon Capture and Storage, Whitepaper on Regional Infrastructure for Midcentury Decarbonization. https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf. In addition, Wabash Valley Resources' proposed CCUS project is in close proximity. For more information, see: https://www.wvresc.com/

[65] These projects include Panda Sherman and Golden Spread Mustang in Texas, Mississippi Power's Daniel plant, and Alabama Power's Barry plant, as summarized in a Working Draft of the *2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation* technical discussion paper prepared for the Indiana Electric Association and other parties.

4.6.8.3 CCUS Policy Support Considerations

The U.S. tax code currently offers a performance-based tax credit for eligible carbon capture and sequestration projects that securely store CO2 in geological formations or use CO2 for enhanced oil recovery. These incentives, known as the 45Q credits, award between $35-50 per sequestered ton of CO2 and are available for 12 years after the project enters into service. As of the time of the production of this report, Congress is also considering additional policy support for CCUS projects that could include increases to the 45Q credit value, direct payment of subsidies, longer construction windows to preserve credit eligibility, and other grants or direct support for demonstration or transportation projects. NIPSCO will continue to track CCUS policy activity along with broader federal environmental policy initiatives as it evaluates long-term decarbonization options in future IRPs.

4.6.8.4 Long Duration Storage

Although a large majority of storage bidders in the RFP offered four-hour duration lithium-ion battery storage technologies, longer duration storage technologies may become more viable over the long-term in order to balance diurnal variations in renewable energy resources as well as variations in demand from weekends (low demand) to weekdays (high demand). The technology can also provide needed capacity during longer duration weather events, such as snowstorms, extended cloud cover, or wind droughts that could last for several days.

The value of long-duration storage is likely to increase as intermittent renewable generation increases within the MISO footprint. In addition to energy arbitrage, some long-duration technologies may also be able to effectively offer additional ancillary services value, such as spinning reserve and regulation to the portfolio (*See* Section 9 for more detail on NIPSCO's evaluation of ancillary services value in this IRP).

4.6.8.5 Long-Duration Storage in the RFP

While long-duration storage RFP bids were either non-competitive or unpriced (due to technology immaturity), multiple bidders offered information and perspectives on potential long-duration storage technologies. Technologies included:

- **Gravity storage**, where large objects are lifted to charge and released to discharge. Such solutions are generally scalable, highly efficient, and have few limits on cycle frequency of depth of discharge, providing certain advantages over lithium-ion technology. One bidder proposed a gravity storage solution to use locally sourced material for the storage system objects, such as coal combustion residuals or other items that might otherwise be landfilled.

- **Flow batteries**, which store energy in electrolyte reservoirs, transferring electrons back and forth between oxidation states causing charge and discharge. Electrolytes are dissolved in water and stored in two tanks connected by an iron selective membrane. These batteries can cycle frequently without degradation (contrary to lithium-ion), although their round-trip efficiency is usually lower.

- **Compressed or liquefied air**, where air or gas is compressed or liquefied during charging and expanded or evaporated during discharging. The component parts of these technologies are generally well understood, and it may be possible to use existing infrastructure, such as abandoned natural gas storage facilities, in a compressed air application. However, siting challenges may exist, and round-trip efficiencies are generally lower than other technologies.

Given the expectation that energy storage will be a part of NIPSCO's long-term portfolio (*See* Section 9 for more information on the key outcomes of the portfolio analysis), NIPSCO will continuously evaluate the landscape of storage options, as technology advances and market conditions evolve. Although four-hour lithium-ion battery storage may comprise early additions to the portfolio, longer-duration options are likely to be considered in more detail in future IRPs.

4.6.9 Small Modular Reactors

SMRs are a new generation of nuclear fission technology utilizing smaller reactor designs, modular factory fabrication, and passive safety features. SMR can potentially provide a zero-carbon alternative for providing base-load electricity without CO2 emissions, and its siting flexibility and improved safety features potentially allow the technology to be sited closer to demand centers, reducing transmission investments. Key features of an SMR include:

- Small physical footprints;
- Limited on-site preparation, leading to faster construction time and scalability;
- Siting flexibility including sites previously occupied by coal-fired plants; and
- Passive safety features, allowing the reactor to safely shutdown in an emergency without requiring human interventions.

SMR is still in the early stages of development, and NIPSCO did not receive any bids related to this technology in the RFP, even in an unpriced informational fashion, as it did with other emerging technologies. In addition, there remain uncertainties regarding the cost, performance, and availability of the technology. As a result, NIPSCO has not evaluated SMR technology as a realistic resource option associated with the implementation of its preferred portfolio over the next several years. However, as the technology evolves and as potential demonstration projects are pursued in the coming years, NIPSCO will continue to monitor progress on SMRs. Depending on technology evolution, future IRPs may assess the resource in more detail, particularly as a long-term option to achieve decarbonization objectives well into the 2030s.

Section 5. Demand-Side Resources

5.1 Existing Resources

5.1.1 Existing Energy Efficiency Resources

NIPSCO actively promotes energy conservation and efficiency to customers and works with its contractors to offer cost-effective energy efficiency programs. On September 1, 2021, the Commission issued a Final Order in Cause No. 45456 approving a Settlement Agreement among NIPSCO, the Indiana Utility Consumer Counselor, and the Citizens Action Coalition of Indiana, Inc. which included NIPSCO's proposed EE programs for the period of January 1, 2022 through December 31, 2023 (the "2022-2023 Plan"). To support the continuation of its program offerings for the period 2022 through 2023, NIPSCO recommended, and its OSB approved, TRC as the vendor to continue implementing both its residential and C&I programs. The OSB also agreed that ILLUME Advising would continue as the EM&V vendor for both program years.

2022-2023 Residential Programs

Home Rebates

The Home Rebates program is designed to provide incentives to residential customers to replace inefficient HVAC equipment with energy-efficient alternatives. These measures will be paid per-unit installed, reimbursing customers for a portion of their cost. The program's intent is to help remove the financial barrier associated with the initial cost of these energy-efficient alternatives. The program will promote premium efficiency air conditioners, air conditioner tune-ups, smart thermostats, ENERGY STAR® air purifiers, ENERGY STAR dehumidifiers, ENERGY STAR clothes dryers, ductless mini-split heat pumps, ENERGY STAR pool pumps, heat pumps and heat pump water heaters.

Lighting Products

The Lighting Products program is designed to increase the purchase and use of energy-efficient lighting products among NIPSCO's residential electric customers. The program provides instant discounts by using upstream wholesale incentives to buy down the incremental costs on lighting products that meet the energy efficiency standards set by the DOE's ENERGY STAR Program. ENERGY STAR specifications are an important external factor to certify the quality and efficiency of program measures. As the ENERGY STAR specifications change, program offerings are adjusted accordingly. These adjustments ensure that the program offers incentives for lighting products that meet the latest standards and highest quality of efficiency. General service lamps will not be included in this program. Other specialty, reflector and retrofit kits will be included in this program. As part of the Settlement Agreement approved in Cause No. 45456, if the EISA standards go into effect, adjustments will be made to the program through the EM&V process.

Home Energy Analysis

The Home Energy Analysis program is designed to help eligible customers improve the efficiency and comfort of their homes, as well as deliver an immediate reduction in electricity (kWh) consumption and promote additional efficiency work. This program will provide homeowners with the direct installation of low-cost, energy-efficient measures followed by the delivery of a Comprehensive Home Assessment report to the customer. This program is unique in that it provides a whole home assessment leading to easy to achieve kWh savings opportunities.

Appliance Recycling

The Appliance Recycling program is designed to provide an incentive to residential customers who choose to recycle a qualifying primary or secondary working refrigerator and/or freezer, room air conditioner and dehumidifier. TRC will utilize a qualified subcontractor for the implementation of this program.

School Education

The School Education program is designed to produce electric savings by influencing fifth grade students and their families to focus on the efficient use of electricity. It will provide classroom instruction, posters, and activities aligned with national and state learning standards and energy education kits filled with energy-saving products and advice. Students will participate in an energy education presentation at school, learning about basic energy concepts through class lessons and activities. Students will also receive an energy education kit of quality, high-efficiency products and are instructed to install the energy-efficient products at home with their families as well as complete a worksheet. The experience at home will complete the learning cycle started at school.

Multi-Family Direct Install

The MFDI program is designed to provide a “one-stop shop” to multifamily building owners, managers, and tenants of multifamily units containing three or more residences receiving service from NIPSCO. With flexible and affordable options, the program will generate immediate energy savings and improvements in two distinct program phases. Phase I is a walkthrough assessment of each property, which is conducted to determine eligibility for direct installation services provided by the MFDI program, along with complementary incentive offers available through other NIPSCO programs. Property managers will be presented with an Energy Improvement Plan that prioritizes recommendations along with a proposal to provide the direct installation services outlined in Phase II. Phase II is an in-unit direct installation of energy-efficient devices at no-cost or low-cost to the tenant or landlord, such as LED light bulbs, low-flow showerheads, faucet aerators, pipe wrap, and programmable thermostats. Educational materials about home operation, maintenance, and behavior factors that may reduce energy consumption, will be provided to tenants in each living unit. TRC will utilize a qualified subcontractor for the implementation of this program.

Home Energy Report

The Home Energy Report program (also known as the Behavioral program) is designed to encourage energy savings through behavioral modification. The program will provide customers with home energy reports that contain personalized information about their energy use and provide ongoing recommendations to make their homes more efficient. Customers will be randomly chosen to participate in the program and may opt-out if they do not wish to participate. The reports engage customers and drive them to take action to bring their energy usage in line with similar homes and encourage participation in other complimentary residential programs. The program will empower customers to understand their energy usage better and uses competition through neighbor comparisons to influence customers to act on this knowledge, resulting in changed behavior.

Residential New Construction

The Residential New Construction program is designed to increase awareness and understanding by home builders of the benefits of energy-efficient building practices, with a focus on capturing energy efficiency opportunities during the design and construction of single family homes. This program is designed to produce long-term, cost-effective savings as a result of the training they have received to achieve the various Home Energy Rating System tiers, along with strategies for incorporating the Silver, Gold, and Platinum designations into their marketing efforts to attract home buyers.

HomeLife EE Calculator

The HomeLife EE Calculator program is designed to offer NIPSCO's residential customers an online "do-it-yourself" audit and an energy savings kit for carrying out this audit, at no cost to the customer. The audit tool will effectively: (1) identify low-cost/no-cost measures that a NIPSCO residential customer can easily implement to manage electric consumption; (2) allow eligible customers to request a free home energy kit; (3) educate customers about the variety of programs available to them through the residential energy efficiency portfolio; and (4) assist customers in finding qualified and experienced contractors through a network of trade allies.

Income Qualified Weatherization

The IQW program is designed to provide energy efficiency services to qualifying low-income households. For a household to be eligible to participate in the IQW program, the customer must be a NIPSCO residential customer with active service that receives Low-Income Home Energy Assistance, Temporary Assistance for Needy Families, Supplemental Security Income, or Supplemental Security Disability Income and has not received weatherization services in the past 10 years from the date of application. Qualifying participants receive the direct installation of no-cost EE measures and a Comprehensive Home Assessment to identify areas of the home where additional energy savings can be achieved to make the home more comfortable and reduce energy costs.

Residential Online Marketplace

The Residential Online Marketplace program provides an online store for NIPSCO electric customers to purchase and install EE measures with an instant incentive applied at the time of purchase. The Residential Online Marketplace ensures only NIPSCO customers are eligible to purchase and limits are set on the quantities purchased to ensure timely installation.

Table 5-1 shows the projected energy savings (MWh) by year for each of the Residential programs[66].

Table 5-1: 2022-2023 Projected Residential Energy Savings (MWh)

Residential Programs	2022	2023	2022-2023
Home Rebates	1,905	1,905	3,810
Lighting Products	11,500	11,500	23,000
Home Energy Analysis	384	384	768
Appliance Recycling	2,900	2,945	5,845
School Education	2,167	2,167	4,334
Multifamily Direct Install	1,502	1,502	3,004
Home Energy Report	23,120	23,444	46,564
Residential New Construction	886	886	1,772
Home Life EE Calculator	185	185	370
Income Qualified Weatherization	1,060	1,060	2,120
Residential Online Marketplace	630	909	1,539
Total Residential Programs	**46,239**	**46,887**	**93,126**

Table 5-2 shows the annual total program budget for each of the Residential programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.[67]

Table 5-2: 2022-2023 Residential Program Budget

Residential Programs	2022	2023	Total
Home Rebates	$ 698,494	$ 704,281	$ 1,402,775
Lighting Products	$ 2,941,831	$ 2,976,763	$ 5,918,594

[66] Table 5-1 represents incremental, gross savings at the meter from the plan approved by the Commission in Cause No. 45456. On a net basis, inclusive of measure life considerations, the annual, cumulative impacts modeled for IRP purposes are slightly different. In addition, at the time of the development of the DSM inputs for the IRP, slightly different adjustments were applied to the near-term DSM savings expectations, resulting in slightly different numbers used for IRP modeling purposes. However, given that these savings are part of the plan approved by the Commission, they were universally applied across all portfolios and do not impact comparisons across portfolio options.

[67] In its Final Order, the Commission approved that NIPSCO (with OSB approval) is authorized to increase any individual program funding by up to 20% of the total program budget, even if this exceeds the overall 2022-2023 DSM Plan budget approved by the Commission. These budgets do not reflect the potential adjustment.

Home Energy Analysis	$ 232,562	$ 233,729	$ 466,291
Appliance Recycling	$ 446,068	$ 461,920	$ 907,988
School Education	$ 1,012,988	$ 1,019,570	$ 2,032,558
MFDI	$ 648,845	$ 653,404	$ 1,302,249
Home Energy Report	$ 2,405,925	$ 2,510,799	$ 4,916,724
Residential New Construction	$ 261,262	$ 263,951	$ 525,213
HomeLife EE Calculator	$ 83,195	$ 83,757	$ 166,952
IQW	$ 872,791	$ 876,012	$ 1,748,803
Residential Online Marketplace	$ 115,475	$ 167,834	$ 283,309
Total Residential Programs	**$ 9,719,436**	**$ 9,952,020**	**$ 19,671,456**

2022-2023 C&I Programs

Prescriptive

The Prescriptive program is designed to provide incentives for a set list of energy efficient measures and will be paid based on per unit installed, reimbursing the customer for a portion of the cost. The Prescriptive program will offer incentives to NIPSCO's C&I customers that are making electric EE improvements in existing buildings.

Custom

The Custom program will be available to C&I customers for installing new energy-saving equipment. Custom incentives are designed for more complicated projects, RCx projects), or those that incorporate alternative technologies. Project pre-approval will be required for all Custom incentives to ensure that only cost-effective projects are approved. Qualifying measures will be required to have a Total Resource Cost test score greater than 1.0, have a simple payback greater than 12 months (less than 12 months for RCx measures), and not be included as an EE measures in the Prescriptive Program. RCx projects examine energy consuming systems for cost-effective savings opportunities. The RCx process identifies operational inefficiencies that can be removed or reduced to yield energy savings.

C&I New Construction

The C&I New Construction program is designed to encourage construction of energy efficient C&I facilities within the NIPSCO service territory. This program will offer financial incentives to encourage building owners, designers and architects to exceed standard building practices and achieve efficiency, above and beyond the 2010 Indiana Energy Conservation Code. The goal of the New Construction program is to produce newly constructed and expanded buildings that are efficient from the start. New construction projects that may be eligible for incentives under the New Construction program may include any of the following: (1) new building projects wherein no structure or site footprint presently exists; (2) addition to or expansion

of an existing building or site footprint; and (3) a total "gut" rehabilitation for a change of purpose requiring replacement of all electrical and mechanical systems/equipment.

Small Business Direct Install

The SBDI program is designed to facilitate participation in the NIPSCO business EE program of small C&I customers that do not possess the in-house expertise or capital budget to develop and implement an energy efficiency plan. The SBDI program will offer a variety of ways for small businesses, with billing demands not exceeding 200 kW, to improve the efficiency of their existing facilities. Measures will be paid out on a per unit basis, much the same way as the Prescriptive program, but with slightly higher incentive rates in an effort to encourage energy efficient investment from these smaller commercial customers. Incentive payments to the approved trade allies will occur following measure implementation and submission of all required paperwork. If additional incentives are available through other programs, customers will be directed to the appropriate application.

C&I Online Marketplace

The C&I Online Marketplace program will provide an online store for NIPSCO electric customers to purchase and install EE measures with instant incentive applied at the time of purchase. The C&I Online Marketplace program will ensure only NIPSCO customers are eligible to purchase and limits are set on the quantities purchased to ensure timely installation.

Smart Energy Engagement

The Smart Energy Engagement program will provide NIPSCO customers with a tailored self-service platform when they opt-in to the program. The Smart Energy Engagement platform will provide customers with the knowledge and insights to make meaningful and energy efficient choices in their facilities. Through personalized energy efficiency suggestions, the program will provide uplift to other C&I programs while providing behavioral savings based upon the changes made at the facility outside of other commercial and industrial programs.

Table 5-3 shows the projected energy savings (MWh) by year for each of the C&I programs.[68]

[68] Table 5-3 represents incremental, gross savings at the meter from the Final Order in Cause No. 45456. At the time of the IRP, slightly different adjustments were used for modeling but were universally applied.

Table 5-3: 2019-2021 Projected C&I Energy Savings (MWh)

C&I Programs	2022	2023	Total
Prescriptive	42,388	43,130	85,518
Custom	37,591	37,481	75,072
C&I New Construction	4,607	4,688	9,295
SBDI	2,764	2,813	5,577
C&I Online Marketplace	4,252	4,344	8,596
Smart Energy Engagement	544	1,305	1,849
Total C&I Programs	**92,146**	**93,761**	**185,907**

Table 5-4 shows the total annual program budget for each of the C&I programs. Program budget includes implementation costs, NIPSCO administration costs, NIPSCO marketing costs, and EM&V costs.

Table 5-4: 2022-2023 C&I Program Budget

C&I Programs	2022	2023	Total
Prescriptive	$ 6,300,411	$ 6,652,393	$ 12,952,804
Custom	$ 6,216,345	$ 6,478,063	$ 12,694,408
C&I New Construction	$ 743,239	$ 790,337	$ 1,533,576
SBDI	$ 378,354	$ 401,330	$ 779,684
C&I Online Marketplace	$ 555,857	$ 603,107	$ 1,158,964
Smart Energy Engagement	$ 21,652	$ 53,524	$ 75,176
Total C&I Programs	**$ 14,215,858**	**$ 14,978,754**	**$ 29,194,612**

Table 5-5shows the projected energy savings (MWh) by year for all Residential and C&I programs included in the 2022-2023 Plan.

Table 5-5: 2022-2023 Projected Combined Energy Savings (MWh)

	2022	2023	Total
Total Residential Programs	46,239	46,887	93,126
Total C&I Programs	92,146	93,761	185,907
Total 2022-2023 Plan	**138,385**	**140,648**	**279,033**

Table 5-6 shows the annual total program budget for all Residential and C&I programs included in the 2022-2023 Plan.

Table 5-6: 2022-2023 Combined Program Budget

	2022	2023	Total
Total Residential Programs	$9,719,436	$9,952,020	$19,671,456
Total C&I Programs	$14,215,858	$14,978,754	$29,194,612
Total 2022-2023 Plan Budget	**$23,935,294**	**$24,930,774**	**$48,866,068**

Table 5-7 shows the eligible customer classes and rate schedules for each of the Residential and C&I programs included in the 2022-2023 Plan.

Table 5-7: Eligible Customers

Program	Customer Class	Electric Rate Schedule
Home Rebates	Residential	811
Lighting Products	Residential	811
Home Energy Analysis	Residential	811
Appliance Recycling	Residential	811
School Education	Residential	811
MFDI	Residential	811
Home Energy Report	Residential	811
Residential New Construction	Residential	811
HomeLife EE Calculator	Residential	811
IQW	Residential	811
Residential Online Marketplace	Residential	811
Prescriptive	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
Custom	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
C&I New Construction	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
SBDI	C&I	820, 821, 822, or 823 who have not had a billing demand of 200 kW or greater in any month during

Program	Customer Class	Electric Rate Schedule
		the previous 12 months
C&I Online Marketplace	C&I	820, 821, 822, 823, 824, 825, 826, 831, 832, 833, 841, or 844
Smart Energy Engagement	C&I	820, 821, 822, or 823 who have not had a billing demand of 200 kW or greater in any month during the previous 12 months

5.1.2 Existing Demand Response Resources

5.1.2.1 Capacity Resources

On December 4, 2019, the Commission issued a Final Order in Cause No. 45159, NIPSCO's most recent rate case which revised its industrial service structure by removing Rider 775 and Rate 734 and added Rate 831. The new industrial service structure requires NIPSCO's largest industrial customers on Rate 831 to designate their firm service with the remainder of their service requirements being registered as a MISO LMR which is by definition curtailable. NIPSCO experienced an increase in registered LMRs as a result of this new industrial power service for large customers structure, unless those Rate 831 customers utilize other options within the rate to acquire capacity from the MISO annual Planning Resource Auction or through a bilateral agreement between NIPSCO and a third party entered on their behalf. In addition, the large industrial customers will continue to be eligible to participate in MISO's DR Resource program discussed below.

5.1.2.2 Energy-Only Resources

NIPSCO offers DRR1 and EDR through Riders 781 and 782, respectively. These Riders are available to a customer on Rates 823, 824, 825, 826, 831, 832, and 833 that has a sustainable ability to reduce energy requirements through indirect participation in the MISO wholesale energy market by managing electric usage as dispatched by MISO. Through these Riders, the Customer or Aggregator of Retail Customer curtails a portion of its electric load through participation with the Company acting as the Market Participant with MISO. These Riders are available to any load that is participating in the Company's other interruptible or curtailment Riders, unless MISO rules change and do not permit load used by the Company as a LMR to also participate as a DRR1 or EDR. Although the DRR1 and EDR offered under Riders 881 and 882, respectively, do not qualify as a Capacity Resource, they do offer a means for Customers to offer into the MISO market and

to be paid for the portion of their electric load curtailed. This provides economic benefit to the customers participating in these Riders and for other NIPSCO customers through an overall lower electric system demand, which can avoid purchased power or the need for higher cost generation resources to be committed through the MISO market. Currently, NIPSCO has one customer participating in Rider 881 as DRR1. No customers are participating in Rider 882 as EDR.

5.2 DSM MPS

5.2.1 DSM MPS – Purpose and Key Objectives

To support the IRP and DSM planning for NIPSCO, NIPSCO contracted with the GDS Team to conduct a DSM MPS (a copy of which is included in Appendix B). The DSM MPS provides an update of DSM program costs and savings for a 20-year time horizon (2024-2043).[69] The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities in order to develop estimates of technical, economic, and achievable potential. Separate estimates of energy efficiency and demand response potential were developed. The effort was highly collaborative, as the GDS Team worked closely with the NIPSCO OSB to produce reliable estimates of future savings potential, using the best available information and best practices for developing market potential savings estimates.

5.2.2 Impact of Opt-out Customers

The GDS Team reviewed the latest information available from NIPSCO related to energy efficiency program participation, measure and program savings data, results of NIPSCO's 2016 MPS, NIPSCO's electric load and customer forecasts, NIPSCO load research data, electric avoided costs, program evaluation reports, and NIPSCO's 2022-2023 Plan. NIPSCO requested that GDS prepare its base case DSM market potential assuming that C&I electric customers, who had opted out of NIPSCO's energy efficiency programs prior to January 1, 2017, would be excluded from the DSM MPS. In Indiana, commercial or industrial customers with a peak load greater than 1 MW are eligible to opt out of utility-based electric energy efficiency programs. In the NIPSCO service area, approximately 16% of commercial kWh sales have opted out of utility-based electric energy efficiency programs, while roughly 80% of industrial kWh sales have opted out.

5.2.3 Modeling Framework

The GDS Team used its energy efficiency and DR planning models to prepare the DSM MPS. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, savings of other fuels, and benefit/cost ratios over the planning horizon. These models are transparent and all formulas, model inputs and model outputs can be viewed by the model user.

[69] Near term (2022-2023) savings in the IRP are informed by NIPSCO's currently approved DSM Plan. Based on discussions with the NIPSCO OSB it was agreed that the DSM MPS would be used to inform the remaining years of the IRP.

5.2.4 Key Assumptions That Impact Energy Efficiency Potential

The GDS Team updated several input assumptions during the process of preparing the DSM MPS. The changes made for a few of these input assumptions are discussed below.

5.2.4.1 Updated NIPSCO Load Forecast, Avoided Cost Forecast and General Planning Assumptions

NIPSCO provided the GDS Team with its latest electric load forecast for 2020 through 2040. Following discussions with NIPSCO, CRA, and the NIPSCO OSB, it was agreed that the original NIPSCO forecast included implied assumptions about future EE based on historical DSM performance. GDS coordinated with NIPSCO to add these historical impacts back into the MPS forecast to avoid any potential over-counting of future energy efficiency potential in the NIPSCO service area.[70] The GDS Team then extended the NIPSCO load forecast through the year 2043. GDS used this new load forecast to calculate the percent of electric MWH sales and peak demand saved each year by DSM programs. NIPSCO's new load forecast projects that total MWH sales to ultimate customers will only increase 0.3% per year, on average, through the year 2048.

NIPSCO also provided GDS with updated planning assumptions for the general inflation rate, escalation rates for NIPSCO electric rates, the utility discount rate, line losses by class of service, and the planning reserve margin.[71] GDS used these assumptions to develop the 2021 MPS.

5.2.4.2 NIPSCO DSM Assumptions for Measure Costs, Savings, Useful Lives, and Market/Equipment Characteristics

GDS reviewed the assumptions for measure costs, savings, and useful lives included in prior NIPSCO DSM plans, as well as the 2019 DSM Savings, and updated these assumptions where appropriate. GDS utilized data specific to NIPSCO when it was available and current. GDS used the most recent NIPSCO evaluation report findings (as well as NIPSCO program planning documents), the 2015 Indiana TRM, the Illinois TRM, and the Michigan Energy Measures Database to inform a large portion of the data requirements. Evaluation report findings, NIPSCO program planning assumptions, and the Indiana TRM were leveraged to the extent feasible. Additional data sources were only used if these sources either did not address a certain measure or contained outdated information. Building energy simulation modeling results formed the basis for most heating and cooling end use measure savings, primarily in the residential sector. The NREL Energy Measures Database also served as a key data source in developing measure cost estimates.

[70] NIPSCO and the GDS Team also coordinated with CRA to confirm that the modified sales forecast used in the MPS closely aligned with the NIPSCO sales forecast used in the 2022 IRP, and that both made adjustments to remove any embedded assumptions about future DSM program impacts.

[71] NIPSCO provided the GDS Team with both average and peak line loss factors. The GDS Team used the peak LLFs to adjust savings at the meter to the generator-level. NIPSCO has not conducted a marginal versus average line loss study, but the use of the peak LLF for DSM impacts is used as a proxy for the marginal LLF. The peak residential line loss used in the analysis was 4.11%. The peak commercial and industrial LLF were 3.76% and 2.41% respectively.

Additional source documents included American Council for an Energy-Efficient Economy research reports, covering topics like emerging technologies.

In addition to measure assumption development, the GDS Team engaged in primary market research to collect updated equipment penetration, saturation, and efficiency characteristics, as well as customer willingness to participate in program offerings data, across select end-uses/technologies. GDS conducted a combination of online/mail surveys, as well as a limited amount of on-site follow up site visits, to conduct the research. The resulting data was used to develop updated estimates of baseline and efficient equipment saturation estimates in the market potential study and to develop expected long-term adoption rates for energy efficiency over the study horizon.

5.2.4.3 Federal Appliance and Equipment Efficiency Standards

The DOE develops and implements federal appliance and equipment standards to improve energy efficiency, saving consumers energy and money. This DOE program was initially authorized to develop, revise, and implement minimum energy efficiency standards by the federal Energy Policy and Conservation Act in 1975. Several subsequent legislative amendments have required regular updates to these standards and have expanded the list of products covered by the standards. The DOE is currently required to periodically review standards and test procedures for more than 60 products, representing about 90% of home energy use, 60% of commercial building energy use, and 30% of industrial energy use.

By law, the DOE is expected to review each national appliance standard every six years and publish either a proposed rule to update the standard or determine that no change to the existing standard is needed. As of March 2021, DOE has missed legal deadlines for twenty-eight product standards since 2016.[72] Given these delays in future standard updates, the initial start year of 2024 for this analysis, and that the analysis is not intended to predict how or when energy codes and standards will change over time, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.

The primary adjustment in this analysis impacts residential screw-based lighting. Although DOE did issue a final rule stating that the EISA backstop has not been triggered and adopted a narrow definition of general service lighting, based on discussion with NIPSCO program administrators and the NIPSCO OSB, the base case analysis for the 2021 MPS severely limited the future potential for residential lighting throughout the analysis timeframe. The base case assumes only a limited number of direct-install screw-based lighting opportunities for standard, specialty, and reflector bulbs over the analysis period.

Although not exhaustive, other key adjustments include:

[72] Missed Deadlines for Appliance Standards. Prepared by the Appliance Standards Awareness Project. Updated March 2021.

- The baseline efficiency for ASHP is anticipated to improve to 15 SEER/8.8 HSPF in 2023. As the new standards allow for a sell-through period, the baseline efficiency is assumed to be the new federal standard beginning in 2024.

- The baseline efficiency for split system central AC systems is anticipated to improve to 14 SEER in 2023. As the new standards allow for a sell-through period, the baseline efficiency is assumed to be the new federal standard, beginning in 2024.

- DOE established the first national standards for pool pumps in 2017, becoming effective in 2021. The new standards cut energy use for in-ground pool pumps by approximately 70% and can be met by switching from single-speed to variable-speed pool pumps.

- In 2019, the DOE made new standards effective for residential, portable and whole-home dehumidifiers. The new standards are based on a new metric, the integrated energy factor, and improve the test procedure to better reflect the actual energy consumption of dehumidifiers in the home. The new standards range from 1.30 L/kWh for small dehumidifiers up to 2.8 L/kWh for larger capacity dehumidifiers.

- In July 2019, the DOE made new standards effective for more efficient furnace fan/motors. The standards are expected to improve efficiency by approximately 45% over the current baselines. To date, many furnaces are equipped with standard induction motors, which operate at about 60-65% efficiency. The new standard creates a shift to electronically commutated motors.

- DOE established new standards for pre-rinse spray valves, setting maximum flow rates between 1.0 and 1.28 gallons per minute. The new standards took effect in early 2019 and were reflected in the analysis

5.2.5 Energy Efficiency Measures & Potential

5.2.5.1 Measures Considered

For the residential sector, there were 182 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-8 provides a summary of the types of measures included for each end use in the residential sector. The measure list was developed based on a review of current NIPSCO programs, the Indiana TRM, other regional TRMs, and industry documents related to emerging technologies. The residential measures were then further broken out to include permutations across housing type (single-family vs. multifamily) and income type (income-qualified vs. market rate).

Table 5-8: Types of Electric Energy Efficiency Measures included in the Residential Sector Analysis

End Use	Measure Types Included
Electronic Equipment	ENERGY STAR Desktop and Laptop Computers, Monitors, and Printer/Fax/Copier/Scanner ENERGY STAR Smart Power Strips and Smart Plugs ENERGY STAR Televisions
Appliances	ENERGY STAR and Smart Refrigerators ENERGY STAR Freezers ENERGY STAR Washing Machines ENERGY STAR and Smart Clothes Dryers Heat Pump Dryers ENERGY STAR Dehumidifier Refrigerator Pick-up and Recycling Freezer Pick-up and Recycling Refrigerator Replacement in Low Income Homes
Envelope	Building Insulation Improvements (Attic, Wall, Floor, Etc.) Air sealing (Weatherization) Radiant Barriers High Efficiency Windows and Smart Window Film Covering Cool Roofing
HVAC (Heating & Cooling) Equipment	High Efficiency Air Conditioning High Efficiency Air Source Heat Pump (ASHP) Ductless Minisplit Heat Pumps Geothermal Heat Pumps AC/ASHP Tune-Up HVAC Filter Whistle Heating & Cooling Duct Sealing and Repair High Efficiency Natural Gas Furnace High Efficiency Natural Gas Boiler Wi-Fi Smart Thermostat Smart Vents/Sensors
Lighting	Interior LED Bulbs and Fixtures Exterior LED Bulbs and Fixtures LED Nightlights Occupancy Sensors Smart Light Switch Exterior Lighting Controls
Pools	Pool Pump Controls High Efficiency Pool Pumps High Efficiency Pool Pump Heaters
Water Heating	Heat Pump Water Heater Smart Water Heater – Tank Controls and Sensors Faucet Aerators & Low Flow Showerheads Thermostatic Restriction Valve and Shower Timers Hot Water Pipe and Tank Insulation Solar Water Heating System
Other	Home Energy Reports and Other Types of Behavioral Programs Energy Efficiency Education Kits for Employees of NIPSCO's Customers High Efficiency Well Pump High Efficiency Hot Tub Dryer Vent Cleaning

End Use	Measure Types Included
	Refrigerator Coil Cleaning

For the C&I sector, there were 272 unique electric energy efficiency measures included in the energy efficiency potential analysis. Table 5-9 provides a summary of the types of measures included for each end use in the C&I sector. Measures are assumed to be included as part of NIPSCO's current portfolio of offerings, either under their current Prescriptive or Small Business Direct Install programs, or under the Custom program offering.

Table 5-9: Types of Electric Energy Efficiency Measures included in the C&I Sector Analysis

End Use	Measure Types Included
Cooking	Efficienct Steamers Efficient Griddles Efficient Fryers Efficient Overs Efficient Holding Cabinets
Envelope	Building Insulation Improvements High Efficiency Windows Reflective Film
HVAC Controls	Smart Thermostats Custom Energy Management System Installation/Optimization Occupancy Control System Retro-Commissioning
Lighting	Fixture Retrofits High Bay LED Equipment LED Bulbs and Fixtures Lighting Occupancy Sensors Custom Interior and Exterior Lighting Advanced Lighting Controls Lighting Power Density Reduction Retro-Commissioning
Office Equipment	POS Terminals Printer/Copier/Fax Machines Desktop and Laptop PCs and Monitors Computer Room Economizers Computer Room Hot Aisle Cold Aisle Configuration High Efficiency Computer Room Air Conditioning Units Efficient Servers Office Equipment / Plug Load Controls
Refrigeration	Strip Curtains and Auto Door Closers Efficient Refrigerators/Freezers/Ice Machines High Efficiency/Variable Speed Compressors Electronically Commutated Motors Cooler Motors Door Heater Controls Efficient Compressors and Controls Floating Head Pressure Controls

End Use	Measure Types Included
	Display Case Lighting and Controls Custom Refrigeration Retro–Commissioning
Space Cooling	Efficient Cooling Equipment Evaporative Pre-Cooler Economizer Air Source Heat Pump Geothermal Heat Pump Chiller/HVAC Maintenance Chilled Water Reset Room AC Custom HVAC/Chillers Retro-Commissioning
Ventilation	Variable Speed Drive Duct Repair and Sealing
Water Heating	Energy Star Dishwashers Energy Star Clotheswashers Heat Pump Water Heaters Faucet Aerator/Low Flow Nozzles Pre-Rinse Spray Valves Custom Water Heating
Other	Compressed Air – Engineered Nozzle Compressed Air Audit and Leak Repair Efficient Transformers Custom Motors and Drives Custom Process Whole Building Energy Monitoring Building Operator Certification Behavior Based Efficiency Retro-Commissioning
Industrial - Agriculture	Engine Block Heater Timer Energy Efficient/Energy Free Livestock Waterer High Volume Low Speed Fans High Efficiency Exhaust Fans Dairy Refrigeration Tune-up
Industrial – Machine Drive	High Efficiency Compressed Air Equipment and Controls Synchronous belt drives Motors – Efficient Rewind Motors and Drives Fan System Optimization Pumping System Optimization Energy Information Systems Advanced Lubricants Sensors & Controls Retro-Commissioning
Industrial – Process and Other	Strategic Energy Management High Efficiency Welders High Speed Turbo Blower for Wastewater Hybrid Injection Molding Fiber Laser Replacing CO2 laser High Efficiency Battery Charger Pellet Dryer Insulation

End Use	Measure Types Included
	Lab Fume Hood Ventilation Reduction and Control Industrial Air Curtain Process Compressor Optimization Process Controls / EMS

5.2.5.2 Achievable Electric Energy Efficiency Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial constraints, customer awareness and willingness-to-participate in programs, technical constraints, and other barriers that the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- MAP estimates achievable potential with NIPSCO paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- RAP estimates achievable potential with NIPSCO paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

Residential Sector Achievable Potential

Table 5-10 shows the cumulative annual achievable residential sector energy efficiency potential for the years 2024 to 2043 and estimates of the annual NIPSCO energy efficiency budgets for the residential sector.[73] Cumulative annual residential MWh savings represent 27% and 15% of residential sales in the maximum achievable and realistic achievable potential scenarios, respectively.

Table 5-10: Achievable Residential Sector Incremental Annual Energy Efficiency Potential and Annual Utility Budgets (Maximum and Realistic Achievable)

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2024	50,366	9.4	$17,245,434	45,035	8.5	$9,363,102
2025	85,608	18.5	$23,957,484	72,106	15.5	$11,020,579

[73] All achievable potential savings are gross and do not include any adjustments for expected free-ridership and/or spillover.

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2026	127,468	30.3	$32,227,373	101,220	23.2	$12,786,099
2027	176,830	45.1	$41,806,956	132,398	31.6	$14,626,688
2028	228,929	62.5	$52,211,328	161,081	40.4	$16,533,275
2029	285,999	82.4	$62,431,679	190,284	49.1	$18,396,048
2030	346,854	104.2	$71,793,701	220,.76	58.0	$20,275,471
2031	410,763	127.5	$80,060,363	250,886	67.3	$22,192,009
2032	479,875	151.4	$86,300,126	279,387	76.4	$23,871,191
2033	539,072	174.2	$90,583,304	305,906	85.3	$24,972,401
2034	592,381	195.9	$93,761,064	330,027	94.0	$26,369,185
2035	643,187	216.5	$95,859,792	353,525	102.6	$27,508,982
2036	690,687	235.7	$97,153,498	376,161	110.7	$28,521,946
2037	735,238	253.7	$97,863,520	398,479	118.6	$29,352,722
2038	776,413	70.1	$98,118,519	419,720	126.0	$30,061,955
2039	816,633	285.5	$101,632,810	440,993	132.8	$32,681,985
2040	853,399	299.6	$102,154,997	461,177	139.4	$33,312,211
2041	886,611	312.5	$102,238,857	480,345	145.6	$33,879,207
2042	916,354	323.9	$102,829,779	498,286	151.5	$34,619,673
2043	943,612	334.1	$103,112,316	515,223	157.0	$35,112,002

Table 5-11 below provides the UCT benefit/cost ratios for the period 2024 to 2043 for the residential sector maximum and achievable potential[74]. The overall UCT benefit/cost ratio for the residential portfolio of energy efficiency programs is 1.71 in the realistic achievable potential scenario. In the maximum achievable potential scenario, the overall UCT drops below 1.0 to 0.86.[75]

Table 5-11: Utility Cost Test Benefit/Cost Ratios for Residential Programs (2019 to 2048 Period)

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio

[74] NIPSCO utilized the UCT as the test for screening measures for inclusion.

[75] Economic screening for cost-effectiveness was performed assuming incentive levels consistent with historical levels. The GDS Team did not rescreen measure cost-effectiveness in the MAP scenario assuming 100% incentives. As a result, the MAP scenario includes measures that are not cost-effectiveness under the UCT at 100% incentives and the overall MAP UCT falls below a 1.0.

MAP	$841,694,153	$958,024,364	($116,330,211)	0.88
RAP	$470,746,985	$273,081,219	$197,665,766	1.72

C&I Achievable Electric Energy Efficiency Savings

Table 5-12 shows the cumulative annual achievable energy efficiency savings for the years 2024 – 2043 and estimates of the annual energy efficiency budgets. Cumulative annual savings by 2043 for the MAP and RAP scenarios represents 20% and 16% of C&I sales respectively.[76]

Table 5-12: Achievable C&I Sector Energy Efficiency Potential and Annual Budgets

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2024	88,301	16.5	$49,047,767	80,368	14.1	$13,133,235
2025	174,181	32.0	$48,535,990	155,758	27.0	$12,721,890
2026	259,712	47.0	$48,368,022	227,913	39.0	$12,355,219
2027	343,634	61.5	$48,376,420	296,288	50.2	$12,023,457
2028	425,512	75.5	$48,360,068	359,462	60.7	$11,721,374
2029	493,640	87.2	$47,927,154	408,819	68.6	$11,307,472
2030	564,392	99.5	$51,544,572	459,678	76.9	$12,245,644
2031	638,296	12.5	$54,621,761	513,537	85.8	$13,173,990
2032	708,997	124.9	$57,082,250	565,934	94.3	$14,058,857
2033	779,631	137.4	$58,939,912	619,913	103.2	$14,883,277
2034	838,585	148.1	$60,288,922	664,530	110.4	$15,632,102
2035	886,664	158.7	$61,151,215	701,379	116.1	$16,302,651
2036	914,019	161.9	$61,771,723	721,384	119.1	$16,887,147
2037	941,500	167.2	$62,216,028	743,405	122.5	$17,376,241
2038	965,836	171.9	$62,544,201	764,165	125.7	$17,793,928
2039	975,022	172.2	$62,722,386	773,346	125.9	$18,149,958
2040	986,901	172.9	$62,904,305	786,104	126.8	$18,431,551
2041	1,001,908	174.3	$63,090,045	802,193	128.4	$18,673,789
2042	1,014,321	175.3	$63,279,685	815,329	129.9	$18,891,199
2043	1,026,889	176.5	$63,473,307	828,760	131.5	$19,085,795

[76] C&I savings and sales exclude current opt-out customers. All achievable potential savings are gross and do not include any adjustments for expected free-ridership and/or spillover.

Table 5-13 shows the NPV of benefits, NPV of costs, net benefits, and the benefit-cost ratio for the C&I sector as a whole, under both the maximum and achievable potential scenarios.

Table 5-13: Benefit Cost Analysis Results – UCT

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$1,044,498,910	$647,750,938	$396,747,972	1.6
RAP	$821,153,048	$170,179,466	$650,973,582	4.8

5.2.6 DR Potential

Prior to NIPSCO's rate case in 2018, NIPSCO's demand response portfolio was comprised of load curtailment agreements from a small number of large industrial customers. NIPSCO was responsible for procuring capacity to meet the full peak loads of these customers, but also offered a substantial portion of these loads to MISO as LMRs to help satisfy capacity requirements. With the 2018 rate case, NIPSCO must now only procure enough resources for a portion of these customers' loads (known as "firm" loads, approximately 170 MW in total). However, NIPSCO can no longer claim the remaining "non-firm" portion of these customers' loads – nearly 700 MW – as demand response. See above for a description of Rate 831.

Thus, while NIPSCO now has a lower total load obligation than before the 2018 rate case, it also cannot claim any demand response from Rate 831 customers. The change to NIPSCO's demand response portfolio is important to keep in mind when making comparisons to NIPSCO's historical demand response offerings and prior potential studies. For the 2021 MPS and the 2022 IRP, the "non-firm" load associated with Rate 831 customers was neither included in the demand response potential assessment nor in NIPSCO's future capacity requirements.

In addition to the removal of Rate 831 interruptible loads from the NIPSCO DR portfolio, residential AC cycling via direct load control switches was suspended in 2015. NIPSCO does not currently have any other DR offerings. As a result, the DR portion of the MPS considered the following DR program types: residential smart (Wi-Fi enabled) thermostats, residential water heater DR, residential and small C&I dynamics rates[77], and medium and large C&I load curtailment.

Similar to the energy efficiency portion of the MPS, for the DR portion of the MPS cost-effectiveness is screened using the UCT and includes two achievable potential scenarios. For each demand response program, the maximum achievable potential represents aggressive assumptions around incentives and program design, which in turn drives higher participation. In the MAP

[77] Represented by an event-based critical peak pricing program. Enabling AMI is assumed to be in place by 2030, at which time demand response potential savings begin to accrue. AMI costs are not included in demand response program costs.

scenario, incentives are maximized so that the overall UCT is at or near a 1.0. The realistic achievable potential represents more "middle-ground" assumptions around program incentives and design. Thus, the RAP scenarios have lower total demand response potential, but are more cost-effective than the MAP scenarios. Each program is also assumed to have a ramp rate, reaching full program capacity after two or three years, which reflects time required to market to and enroll customers in each program.

The MAP and RAP demand response by program over the 2024-2043 Market Potential Study horizon are shown in Figure 5-1 and Figure 5-2 respectively.

Figure 5-1: Maximum Achievable DR Potential by Program

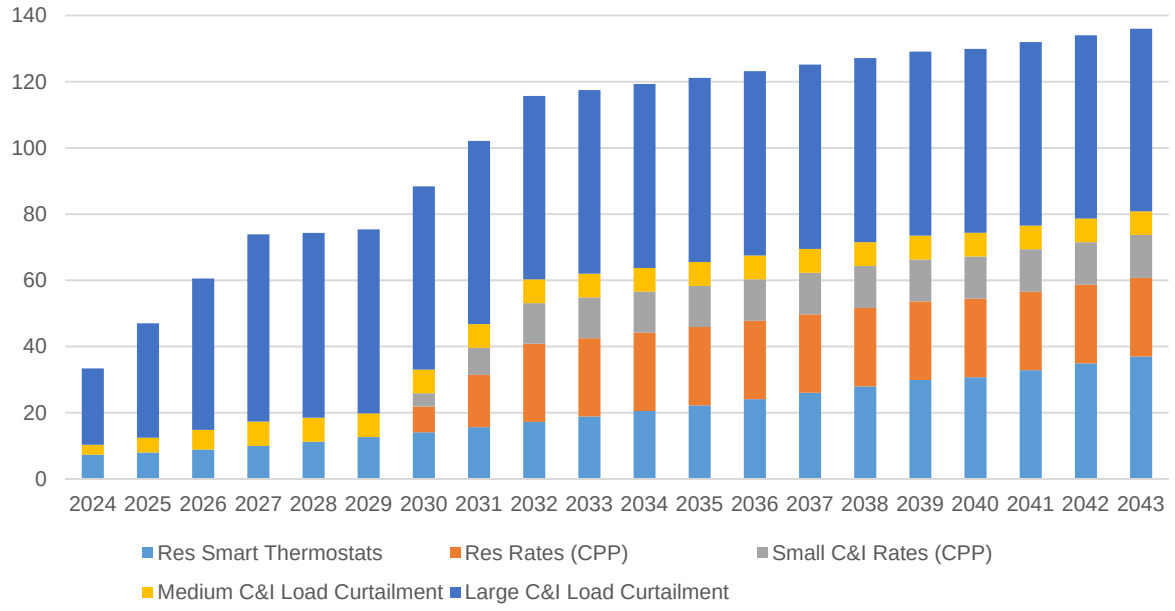
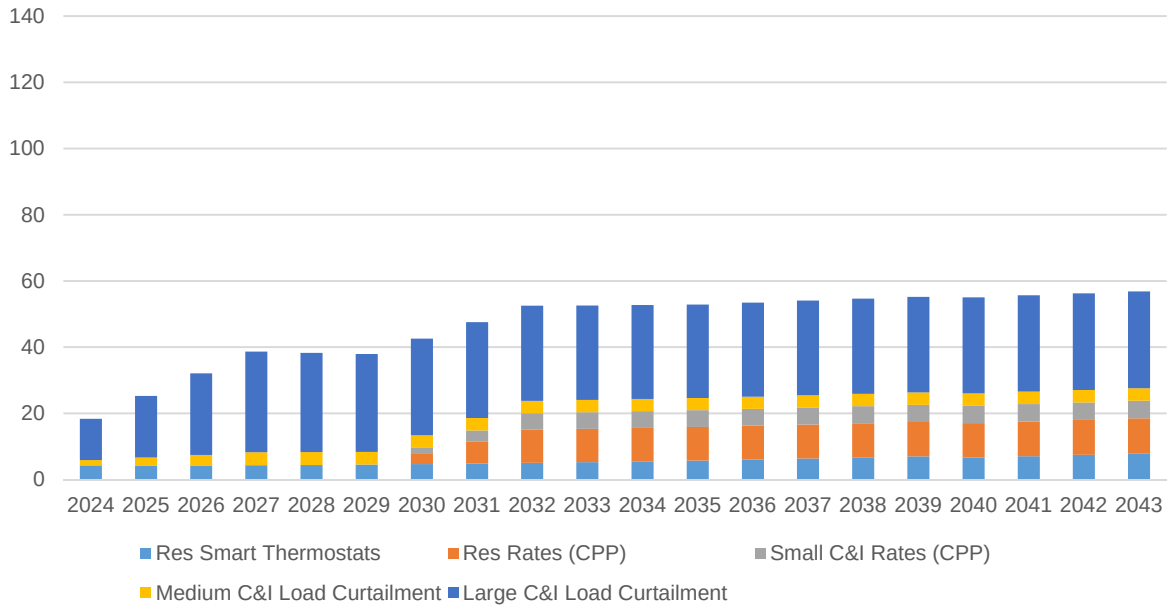


Figure 5-2: Realistic Achievable DR Potential by Program



5.3 Future Resource Options

5.3.1 Energy Efficiency Bundles

For the DSM base case of the IRP analysis, NIPSCO used the realistic achievable potential identified in the MPS as the starting point for developing energy efficiency bundles to be modeled in Aurora.[78] Based on coordination between NIPSCO and the NIPSCO OSB, the GDS Team initially provided energy efficiency inputs at the aggregate sector level in order to minimize the chances that the IRP would only select the lowest cost measures and limit NIPSCO's ability to offer broad programs. Following a review of these initial cost and savings inputs, the GDS Team further segmented the residential sector savings into high-cost measures (Tier 2) and low/mid cost measures (Tier 1). The GDS Team provided the energy efficiency IRP inputs across three different vintage bundles: 2024-2029, 2030-2035, and 2036-2041 to better optimize the value of energy efficiency to the system over different time periods.

In addition, four adjustments to the MPS's realistic achievable energy efficiency potential were necessary, prior to inclusion in the IRP. The first adjustment converted the energy efficiency potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of NIPSCO's programs. Net savings were calculated by applying NIPSCO's most current (2019) program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings.

[78] The realistic achievable potential was selected as the 'base case' for purposes of IRP modeling based on the overall cost-effectiveness relative to the maximum achievable potential. The maximum achievable potential was also provided to NIPSCO for additional scenario modeling. These inputs can be found in an appendix to this document.

The second adjustment aligned the level of income-qualified potential, identified in the realistic achievable potential, with levels achieved historically by NIPSCO. The MPS assumes NIPSCO pays near full cost for all possible income-qualified potential savings, regardless of cost-effectiveness. However, this produces an income-qualified budget that significantly outpaces historical spending for the income-qualified sector and would create cross-subsidization concerns across customer segments. As a result of aligning the income-qualified sector spending in the IRP with recent historical levels, income-qualified achievable savings were also scaled accordingly.

The third adjustment was to provide the achievable potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on the LLFs noted above, to convert savings from the meter level up to the generator level.

The fourth adjustment was to re-screen the cost-effectiveness of measures under an alternative cost of avoided generation. The MPS's avoided cost of generation was based on a CCGT unit. However, NIPSCO does not expect for that type of unit to be the marginal capacity addition for future capacity needs in the portfolio based on the 2018 IRP's key findings, a conclusion confirmed in this IRP's portfolio analysis.[79] As a result, the overall cost-effectiveness of measures was re-screened using a lower avoided cost of generation associated with a combustion turbine, or "peaking" unit.

Due to annual differences in the mix of energy efficiency measures included in the realistic achievable scenario and associated NTG ratios, as well as alignment of income-qualified savings with historical levels, the energy efficiency impacts modeled in the IRP ranged from 92% of the gross realistic achievable potential identified in the MPS in 2024 to 87% in 2041. The fourth adjustment, the alternative avoided cost of generation, had a negligible impact (0.1% reduction) on the modeled inputs.[80]

The energy efficiency impacts provided to NIPSCO for IRP modeling, by vintage block, are shown in Table 5-14 through Table 5-16 below.[81] The EE MWh and MW impacts for each vintage block provide the cumulative annual lifetime savings. Conversely, because EE program costs are only incurred during the year of measure installation, budgets are only reflected during the identified years in each vintage block.

In addition to the annual impacts shown in these tables, hourly (or 8,760) shapes that reflect the various measures and end-uses reflected in the achievable potential were provided to NIPSCO to permit the IRP model to assess the value of energy savings on an hourly basis. The 8,760 shapes are unique for each EE sector and vintage bundle.

[79] See Section 9 for more detail on NIPSCO's portfolio modeling process and results.

[80] The avoided cost of energy is the primary driver in overall cost-effectiveness for energy efficiency measures. The alternate avoided cost of generation had a more sizable influence on the demand response IRP inputs.

[81] MW represents the summer impact.

Table 5-14: 2024-2029 Energy Efficiency Base Case Bundles

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2024	42,020	6.8	$5,672,439	608	0.6	$766,210	780	0.3	$712,070	72,236	12.6	$10,061,654	115,644	20.3	$17,212,373
2025	64,645	11.7	$6,518,628	1,343	1.4	$963,319	1,597	0.5	$754,496	140,139	24.1	$9,837,750	207,723	37.8	$18,074,194
2026	88,707	17.0	$7,371,826	2,236	2.4	$1,185,332	2,406	0.8	$800,200	205,301	34.9	$9,661,507	298,650	55.0	$19,018,865
2027	114,128	22.6	$8,214,631	3,292	3.5	$1,426,181	3,275	1.0	$850,409	267,221	45.0	$9,525,882	387,917	72.1	$20,017,104
2028	136,284	28.1	$9,061,965	4,369	4.7	$1,678,014	4,210	1.3	$905,505	324,590	54.5	$9,423,873	469,453	88.6	$21,069,358
2029	158,502	33.7	$9,842,780	5,387	5.8	$1,932,244	5,211	1.6	$966,344	369,219	61.6	$9,233,829	538,318	102.7	$21,975,197
2030	107,022	27.6		4,843	5.2		5,080	1.6		350,417	58.9		467,363	93.3	
2031	98,966	26.5		4,286	4.6		4,967	1.6		333,787	56.9		442,005	89.6	
2032	88,666	25.0		3,642	3.9		4,936	1.5		312,003	54.2		409,246	84.6	
2033	77,105	23.3		2,917	3.1		4,674	1.5		291,283	51.4		375,980	79.3	
2034	71,350	22.3		2,511	2.3		4,323	1.4		262,510	46.8		340,693	72.8	
2035	65,378	21.2		2,485	2.2		3,945	1.4		238,977	42.5		310,785	67.4	
2036	58,601	20.0		2,460	2.2		3,537	1.3		202,094	36.0		266,692	59.5	
2037	51,577	18.7		2,434	2.2		3,097	1.2		167,155	29.9		224,262	52.0	
2038	45,685	17.2		2,409	2.2		2,616	1.2		136,257	24.5		186,967	45.0	
2039	36,884	14.8		2,377	2.2		2,339	1.1		96,404	16.5		138,005	34.6	
2040	31,194	12.7		2,342	2.1		2,208	1.0		76,862	12.3		112,606	28.2	
2041	25,119	10.4		2,301	2.1		2,074	1.0		62,075	9.0		91,568	22.5	
2042	19,186	8.1		2,255	2.1		1,917	0.9		48,474	6.1		71,832	17.2	
2043	12,863	5.7		2,200	2.1		1,754	0.8		37,030	3.6		53,846	12.1	
2044	6,784	3.5		2,099	2.0		1,585	0.8		22,918	1.0		33,386	7.2	
2045	5,535	2.6		2,032	1.9		1,537	0.7		17,431	0.7		26,534	5.9	
2046	4,477	1.6		1,950	1.8		1,487	0.7		12,108	0.5		20,021	4.6	
2047	3,269	0.5		1,853	1.6		1,434	0.7		6,987	0.3		13,542	3.1	
2048	2,896	0.5		1,741	1.5		1,407	0.7		3,593	0.2		9,637	2.8	
2049	2,292	0.4		1,464	1.2		1,202	0.6		253	0.0		5,211	2.1	
2050	1,900	0.3		1,271	1.0		1,006	0.5		240	0.0		4,418	1.8	
2051	1,442	0.2		1,032	0.8		790	0.4		225	0.0		3,490	1.5	
2052	1,047	0.2		743	0.6		552	0.3		206	0.0		2,549	1.1	
2053	569	0.1		399	0.3		289	0.1		186	0.0		1,443	0.6	
2054	0	0.0		0	0.0		0	0.0		140	0.0		140	0.0	
2055	0	0.0		0	0.0		0	0.0		117	0.0		117	0.0	
2056	0	0.0		0	0.0		0	0.0		91	0.0		91	0.0	
2057	0	0.0		0	0.0		0	0.0		63	0.0		63	0.0	

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2058	0	0.0		0	0.0		0	0.0		32	0.0		32	0.0	

Table 5-15: 2030-2035 Energy Efficiency Base Case Bundles

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2030	73,637	11.8	$10,645,345	1,626	1.6	$2,180,718	1,210	0.3	$1,033,695	64,790	10.2	$9,990,166	141,264	24.0	$23,849,925
2031	104,181	18.9	$11,497,378	3,309	3.3	$2,416,098	2,487	0.7	$1,108,192	130,178	20.1	$10,731,919	240,155	43.0	$25,753,588
2032	135,041	26.1	$12,211,052	5,103	5.1	$2,632,386	3,772	1.0	$1,190,305	199,379	30.6	$11,431,164	343,295	62.8	$27,464,907
2033	165,824	33.3	$12,483,614	6,987	7.0	$2,825,041	5,149	1.4	$1,280,730	268,994	41.3	$12,074,547	446,955	83.0	$28,663,932
2034	188,222	39.6	$13,104,763	8,553	8.9	$2,991,165	6,631	1.8	$1,380,296	338,157	52.4	$12,648,607	541,563	102.8	$30,124,832
2035	210,094	45.9	$13,585,116	9,731	10.0	$3,129,427	8,215	2.2	$1,488,355	395,206	61.8	$13,154,113	623,246	119.9	$31,357,011
2036	145,775	38.2		8,645	8.8		8,045	2.2		364,850	58.0		527,315	107.2	
2037	133,917	36.5		7,662	7.8		7,894	2.2		337,666	55.0		487,139	101.4	
2038	120,712	34.5		6,652	6.7		7,845	2.1		304,060	51.0		439,270	94.3	
2039	106,595	32.5		5,632	5.6		7,463	2.1		274,678	47.0		394,368	87.2	
2040	99,287	31.2		5,104	4.5		6,894	2.0		231,375	40.0		342,660	77.7	
2041	91,702	30.0		5,066	4.5		6,284	1.9		205,377	35.5		308,429	71.8	
2042	83,051	28.4		5,030	4.4		5,628	1.8		177,979	30.7		271,688	65.3	
2043	74,132	26.8		4,994	4.4		4,921	1.7		148,882	25.6		232,929	58.5	
2044	66,227	25.1		4,994	4.4		4,166	1.6		124,544	21.3		199,931	52.3	
2045	53,493	21.9		4,934	4.4		3,675	1.5		90,730	14.4		152,831	42.2	
2046	45,481	19.3		4,859	4.4		3,510	1.4		78,183	11.6		132,033	36.7	
2047	37,152	16.5		4,767	4.4		3,330	1.4		65,211	8.8		110,460	31.0	
2048	29,401	13.0		4,659	4.3		3,106	1.3		52,968	6.4		90,134	25.0	
2049	21,378	9.4		4,534	4.3		2,862	1.2		40,810	3.8		69,585	18.8	
2050	13,644	6.1		4,256	4.1		2,608	1.2		25,069	1.2		45,577	12.6	
2051	11,276	4.5		4,108	3.9		2,548	1.1		19,691	1.0		37,623	10.5	
2052	9,225	2.9		3,952	3.7		2,484	1.1		14,183	0.8		29,844	8.4	
2053	7,024	1.2		3,790	3.4		2,417	1.1		8,549	0.6		21,781	6.2	
2054	6,344	1.1		3,622	3.2		2,384	1.1		4,532	0.3		16,883	5.6	
2055	4,958	0.9		2,996	2.5		2,033	0.9		396	0.1		10,383	4.4	
2056	4,054	0.7		2,487	2.1		1,687	0.8		367	0.1		8,595	3.7	
2057	3,057	0.5		1,927	1.7		1,311	0.6		336	0.1		6,632	2.8	
2058	2,116	0.4		1,323	1.1		906	0.4		304	0.1		4,648	2.0	
2059	1,094	0.2		678	0.6		469	0.2		271	0.1		2,512	1.0	

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2060	0	0.0		0	0.0		0	0.0		203	0.1		203	0.1	
2061	0	0.0		0	0.0		0	0.0		166	0.0		166	0.0	
2062	0	0.0		0	0.0		0	0.0		127	0.0		127	0.0	
2063	0	0.0		0	0.0		0	0.0		86	0.0		86	0.0	
2064	0	0.0		0	0.0		0	0.0		44	0.0		44	0.0	

Table 5-16: 2036-2041 Energy Efficiency Base Case Bundles

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2036	86,182	13.8	$14,037,844	2,252	2.1	$3,241,120	1,865	0.5	$1,605,310	85,505	13.1	$13,586,204	175,804	29.5	$32,470,479
2037	119,901	21.6	$14,414,673	4,379	4.2	$3,320,083	3,824	1.0	$1,731,492	167,657	25.3	$13,935,305	295,761	52.0	$33,401,554
2038	152,893	29.3	$14,760,648	6,507	6.3	$3,369,455	5,800	1.5	$1,868,904	251,076	37.6	$14,224,827	416,276	74.6	$34,223,833
2039	189,011	37.4	$16,816,359	8,639	8.3	$3,405,708	7,907	2.0	$2,015,673	329,395	49.8	$14,462,555	534,952	97.5	$36,700,295
2040	214,485	44.3	$17,211,164	10,257	10.3	$3,430,339	10,151	2.6	$2,173,736	404,355	62.0	$14,637,419	639,248	119.2	$37,452,657
2041	239,990	51.1	$17,522,638	11,365	11.2	$3,442,526	12,524	3.2	$2,345,291	460,125	71.3	$14,779,493	724,003	136.9	$38,089,948
2042	172,854	43.1		10,143	10.0		12,302	3.1		422,317	66.7		617,616	122.9	
2043	160,371	41.3		9,087	8.9		12,108	3.1		389,312	63.0		570,878	116.3	
2044	146,955	39.6		8,080	7.8		12,105	3.1		349,898	58.5		517,037	108.9	
2045	132,747	37.7		7,072	6.7		11,640	3.0		317,153	54.2		468,612	101.6	
2046	123,841	36.4		6,580	5.6		10,767	2.9		265,562	45.6		406,750	90.5	
2047	114,784	35.1		6,580	5.6		9,825	2.8		233,322	39.9		364,511	83.5	
2048	104,518	33.5		6,579	5.6		8,812	2.7		200,059	34.0		319,969	75.8	
2049	94,088	31.8		6,579	5.6		7,721	2.5		166,046	28.1		274,435	68.1	
2050	84,783	29.9		6,579	5.6		6,512	2.3		138,177	23.0		236,051	60.8	
2051	70,447	26.3		6,423	5.6		5,653	2.2		99,698	15.3		182,222	49.5	
2052	62,046	23.4		6,255	5.6		5,377	2.1		85,253	12.4		158,930	43.5	
2053	53,596	20.5		6,076	5.6		5,078	2.0		70,707	9.5		135,457	37.5	
2054	41,744	15.9		5,889	5.5		4,719	1.9		57,348	6.9		109,700	30.3	
2055	29,763	11.3		5,696	5.5		4,332	1.8		44,312	4.4		84,104	22.9	
2056	17,946	7.1		5,324	5.2		3,949	1.7		27,224	1.6		54,443	15.6	
2057	14,826	5.2		5,148	5.0		3,868	1.7		21,249	1.3		45,090	13.2	
2058	12,174	3.4		4,972	4.7		3,770	1.6		15,237	1.0		36,154	10.7	
2059	9,482	1.6		4,796	4.4		3,679	1.6		9,190	0.7		27,146	8.3	
2060	8,627	1.5		4,620	4.2		3,633	1.6		4,845	0.4		21,725	7.6	
2061	6,604	1.2		3,739	3.3		3,082	1.3		458	0.1		13,883	5.9	

	Residential Tier 1			Residential Tier 2			IQW			C&I			Total		
	Cumulative			Cumulative			Cumulative								
Year	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget	MWh	MW	Budget
2062	5,253	0.9		3,012	2.7		2,544	1.1		422	0.1		11,231	4.8	
2063	3,866	0.7		2,272	2.0		1,969	0.9		386	0.1		8,493	3.6	
2064	2,596	0.5		1,522	1.3		1,353	0.6		351	0.1		5,822	2.5	
2065	1,305	0.2		764	0.7		695	0.3		316	0.1		3,081	1.3	
2066	0	0.0		0	0.0		0	0.0		237	0.1		237	0.1	
2067	0	0.0		0	0.0		0	0.0		191	0.1		191	0.1	
2068	0	0.0		0	0.0		0	0.0		144	0.0		144	0.0	
2069	0	0.0		0	0.0		0	0.0		96	0.0		96	0.0	
2070	0	0.0		0	0.0		0	0.0		48	0.0		48	0.0	

The DSM bundles were incorporated into the IRP as eligible resources in the portfolio optimization analysis and through additional portfolio evaluation discussed later in this report. The DSM bundling approach allows for a representation of potential program duration over time, with differentiation across customer type and costs. Figure 5-3 provides an illustration of the annual expected MWh savings for each energy efficiency bundle under RAP assumptions, along with a summary of the levelized costs. Figure 5-4 provides an illustration of the peak demand savings for each bundle. As shown, the expected savings during the summer peak period for the energy efficiency bundles are considerably greater than those during the winter.

Figure 5-3: Energy Efficiency MWh Savings Bundle Illustration - RAP

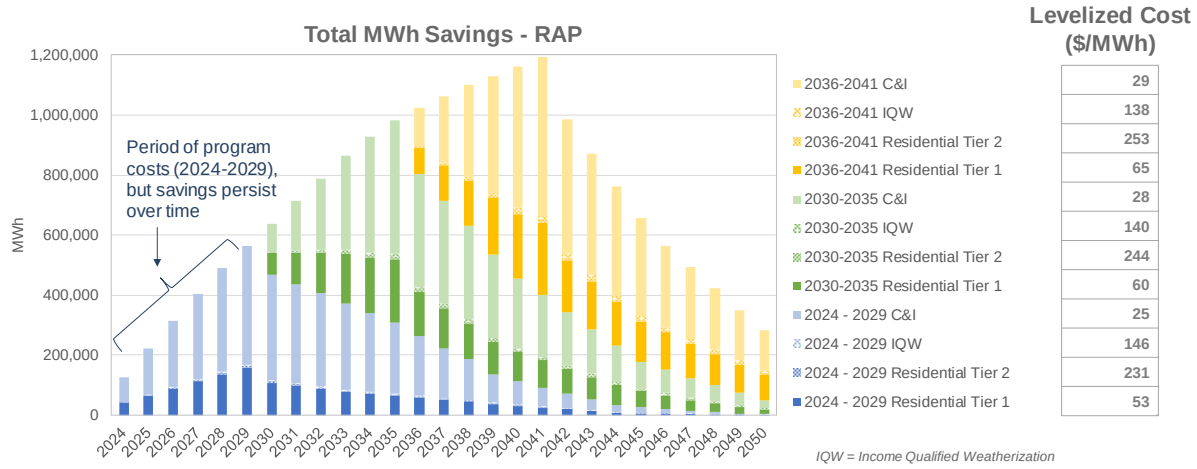
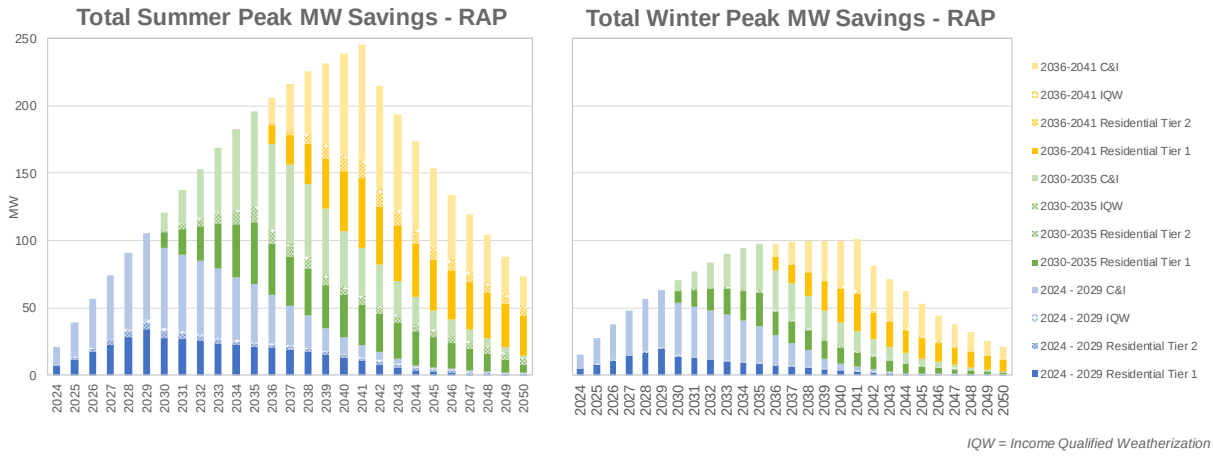


Figure 5-4: Energy Efficiency Peak MW Savings Bundle Illustration - RAP



5.3.2 DR Bundles

In IRP modeling, NIPSCO considered DR alongside other supply resources to supply capacity and energy needs. To facilitate this effort, the GDS Team provided NIPSCO with annual program potential and costs for the RAP and MAP scenarios for three program sub-segments. The first sub-segment was the Residential segment, which includes only the residential smart thermostat results, because the water heater direct load control program was not found to be cost effective in any scenario. The second sub-segment was the C&I segment, which consists of the Medium and Large C&I load curtailment programs. The third and final sub-segment was the Dynamic Rates sub-segment, which includes both the Residential and Small C&I critical peak pricing dynamic rates programs.

Consistent with the EE IRP inputs, the GDS Team rescreened the demand response program cost-effectiveness under an alternate avoided cost scenario, which assumed a lower cost for avoided generation than used in the MPS. This alternate case is meant to reflect the cost of a CT as the proxy unit, instead of a CCGT unit as in the base case. This change had no impact on residential water heater direct load control, residential rates, and small C&I rates. For the remaining programs (residential smart thermostats and Medium C&I Load Curtailment) the incentive levels, and therefore the enrollment rates, were reduced to ensure the programs remained cost-effective. The result is a reduction in the total demand response potential as well as overall program costs per kW of capacity. The alternative case MAP potential is 41 MW, compared to 57 MW in the base case used in the MPS. The alternate avoided cost MAP potential is 100 MW, compared to 136 MW in the MPS. This corresponds to a 26% and 28% reduction in potential for the RAP and MAP scenarios, respectively.

Table 5-17 provides the DR inputs used in the IRP modeling based on the RAP scenario.[82]

Table 5-17: DR Base Case Bundles

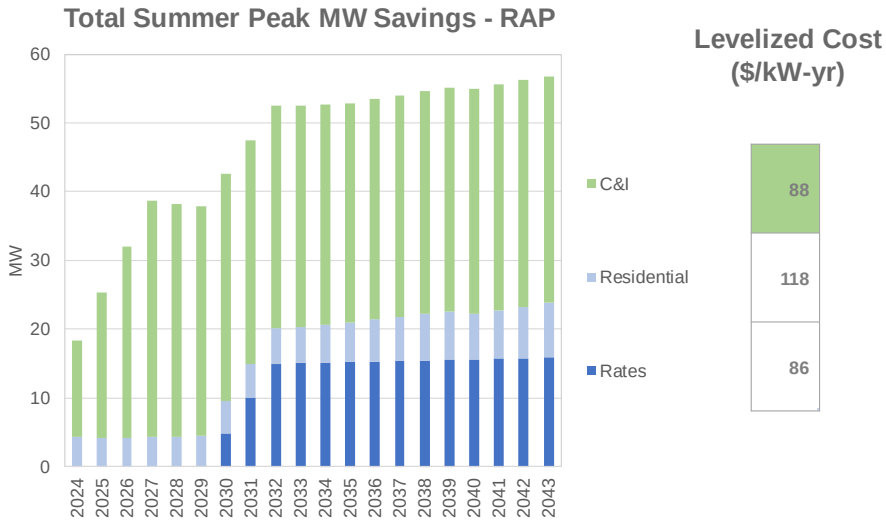
	Rate DR		Residential DR		C&I DR	
Year	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**
2024	0.00		2.15	$53.97	8.53	$84.12
2025	0.00		2.13	$39.24	12.89	$68.95
2026	0.00		2.13	$40.17	17.21	$61.96
2027	0.00		2.16	$40.91	21.48	$58.20
2028	0.00		2.21	$41.61	21.36	$59.70
2029	0.00		2.27	$42.27	21.25	$50.11
2030	4.90	$221.28	2.34	$42.91	21.17	$51.33
2031	10.00	$103.60	2.43	$43.56	21.14	$52.55
2032	15.00	$63.26	2.53	$44.19	21.16	$53.74
2033	15.08	$21.02	2.64	$44.81	21.19	$54.93
2034	15.16	$21.28	2.75	$45.41	21.22	$56.12
2035	15.24	$21.53	2.88	$46.00	21.24	$57.30

[82] The RAP was selected as the 'base case' for purposes of IRP modeling based on the overall cost-effectiveness relative to the MAP. The MAP was also provided to NIPSCO for additional scenario modeling. These inputs can be found in Appendix B to this document. As with the EE inputs, the costs have been adjusted to represent program costs less the avoided transmission and distribution benefit from the programs.

	Rate DR		Residential DR		C&I DR	
Year	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**	**MW**	**$/kW-yr**
2036	15.32	$21.79	3.03	$46.56	21.24	$58.50
2037	15.40	$22.03	3.19	$47.10	21.24	$59.70
2038	15.48	$22.27	3.35	$47.66	21.23	$60.91
2039	15.56	$22.52	3.51	$48.42	21.20	$62.12
2040	15.64	$22.77	3.32	$48.65	21.17	$63.34
2041	15.73	$23.00	3.53	$49.13	21.13	$64.56
2042	15.81	$23.23	3.75	$49.67	21.07	$65.79
2043	15.89	$23.46	3.96	$50.27	21.01	$67.03

DR bundles were similarly incorporated in to the IRP analysis under three total bundles for Dynamic Rates, Residential, and C&I customers. DR programs provide summer peak savings as summarized in Figure 5-5, but minimal winter peak and energy value to the portfolio.

Figure 5-5: DR Summer Peak MW Savings Bundle Illustration - RAP



5.4 Consistency between IRP and Energy Efficiency Plans

The DSM Statute, which became law on May 6, 2015, requires, among other things, that a utility's EE goals are (1) reasonably achievable; (2) consistent with the utility's IRP, and (3) designed to achieve an optimal balance of energy resources in the utility's service territory. A utility was required to petition the Commission for approval of an energy efficiency plan under the DSM Statute beginning not later than calendar year 2017, and not less than once every three years thereafter.

To remain consistent with the requirements of DSM Statute, NIPSCO carried out a lengthy analysis of the DSM resources included in its IRP process. As noted above, NIPSCO completed

a Market Potential Study in 2021 to determine the achievable amount of savings. *See* Appendix B. NIPSCO, through the MPS process discussed above, conducted an in-depth review of the amount of savings that would be achievable in its service territory with its current customer base. Following that in-depth review process and as outlined above, NIPSCO incorporated energy efficiency and demand response bundles into the model for selection as resources. NIPSCO allowed the EE and DR, broadly referred to as DSM resources, to be selected across all portfolio concepts that were evaluated in the Existing Fleet and Replacement analysis phases (*See* Section 9).

In accordance with the DSM Statute, NIPSCO intends to request approval in 2022 of an EE plan for implementation in 2024 that includes:

- EE goals that are: (1) reasonably achievable; (2) consistent with NIPSCO's 2021 IRP; and (3) designed to achieve an optimal balance of energy resources in its service territory;
- EE programs that are: (1) sponsored by an electricity supplier; and (2) designed to implement EE improvements;
- program budgets;
- program costs that include: (1) direct and indirect costs of energy efficiency programs; (2) costs associated with the EM&V of program results; (3) recovery of lost revenues and performance incentives;[83] and
- EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Action Plan prior to its filing in 2022 based on the EE selected by the IRP model. This may be updated if another MPS has been completed. The DSM Action Plan will take into account the results of the IRP for implementation and evaluation of the EE plan.

The benefit of a DSM Action Plan is that it uses various forms of information, including the IRP, to develop the best strategy for an energy efficiency plan. The DSM Action Plan will then be used to develop the DSM RFPs. The results of the winning bids will be utilized to develop the filing, with support from the MPS, IRP and DSM Action Plan. This is the most effective way to ensure NIPSCO has an EE plan that is based on real-world, achievable results from vendors who are committed to those results. Bidders' responses to the savings identified in NIPSCO's DSM RFP will vary based on the individual bidder's perception of NIPSCO's customer base and their previous experiences within other service territories, etc. This unique process for development of the DSM RFPs and creation of the EE plan allows NIPSCO to compensate for the

[83] For purposes of this filing, the "direct costs" are those associated with implementing the programs, including any costs associated with program start up, while "indirect costs" are the NIPSCO administrative costs;

long lead time between the completion of a market potential study and the actual implementation of a program.

It is important to note that the final program design is determined by the bidder(s) selected by NIPSCO, with consideration of input from its OSB. The selected bidder's(s') predictions of the market into the program design as they determine what may or may not work in the NIPSCO's service territory is important for designing an EE program. That means that the programs included in the MPS typically change. NIPSCO uses the MPS as a feed into the IRP to develop the Action Plan. This Action Plan allows NIPSCO to take into account not just the results of the IRP, but also the experience of NIPSCO and its vendors with a particular program or measure. For example, electric hot water heating has a great deal of potential, but NIPSCO has not found there to be much interest from customers in the program. Knowing this means that NIPSCO will either (a) not structure a large amount of savings around a measure which has historically shown little participation or (b) need to increase the incentive to increase participation, which may impact the cost effectiveness of the program.

That does not mean that the EE plan will be without change. Until the programs are administered to the customer base and the first-hand experiences with energy efficiency occur, informed judgments must be used to establish the initial estimates of program impacts in NIPSCO's service territory. That is the benefit of utilizing an OSB. It provides an on-going mechanism to adjust to changing market conditions, including codes and standards and new technologies, and to ensure NIPSCO is capturing as much energy efficiency savings as possible for the amount of funding available.

Section 6. Transmission and Distribution System

Consistent with the principles set out in Section 1, NIPSCO continues to invest in its existing T&D resources to ensure reliable, compliant, flexible, diverse and affordable service to its customers. NIPSCO continually assesses the current physical T&D system resources for necessary improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at the state, regional, and federal levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. The goals of the planning process include:

- Adequately serve native customer load and maintain continuity of service to customers under various system contingencies.
- Proactively maintain and increase availability and reliability of the electric delivery system.
- Manage costs while being consistent with the above guidelines

6.1 Transmission System Planning

6.1.1 Transmission System Planning Criteria and Guidelines

NIPSCO Transmission System Planning Criteria requires performance analysis of the transmission system for the outage of various system components including but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy of transmission system performance is measured in terms of NIPSCO planning voltage criteria, facility thermal ratings, fault interrupting capability, voltage stability, and generator rotor angle stability as documented in the NIPSCO 2021 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (Confidential Appendix C). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

6.1.2 North American Electric Reliability Corporation

NIPSCO is subject to the NERC, which is certified by the FERC to establish and enforce reliability standards for the bulk-electric system and whose mission is to ensure the reliability of the North American bulk electric system. NIPSCO is registered with NERC as a Balancing Authority, Distribution Provider, Generator Owner, Generator Operator, Resource Planner, Transmission Owner, Transmission Operator, and Transmission Planner. Together with MISO, in a Coordinated Functional Registration, NIPSCO is registered as a Balancing Authority, Transmission Owner, and Transmission Operator. Each Registered Entity is subject to compliance with applicable NERC standards, and ReliabilityFirst Regional Reliability Organization standards approved by FERC. Non-compliance with these standards can result in potential fines or penalties.

6.1.3 Midcontinent Independent System Operator, Inc.

NIPSCO participates in the larger regional transmission reliability planning process through its membership in the MISO, which annually performs a planning analysis of the larger regional transmission system through the MTEP. The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies. It should be noted that any transmission project driven by local factors that NIPSCO needs to build must be submitted to MISO for its planning review to ensure that there is no harm to other systems in the region. Under extenuating circumstances, NIPSCO can request expedited review of these projects.

Requests by generation owners to connect new generators to the NIPSCO transmission system, to change the capacity of existing generators connected to the NIPSCO transmission system, or otherwise modify existing generators connected to the NIPSCO transmission system are handled through the MISO Generation Interconnection Process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests. Requests by generation owners connecting to the PJM transmission system are to be coordinated with NIPSCO by PJM through MISO per the process defined by the MISO-PJM JOA.

Requests by generation owners in the MISO footprint to retire existing generators are handled through the MISO Attachment Y process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify either operating procedures or improvements and upgrades necessary to accommodate these requests. Requests by generation owners in the PJM footprint to retire existing generators may be reviewed by MISO for impacts on the NIPSCO transmission system per the process defined by the MISO-PJM JOA, but the generation owners in the PJM footprint are under no obligation to mitigate any resulting constraints on the NIPSCO transmission system.

Requests by generation owners to secure transmission service are handled through the MISO Transmission Service Request process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

Because NIPSCO is situated on a very significant boundary (seam) between MISO and PJM, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM as defined in the MISO-PJM JOA. In addition, MISO may propose transmission system projects or other upgrades that are not reliability based, but are economically based targeted at gains in market efficiency including the lowering of delivered energy costs to the end use customer. These projects must pass the criteria specified in MISO's tariff (including a minimum benefit to cost ratio) before approval.

NIPSCO is also an active participant in MISO and PJM's IMEP planning processes as defined in the MISO-PJM JOA. The IMEP processes focus on evaluating potential transmission projects to lower the overall production cost and lower delivered energy costs to the end use

customer for both of the MISO and PJM footprints. These projects must pass the criteria specified in MISO-PJM JOA (including a minimum joint benefit to cost ratio) before approval.

6.1.4 Market Participants

MISO has a process through which market participants can request voluntary upgrades on the NIPSCO transmission system to better accommodate generation outlet capacity, reduce congestion, or other market driven needs. If a market participant wishes to pursue these types of upgrades, they must submit their proposal to MISO and NIPSCO for evaluation in the process defined by the MISO tariff and corresponding Business Practice Manuals. The costs to perform these types of upgrades are negotiated between the market participant and NIPSCO.

6.1.5 Customer Driven Development Projects

NIPSCO may be contacted to undertake transmission upgrades by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts and NIPSCO Economic Development will determine if identified transmission upgrades are necessary to meet the customer's development or expansion plans. Any transmission upgrades identified via this route, that are applicable under the MISO planning processes, are evaluated by MISO to ensure there is "no harm" to any other system in the region as a result of these upgrades.

6.1.6 NIPSCO Transmission System Capital Projects

NIPSCO's current capital project plan for future years as driven by NIPSCO's planning processes and any projects designated and approved through the MISO MTEP planning effort includes:

- Dune Acres 138kV breaker upgrades
- MISO MTEP20 IMEP Project: Rebuild of the Michigan City to Trail Creek to Bosserman 138kV circuits.
- Maple to LNG 138kV circuit rebuild
- LNG to Stillwell 138kV circuit rebuild
- Maple to New Carlisle 138kV circuit rebuild
- New Hiple to Northport 138kV Circuit
- New 138/69kV substation, Menges Ditch, in Elkhart County

In addition to current portfolio, NIPSCO completed the following transmission system projects, including:

- Multi-Value Project 11: Sugar Creek Substation upgrades to accommodate the new 345 kV circuit from Ameren's Kansas West substation to the NIPSCO/Duke Energy Indiana jointly-owned Sugar Creek substation
- Circuit 13812 Maple Substation upgrade
- Circuit 13854 Aetna Substation line drop upgrade
- LaGrange Substation 138kV Ring bus conversion
- Hiple 138kV relay upgrades for added redundancy
- Kosciusko circuit 13881 switch upgrades
- Bosserman to New Carlisle Circuit rebuild
- MISO Market Efficiency Project: Reynolds Circuit 138109 switch upgrades.
- MISO Market Efficiency Project: Circuit 13835, Roxana to Praxair, line upgrade
- MISO Market Efficiency Project: Circuit 13813, Michigan City to Bosserman, line upgrade
- MISO Market Efficiency Project: Circuit 34504, Munster to Burnham, line upgrade

6.1.7 Electric Infrastructure Modernization Plan

The TDSIC plan is an initiative to modernize infrastructure through upgrades to the NIPSCO electric and natural gas delivery systems. The Commission issued its Order in Cause No. 44733 on July 12, 2016 approving NIPSCO's 7-Year Electric TDSIC Plan (2016-2022). NIPSCO terminated this 7-Year Electric Plan effective May 31, 2021, and filed a new Electric Plan on June 1, 2021 in Cause No. 45557.[84] NIPSCO's Electric TDSIC Plan, which runs from 2021 through 2026, is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time.

NIPSCO's Electric TDSIC Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of three main segments: (1) investments that target replacement of aging assets (Aging Infrastructure); (2) investments intended to maintain the reliability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability); and (3) investments to modernize NIPSCO's communications and AMI technologies (Grid Modernization).

[84] As of the submission of this 2021 IRP, NIPSCO's proposed TDSIC Plan was pending before the Commission.

6.2 Distribution System Planning

NIPSCO's distribution system is reviewed for local circuit, substation and source feed adequacy. Normal operating status as well as single element or contingency failure loading and voltage operating characteristics are evaluated along with circuit and system wide reliability metrics (i.e., CAIDI, SAIDI, SAIFI).[85] Distribution operating and design criteria rely on NIPSCO design thresholds in accordance with Company Standards, Distribution Systems Planning Criteria, and equipment manufacturer ratings. Voltage operating criteria are based on American National Standards Institute (ANSI) C84.1 and Indiana Administrative Code 170 IAC 4-1-20.

System improvement plans are developed and applied based upon mitigation of identified deficiencies associated with service capacity, service voltage, reliability levels, and load growth patterns. Specific and trending distribution component failures are mitigated through capital and infrastructure improvement processes. Infrastructure upgrade and replacement activities consider system characteristics including severity of operating deficiencies, likelihood of failure, potential customer impact, current substation and line topology, and equipment age and condition. Available new technologies are integrated into improvement and replacement activities where appropriate.

Net metering is an electricity policy for consumers who own renewable (solar, wind, biomass) energy facilities. Its application provides an incentive for customers to install renewable energy systems and generate electricity to offset their individual usage each month. If a participant produces more electricity than they use on a monthly basis, the customer can receive energy credits worth their utility retail rate for their excess generation that can be applied to future usage. The Net Metering program is ending for new customer applications for non-residential customers as of October 1, 2021 and for residential customers as of July 1, 2022. As new customers seek to interconnect after the Net Metering end dates the EDG, currently pending with the Commission in Cause No. 45505, will be made available to customers interested in interconnecting if approved by the Commission.

The renewable feed-in tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources and helped accelerate the move toward renewable energy sources. The tariff provides power developers with a predictable purchase price for self-generation under a long-term power purchase arrangement, which helps support financing opportunities for these types of projects. The micro solar, micro wind, intermediate wind, and biomass capacity are not fully subscribed and applications are still being accepted. The intermediate solar category is closed and no longer accepting applications.

NIPSCO implemented its renewable feed-in tariff in July 2011 along with its existing net metering program. These programs helped introduce customer-owned renewable resource based generation onto NIPSCO's electric distribution system. The feed-in tariff program began to attract

[85] CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year. SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year.

a significant amount of renewable generation projects which began coming "on line" in 2012 and has continued to grow. NIPSCO's net metering, feed-in tariff, and pending EDG tariff generation interconnection programs provide, or will provide, an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's electric distribution systems. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts across the service territory.

By the end of 2020, renewable generation data identified 30.4 MWs associated with the net metering program and 36.1 MWs of generation associated with the feed-in tariff program. An aggregate breakdown by renewable fuel type is provided below. These values represent generation resources that include landfill gas combustion engines, animal waste gas combustion engines, photovoltaic solar array farms, small roof mounted and ground mounted residential solar arrays, intermediate sized commercial wind turbines, and small commercial and residential wind turbines.

Net Metering Generation:

- 28.2 MWs - Solar Generation
- 1.9 MWs - Wind Generation
- 0.3 MWs - Solar/Wind Combination Generation

Feed-In Tariff Generation:

- 21.6 MWs - Solar Generation
- 0.2 MWs - Wind Generation
- 14.3 MWs - Biomass Generation

The above biomass related generation value excludes 13.6 MWs of existing landfill based generation interconnected to NIPSCO's distribution system. Although these renewable generation sources feed into NIPSCO's network, the power deliveries are associated with customer PPAs with parties other than NIPSCO. These customers do not participate in NIPSCO's net metering or feed-in tariff programs. In total, approximately 80 MWs of generation is interconnected to NIPSCO's distribution system.

Long term system performance evaluations associated with customer generation continue to evolve as generation penetration levels increase. Performance concerns continue to be associated with adequate control of voltage on distribution primary systems. As larger customer owned generation is added or multiples of mid to large unit are introduced on common circuits, control of voltage levels at remote locations becomes more challenging under normal operating conditions, much less under abnormal operating conditions. Overall, impacts on system operations has yet to be fully determined and will depend upon the demonstrated long term performance and reliability of various installed generating resources including solar, wind, and biomass based generation fueled resources. Differences in operational characteristics, generation penetration,

power delivery timing, and location all affect the relative impact on local distribution system operations at any given time.

The diverse types of customer-owned generation also have varying effects on the electric system. NIPSCO has observed that local generation most often varies substantially depending upon individual customer equipment, generation size, and generation input resources. Fuel resource type affects power delivery in various ways depending upon owner controlled resources as is the case of landfill and animal by-product gas inputs, or external environmental conditions such as wind velocity and solar irradiance. Highly variable outputs have been observed to occur on both solar and wind turbine installations. For instance, rapid changes in solar generation have exhibited swings of 85% of full rated output, within seconds. These conditions represent sizable down-up-down shifts in system operating characteristic on local circuits associated with some of the larger half MW or greater rated customer owned solar fields. These swings can present challenges to maintaining appropriate service voltage stability on distribution circuits. In addition to these more rapid changes relating to industry recognized "cloud affect,"

NIPSCO has also observed that more widespread weather patterns such as seasonal rain or snow storms also dramatically influence individual daily peak PV generation outputs on a longer term scale. Longer duration output reductions of 75% to 95% of rated equipment output have been observed during seasonal inclement weather conditions. Significantly reduced output levels can extend over several or more days, especially during winter season months. Wind powered generation was also observed to be as much, if not more, unpredictable and variable in power delivered to the distribution system. However, this has had less impact on NIPSCO distribution systems in recent years because little activity has occurred associated with small scale wind generation. On the other hand, large biomass fueled combustion turbines continue to be less volatile in generated outputs in comparison to solar and wind associated generation. Landfill based biomass generation facilities tend to be the most predictable followed by animal waste gas associated generation. However, even though biomass fueled resources exhibit a steadier dispatch of power, random events still occur where large customer generation drops off completely. The impact of lost generation becomes more significant with larger individual generators since local distribution systems need to adjust to compensate for fast changes in power resources. NIPSCO has also observed a trend with older large biomass (landfill) generation resources where output decreases with age of the landfill itself and associated generation equipment. 25% to 50% reductions in output have been observed at several sites.

Based upon past distribution system operating history associated with installed renewable generation resources, these technologies present a recognized energy resource that can be utilized to successfully supplement customer electric energy needs. However, their impact on local electric distribution infrastructure has not demonstrated to be sufficiently available to be considered an adequate substitute for NIPSCO's local electric resources in reliably meeting electric capacity and service needs for its customers. Considering that distributed generation resources have no obligation for power deliverability, operate in a "take it as you make it" mode, and can cease operations at any time for whatever reason, all lead to the lower confidence level regarding availability of power supply, especially during periods of system stress or problems. Consequently, continued traditional capital investment into local distribution infrastructure is necessary to insure that the utility can meet all service obligations to its customers.

6.2.1 Evolving Technologies and System Capabilities

NIPSCO continues the expansion of its distribution SCADA systems, improve its DA systems, and apply other new technologies.

NIPSCO's application of SCADA on distribution substations has undergone expansion, resulting in an increase in coverage from 25% to its current level of 43% of all associated stations. Distribution circuit coverage stands at approximately 48% of all circuits. As part of its ongoing infrastructure improvement programs, new, as well as rebuilt distribution substations, and their associated circuits, are assessed for the application of SCADA and DA in their scope and construction. New station projects, as well as full or partial station rebuild projects are currently being implemented at a rate of approximately five or more per year. Based on continuation of these activities, further expansion of NIPSCO's substation SCADA and DA systems are anticipated to continue.

NIPSCO initiated a new program for technology upgrades on existing control schemes and systems associated with its legacy DA systems. The original DA systems at NIPSCO date back to as early as the 1990's. Older system control schemes and equipment are scheduled to be upgraded to new SEL distribution network automation control systems. These new systems feature automatic network reconfiguration and self-healing actions using algorithms that provide more flexibility and higher levels of reliability. They allow much greater levels of customization of settings and flexibility to fit specific operating conditions. The newer DA automated systems will further enhance how the system determines the best path forward when recognizing faults and restoring customer services. Application of these newer DA control schemes are anticipated to further reduce the amount of permanent outages seen by customers, resulting in improvements in SAIDI and SAIFI metrics. In addition to the above operational improvements, the new systems also provide an opportunity for scaling (expansion) of DA systems that did not exist prior due to previous limitations on the older technologies.

In 2020, NIPSCO initiated the roll out of it new "trip saver" program for the application of more advanced types of local distribution line protection. This program applies new state of the art automated line reclosers. These newer devices are being applied throughout NIPSCO's territory to better handle temporary line faults. This equipment is applied and mounted in place of typical line fuses, and combines the best aspects of fuse-saving and fuse-blowing strategies to improve overall system reliability and prevent temporary faults from becoming sustained outages. Application of these devices will reduce the amount of permanent outages seen by customers resulting in improvements in SAIDI and SAIFI metrics. New equipment is being applied to replace older technologies such as "triple-shot" fuse installations and older traditional hydraulic reclosers.

NIPSCO continues to evaluate the benefits of emerging smart grid, DA, and other applicable technologies and to assess their deployment based upon corporate investment strategies in infrastructure as part of its long term approach.

Section 7. Environmental Considerations

7.1 Environmental Sustainability

NIPSCO is committed to delivering energy safely, reliably, and in an environmentally responsible and sustainable way. Since 2005, NIPSCO's impact to the environment has been reduced, and NIPSCO remains committed and on-track to achieve aggressive GHG and other environmental impact targets. Progress and targets for electric generation are summarized in Table 7-1.

Table 7-1: Environmental Sustainability Targets

	Progress Through 2020 % Reductions from 2005	Target 2025 % Reductions from 2005	Target 2030 % Reductions from 2005
Carbon Dioxide (Electric Generation)	**66%**	**50%**	**90%**
NOx	**89%**	**90%**	**99%**
SO2	**98%**	**90%**	**99%**
Mercury	**96%**	**90%**	**99%**
Water Withdrawal	**91%**	**90%**	**99%**
Water Discharge	**95%**	**90%**	**99%**
Coal Ash Generated	**71%**	**90%**	**100%**

NIPSCO has also invested in environmental controls across its coal fleet which allow for compliance with environmental requirements and environmental improvements while NIPSCO transitions to a more sustainable generation portfolio. See Table 7-2.

Table 7-2: Environmental Controls

Unit	Year In Service	Fuel Source	Particulate Matter (PM) Control	Sulfur Dioxide (SO2) Control	Nitrogen Oxide (NO_x) Control	Mercury (Hg) Control	Coal Ash	*Planned Retirement
MCGS U12	1974	Coal	Baghouse	Dry FGD	OFA & SCR	ACI & FA	SFC	2028
RMS U14	1976	Coal	ESP	Wet FGD	OFA & SCR	ACI & FA	SFC	2021
RMS U15	1979	Coal	ESP	Wet FGD	LNB w/ OFA, SNCR	ACI & FA	SFC	2021
RMS U16A	1979	Natural Gas	--	--	--	--	--	--
RMS U16B	1979	Natural Gas	--	--	--	--	--	--
RMS U17	1983	Coal	ESP	Wet FGD	Advanced LNB w/ OFA	--	--	2023
RMS U18	1986	Coal	ESP	Wet FGD	Advanced LNB w/ OFA	--	--	2023
Sugar Creek	2002	Natural Gas	--	--	SCR	--	--	--
Norway	1923	Water	--	--	--	--	--	--
Oakdale	1925	Water	--	--	--	--	--	--

ESP = Electrostatic Precipitator
SCR = Selective Catalytic Reduction
ACI = Activated Carbon Injection
FGD = Flue Gas Desulfurization
LNB = Low NOx Burners
FA = Fuel Additives
OFA = Over-Fire Air System
SNCR = Selective Non-Catalytic Reduction
SFC = Submerged Flight Conveyor

7.2 Environmental Compliance Plan Development

NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste, and solid waste that protect health and the environment. NIPSCO is committed to complying with all regulatory requirements. This commitment is embodied in the NiSource Environmental, Health & Safety, and Climate Change Policies and is implemented through a comprehensive environmental management system. Compliance plans are

developed, reviewed, and evaluated for implementation to meet new and changing legislative and regulatory developments.

7.3 Environmental Regulations

7.3.1 Solid Waste Management

The EPA finalized a rule regulating the management and disposal of the CCR which became effective on October 19, 2015. The CCR rule regulates CCRs under the RCRA Subtitle D as nonhazardous. The CCR rule is implemented in phases establishing requirements related to groundwater monitoring, CCR management and disposal, reporting, recordkeeping, and document management.[86] The rule allows NIPSCO to continue its byproduct beneficial use program, significantly reducing CCR that must be disposed.

To comply with the rule, NIPSCO completed capital expenditures in 2019 to modify its infrastructure and manage CCRs. NIPSCO continues to assess and monitor groundwater quality at its generating stations to comply with CCR rule requirements and to determine if historic CCR management and disposal practices will require corrective measures.

7.3.2 Clean Water Act

The CWA establishes water quality standards for surface waters as well as a permit program for regulating discharges into the waters of the United States. Under the CWA, EPA created a program to establish wastewater discharge standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge from a point source into navigable waters without a permit. The NPDES permit program implements the CWA's provisions.

7.3.3 Effluent Limitations Guidelines

EPA first promulgated the ELG Rule in 1974, and has amended the regulation many times, with the latest revision effective date of December 14, 2020. The ELG Rule regulates wastewater discharges from power plants operating as utilities. The implementing requirements are incorporated into NPDES permits. Significant capital expenditure is not required for NIPSCO to comply with the ELG Rule given the expected retirement dates of the coal units at Schahfer, and the dry FGD and CCR-related investments at Michigan City.

7.3.4 Clean Air Act

NIPSCO emissions of nitrogen oxides of NO_x, SO2, and mercury have been reduced by nearly 90% since 2005. All Northern Indiana counties are in attainment of the NAAQS with the exception of the ozone standards in Lake and Porter Counties, which are included in Chicago metropolitan area nonattainment.

[86] https://www.nipsco.com/about-us/ccr-rule-compliance-data-information

In April 2021, the EPA published the Revised CSAPR Update for the 2008 NAAQS. Starting with the 2021 ozone season (i.e., May through September), the rule requires additional NOx reductions from power plants in 12 states, including NIPSCO generation stations. NIPSCO plans to comply with this rule through the continuous operation of emissions controls, retirement of coal generation, allowance allocations from the EPA, and allowance transactions (as appropriate). Emission allowance inventories under the EPA CSAPR and Acid Rain programs are provided in the tables below.

Retaining Schahfer Units 17 and 18 beyond 2023 would likely require expenditures to further reduce NOx emissions. Although both Schahfer Units 17 and 18 are already equipped with low-NO_x burners and OFA systems for NO_x reduction, SCR or SNCR could be installed for post-combustion NO_x control for compliance with anticipated regulation.

In July 2019, under the authority of the Clean Air Act, the EPA published the final ACE Rule, which establishes emission guidelines for states to use when developing plans to limit carbon dioxide at coal-fired electric generating units based on heat rate improvement measures. The U.S. Court of Appeals for the D.C. Circuit vacated and remanded the rule in January 2021. NIPSCO will continue to monitor this matter. Potential requirements under the ACE Rule were not included in the IRP modeling because they are unlikely to be implemented.

7.3.5 Emission Allowance Inventory and Procurement

7.3.5.1 CSAPR Emission Allowance Inventory

Under CSAPR, the EPA allocates annual SO2, annual NO_x, and ozone season NO_x allowances to NIPSCO, which are summarized in Table 7-3.

Table 7-3: CSAPR Allowance Inventory

CSAPR Allowance Inventory*

Year	Annual SO2	Annual NO_x	Ozone Season NO_x
Bank**	149,348	11,973	203
2021 – 2023 Annual Allocation	28,998	13,026	***
2024 Annual Allocation	21,725	12,178	N/A
Total	**258,067**	**63,229**	**4,006**

** Allowance inventory available as of August 2021*

*** Reflects emission allowances from 2020 and earlier*

****2,192 allowances were allocated for 2021 and 1,611 allowances were allocated for 2022*

7.3.5.2 Title IV Acid Rain - SO2 Emission Allowance Inventory

In conjunction with CSAPR, the Title IV Acid Rain Program will continue to regulate SO2 emissions. Table 7-4 lists the actual number of SO2 Acid Rain Program emission allowances held

in inventory by NIPSCO as of July 2021 for the period 2021 through 2051. Based on current projections of future emissions, NIPSCO does not need to procure additional allowances to comply with the Acid Rain Program.

Table 7-4: SO2 Acid Rain Program Emission Allowances

Acid Rain Program SO2 Allowance Inventory*	
Year	**Allowances**
Bank**	315,086
2021-2051 Annual Allocation	50,706
Total	**1,886,972**

***** Allowance inventory available as of August 2021
** Reflects emission allowances from 2020 and earlier

7.4 Climate-Related Considerations

As of 2021, NIPSCO has reduced carbon dioxide emissions from electric generation by 66% since 2005, and has targeted a 90% reduction by 2030 through the anticipated retirement of all NIPSCO-owned coal generation.

Although several legislative and executive actions related to GHG emissions have been attempted over the last decade, there is currently no federal price on carbon and no binding power sector GHG emission limits at the federal level. However, given multi-faceted efforts through the Biden Administration and Congress to reduce GHG emissions, NIPSCO's IRP modeling includes several climate-related scenarios, including net-zero, clean energy standard, and carbon price scenarios. Refer to Section 8 for further discussion of carbon policy and prices.

This report also describes the resilience of NIPSCO's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario, which aligns with recommendations from the Task Force for Climate-Related Financial Disclosures.

Section 8. Managing Risk and Uncertainty

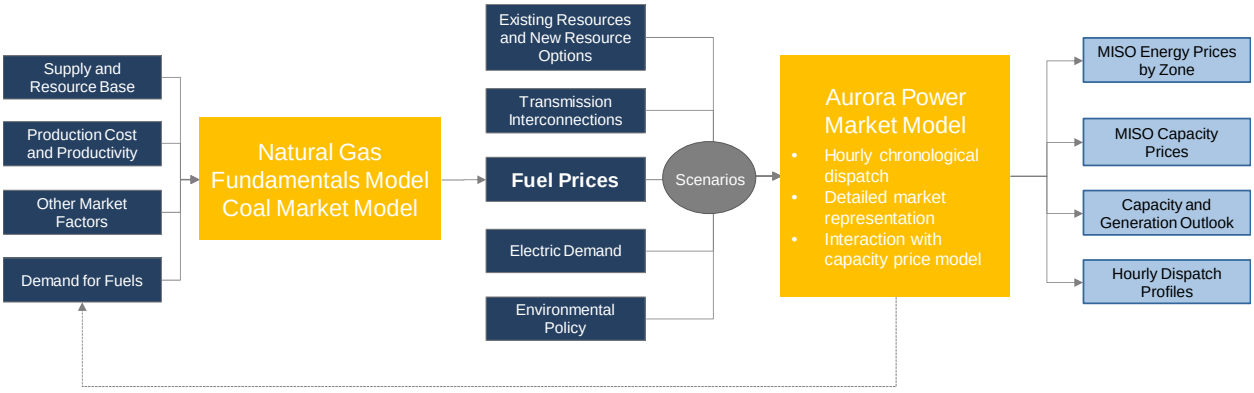
8.1 Introduction & Process Overview

In the 2021 IRP, NIPSCO deployed an approach to evaluating risk and uncertainty that involved the development of a fundamentals-based set of key Reference Case market drivers and the deployment of both scenarios and stochastic analysis to assess variance around this Reference Case.[87] NIPSCO developed the major inputs and associated uncertainty ranges for the 2021 IRP through the following process:

- Development of the Reference Case set of assumptions through fundamental energy sector, commodity price, and load forecasting models;
- Identification of the key drivers of uncertainty and appropriate assignment to scenario or stochastic analysis frameworks;
- Development of distinct scenario themes with accompanying model-based forecast assumptions; and
- Development of stochastic distributions for relevant variables.

The major market assumptions for the Reference Case and the scenarios were developed using a set of fundamental market models deployed by CRA and summarized in Figure 8-1. These models include the NGF model for natural gas price projections and the Aurora model for long-term MISO-wide capacity expansion, production cost analysis, and granular power price forecasting. Section 2 has additional detail on the models used in the IRP.

Figure 8-1: Fundamental Market Modeling Structure



[87] Since the development of the Reference Case assumptions in Spring 2021, market forwards for key fuel and power prices have increased. Although near-term market prices are higher than the Reference Case forecast as of the time of the submission of this report, NIPSCO's IRP assumptions remain valid for portfolio analysis because (i) as discussed in Section 8.5, NIPSCO's stochastic analysis was designed to capture price volatility consistent with current market behavior and covers recent price movements; (ii) market forwards suggest a decline in fuel and power prices by 2023 towards levels consistent with the Reference Case forecast; and (iii) the scenario ranges cover a widening envelope of price outcomes over time to reflect potential fundamental drivers of long-term higher or lower price trajectories.

The next section provides an overview of the fundamental drivers that underpin the NIPSCO Reference Case for gas prices, coal prices, carbon prices, and power market prices, while the remainder of the chapter discusses the scenarios and associated assumptions and the stochastic distributions that were developed to support the 2021 IRP process.

8.2 Reference Case Market Drivers and Assumptions

8.2.1 Natural Gas Prices

Figure 8-2 provides an overview of the key inputs that drive CRA's fundamental forecast in the NGF model. NIPSCO's 2021 Reference Case natural gas price forecast is driven by several key market assumptions regarding the major supply and demand dynamics in the North American natural gas market. Figure 8-3 summarizes the major supply side drivers, along with CRA's approach and assumptions for each driver, as well as supporting explanations. Figure 8-4 summarizes the same information for the major demand side drivers. The remainder of this section then provides additional detail related to each driver.

Figure 8-2: Overview of CRA's NGF Model Inputs



Figure 8-3: Supply Side Natural Gas Price Drivers – Reference Case

Driver	CRA Approach	Explanation
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	CRA assumes a starting point of PGC 2018 "Minimum" resource, and grows the resource base to achieved PGC 2018 "Most Likely" volumes by 2050 to reflect pace of incremental discoveries over time
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	CRA based individual well productivity on historic data analyzed for each producing region, IP rates improve annually consistent with EIA assumptions The "Poor Heavy" resource base reflects CRA's view that the sampled production data is biased, reflecting the geology that producers expected to be most productive
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	CRA starts from drilling and operating costs reported by major producers in each supply basin, cost improvements over time are based on latest EIA assumptions
NGL & Condensate Value	• Liquids valued at 70% of Annual Energy Outlook ("AEO") 2021 Reference Oil Price	On average since 2011, NGL prices have been around 70% of US oil prices on an MMBtu basis
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	AEO21 revised EIA's forecast of domestic oil prices and production lower relative to AEO20; this pull-back in turn lowers volumes of associated gas, particularly in the short-term

*IP = Initial Production

Figure 8-4: Demand Side Natural Gas Price Drivers – Reference Case

Driver	CRA Approach	Explanation
Domestic Demand	• Electric demand taken from AURORA base case, Residential / Commercial / Industrial demand based on AEO 2021 Reference Case	CRA expects natural gas demand in the power sector to be relatively stable to modestly declining under Reference Case conditions; gas and renewable generation is likely to replace coal and some nuclear generation plus incremental load growth
LNG Exports	• Under-construction projects completed and total exports rising from around 7 bcf/d in 2020 to around 14 bcf/d by 2030	CRA expects no further export capacity beyond projects which are already operating or which have already achieved Final Investment Decision, due to weaker international prices and increased competition from suppliers with lower production costs or located closer to demand centers Completed facilities, on aggregate, operate at between 60-75% utilization once completed, consistent with historical operations
Pipeline Exports	• Exports rise from 5 bcf/d in 2020 to just under 10 bcf/d by 2030	CRA expects modest growth in pipeline exports to Mexico as utilization rates increase from current levels to 70% over time, reflecting growing gas demand as the energy transition continues

Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on the PCG 2018[88] "minimum" value as the starting value for recoverable shale reserves, with the resource base growing over time at a steady rate until the PGC "most likely" value is reached in 2050. The assumed values and ranges are shown in Figure 8-5.

[88] Note that the PGC 2018 view was released in October 2019, with PGC 2020 not available at the time of the development of NIPSCO's 2021 IRP assumptions. Scenario development (discussed further below) incorporates a range of views on the future resource base, anticipating potential ranges of resource base in the PGC 2020 report.

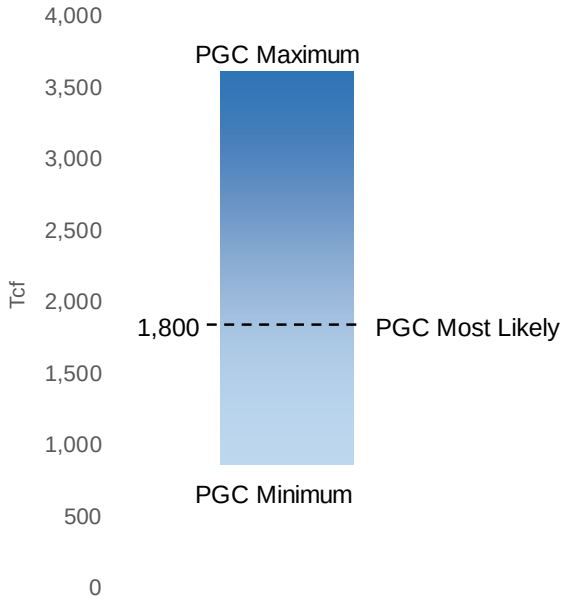
PGC evaluates three categories of potential resource:

- Probable – gas associated with known fields;
- Possible – gas outside of known fields, but within a productive formation in a productive province; and
- Speculative – gas in formations and provinces not yet proven productive.

PGC assigns resource to three probability categories:

- Minimum – 100% probability that resource is recoverable;
- Most Likely – what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions; and
- Maximum – the quantity of gas that might exist under the most favorable conditions, close to 0% probability that this amount of gas is present.

Figure 8-5: Uncertainty Range for Shale Resources in PGC 2018

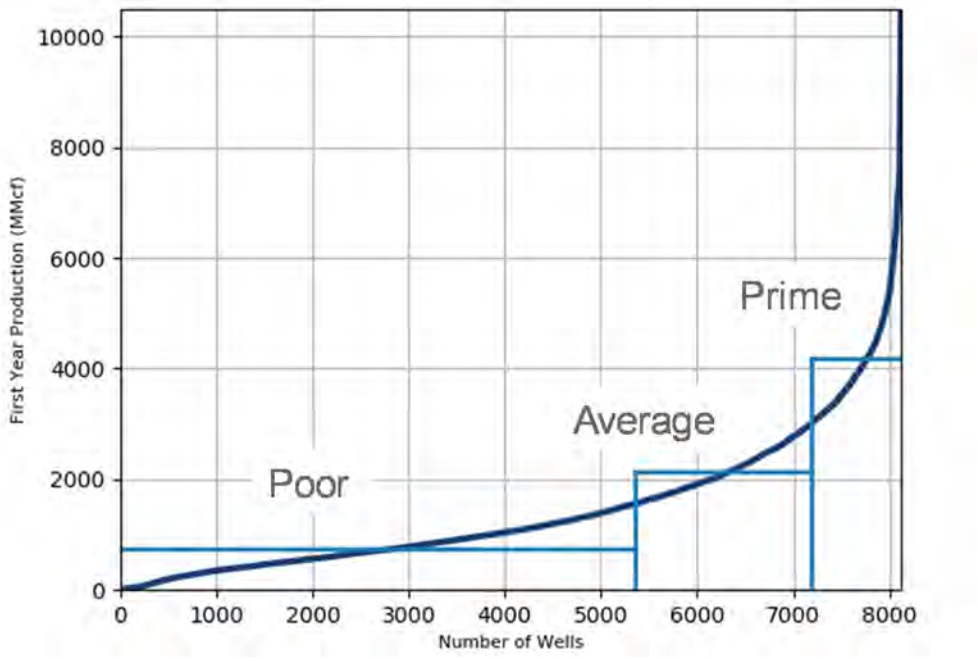


Well Productivity

Natural gas well productivity assumptions are important drivers of ultimate production efficiency, especially since the bulk of the natural gas resource is currently unproven, meaning that the geology of that resource is currently unknown. In developing assumptions for this variable, CRA generated productivity distributions for each production basin based on drilling data in regions that producers expected to have favorable geology. CRA's view is that historical data has

a bias towards higher producing sub-regions, since the wells that are completed and ultimately produce gas do not reflect a random sampling of the underlying geology in each basin. Therefore, to reflect the expectation that the remaining resource is more likely to be lower quality over time as the premium acreage is depleted, CRA assumes a "Poor Heavy" productivity distribution for future undiscovered resource in the Reference Case. An example of this distribution for the Appalachian region is shown in Figure 8-6, with the number of wells shown on the x-axis and the level of first-year production shown on the y-axis.[89]

Figure 8-6: Well Productivity Distribution Illustration for Appalachia



Well Costs

CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region. Producers reported improvements in drilling and O&M costs across most, but not all, shale basins in 2020, and CRA broadly assumes that these improvements will continue over time. Figure 8-7 summarizes current drilling costs in the major production regions, while Figure 8-8 summarizes current O&M costs in the same basins.

For going forward costs, CRA relies on the EIA's AEO projections for improvements in drilling and O&M costs. EIA's approach incorporates annual improvements to key well inputs that account for ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources from historical time periods. Drilling costs are expected to decline by 1% per year for tight oil and shale gas formations and decline by 0.25% per

[89] Distribution is based on CRA analysis of the Lasserdata drilling database. This proprietary database is produced by Lasser, Inc. and includes historical monthly oil and gas production data.

year for all other basins. Equipment and operating costs are expected to decline by 0.5% per year for tight oil and shale gas formations and decline by 0.25% per year for all other basins.

Figure 8-7: Shale Gas Drilling Costs

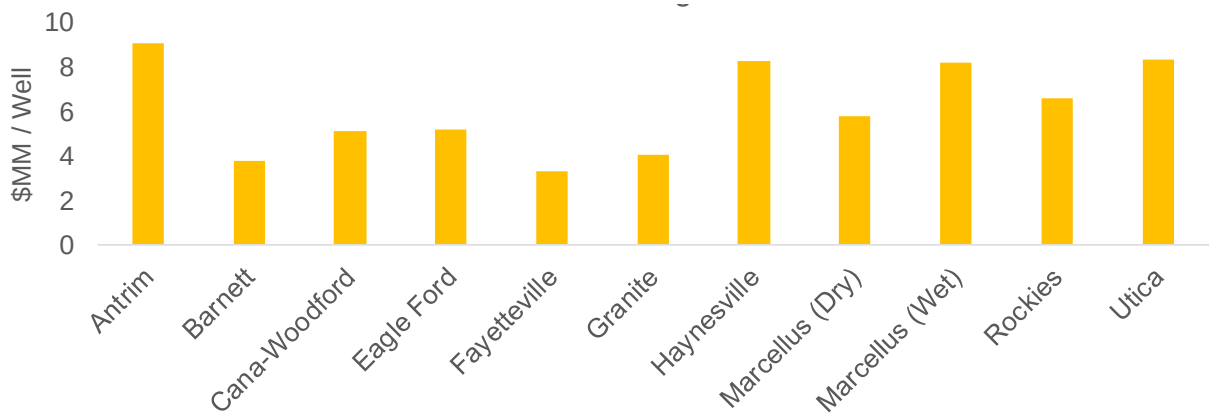
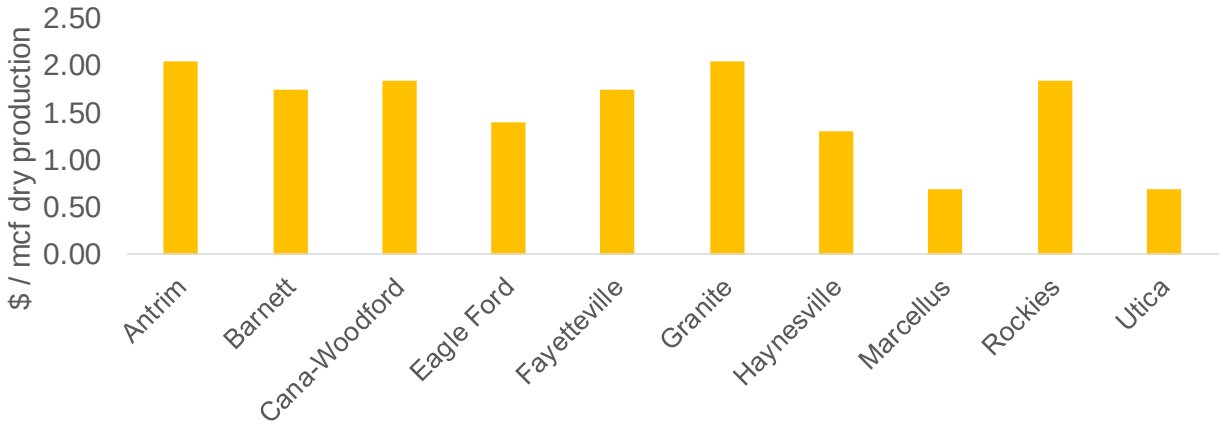


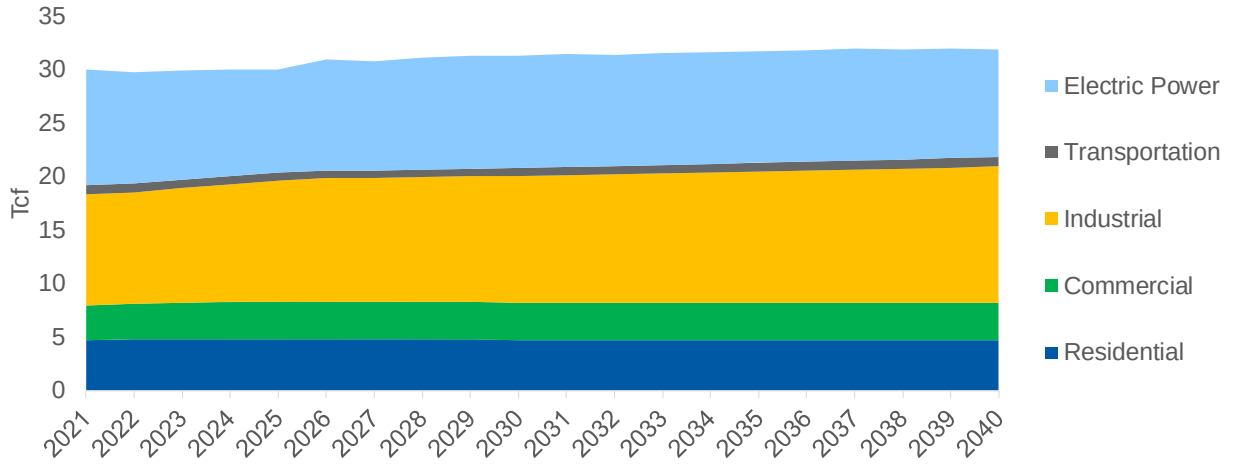
Figure 8-8: Shale Gas O&M Costs



Domestic Demand

In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for residential, commercial, industrial, and transport demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-9 presents historical and forecast domestic demand assumptions through 2040 from these sources. Electric sector demand is expected to be relatively flat throughout the forecast horizon. The AEO's growth expectations for other sectors are also relatively flat, with some growth expected in the industrial sector over time.

Figure 8-9: Domestic Natural Gas Demand Assumptions – Reference Case

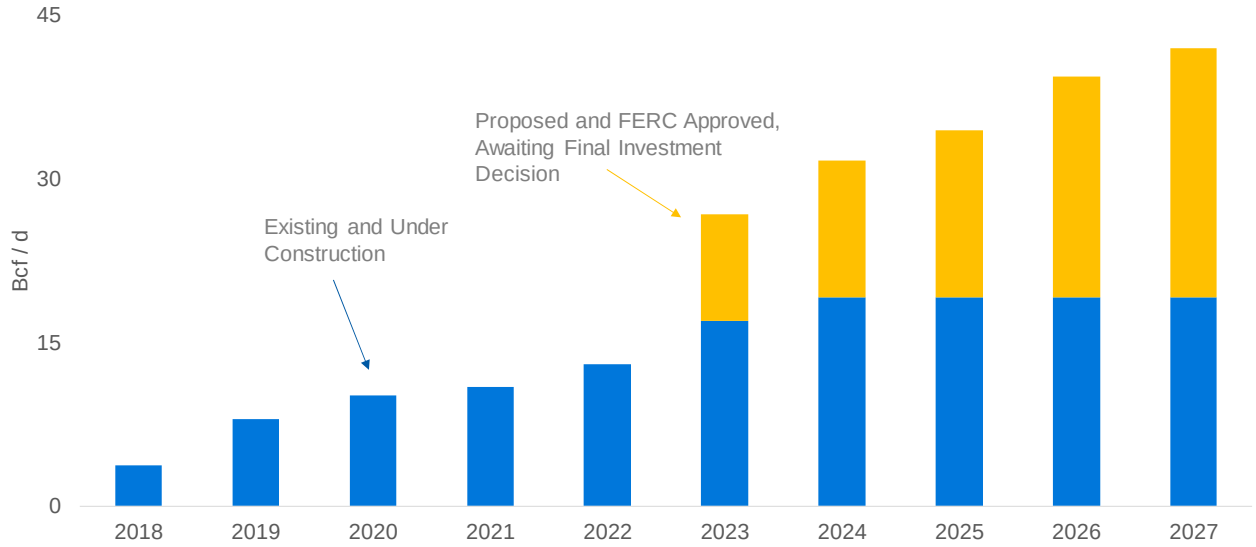


Exports – LNG and to Mexico

CRA develops projections for natural gas exports to Mexico via pipeline and to other international markets through LNG by reviewing estimates published by sources like the AEO and conducting analysis of specific export projects under development.

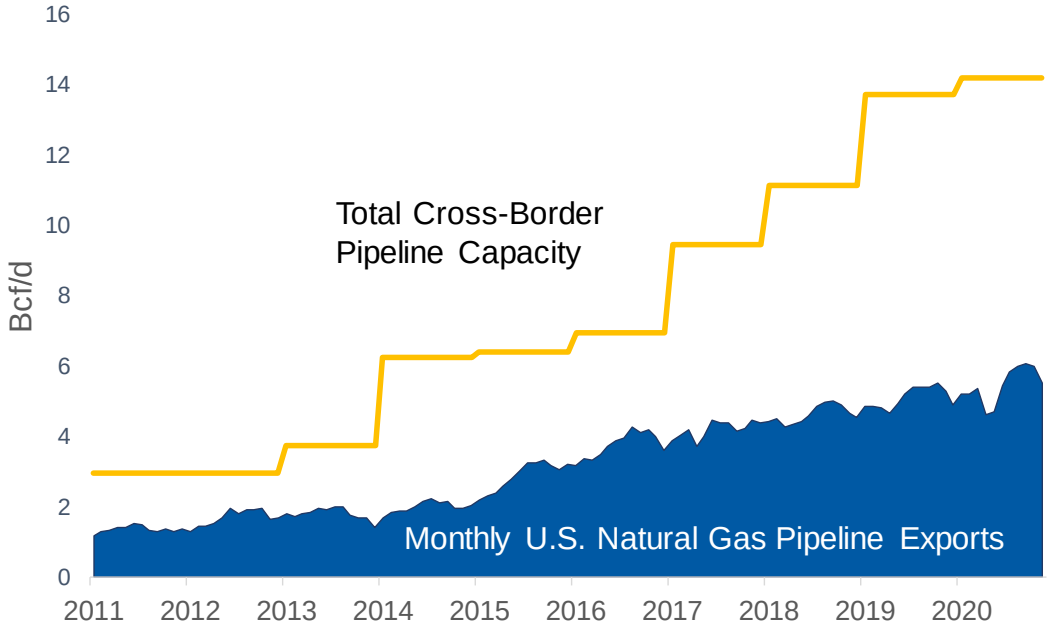
While several LNG export projects are now online or under construction, due to softening prices and increased competition, CRA expects that few, if any, currently proposed projects will be completed after Calcasieu Pass and Golden Pass come online in 2023 and 2024. CRA's Reference Case projection for LNG exports is shown in Figure 8-10 in the blue bars, growing to just under 20 bcf/day by 2024. The incremental proposed projects shown in yellow are not included in the Reference Case view.

Figure 8-10: LNG Export Volume Projections by Year and Approval Status



While CRA expects that exports to Mexico will also increase over time, actual exports to Mexico are not keeping pace with the expansion of cross-border export capacity, as illustrated in Figure 8-11. Numerous pipeline projects within Mexico have faced construction delays, and completed projects are operating well below capacity. For example, the 1.1 Bcf/d Comanche Trail pipeline has been utilized only 10% on average since completion in June 2017, and the 1.4 Bcf/d Trans-Pecos pipeline completed in 2017 currently has operated at 10-15% of total capacity since completion. Therefore, in the Reference Case, CRA projects modest additional growth in export volume, but expects that pipeline capacity will continue to be underutilized.

Figure 8-11: Net Exports to Mexico by Pipeline

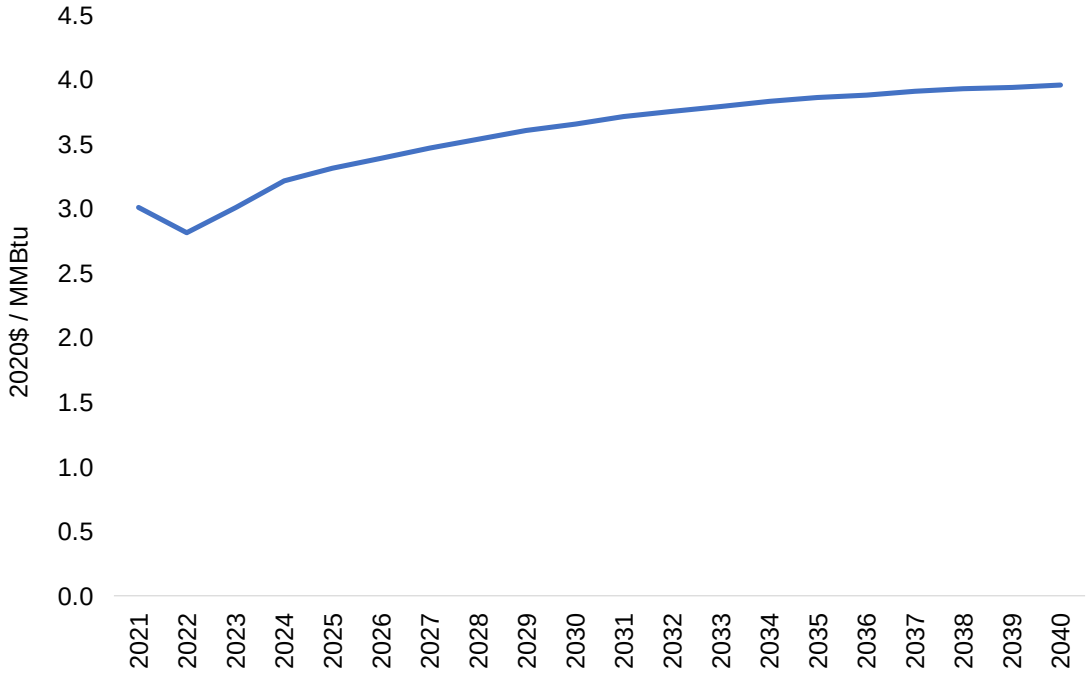


Reference Case Price Forecast

CRA's Reference Case price forecast was developed based on each of the supply-demand inputs discussed above and is shown in Figure 8-12. Although prices at Henry Hub have remained below $3/MMBtu in recent years, the Reference Case still expects price rises towards $4/MMBtu (real) over the long-term. A brief summary of the key drivers of the expectation for increasing prices follows:

- CRA's reference case view continues to reflect upward pressure in the medium term, driven by industry consolidation as well as modest restrictions on supply access driven by the Biden Administration's ban on further drilling in federal lands;
- Expectations for downward price pressure driven by improvements in drilling and O&M costs are likely to be moderated by lower domestic oil prices and associated gas volumes; and
- CRA has observed limited productivity improvements in 2020 relative to prior years, and these seem to be primarily driven by crowding into prime regions, not technical advancements.

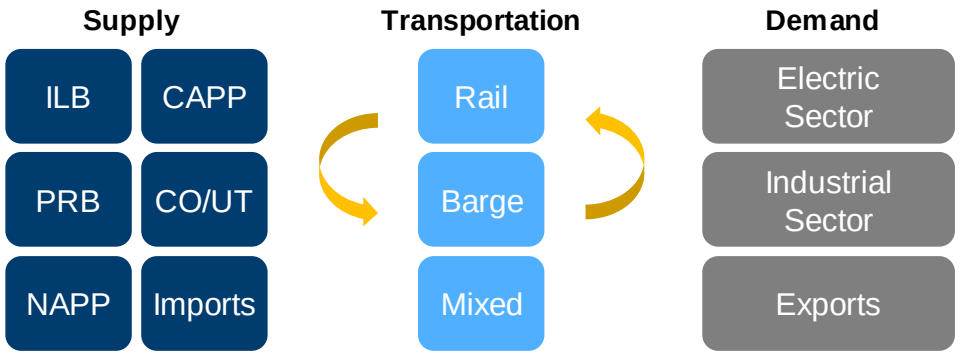
Figure 8-12: Reference Case Gas Price Forecast



8.2.2 Coal Prices

NIPSCO's 2021 Reference Case coal price forecast was driven by a fundamental view of the major supply and demand dynamics for each of the four major coal basins in the United States, integrated with other Reference Case assumptions for natural gas prices (discussed above), carbon prices (discussed below), and the expected evolution of the power sector over time. The core forecasting process incorporates perspectives on coal supply, demand, and transportation to deliver fuel to plants throughout the U.S, as illustrated in Figure 8-13. CRA's process assesses the future supply/demand balance for the U.S. coal market based on macroeconomic drivers, including domestic and international demand, and microeconomic drivers, including trends in mining costs and production.

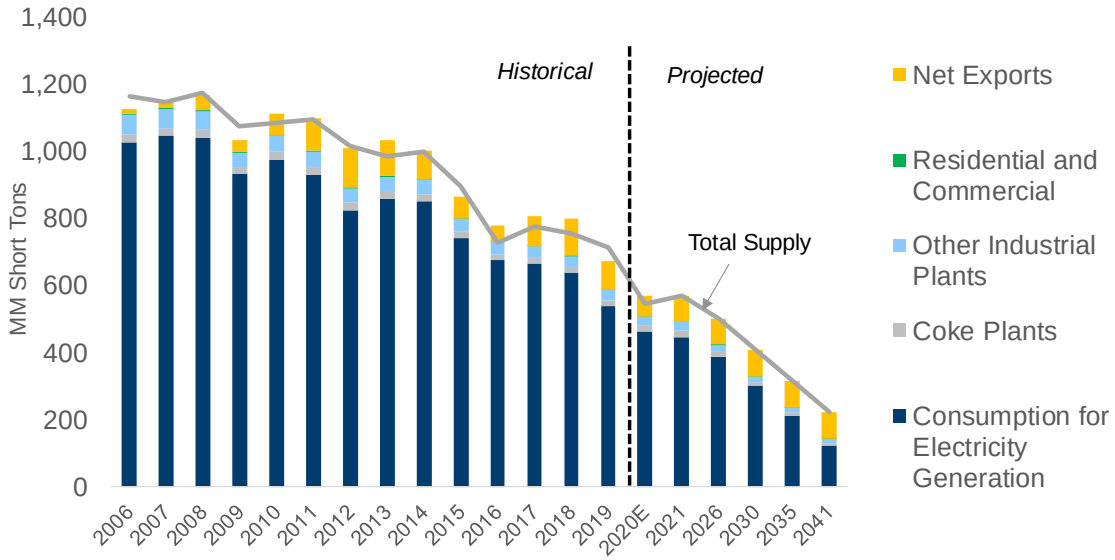
Figure 8-13: Coal Forecasting Process Overview



Coal Supply and Demand Trends

Figure 8-14 summarizes historical and projected supply and demand for U.S. coal over the period from 2006 through 2041, which shows that coal demand has generally been in decline over the last fifteen years. A total of 20 GW of coal generating capacity retired in the U.S. in 2019 and 2020, and low natural gas prices have continued to dampen demand, such that total demand for U.S. coal declined by about 228 million tons/year (or 29%) between 2018 and 2020, with domestic demand declining by about 178 million tons/year (or 26%), and total U.S. coal exports declining by about 50 million tons/year (or 43%). Furthermore, 2019 coal demand was about half of where it was in 2010. Modest additional declines are expected in the next five years, with more substantial declines expected after 2026, particularly if carbon regulation is implemented, as is projected in the Reference Case.

Figure 8-14: Supply-Demand Balance for U.S. Coal – 2006-2041[90]



Reference Case Price Forecast

CRA's Reference Case price forecast is driven by both the regional production outlook and an assessment of production costs at various demand levels. Figure 8-15 presents the Base Case price outlook by coal supply region, with additional basin-level commentary provided below:

- CAPP: Demand for CAPP steam coal has declined steeply, due to the high production cost of this coal, and the diversion of most remaining Central Appalachian coal supplies to the metallurgical coal market.

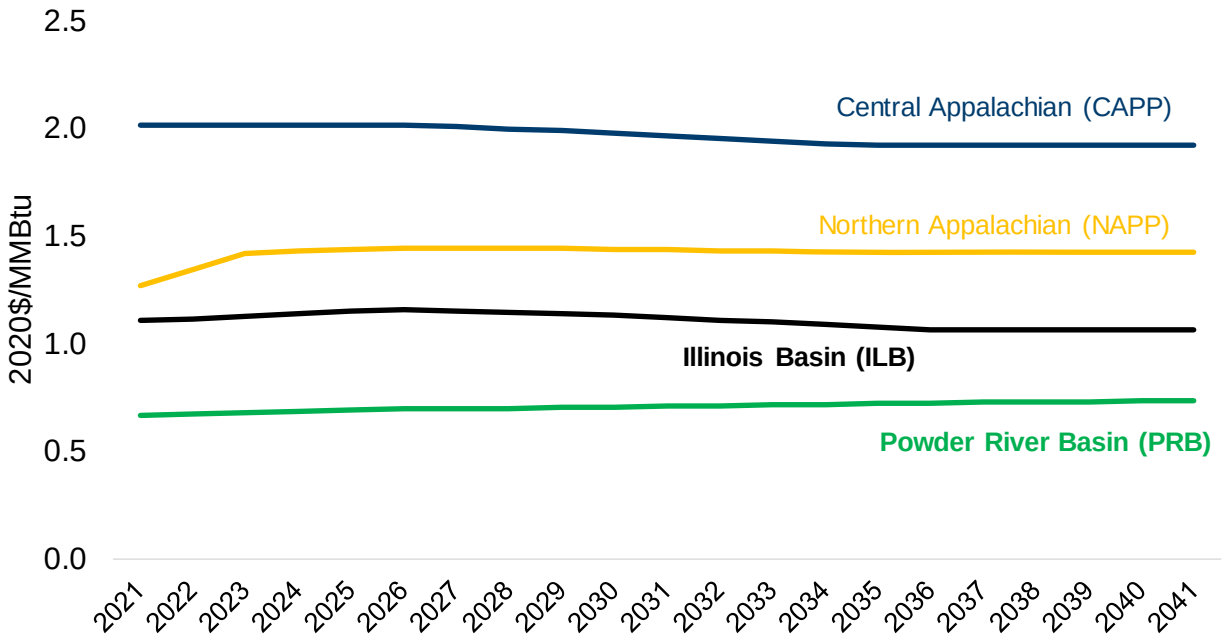
- NAPP and ILB: The current prices for NAPP and ILB coals appear to be below the levels needed to sustain the current levels of coal production in these regions.

[90] 2006-2019 data is from EIA and the Mine Safety and Health Administration.

Therefore, some upward movement in these prices is expected during 2021-2026. After 2026, real declines in prices are expected to resume as coal demand falls.

- PRB: Prices for PRB coal are expected to increase slightly in real terms (by an average of about 0.5%/year) over the forecast period. This reflects the unique geology of the PRB region, in which the coal seams slope downward at a gradual but constant rate, so that any amount of incremental coal production is likely to result in gradually increasing mining costs over time.

Figure 8-15: Reference Case Coal Price Forecast



8.2.3 Carbon Policy and Prices

Although several legislative and executive actions related to carbon emissions have been attempted over the last decade, there is currently no price on carbon and no binding emission limits at the federal level. As of the time of the development of NIPSCO's 2021 IRP assumptions, the Biden Administration has begun to take executive actions related to carbon emission reductions and has introduced several climate-related legislative proposals as part of its overall infrastructure package. Recent and potential executive actions include:

- Re-joining the international Paris accords and re-engagement in international agreements related to greenhouse gas emission reductions;

- Limiting access to fossil fuel production on federal lands and directing the EPA to impose stricter standards on production;

- Directing the EPA to re-interpret Clean Air Act authority to regulate CO2 emissions from power plants;

- Appointing FERC commissioners who could encourage or institute carbon pricing in wholesale markets; and

- Mandating the reduction of greenhouse gas emissions for federal fleets, buildings, and other operations.

Legislative proposals being debated in 2021 include:

- Extensions of the investment and production tax credits for renewable and other clean energy resources such as nuclear and carbon capture and storage, and expansions of similar tax credits for resources like storage and new transmission;

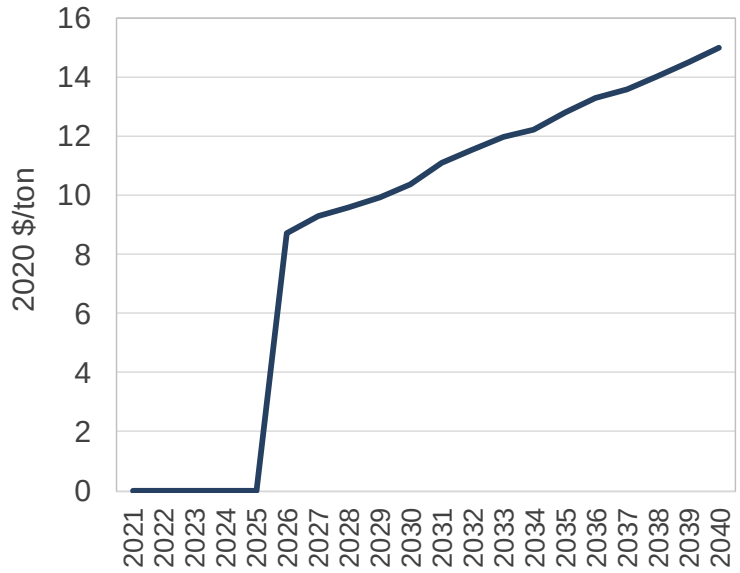
- A goal of a 100% carbon-free power sector by 2035, potentially through a clean energy standard;

- Direct subsidies and incentives for electric vehicles and energy efficiency measures; and

- New research and development initiatives, including investment in infrastructure resiliency and new technology such as hydrogen.

Given such efforts to regulate carbon emissions, NIPSCO's Reference Case incorporates price on carbon emissions starting in 2026, which is reflective of several different potential pathways for legislative action or executive regulation. Similar to NIPSCO's 2018 IRP, CRA's analysis suggests that pricing between $9-15/ton (in real 2020$) between 2026 and 2040 would achieve 30-40% reductions in CO2 emissions from the U.S. power sector relative to a recent historical year baseline. Such a carbon price would likely result in significant additional coal-to-gas switching nationwide and pressure approximately 80% of the existing coal fleet across the country to retire by 2040. The price would also improve the economics of renewable and other clean energy generation, resulting in total clean energy accounting for over 50% of total U.S. electricity production. The pricing outlook incorporated in the Reference Case is shown in Figure 8-16 in real dollars per short ton.

Figure 8-16: Base Case Carbon Price Forecast



8.2.4 MISO Energy and Capacity Prices

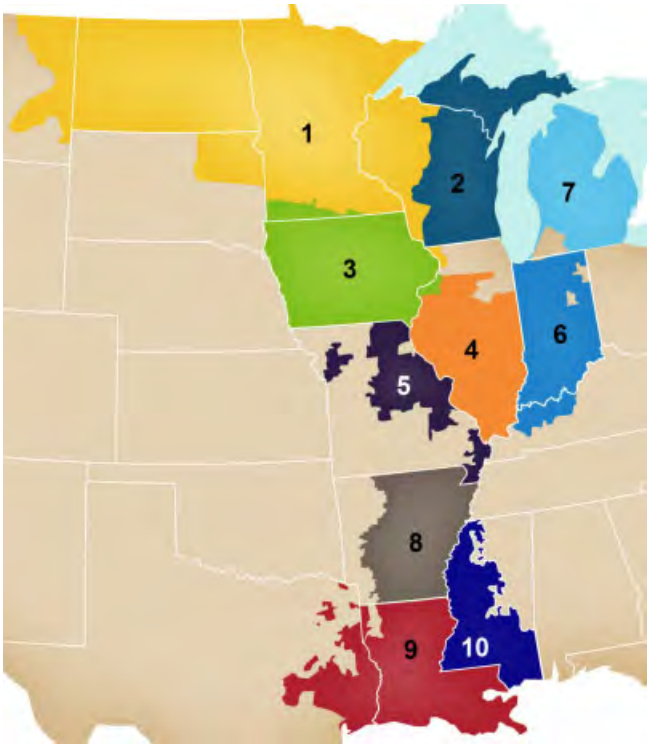
NIPSCO operates within the MISO region, which includes parts of fifteen states throughout the Midwest and South. The traditional MISO North footprint covers parts of Indiana, Michigan, Illinois, Missouri, Kentucky, Iowa, Wisconsin, Minnesota, North Dakota, South Dakota, and Montana, as illustrated in Figure 8-17. Overall, MISO provides the following services to members and participants:

- Oversees markets for energy, capacity (resource adequacy), ancillary services, and transmission rights;
- Maintains load-interchange-generation balance, coordinates reliability, operates or directs the operation of transmission facilities, and oversees transmission planning;
- Coordinates with utilities, states, and federal entities (FERC and NERC) to ensure the reliable, non-discriminatory operation of the bulk power transmission system; and
- Provides approximately $3.5 billion in annual benefits to members due to efficient use of power system for resource adequacy and dispatch across a broad geographic territory

NIPSCO territory and resources fall within LRZ 6, covering Indiana and parts of Kentucky. In developing the Reference Case market price forecasts for energy and capacity, CRA deployed its Aurora market model to represent the entire MISO footprint and produce fundamental, hourly

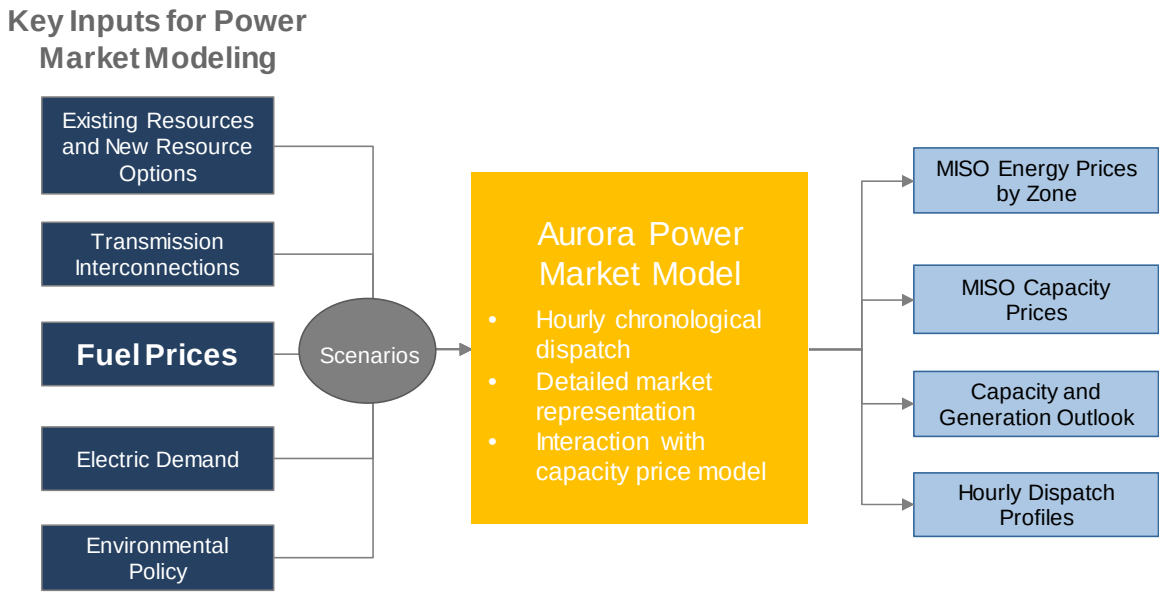
price projections that are internally consistent with the fundamental outlook for natural gas prices, carbon prices, and the future capacity mix in the region.

Figure 8-17: MISO Footprint



Based on the market inputs for fuel and carbon prices, along with other inputs associated with existing and new resource expectations throughout MISO, regional transmission interconnections, and regional electric demand, CRA developed Reference Case expectations for the MISO market, including energy capacity prices according to the process shown in Figure 8-18.

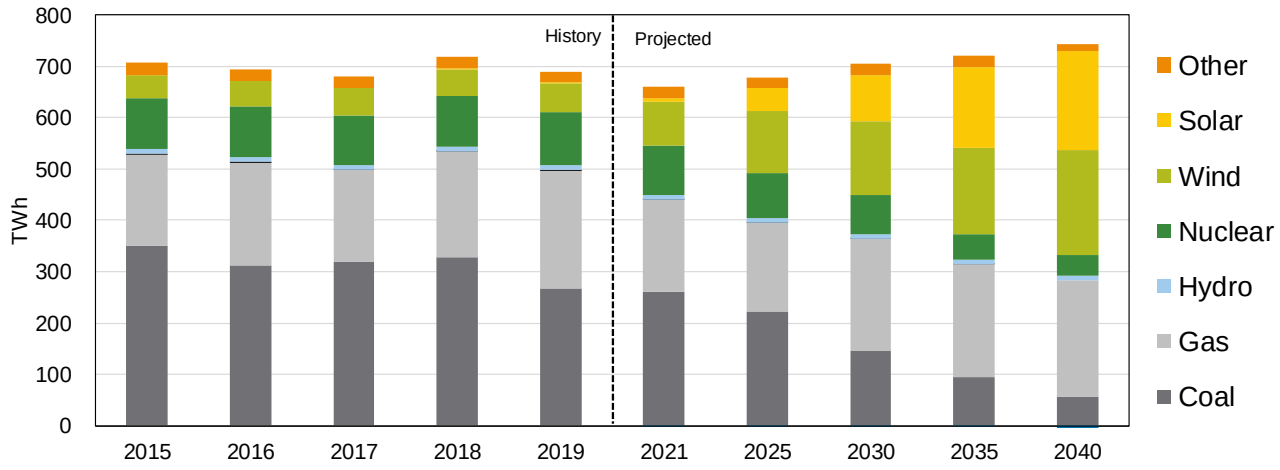
Figure 8-18: Power Market Modeling Process



MISO Capacity Mix

CRA's Reference Case analysis expects a continued shift from coal capacity and energy production toward renewables, and to a lesser extent natural gas, over the next two decades. Since 2015, coal generation has declined from approximately 50% of the total MISO mix to less than 40%, and the Reference Case forecast projects that it will reach 20% by 2030 and less than 10% by 2040. Meanwhile, the Reference Case expects significant growth in renewable energy from wind and solar, such that by 2040 over half of energy generation throughout the region is expected to be from renewable resources. CRA's Reference Case projection of the evolution of the MISO energy mix is presented in Figure 8-19.

Figure 8-19: MISO Generation by Fuel Type – History and Reference Case Projections



Reference Case Energy Price Forecast

CRA's Reference Case MISO energy market forecast is presented in Figure 8-20 on an annual basis and in Figure 8-21 on a monthly basis. The Reference Case expects that power prices will stay relatively flat in the near-term, due to flat gas and coal prices, although upward pressure on prices is expected into the 2020s as a result of higher projected natural gas prices. The expected national carbon price in 2026 drives a projected increase in power prices in that year, although growing renewable penetration over the long-term mitigates future price growth expectations. In fact, convergence in peak and off-peak prices is projected over time in the Reference Case due to growing solar energy output, which tends to reduce peak pricing.

Figure 8-20: LRZ6 (Indiana) Reference Case Annual Price Projections

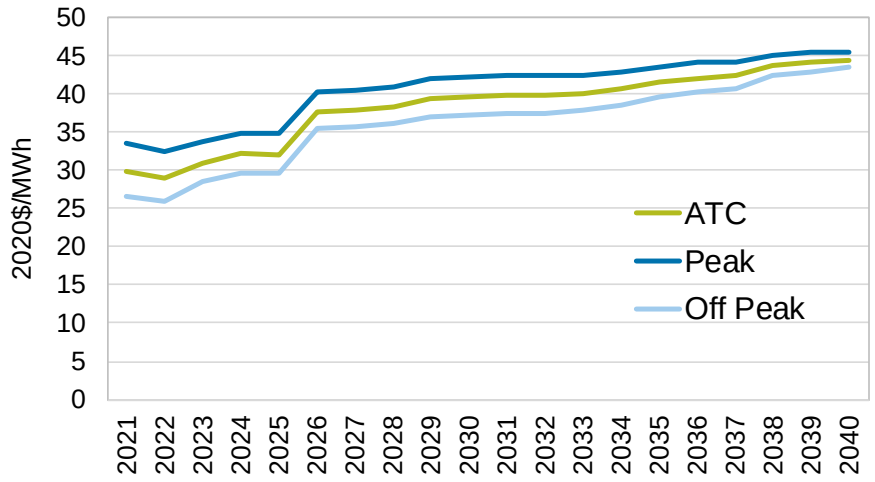
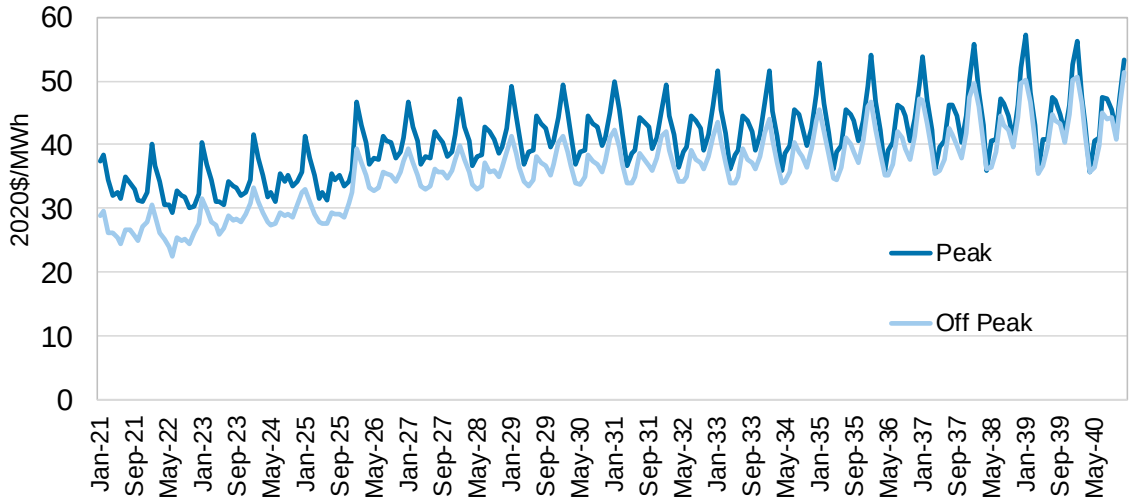
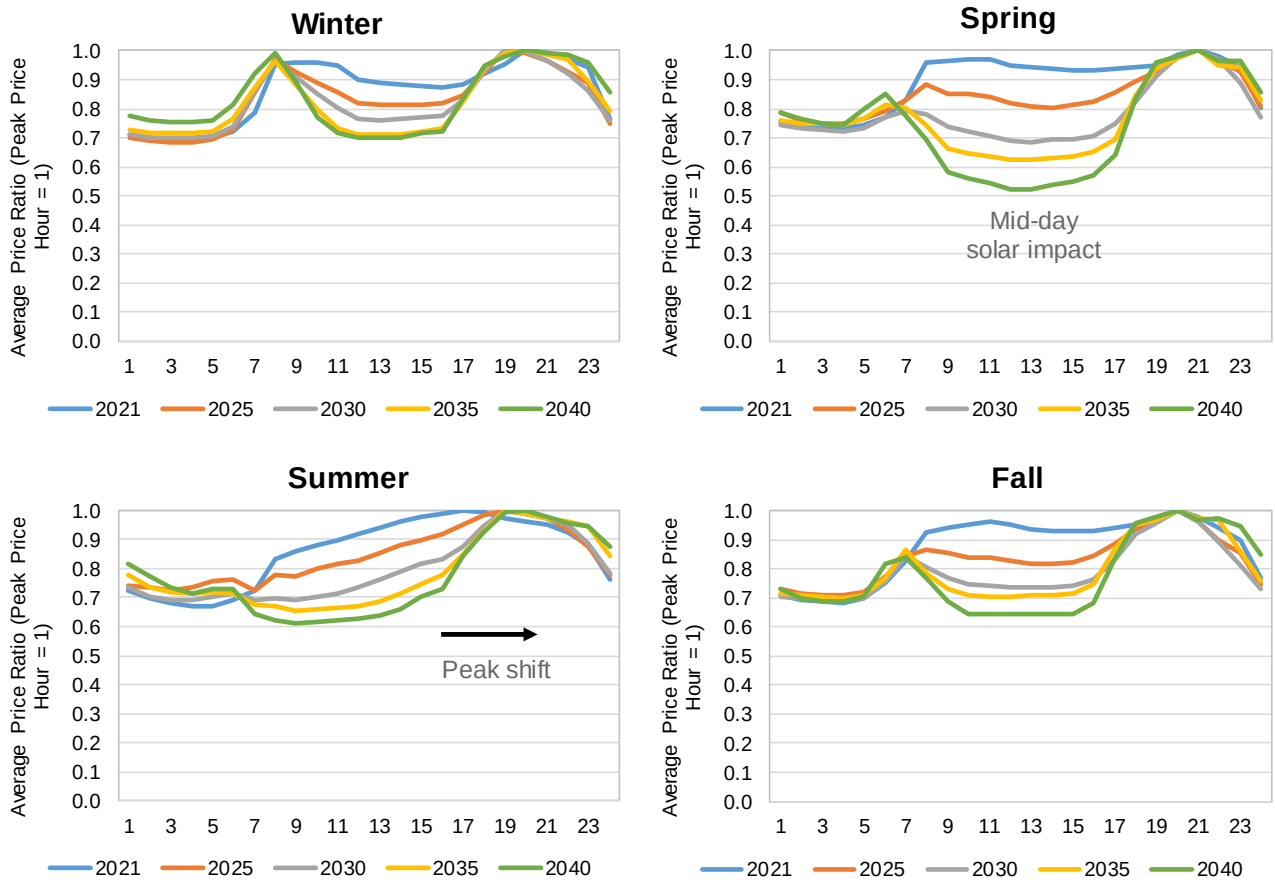


Figure 8-21: LRZ6 (Indiana) Reference Case Monthly Price Projections



Given the expectation for a growing share of intermittent renewable resources in the MISO market over time, hourly price profiles are likely to shift, and CRA's analysis incorporates this phenomenon over time. For example, mid-day prices are expected to decline as a result of solar output, particularly in the spring months when solar output is high, but electric demand is generally low. In addition, the peak price periods during the summer months are expected to shift from mid-afternoon to early evening, in line with solar generation patterns. This is illustrated in Figure 8-22.

Figure 8-22: MISO Hourly Energy Price Shape Projections Over Time



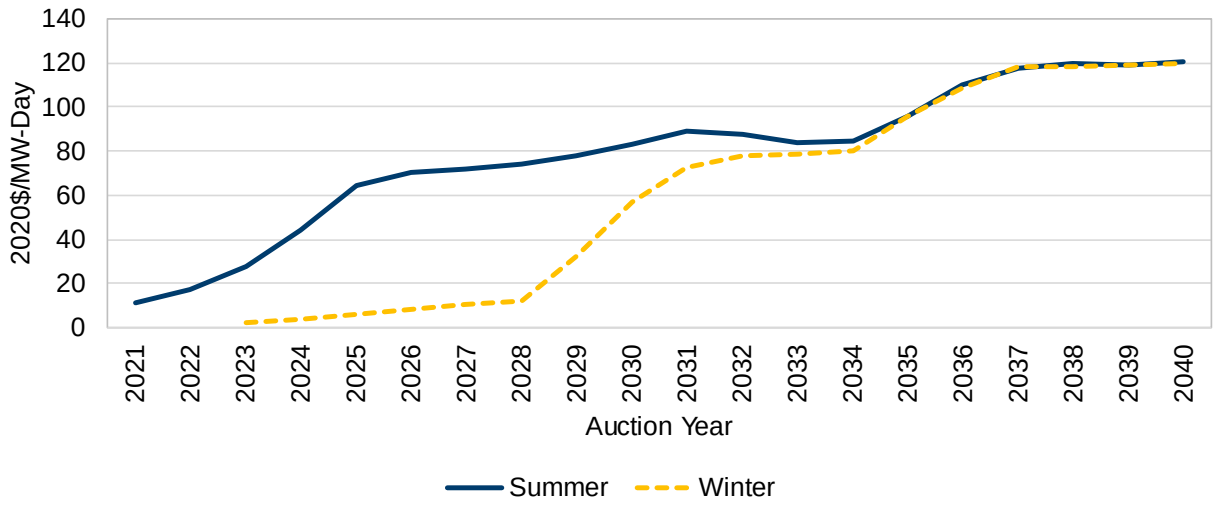
Reference Case Capacity Price Forecast

In addition to the energy market, MISO also operates a capacity market which procures capacity in an annual auction. The capacity market is based on an administratively-set demand requirement and supply offers from market participants that are willing to sell capacity. Recent market prices have been relatively low even as coal capacity retires as a result of flat load and as the market has witnessed increases in renewable capacity and behind-the-meter, demand response, and energy efficiency supply.

Going forward, CRA expects capacity prices to remain low in the near-term, although continued coal retirements over the 2020-2024 period are expected to tighten the reserve margin throughout the system. Over the longer-term, CRA's price forecast is based on existing unit going-forward costs in a utility-dominant market, although there may be periods of volatility between the CONE and $0 (for example, LRZ 7 cleared at CONE in 2020). Given the expectation for MISO to institute a seasonal capacity construct in 2021, the capacity price outlook also includes expectations for pricing in the winter months. In the near-term, winter reserve margins are higher than summer reserve margins, resulting in expectations for lower prices. However, over time,

continued fossil fuel retirement and increasing solar penetration (which gets minimal capacity credit during the winter) drive convergence between expected summer and winter prices. Figure 8-23 presents the Reference Case capacity price projections over time.

Figure 8-23: Reference Case MISO Capacity Price Projections



8.3 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment

After defining the Reference Case market drivers and conditions, NIPSCO worked to identify the key uncertainties and drivers that could impact future portfolio performance over the long-term. These were grouped into four major categories, including:

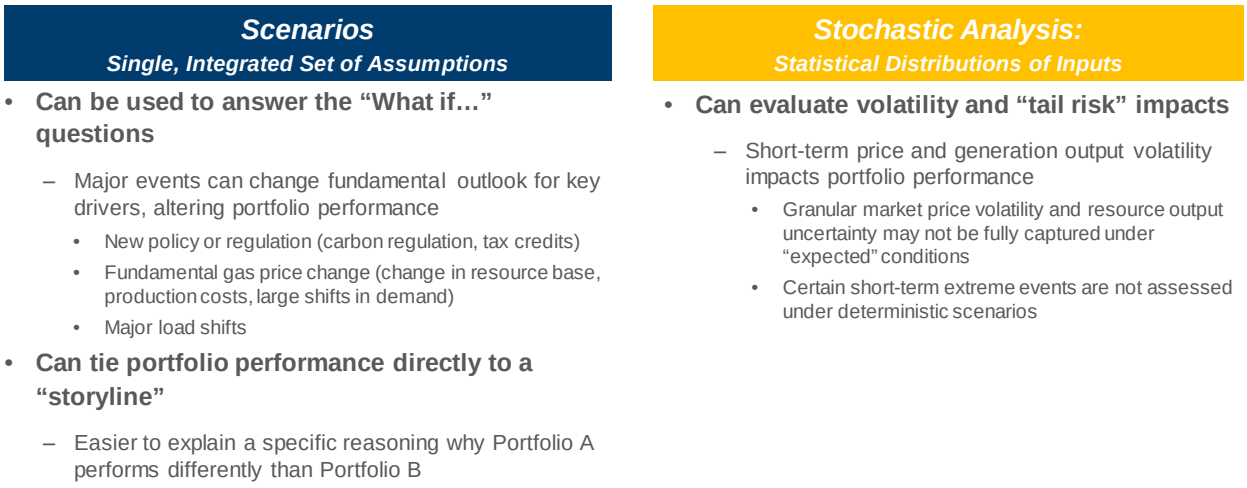
- Commodity prices, especially for natural gas and power;
- Environmental policy, particularly regarding carbon pricing, other greenhouse gas emission reduction policies, and federal subsidies and tax credits for specific technologies;
- NIPSCO load growth, including uncertainty associated with economic growth, EV penetration, DER penetration, electrification, and industrial load; and
- The future value of intermittent resources associated with capacity credit and hourly generation output.

After identifying the major drivers of uncertainty, NIPSCO then assessed whether each would be best addressed through scenario or stochastic analysis. In the 2021 IRP, NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across *both* scenario risk and stochastic risk, since the two complementary approaches can be used to answer different questions and quantify risk in different fashions. Scenarios were structured to assess major

changes to specific market driver assumptions, along with related feedbacks, while stochastic analysis was performed to evaluate more granular volatility and tail risk, largely based on historical data observations. Figure 8-24 provides a summary of the primary purposes and benefits of deploying each approach. In the 2021 IRP, NIPSCO evaluated uncertainty variables in the following fashion:

- Scenario variables:
  - Annual and monthly natural gas prices;
  - Federal carbon policy regulation, including through carbon prices or a clean energy standard;
  - Federal technology incentives, including extensions and expansions of the production and investment tax credits;
  - Hourly MISO power market prices
  - NIPSCO and MISO regional load growth, driven by economic factors, EV and DER penetration, electrification initiatives, and industrial load risk; and
  - Capacity credit for solar resources over time.
- Stochastic variables:
  - Daily natural gas prices;
  - Hourly MISO power market prices; and
  - Hourly renewable generation output for wind and solar resources;

Figure 8-24: Scenario and Stochastic Uncertainty Approaches

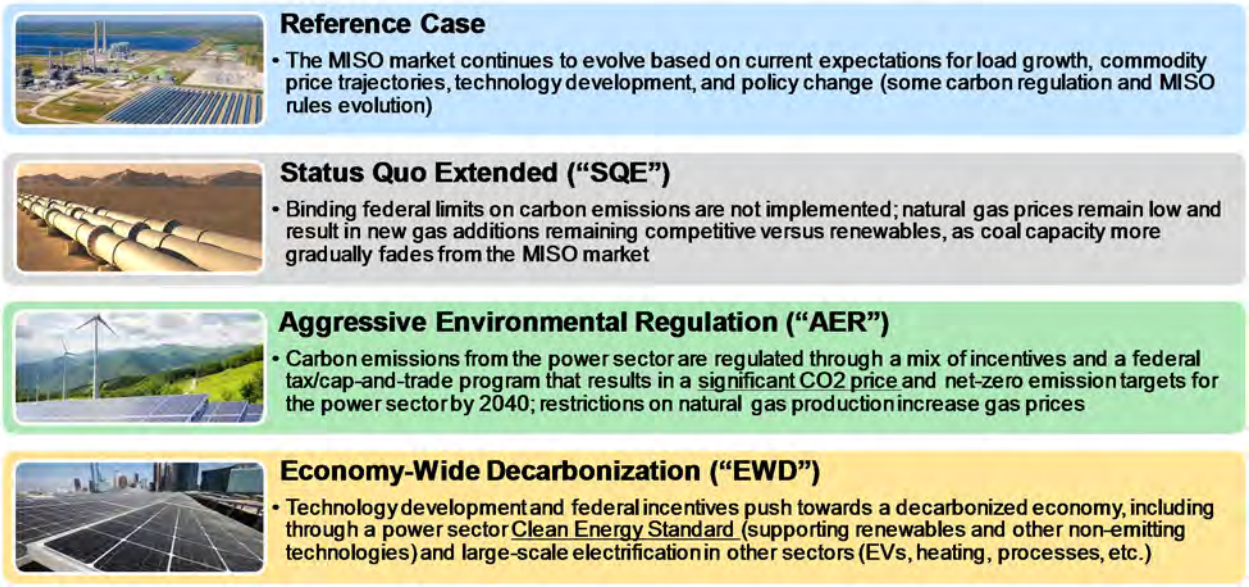


8.4 IRP Scenarios

8.4.1 Scenario Overview

In the scenario development process, NIPSCO developed narratives to describe possible futures, which were organized around "themes" or "states-of-the-world." The first step in developing the scenario themes was to construct assumptions for key macro drivers, which would ultimately translate into changes for the more detailed drivers impacting NIPSCO's portfolio costs. Ultimately, NIPSCO developed three scenarios to supplement the Reference Case, relying on the foundation that was built in its 2016 and 2018 IRP processes, but incorporating recent market and regulatory trends and specific risks related to the 2021 IRP Reference Case assumptions. A summary of the scenario themes is shown in Figure 8-25.

Figure 8-25: Scenario Theme Overview



NIPSCO then assessed the themes for diversity and robustness and translated the scenario themes into specific assumptions for the key inputs of gas price, carbon policy, federal technology incentives, load growth, and solar capacity credit. Figure 8-26 summarizes the directional movement of the key input assumptions relative to the Reference Case, while the subsequent sections of this chapter outline the detailed inputs that were developed for each scenario.[91]

[91] Note that CRA's fundamental MISO market modeling process develops unique MISO market outcomes for each scenario based on the fundamental inputs outlined in the table. Therefore, MISO power market prices are not explicitly noted as input assumptions.

Figure 8-26: Summary of Major Scenario Parameters

Scenario Name	Gas Price	CO_2 Price	Federal Tech. Incentives	Load Growth	Solar Capacity (ELCC) Credit (Current → 2040)
Reference Case	Base	Base	2-year ITC extension (solar); 1-year PTC extension (60%)	Base	50% → 25%
Status Quo Extended	Low	None	No change to current policy	Lower	50% → 30%
Aggressive Environmental Regulation	High	High	5-year ITC extension (solar) plus expansion to storage; 3-year PTC extension (60%)	Close to Base	50% → 15%
Economy-Wide Decarbonization	Base	None	10-year ITC extension (solar) plus expansion to storage; 10-year PTC extension (60%); tracking further potential federal support for advanced tech including hydrogen and NG CCS	Higher	50% → 15%

8.4.2 Status Quo Extended Scenario

Summary Description

The SQE scenario represents a future with persistently low natural gas prices, limited federal regulation of carbon emissions from the power sector, and lower near-term economic growth. The scenario addresses the combined risks of low commodity prices for natural gas and power, no carbon price, and very low load growth for NIPSCO. Given the large amount of uncertainty related to federal action to control carbon emissions, the scenario specifically develops a future where carbon emissions are not restricted while conventional fuel prices remain low, testing the robustness of portfolios against this important risk.

Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the SQE scenario's price trajectory. Overall, lower prices are realized through the following assumptions:

- Larger resource size: PGC and other forecasts have consistently shown growth in resource from year to year. In the SQE scenario, the starting unproven resource anticipates a growth in resources expected in the upcoming PGC 2020. The assumed 15% increase is well within the range of uncertainty from the 2018 unproven PGC estimates.

- Higher well productivity: Improvements in well productivity are assumed to be realized more quickly in this scenario, but stall in the 2040s after achieving long-term targets from the Reference Case.

- Lower fixed and variable well costs: Improvements in drilling technology are assumed to occur more quickly, but stall in the 2040s after achieving long-term targets from the Reference Case. In addition, environmental costs are assumed to decrease to reflect lower CO2 pressure relative to the Reference Case (as discussed in more detail below).

- Lower export demand: Under construction LNG projects are assumed to be delayed in this scenario due to low prices and lack of demand. In addition, LNG capacity factors are assumed to stay around 60% due to low prices and demand. Capacity factors for pipeline exports are assumed to be 50% in this scenario, down from a 70% expectation in the Reference Case.

Figure 8-27 summarizes the major natural gas price drivers for the SQE scenario relative to those in the Reference Case.

Figure 8-27: Summary of Natural Gas Price Drivers for SQE Scenario

Driver	Reference Case	Low (SQE)
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Unproven resource base assumed higher
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Accelerated improvement in well productivity
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Accelerated improvements in drilling technology • Lower environmental costs
NGL & Condensate Value	• Liquids valued at 70% of Annual Energy Outlook (AEO) 2021 Reference Oil Price	• Base view
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	• Base view
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Higher power sector demand, but no change in other sectors
LNG Exports	• Under-construction projects completed and total exports rising from around 7 bcf/d in 2020 to around 14 bcf/d by 2030	• Export projects delayed due to lower price environment
Pipeline Exports	• Exports rise from 5 bcf/d in 2020 to just under 10 bcf/d by 2030	• Lower usage rates on pipelines

Carbon Regulation

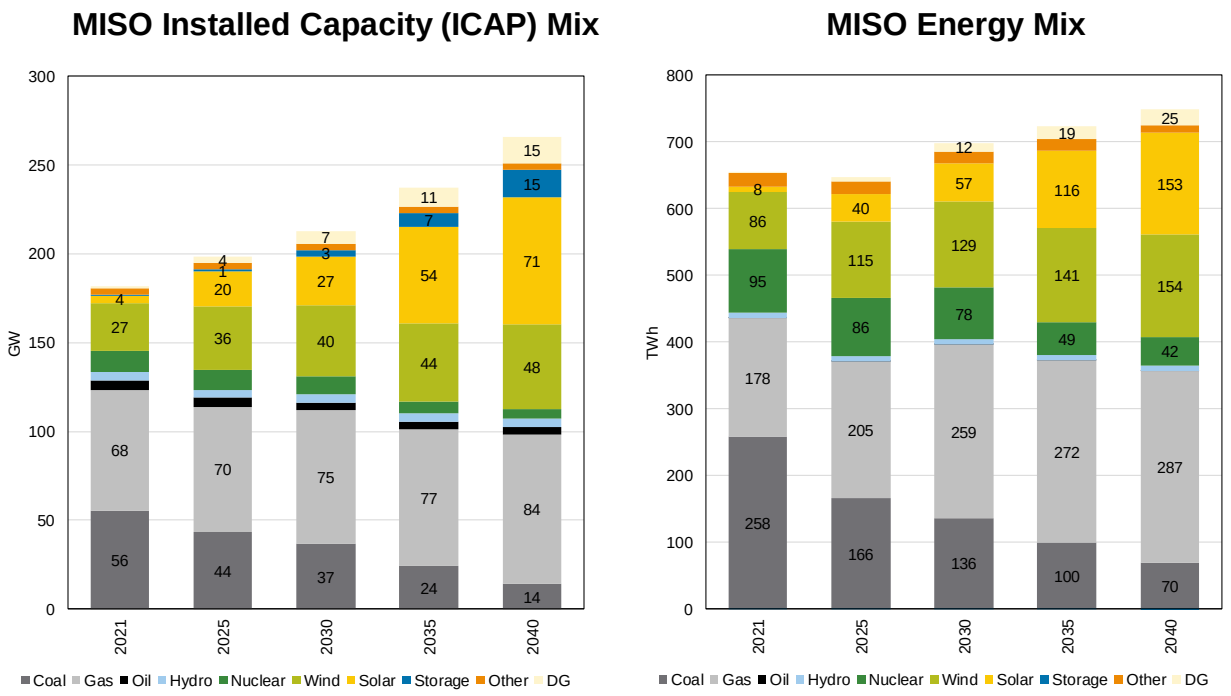
The SQE scenario includes no price on carbon based on an expectation for less stringent environmental regulation at the federal level. The scenario assumes that continued hurdles in Congress stymie proposed environmental legislation, and federal courts limit the scope of any

executive actions. While states continue to advance environmental goals under this scenario, no meaningful carbon emission limits are assumed to be implemented at the federal level.

MISO Power Market Dynamics

In the SQE scenario, the MISO market is expected to transition more slowly away from fossil-fired resources and more gradually towards renewables as a result of lower natural gas prices and no price on carbon. While the Reference Case expects over half of all energy in MISO to come from renewable resources by 2040, the SQE scenario expects close to 40% renewable energy by the same period. The lower expectations for solar generation in this scenario relative to the Reference Case result in ELCC or capacity credit for solar only declining to 30% (as opposed to 25%) by 2040. Meanwhile, natural gas and coal generation are projected to retain an energy share close to 50% by 2040, with most fossil-fired energy produced by natural gas. This is illustrated in Figure 8-28.

Figure 8-28: MISO Power Market Evolution for SQE Scenario



NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast outlines the load impacts associated with the SQE scenario in significant detail, but the low load trajectory is broadly premised on the following drivers:

- Lower economic growth: The Moody's 90th percentile downside is used for key economic growth factors, reflecting a scenario where the impacts of COVID-19

linger, consumer spending lags government stimulus levels, and unemployment grows again.

- Lower electric vehicle and distributed energy resource penetration, as economic conditions and market prices reduce adoption rates.

- Lower industrial load: Additional industrial load loss is assumed to reduce the firm large industrial class requirement down to 70 MW.

8.4.3 Aggressive Environmental Regulation Scenario

Summary Description

The AER scenario represents a future in which environmental regulations are more stringent than anticipated in the Reference Case. More specifically, the scenario contemplates a federal carbon tax or cap-and-trade framework that drives towards a net-zero emissions power sector and results in a significant price on carbon. In addition, the scenario includes the assumption that environmental policy restricts natural gas production and drives higher production costs for natural gas, resulting in a higher natural gas price outlook. Overall, the scenario addresses the risk of earlier and higher carbon prices and the risk of higher prices for natural gas and power.

Natural Gas Prices

As in the SQE scenario, CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the AER scenario's price trajectory. Overall, higher prices are realized primarily through changes in the supply side dynamics for natural gas, including the following assumptions:

- Smaller resource size: Instead of assuming that available gas supply grows over time, the AER scenario assumes that future exploration is limited by policy actions (for example, drilling bans).

- Slower improvements in well productivity: Improvements in technology are assumed to slow over time in the AER scenario, as interest rotates into clean energy sectors due to changing policy incentives.

- Higher fixed and variable well costs: Improvements in technology are assumed to slow, as interest rotates into clean energy sectors due to changing policy incentives. In addition, environmental costs are assumed to increase in the AER scenario to reflect additional regulation of emissions from fossil fuel producing sectors, include natural gas drilling and extraction.

- Lower natural gas liquids and condensate value and lower associated gas volumes: The expected transition from internal combustion engine vehicles to electric vehicles in the AER scenario lowers petroleum demand and results in an assumption for lower oil and associated liquids prices.

Figure 8-29 summarizes the major natural gas price drivers for the SQE scenario relative to those in the Reference Case.

Figure 8-29: Summary of Natural Gas Price Drivers for AER Scenario

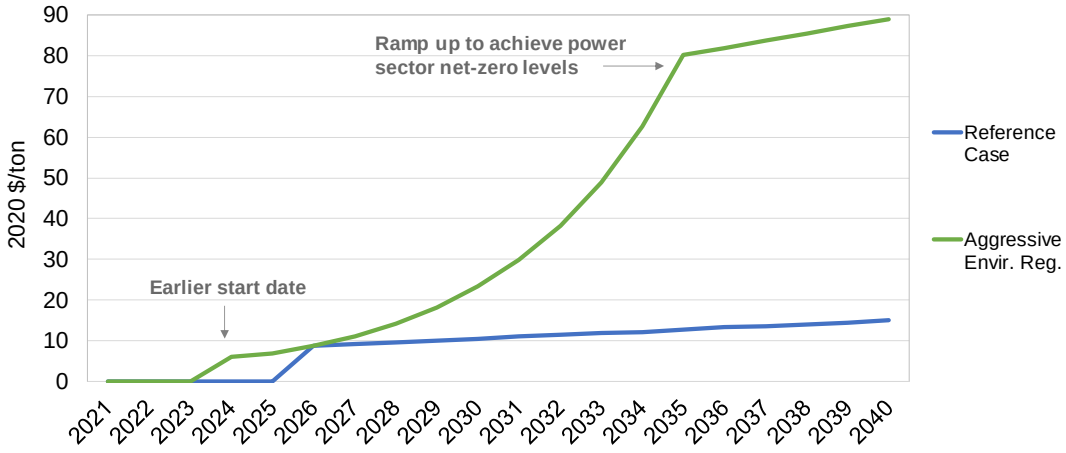
Driver	Reference Case	High (AER)
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Remove resource growth resulting from policy changes (eg. drilling bans)
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Slow improvement as policy drives investment into clean energy sectors
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Slow improvement as policy drives investment into clean energy sectors • Higher environmental costs
NGL & Condensate Value	• Liquids valued at 70% of Annual Energy Outlook (AEO) 2021 Reference Oil Price	• Lower oil prices, given lower demand
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	• Lower, given lower oil demand
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Significant drop in power sector and other demand
LNG Exports	• Under-construction projects completed and total exports rising from around 7 bcf/d in 2020 to around 14 bcf/d by 2030	• Base view, even as U.S. prices increase
Pipeline Exports	• Exports rise from 5 bcf/d in 2020 to just under 10 bcf/d by 2030	• Base view, even as U.S. prices increase

Carbon Regulation

The AER scenario assumes a significant price on carbon, based on the premise that the Biden Administration and Congress lay the groundwork for a carbon emission reduction program via a tax or cap-and-trade regime, with future governments implementing stricter CO2 policy to establish net zero power sector targets by 2040. Under such assumptions, a price on carbon emissions would be instituted by 2024, with a ramp up in stringency over time to achieve net zero levels for the power sector. Based on CRA's analysis, in the AER scenario, a carbon price increase to the $80-90/ton range (in real 2020$) could make certain alternative technologies required to achieve net zero emissions by the 2035-2040 time period (such as hydrogen, CCS, and nuclear) economically feasible. Figure 8-30 summarizes the carbon price projection in the AER scenario relative to the Reference Case. CRA's MISO market analysis (discussed in additional detail below) projects that such a price would achieve clean energy generation percentages in the MISO region of approximately 90-95% by 2040.

In addition to the carbon pricing drivers, the AER scenario also assumes a five-year extension to the federal ITC at the 26% level and a three-year extension to the federal PTC at the 60% level. In addition, the scenario assumes that the ITC is extended to stand-alone storage facilities over the extension period. As of the time of the development of the 2021 IRP assumptions, only storage units paired with renewable energy resources can qualify for the ITC.

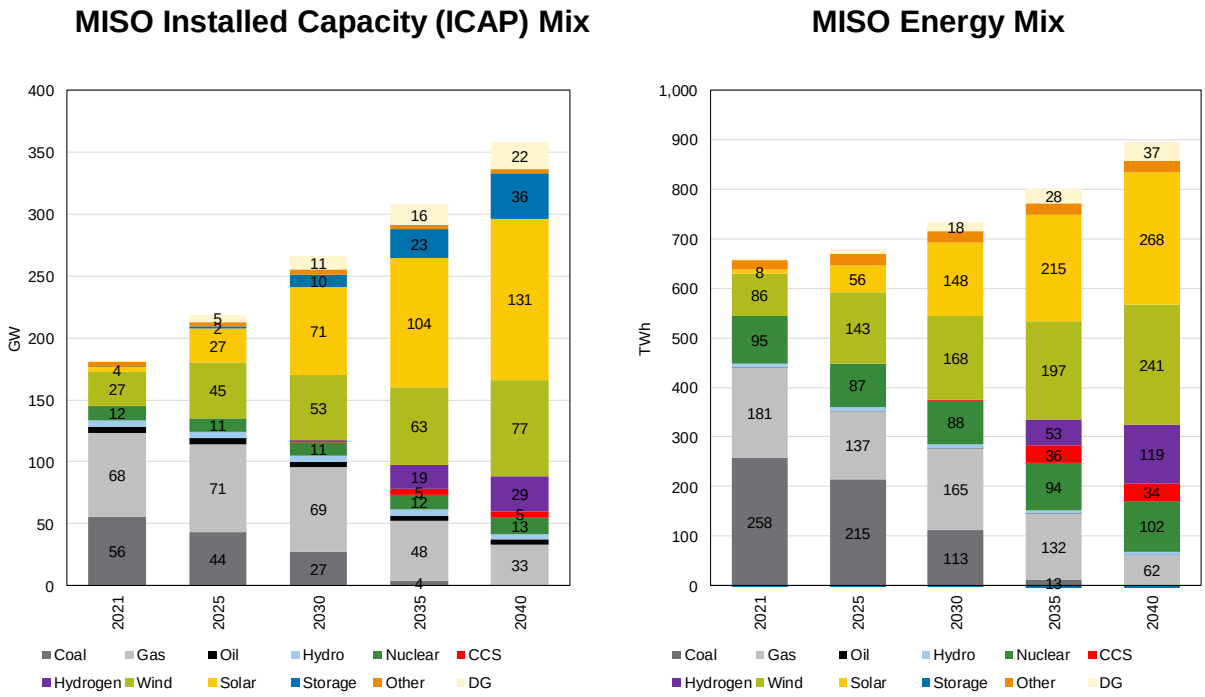
Figure 8-30: Carbon Price Projection in AER Scenario



MISO Power Market Dynamics

In the AER scenario, higher carbon prices and higher natural gas prices are expected to both accelerate the transition away from fossil-fired resources and towards clean technologies across the MISO market. All coal capacity is projected to either retire or retrofit to CCS by 2040. In addition, new nuclear capacity is projected, and hydrogen fuel is projected to be economic in new or existing gas turbine and combined cycle capacity. Overall, the MISO market is projected to generate over 90% of its energy from clean, non-CO2 emitting resources by 2040. The significant penetration of solar results in ELCC credit for solar declining to 15% (as opposed to 25%) by 2040. This is illustrated in Figure 8-31.

Figure 8-31: MISO Power Market Evolution for AER Scenario



NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast outlines the load impacts associated with the AER scenario in significant detail, but the load trajectory is broadly premised on the following drivers:

- Reference Case economic growth.
- Higher electric vehicle penetration due to economic factors associated with carbon taxes on gasoline fuel.
- Higher distributed energy resource penetration as a result of expected increases in retail electric rates and decreases in solar and storage technology costs.

8.4.4 Economy-Wide Decarbonization Scenario

Summary Description

The EWD scenario represents a future in which federal environmental regulations drive significant emission reductions throughout the economy *without* imposing a price on carbon. Instead, CO2 emission reductions are assumed to be the result of a power sector clean energy standard, extended and expanded federal tax credits for clean energy technologies, and measures that incentivize electrification of other parts of the economy, such as transportation and other residential, commercial, and industrial end uses. Electrification measures are projected to

significantly increase power demand, particularly during the winter months. Overall, the scenario addresses the risk of strict environmental regulation without the consequent increase in power prices that would be expected with a carbon price, as well as the risk of higher-than-expected NIPSCO load.

Natural Gas Prices

By design, the natural gas price assumption for the EWD scenario is identical to the Reference Case. While certain environmental regulations in this scenario might decrease demand for natural gas, others might increase production costs. Thus, the long-term outlook from the Reference Case (see above) was preserved.

Carbon Regulation

The EWD scenario assumes several federal policy initiatives that drive towards economy-wide decarbonization. As described in more detail in Chapter 7 (Environmental Considerations), the scenario assumptions broadly adopt several elements of the climate policy objectives outlined in President Biden's infrastructure plan framework. These include the following:

- A ten-year extension for both the ITC at the 26% level and the PTC at the 60% level. In addition, the scenario assumes that the ITC is extended to stand-alone storage resources over the ten-year extension period. Furthermore, tax credit extensions or expansions to other advanced technology, such as hydrogen, CCS, and nuclear are assumed.

- New federal investment and incentives to promote energy efficiency and electrification, including electric vehicles and other heating/industrial processes.

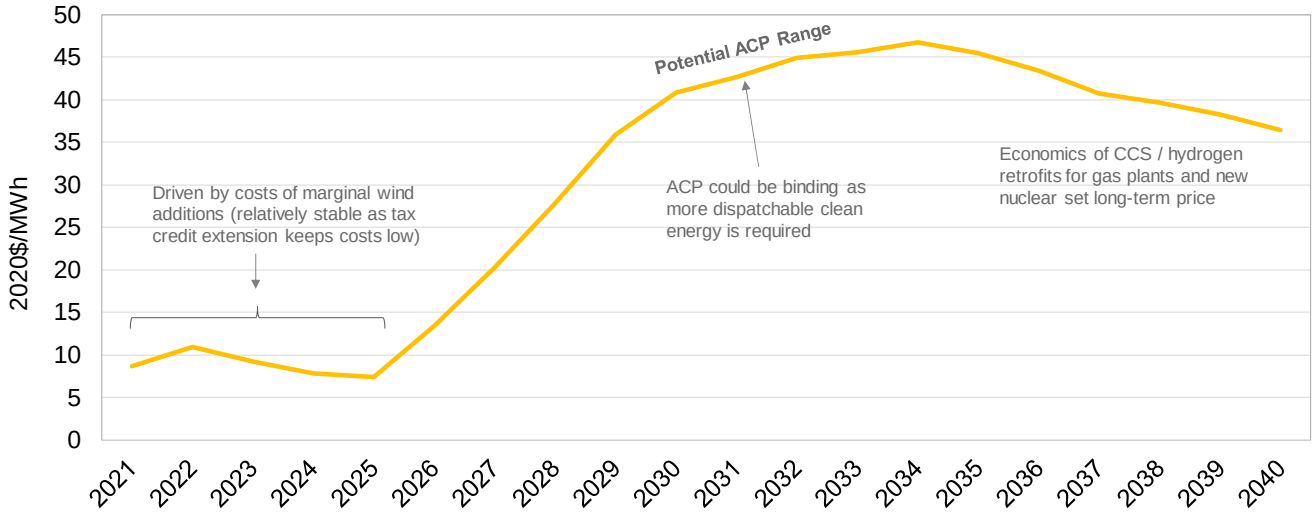
- A national clean energy standard aiming to achieve net-zero carbon emissions from the power sector (inclusive of assumed non-power sector offsets) by 2040. This is broadly consistent with the Biden Administration's stated goal of net-zero emissions for the power sector in 2035, but recognizes the potential for delays in full achievement given required technology advancement.

Overall, based on these scenario design considerations, no carbon *pricing* materializes, but the binding clean energy standard would be expected to drive a market for Clean Energy Credits or Zero Emission Electricity Credits. Under this construct, load serving entities like NIPSCO would be required to demonstrate compliance with the clean energy standard and be able to do so through their own resources or through the purchase Clean Energy Credits from other suppliers. If NIPSCO were to generate more clean energy than the target, excess credits could be sold. This construct is similar to the existing markets for Renewable Energy Credits.

CRA's projection of Clean Energy Credit pricing under the EWD scenario is summarized in Figure 8-32. In the early years of the forecast horizon, the costs of marginal wind (and solar) additions would likely drive the market, keeping prices at or below $10/MWh. Over time, however, as the clean energy standard ramps up, higher cost resource additions would be required

in the market, and a likely ACP would set a ceiling on the Clean Energy Credit price in the early 2030s.[92] By the late 2030s, CRA's analysis suggests that the economics of hydrogen or CCS retrofits for gas plants and new nuclear capacity would improve sufficiently to keep the Clean Energy Credit price in the $35-40/MWh range (real 2020$).

Figure 8-32: Projected Clean Energy Credit Pricing Under EWD Scenario



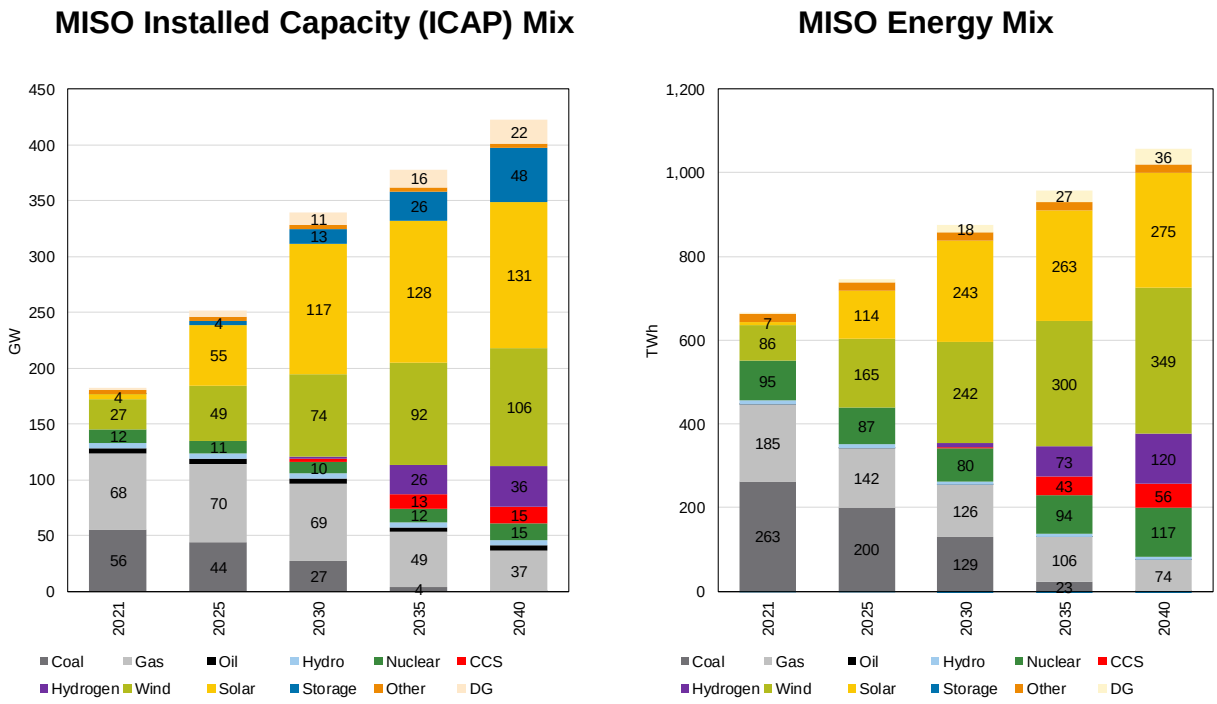
MISO Power Market Dynamics

In the EWD scenario, assumed tax credit extensions/expansions and the clean energy standard both contribute to the acceleration of clean technology expansion across the MISO market. All coal capacity is projected to either retire or retrofit to CCS by 2040, and some natural gas capacity is expected to retrofit to CCS as well. Unlike the AER scenario, where all CCS conversions were associated with coal-fired plants, the lower gas prices in EWD drive additional gas CCS conversions. In addition, new nuclear capacity is projected, and hydrogen fuel is projected to be economic in new or existing gas turbine and combined cycle capacity, given the value associated with expected Clean Energy Credit pricing, as discussed above. Overall, the MISO market is projected to generate over 90% of its energy from clean, non-CO2 emitting resources by 2040. The significant penetration of solar results in ELCC credit for solar declining to 15% (as opposed to 25%) by 2040.

In addition, due to the electrification growth assumptions in the EWD scenario, overall demand requirements across the MISO footprint are significantly higher than in the other scenarios, resulting in the highest capacity buildout overall. The projected MISO-wide capacity and energy mixes over time for the EWD scenario are presented in Figure 8-33.

[92] Note that the ACP backstop price range used in this analysis is based loosely on provisions in the proposed CLEAN Future Act. Such provisions suggest an ACP in the $40-50/MWh (real 2020$) range by the early 2030s.

Figure 8-33: MISO Power Market Evolution for EWD Scenario



NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast outlines the load impacts associated with the EWD scenario in significant detail, but the load trajectory is broadly premised on the following drivers:

- Higher economic growth: The Moody's 10th percentile upside is used for key economic growth factors, reflecting a scenario where post-COVID-19 re-openings and fiscal stimulus boost economic growth more than expected.

- Higher electric vehicle and distributed energy resource penetration, as a result of policy incentives (extended ITC, EV subsidies, etc.), technology advancement, and behavioral change.

- Higher electrification in other sectors of the economy, including residential and commercial/industrial heating, hot water, appliances, and processes, based on information from MISO's MTEP Futures process.

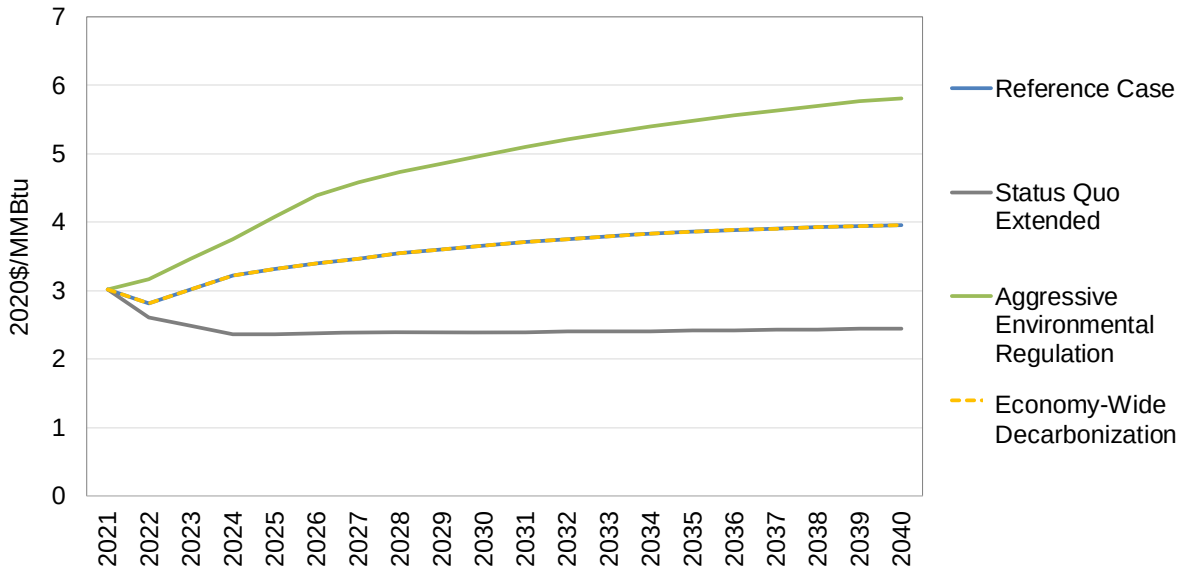
8.4.5 Scenario Comparisons

The following section provides a series of summary comparisons across all four planning scenarios to illustrate the ranges of outcomes NIPSCO has evaluated for key metrics including natural gas prices, carbon regulation, MISO power market dynamics, and NIPSCO load growth.

Natural Gas Prices

Figure 8-34 summarizes natural gas price projections for the Henry Hub across all four scenarios. As discussed above, the supply and demand impacts for the SQE scenario result in gas prices staying at or below $2.50/MMBtu (in real 2020$) over the entire fundamental forecast period. On the other hand, expectations for lower supply, higher production costs, and lower associated liquids prices result in an increase in natural gas prices in the AER scenario over time. In that scenario, gas prices climb to nearly $6/MMBtu (in real 2020$) by 2040.

Figure 8-34: Natural Gas Price Range across Scenarios



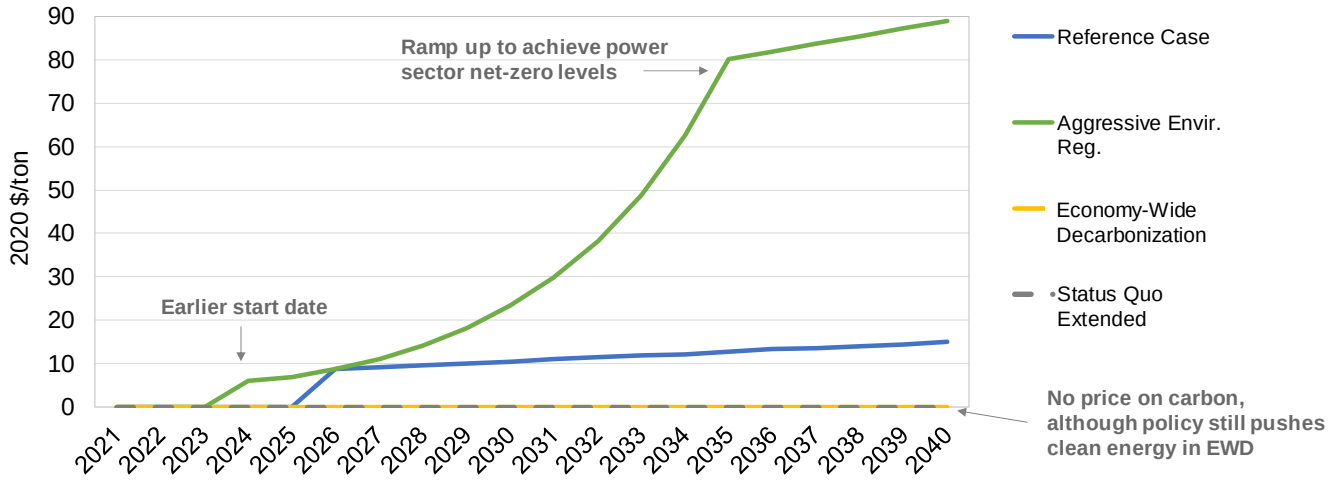
Carbon Regulation

As noted earlier, NIPSCO's scenarios incorporate a wide range of potential carbon regulation outcomes, including the possibility that carbon emissions are not regulated at the federal level over the study horizon as well as two different means of achieving deep power sector decarbonization (through a carbon price or a clean energy standard with extended federal subsidies). The rationale and potential outcome for NIPSCO's carbon policy scenarios relative to the Reference Case are summarized in Figure 8-35, with a comparison of carbon prices illustrated in Figure 8-36. This approach allows NIPSCO's 2021 IRP to assess a broad range of price outcomes, while also recognizing the significant uncertainty associated with policy design and ultimate implementation.

Figure 8-35: Carbon Policy Scenario Comparisons

	Status Quo Extended	Aggressive Environmental Regulation	Economy-Wide Decarbonization
Rationale	Continued hurdles in Congress stymie legislative outcomes, and federal courts limit the scope of executive actions	The current Administration / Congress lay the groundwork, and future governments implement stricter CO_2 policy to establish net zero power sector targets by 2040	Near-term policy action focuses on clean technology and electrification initiatives and initial framework for power sector clean energy mandates
Potential Outcome	States continue to advance goals, but federal legislation stops short of implementing a carbon price, and any potential EPA action is held up in the courts	Policy evolves towards a price on carbon, particularly for the power sector, with a ramp up in stringency over time to achieve net zero levels	No carbon *pricing* materializes, but economy-wide carbon reduction policy momentum includes a binding clean energy standard (100% clean with offsets) for the power sector

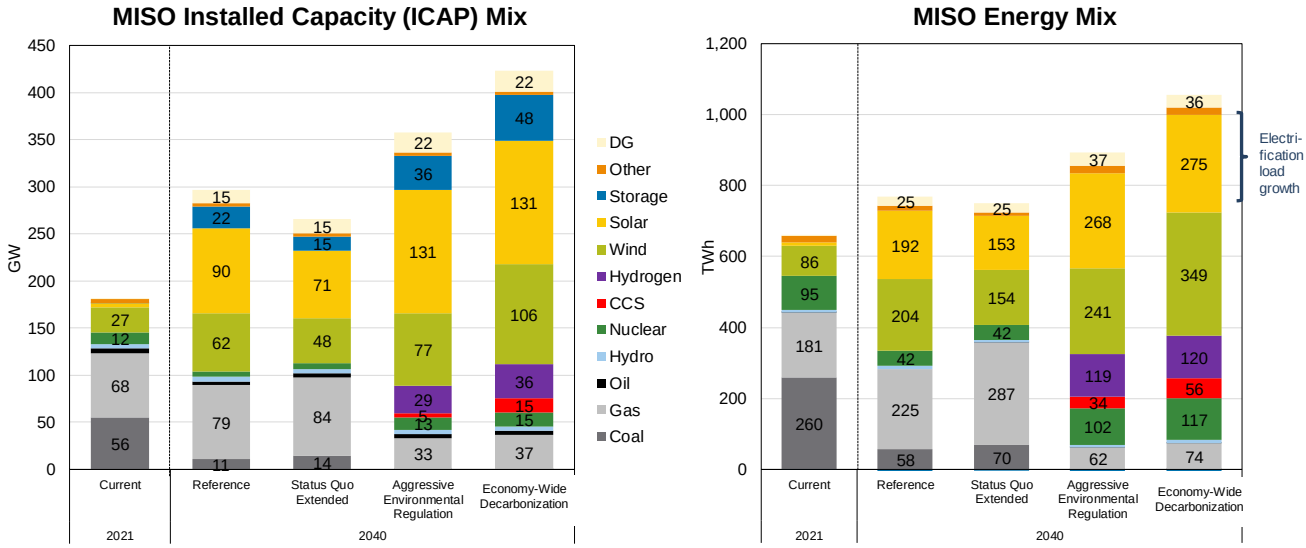
Figure 8-36: Carbon Price Range across Scenarios



MISO Power Market Dynamics

The MISO power market is projected to evolve very differently across NIPSCO's four planning scenarios. As discussed earlier, the Reference Case projects a steady transition away from coal capacity and energy towards renewables and, to a lesser extent, natural gas. The SQE scenario projects a stronger role for fossil capacity and energy over time, while the AER and EWD scenarios project significant shifts towards renewables and new clean energy technologies, including nuclear, CCS, and hydrogen. In addition, incremental load from electrification activities is included in the scenarios that achieve high levels of decarbonization, particularly EWD. These dynamics are illustrated in Figure 8-37, which summarizes the current MISO capacity and energy mix and the projections in 2040 across all four scenarios.

Figure 8-37: MISO Capacity and Energy Mix Outlook across Scenarios



Given the growing penetration of intermittent energy resources across all scenarios, the hourly generation profiles at the MISO market level are also projected to be significantly different across scenarios over time. This impacts expected dispatch of various resource types and market prices at the hourly level. Figure 8-38, Figure 8-39, and Figure 8-40 all display projected hourly generation projections by resource type at the MISO level for a sample summer, winter, and spring shoulder month, respectively for 2040. The figures display expected hourly output for non-dispatchable renewable and nuclear resources, along with gross and net load projections. Major seasonal observations include:

- In the summer, large ramping requirements are likely to develop in the evenings, especially in the AER and EWD scenarios.
- In the winter, higher overnight loads need to be met when solar is unavailable, particularly in the EWD case, with high electrification-driven winter loads.
- In the spring shoulder months, mid-day energy output from renewables could be as high as system loads, resulting in low prices and potential curtailment if not stored.

Figure 8-38: MISO Hourly Generation Projections – Summer, 2040

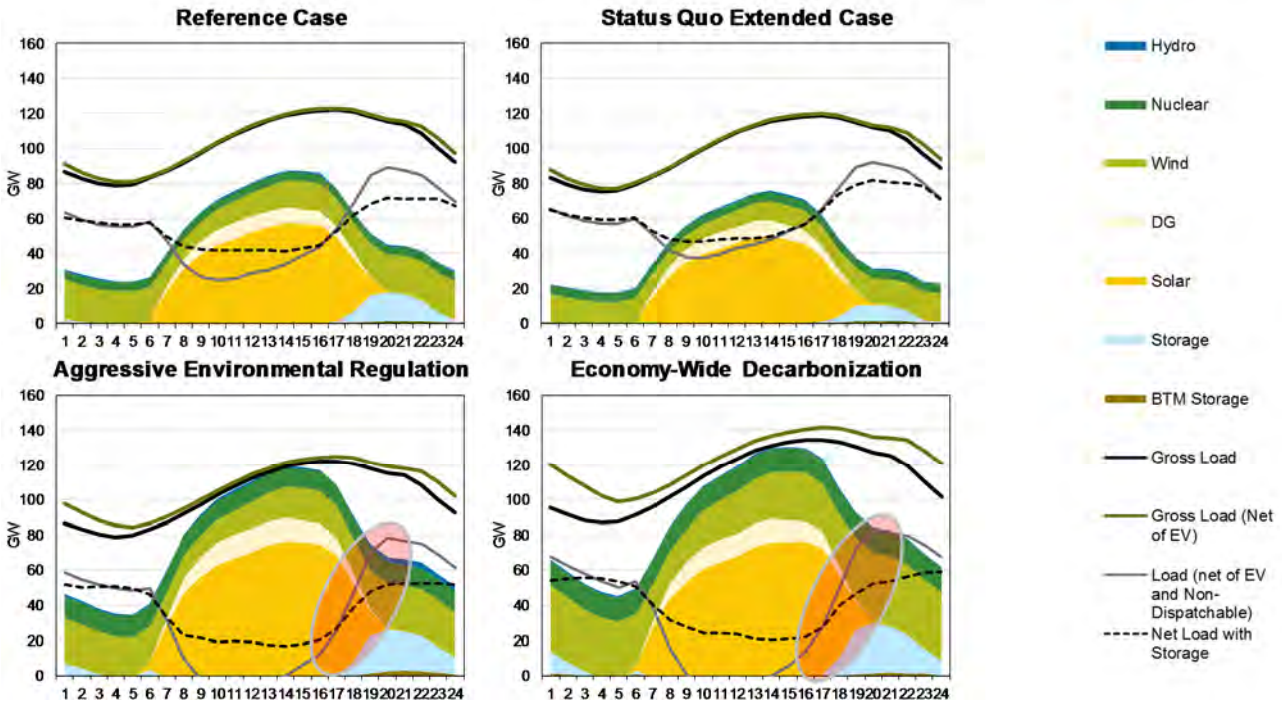


Figure 8-39: MISO Hourly Generation Projections – Winter, 2040

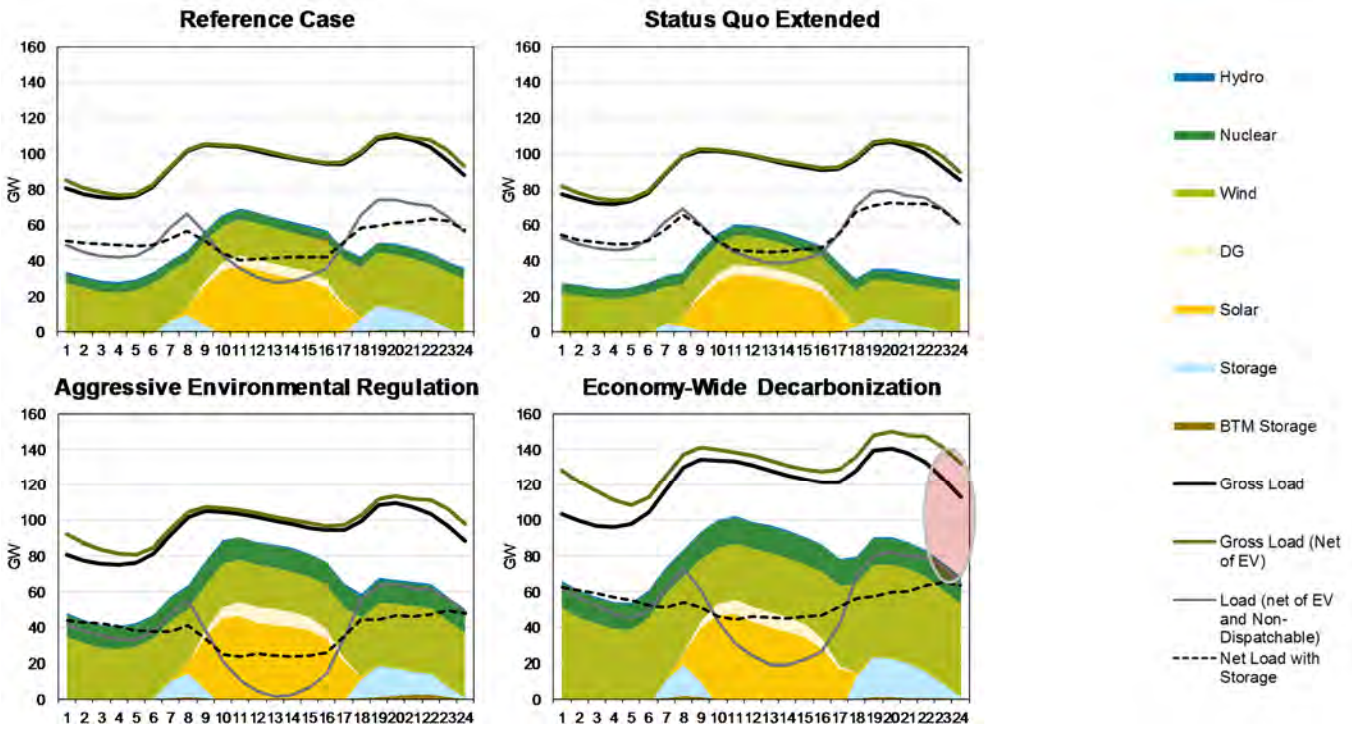
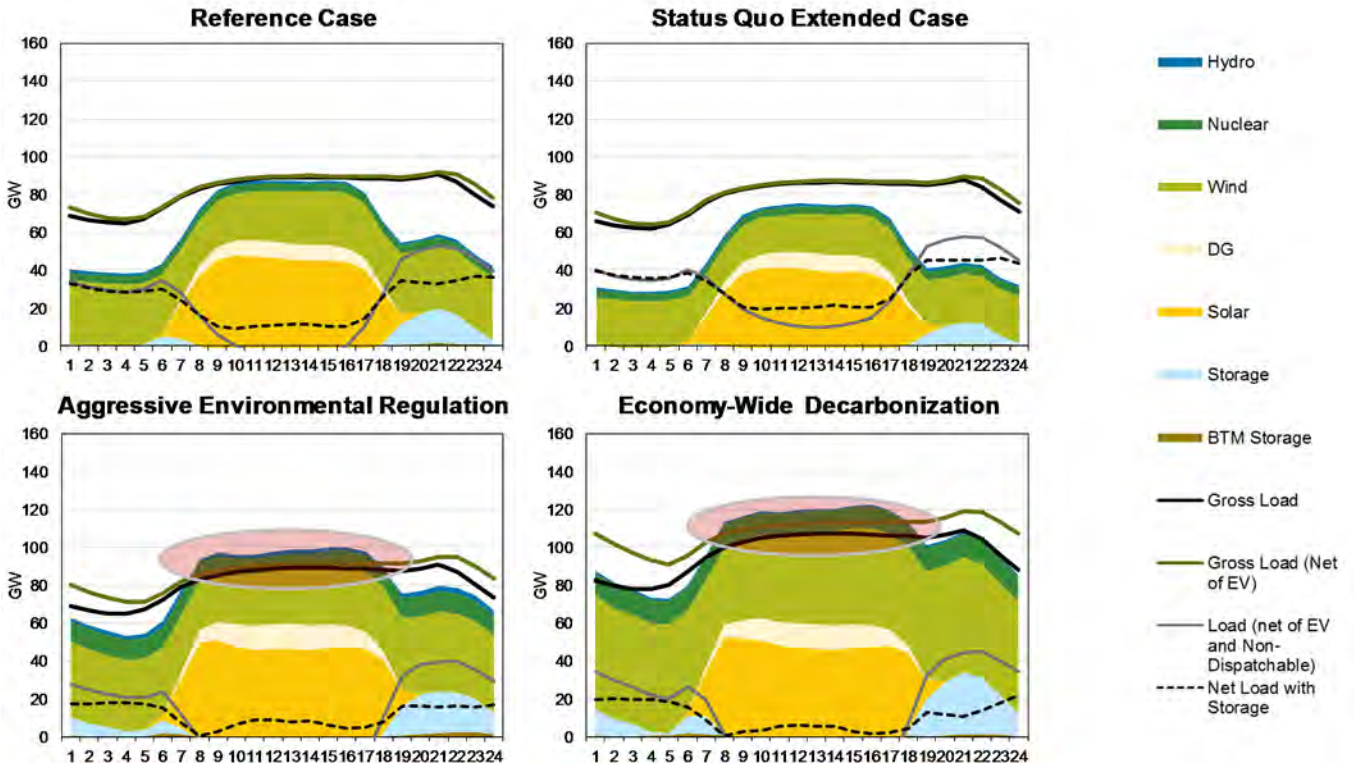


Figure 8-40: MISO Hourly Generation Projections – Spring Shoulder Month, 2040



The different energy market projections contribute to a range of outcomes for MISO-wide clean energy penetration, MISO-wide CO2 emissions, energy prices at various levels of granularity, and capacity prices.

While MISO's generation mix is currently composed of approximately 30% clean energy resources (wind, solar, hydro, other renewables, and nuclear), the four scenarios project this level to grow to between 40% to 70% by 2030 and between 50% to 90% by 2040. Note that to achieve 100% clean energy and net zero emission power sector outcomes in the AER and EWD scenarios, additional offsets outside the power sector are assumed to be acquired by market participations. Figure 8-41 summarizes the projected clean energy percentages over time across scenarios.[93] Similarly, a range of carbon emission reductions across MISO are projected across the four scenarios. The MISO market has already achieved an approximate 30% reduction in CO2

[93] Note that the clean energy calculation is based on total MISO clean energy generation (wind, solar, hydro, other renewables, nuclear, CCS, hydrogen), adjusted for projected imports and exports, divided by MISO net load.

emissions relative to a 2005 baseline, with an expected reduction of between 50% and 63% by 2030 and 63% to 92% by 2040. This is illustrated in Figure 8-42.[94]

Figure 8-41: MISO Clean Energy Percentage Projections across Scenarios

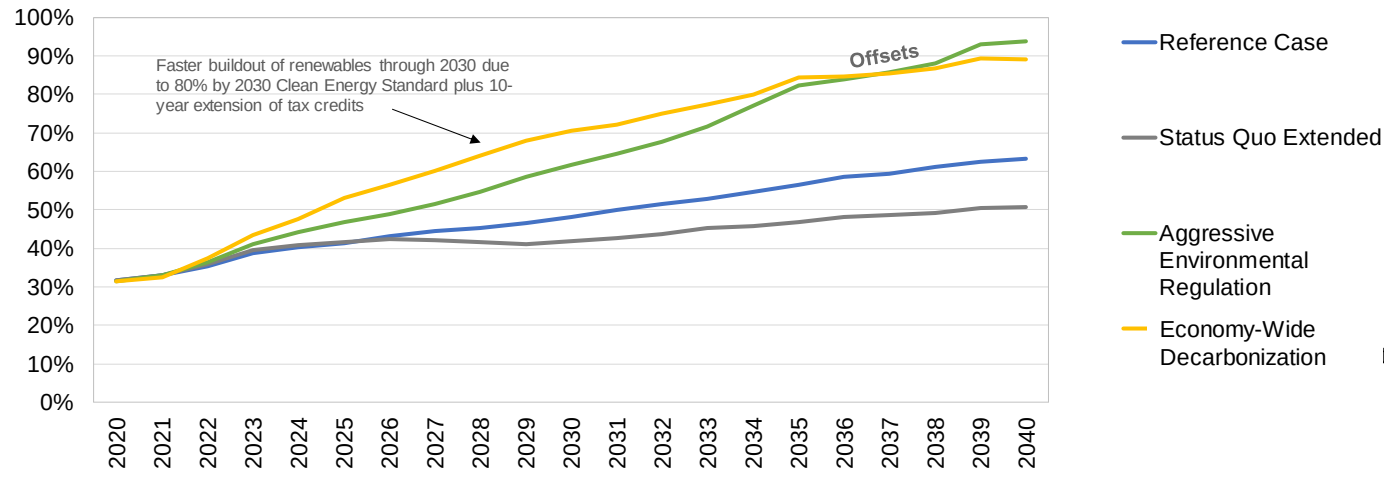
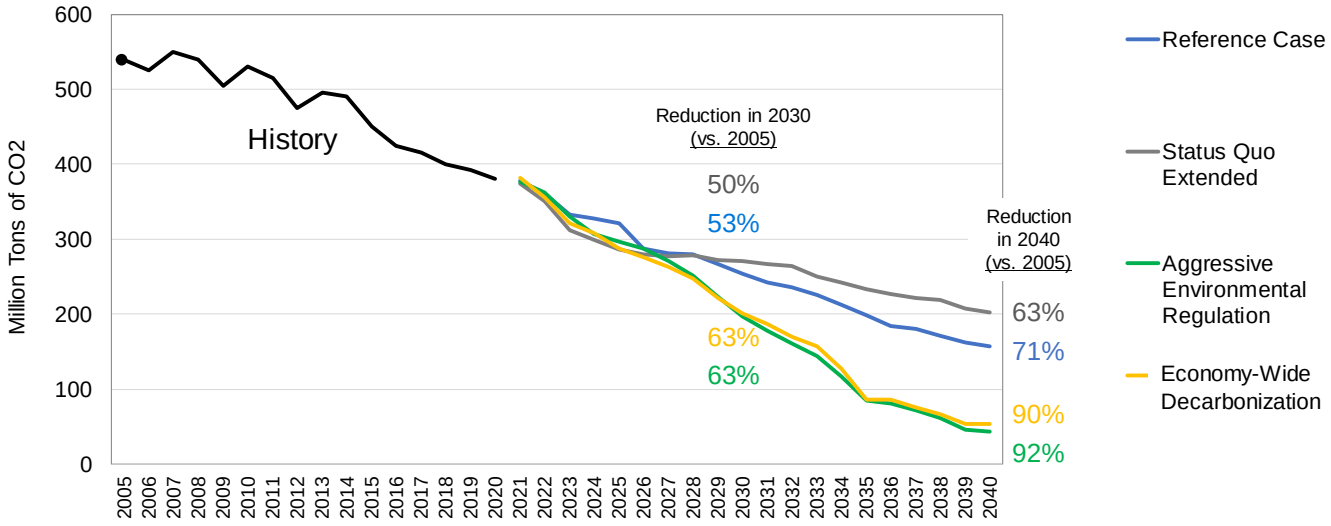


Figure 8-42: MISO CO2 Emission Reduction Projections across Scenarios

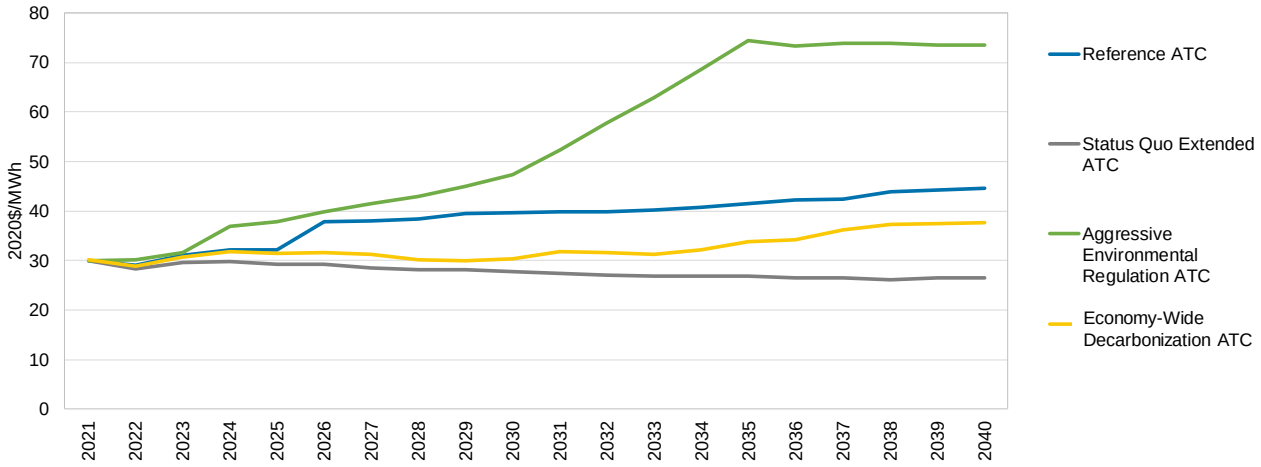


MISO energy prices are projected to vary considerably across scenarios as well. On an "all-hours" or ATC basis, the Reference Case projects prices to increase to approximately

[94] Historical data from 2005-2019 is taken from MISO Futures documentation from 2020 and 2021. CRA interpolated data from 2018 to first model year of 2021.

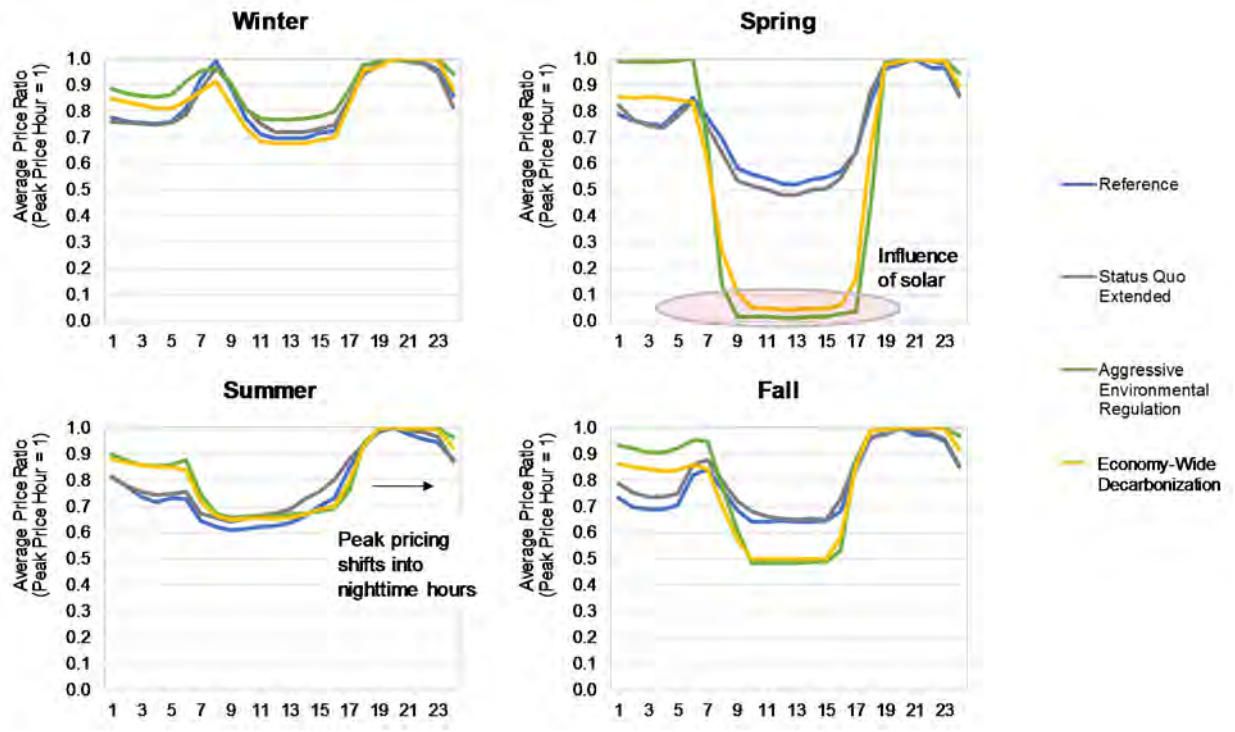
$45/MWh (real 2020$) by 2040, while the scenarios include prices that range between below $30/MWh to above $70/MWh by the same time. Rising natural gas and carbon prices drive the AER scenario's prices highest, while the SQE and EWD scenarios have flatter pricing in real terms due to lower gas price expectations, the lack of a carbon price, and expectations for growing renewable penetration. The ATC price projections across scenarios are summarized in Figure 8-43.

Figure 8-43: MISO Zone 6 ATC Power Prices across Scenarios



On an hourly basis, the shape of power prices is also likely to evolve very differently over time, particularly as growing levels of renewable energy enter the market. By 2040, all scenarios are expected to have peak hours shift later into the evening during summer months, while mid-day prices during the shoulder months (spring and fall) are expected to decline significantly as a result of solar energy penetration, particularly in the AER and EWD scenarios. This dynamic is shown in Figure 8-44, which illustrates the wide range of hourly market price risk that NIPSCO is evaluating across its scenarios.

Figure 8-44: MISO Zone 6 Hourly Price Shapes by Season (2040) across Scenarios



While capacity prices are also expected to vary across scenarios, CRA expects them to remain relatively low in the near-term, although continued coal retirements over the 2020-2024 period are expected to tighten the system. Over time, NIPSCO's analysis incorporates the likelihood of MISO moving to a multi-seasonal capacity construct with different prices across seasons. In the summer months, under the AER scenario, coal retirements and replacement with resources including hydrogen-enabled gas turbines and long-duration storage are projected to push prices higher. This is illustrated in Figure 8-45. In the winter months, reserve margin tightening is most likely in the EWD scenario, due to clean energy targets and significantly growing winter loads from electrification. Capacity pricing in the AER scenario is also likely to increase due to retiring capacity and replacement with a portfolio of zero-emitting resource types, as in the summer season. The winter capacity price projections across scenarios are illustrated in Figure 8-46.

Figure 8-45: MISO Summer Season Capacity Price Projections across Scenarios

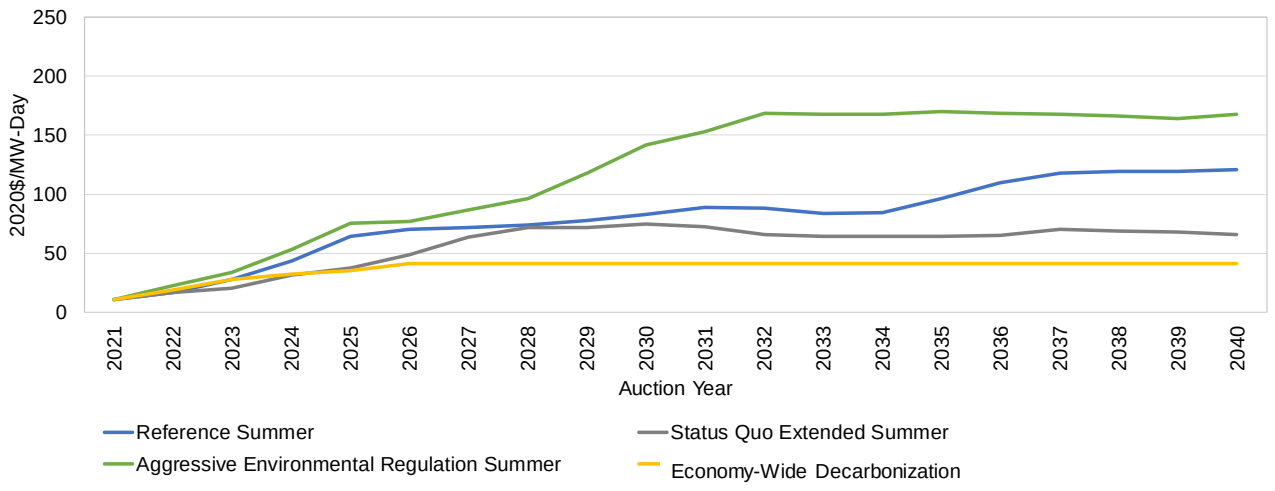
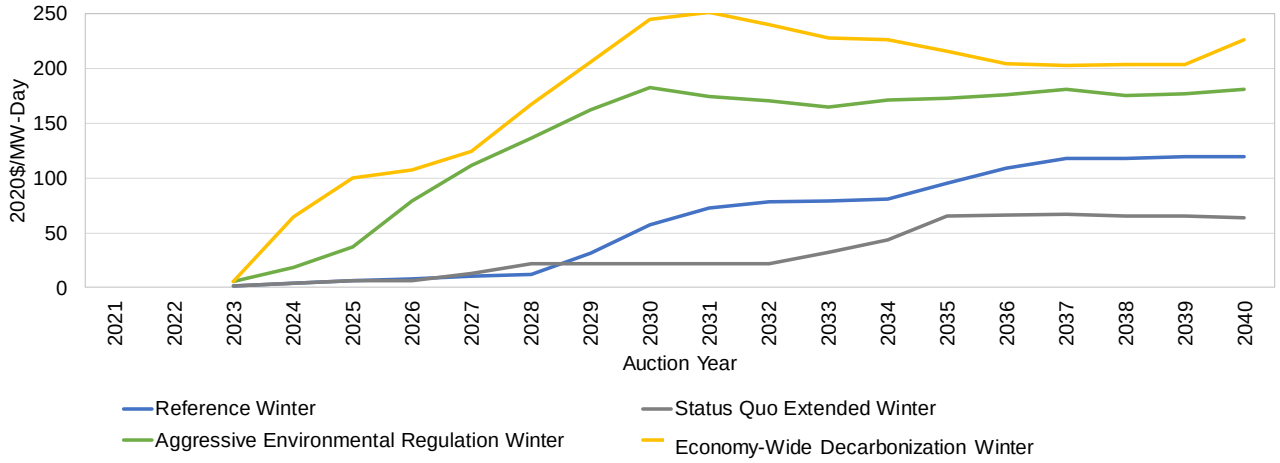


Figure 8-46: MISO Winter Season Capacity Price Projections across Scenarios



NIPSCO Load Growth

Section 3 of this report on NIPSCO's Energy and Demand Forecast provides significant detail regarding the range of load uncertainties evaluated across each of the scenarios. As described in that chapter, NIPSCO's load scenarios vary economic growth assumptions, electric vehicle and distributed energy resource penetration, other electrification, and industrial load loss risk. Overall, this approach results in a significant range of potential energy sales and peak load outcomes for NIPSCO across scenarios. The ranges are summarized in Figure 8-47 and Figure 8-48, with additional supporting detail documented in Section 3.

Figure 8-47: Total NIPSCO Net Energy for Load Forecast across Scenarios

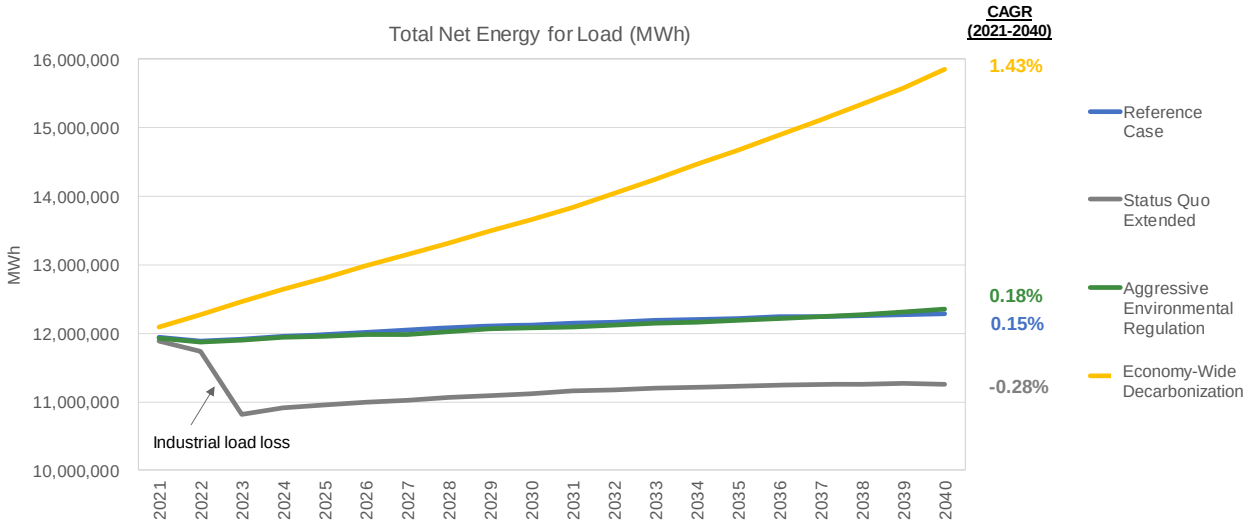
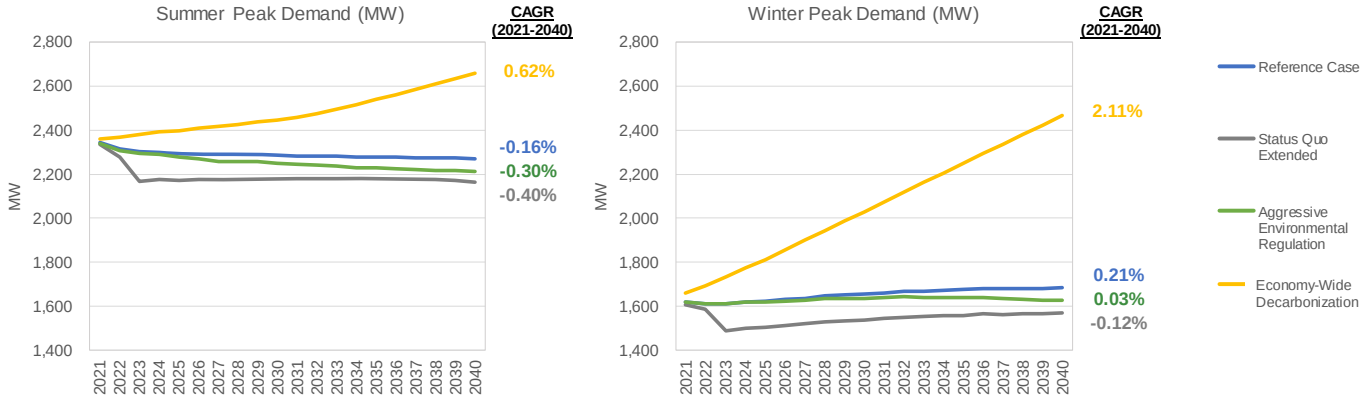


Figure 8-48: NIPSCO Summer and Winter Peak Load Forecasts across Scenarios



8.5 Stochastic Input Development

As discussed above, NIPSCO identified commodity prices and renewable generation output as stochastic variables to be analyzed in the 2021 IRP. The stochastic analysis approach broadly encompassed the following four steps:

1. **Input data development**, including development of fundamental forecasts (as described above), and review of historical price and weather data;

2. **Statistical and fundamental analysis**, including commodity price simulation and analysis to evaluate the impact of renewable energy output on power prices over time;

3. **Final stochastic input development**, including a description of how simulated commodity prices are combined with renewable shapes; and

4. **Portfolio analysis** with the stochastic inputs to evaluate key metrics for NIPSCO's integrated scorecard.

The remainder of this section provides an overview of the first three steps in the overall process, outlining the data development and analysis that contributes to stochastic input development, while the next chapter in this report covers the portfolio analysis.

8.5.1 Input Data Development

Fundamental Forecasts

The commodity price stochastic inputs were developed around the Reference Case natural gas and power price forecasts outlined earlier in this chapter. NIPSCO's stochastic analysis for the 2021 IRP is centered on the Reference Case fundamental forecasts for natural gas and MISO power prices as described above in Section 8.2.

Historical Commodity Price Data

Historical daily average gas and power price data were gathered to observe key price characteristics and calibrate simulation model parameters to reflect realistic market price behavior. These characteristics include, but are not limited to, standard deviation, range of prices around a seasonal median price, magnitude and frequency of sudden price spikes, market heat rate, and correlation between gas and power. Historical prices from the period January 1, 2016 through December 31, 2020 were used to summarize relevant market price behavior and constrain the dataset to include only the most recent market dynamics. This limits the dataset, but has the benefit of excluding data from periods of time with different natural gas fundamentals and with a MISO market generation mix that was very different than today's. The daily gas spot index from Chicago Citygates and the day-ahead ATC price strip from the NIPSCO zone within MISO were the specific pricing points used in this analysis.[95]

Historical Weather and Solar / Wind Availability Data

To determine the expected impact of renewable availability on hourly power prices, historical weather data from NREL was used to proxy historical wind and solar availability using NREL's SAM. To ensure that the weather data collected aligned with expected renewable

[95] Data was retrieved from S&P Global Market Intelligence: Commodity Charting Tool.

availability over the planning horizon, a representative location within NIPSCO's service territory was selected in White County, Indiana.

Using SAM, the historical weather data for this location was downloaded at an hourly granularity from the NREL NSRDB[96] and the NREL Wind Integration Datasets.[97] Data was downloaded for as many historical weather years as were available (2007-2013 for the wind dataset and 2007-2019 for the solar dataset). Both datasets provide historical meteorological data and are managed by NREL. The data includes key meteorological descriptors including diffuse horizonal irradiance, direct normal irradiance, albedo, wind velocity (meters per second), temperature, snow depth, elevation above sea level, atmospheric pressure, and wind direction, among others.

Next, the collected weather data was used in conjunction with SAM's built-in resource performance models to simulate historical hourly solar and wind availability. SAM's performance models take as inputs data elements from the weather files to represent the renewable resource and ambient weather conditions that affect the system's performance. To further ensure that the resulting resource performance data was as representative as possible of the specific wind and solar resources in NIPSCO's portfolio, CRA defined in SAM the solar panel and wind turbine specifications associated with NIPSCO's planned renewable projects.

The process outlined above resulted in seven historical hourly trajectories for wind availability (representing historical weather years 2007 through 2013) and thirteen historical hourly trajectories for solar availability (representing historical weather years 2007 through 2019). The NREL simulations produced reasonable annual average capacity factors for wind and for solar in the selected location (the upper 30% range for a representative wind resource and mid 20% range for a representative solar resource).

8.5.2 Statistical and Fundamental Analysis

Commodity Price Uncertainty using MOSEP

To develop stochastic price paths for natural gas and power prices, CRA simulated daily natural gas and power price volatility using its MOSEP model. MOSEP is a regime-switching, mean-reverting model[98] that takes as input expected paths for electricity and gas prices developed through the fundamental forecasting analysis. The tool's Monte Carlo engine simulates price deviations around the expected paths based on historical volatility and gas-power correlation to yield "actual" or "realized" price paths. The model parameters are calibrated to historical gas market and MISO power market price behavior as mentioned above. A sample illustration of two

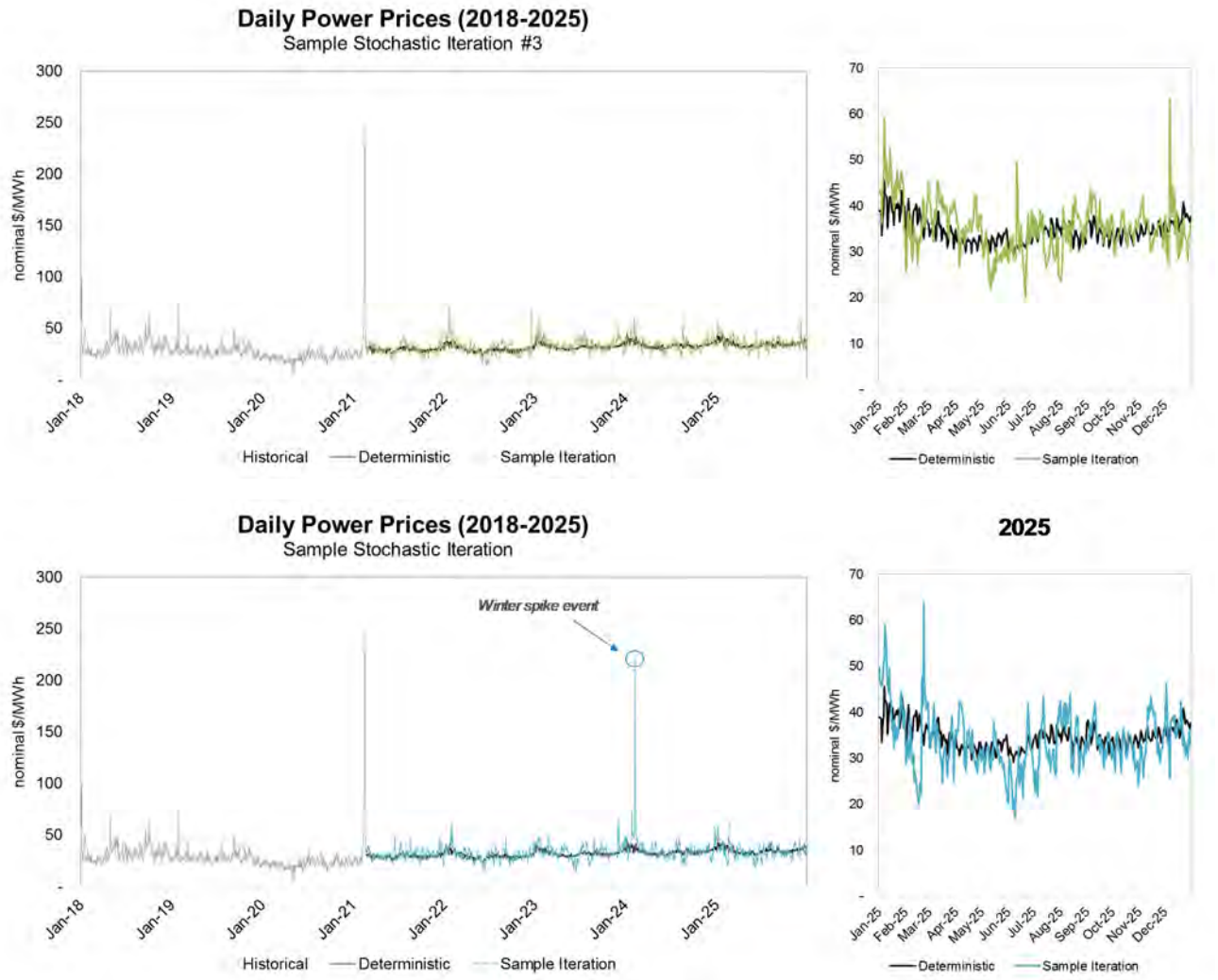
[96] NREL NSRDB, https://nsrdb.nrel.gov/

[97] NREL Wind Integration Datasets, https://www.nrel.gov/grid/wind-integration-data.html

[98] Commodity prices have been found to exhibit a mean-reverting behavior. The regime-switching feature of the model allows for simulation of price spikes by modeling different price regimes (e.g., normal price regime, spike price regime). The simulated switching between regimes is facilitated by a transition matrix. Given the current regime, the transition matrix specifies the probabilities of staying in the current regime or moving to a different regime. The probabilities are estimated based on historical data. For references, see the following paper, on which MOSEP is based - Higgs, H. & Worthington, A. "Stochastic price modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market." Energy Economics, 2008.

daily power price paths produced by MOSEP is shown in Figure 8-49. As illustrated, the stochastic price paths exhibit more daily volatility than the deterministic Reference Case price projections, and this is consistent with historical price behavior.

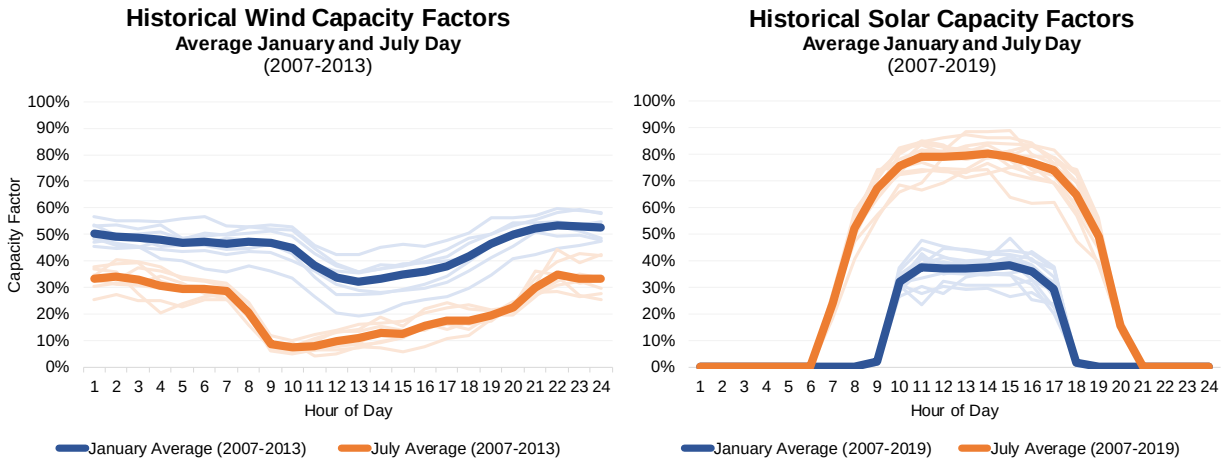
Figure 8-49: Sample Power Price Iterations



Integrating Renewable Output Uncertainty

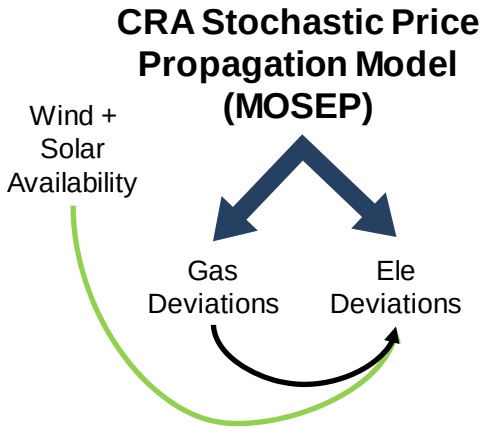
The integration of renewable output uncertainty into NIPSCO's stochastic analysis process was an enhancement for the 2021 IRP. Given the significant growth in intermittent renewable capacity within NIPSCO's portfolio (and the broader MISO market), incorporating the risk of renewable output uncertainty allowed NIPSCO to assess a broader range of risks associated with energy market exposure as market dynamics evolve. A sample illustration of monthly average wind and solar output profiles is shown in Figure 8-50, highlighting the fact that a range of capacity factors is to be expected for intermittent renewable resources over any long-term planning horizon.

Figure 8-50: Sample Renewable Output Iterations



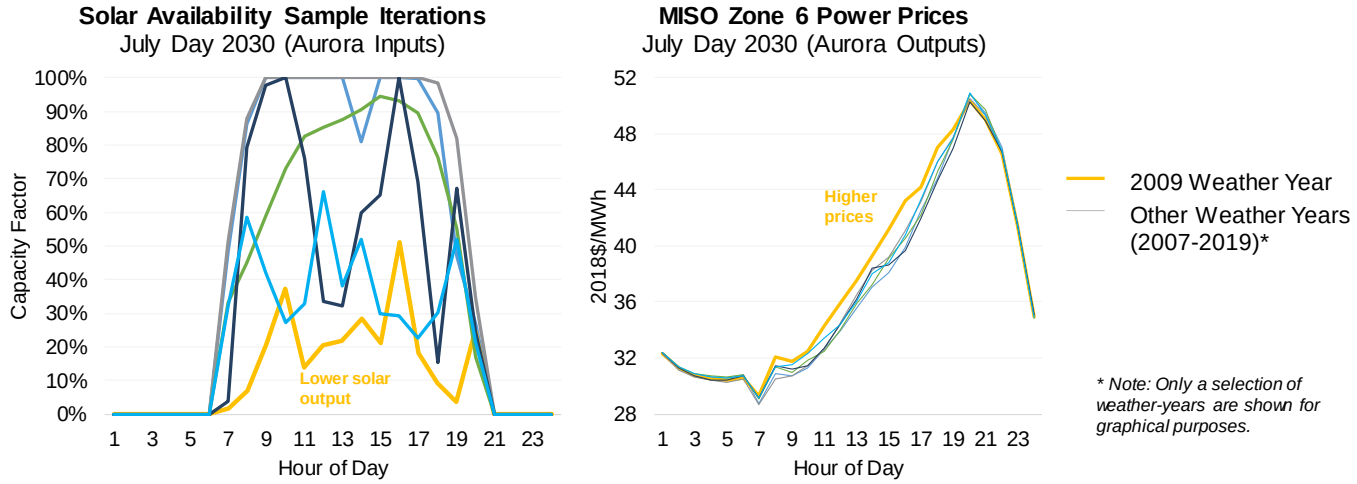
Furthermore, assuming that power prices and renewable output evolve independently of each other potentially underestimates the risk of growing levels of intermittent generation in NIPSCO's portfolio. This is because higher levels of intermittent generation output are generally expected to depress price levels. However, the magnitude of this effect is uncertain, particularly due to lack of relevant actual historical data. Therefore, for NIPSCO's stochastic analysis, the magnitude was estimated through forward power price formation using various levels of renewable penetration followed by a regression analysis to quantify the impact. Adjustments were then made to the hourly power price paths, yielding a set of power prices which are correlated with gas prices and which reflect the expected impact of varying renewable availability. This process is shown in illustrative form in Figure 8-51.

Figure 8-51: Illustration of Renewable Availability Integration in Stochastic Process



To evaluate the impact of different wind and solar output levels on MISO market prices, CRA performed fundamental power market analysis across a variety of inputs for wind and solar output based on a sample of historical weather years. Furthermore, since the negative impact of renewable availabilities on electricity prices is expected to become larger as renewable penetration increases, CRA performed the analysis assuming a number of forward test years and, thus, varying levels of renewable penetration. Figure 8-52 illustrates a small sample of solar output availabilities for a sample July day and their impacts on hourly MISO LRZ 6 power prices for the same day. As is shown, when solar output is lower, market prices would be expected to be higher, illustrating the likely correlation between these two variables.

Figure 8-52: Sample Solar Output and Power Price Iterations – Reference Case



CRA analyzed the relationship between hourly renewable availabilities and hourly power prices through a regression analysis. CRA ultimately specified a regression model that estimates the impact on power prices of hourly solar and wind availabilities. Seasonal variables (fall, summer, spring, or winter) and an hour of day indicator (nighttime vs. daytime) in combination with renewable availabilities were also found to be significant in explaining the variations in power price.[99] Two major conclusions were made from this analysis:

1. **Renewable availability has a significant negative impact on power prices, all else equal**: As shown in Figure 8-53, CRA's regression analysis found that an increase in renewable capacity factor had a significant impact on power prices at the hourly level, with solar output changes being most impactful during the spring and summer months and wind output changes being most impactful during nighttime hours.

2. **The impact of renewable availability on power prices increases with level of renewable penetration**: As shown in Figure 8-54, CRA's regression analysis found that the impact of renewable capacity factors on power prices grows over time, as the share of renewable generation in the market grows. The impact of solar output changes increased by over a factor of three between 2025 and 2040, and the impact of wind output changes increased by over a factor of four between 2025 and 2040 in CRA's simulations.

[99] Interactions between solar and wind availability with seasonal dummy variables were included in the regression because it is expected that the season of the year will change the impact of solar availability and of wind availability on power prices. Hour of day dummy variables were included because it is expected that nighttime will change the impact of wind availability on power prices.

Figure 8-53: Negative Impact on Hourly Power Price per 1% Increase in Renewable Resource Capacity Factor – by Season

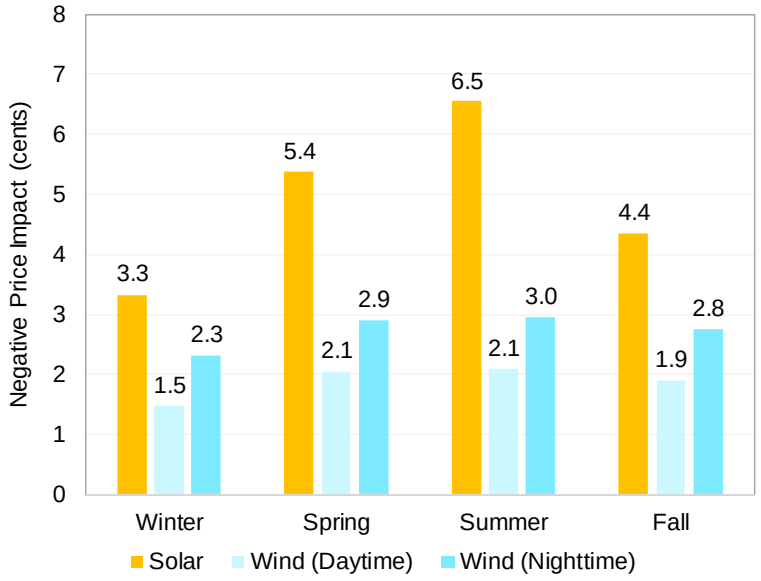
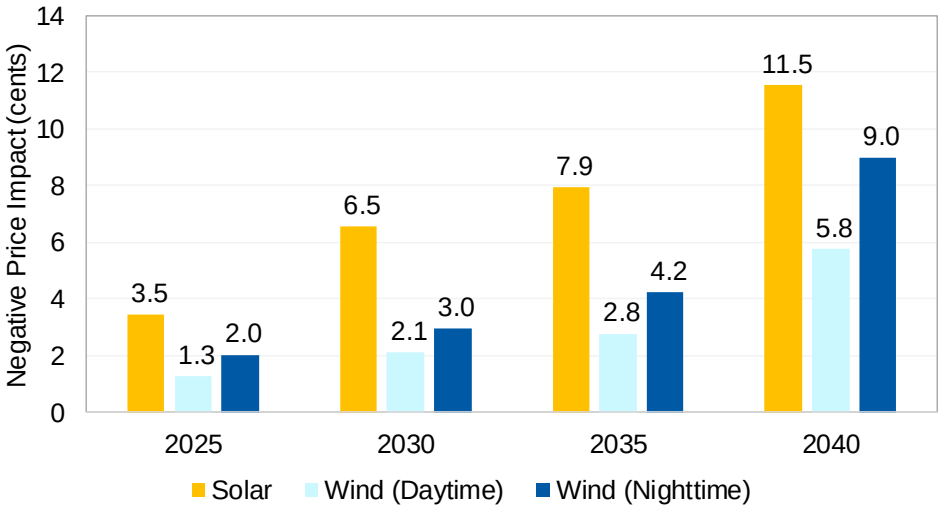


Figure 8-54: Negative Impact on Hourly Power Price per 1% Increase in Renewable Resource Capacity Factor – Summer Season over Time



8.5.1 Final Stochastic Input Development

After analyzing the likely impact of renewable output on future power prices, CRA combined the historical renewable output profiles with the power and gas stochastic price paths developed in the MOSEP tool to create the final stochastic inputs used for NIPSCO's portfolio

analysis. Hourly renewable availabilities were randomly drawn from history and paired with power and gas price paths, with the regression-based impact added to the power prices to arrive at the final sets of stochastic inputs.

The stochastic input development process results in 500 daily or hourly price paths for gas and power, respectively. The paths can be plotted along with estimated prediction intervals. Time series for the twenty-year forecast period for natural gas prices and power prices, including historical price data, are illustrated in Figure 8-55 and Figure 8-56, respectively. These graphics show, on a monthly level, the broad range of the individual price paths (in light gray) along with representations of the monthly 5th, 50th, and 95th percentile values.

The values associated with a given percentile do not represent specific price trajectories, but instead indicate the price levels which exceed the associated proportion of the 500 prices at any given point in time. For example, the top blue line in Figure 8-55 represents the monthly 95th percentile for natural gas prices, which means that 95% of the simulated values are below this price level at any given point in time. In other words, 5% of the price realizations in any given month across the full range of simulated values would be expected to be above this level. These values can come from different price paths over time, since each path is likely to be relatively volatile, moving up and down. In fact, it is highly unlikely that a single path would be at the 95th percentile for a sustained period of time. Overall, the stochastic inputs allow for evaluation of portfolio performance against extreme price outcomes on the high side and on the downside, including at the daily and hourly price levels, which are not shown in these graphics.

Figure 8-55: Stochastic Distribution for Natural Gas Prices

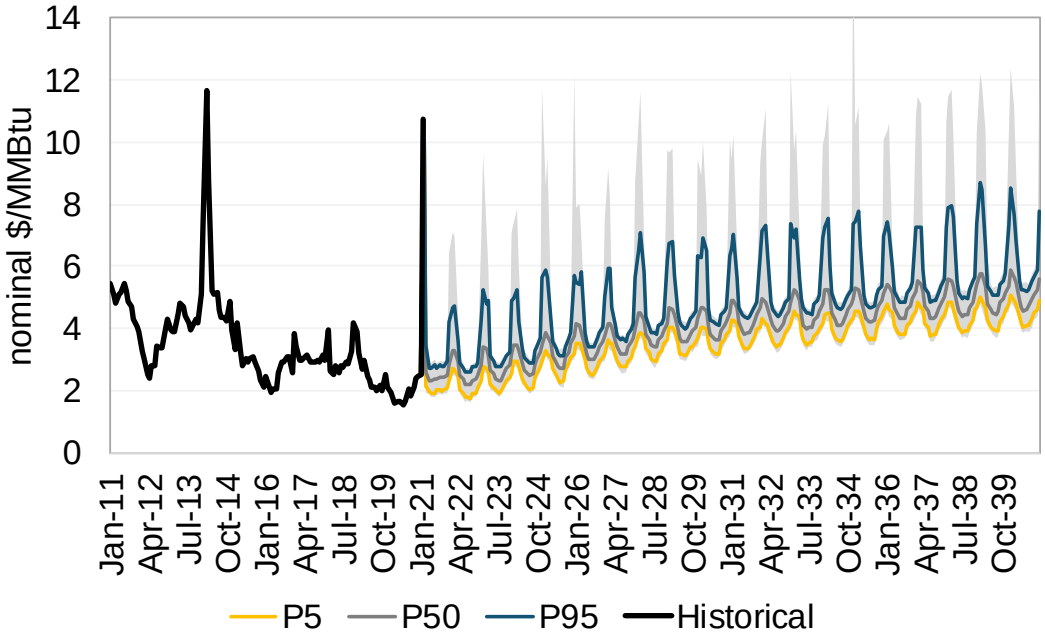
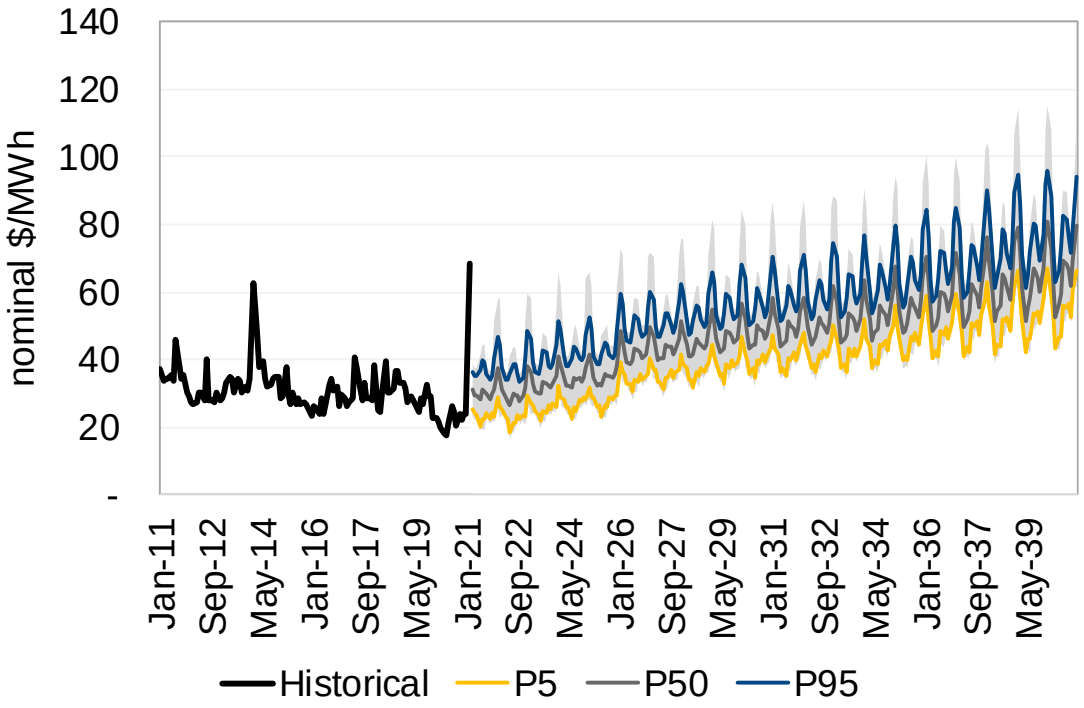


Figure 8-56: Stochastic Distribution for Power Prices



Section 9. Portfolio Analysis

9.1 Existing Fleet Analysis

9.1.1 Process Overview

NIPSCO's 2018 IRP established a roadmap to retire all coal capacity by 2028 and developed a short-term action plan focused on a portfolio of renewable resource additions to replace retiring capacity at the Schahfer plant through 2023 (*See* Section 4 for more detail on the new renewable resources). After the implementation of that short-term action plan, approximately 65% of NIPSCO's generation fleet will be set for the next several years, with the 2021 IRP analysis evaluating potential retirement pathways for the remainder of NIPSCO's existing fleet. As discussed in more detail in Section 2, NIPSCO determined that it was most efficient and effective to evaluate retirement decisions for the existing fleet on a stand-alone basis, while performing an additional replacement analysis to assess a wide range of replacement resource strategies. Although performed in two steps, the existing fleet and replacement analyses are both based on the same major inputs and assumptions, which are described in parts of Section 8 and below.

NIPSCO believes that performing an existing fleet analysis requires careful planning and consideration of several factors. To that end, NIPSCO has used an integrated scorecard methodology to evaluate existing fleet portfolios, as described in Section 2. In addition to the net present value of revenue requirements in the Reference Case, NIPSCO has also considered multiple rate stability metrics, carbon emissions, and the effect of unit retirements on NIPSCO's employees and the local economies of the communities it serves.

9.1.2 Existing Fleet Analysis Methodology

The existing fleet analysis has been conducted according to the following steps:

- Identify plausible retirement and retention plans for the existing fleet and specify individual retirement/retention combinations or "portfolios."

- Identify the least-cost replacement capacity to fill the resulting capacity gap for each retirement portfolio based on the results from the RFP conducted by NIPSCO and other available supply-side and demand side resources (*See* Sections 4 and 5 for more detail on these resource options).

- Evaluate each portfolio, including its associated least-cost capacity replacement, in the IRP tools for each scenario (as defined in Section 8). The evaluation includes a full accounting of the ongoing operations of each existing plant and the costs of alternatives.

- Record costs, risks, and other metrics in the integrated scorecard to identify the preferred existing fleet strategy.

9.1.3 Identification of Existing Fleet Portfolios

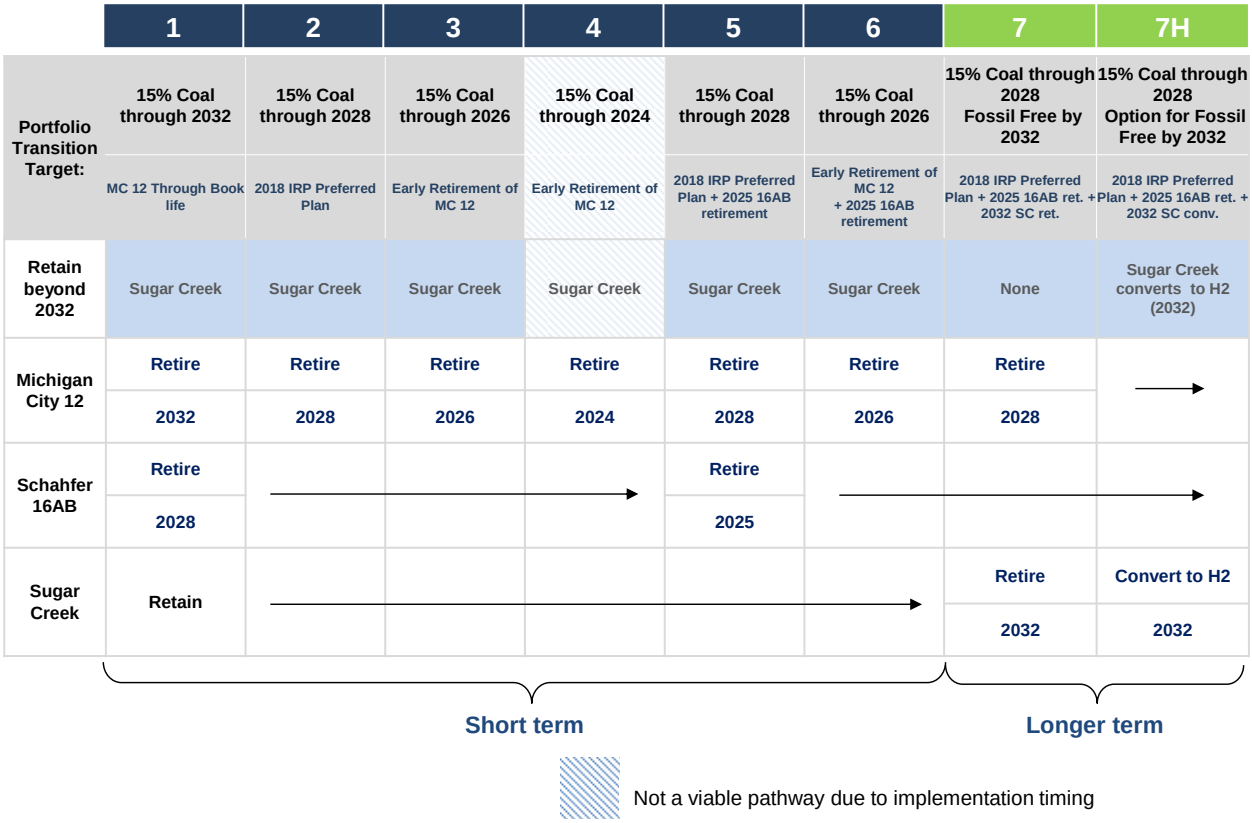
NIPSCO's remaining fossil-fueled generation plants were evaluated for potential retirement throughout the IRP's planning horizon. This includes Michigan City Unit 12 (coal), Schahfer Units 16A and 16B (natural gas steam), and Sugar Creek (natural gas CCGT). NIPSCO identified eight existing fleet portfolios for analysis based on different combinations of unit retirements at different points in time, as summarized in Figure 9-1:

- The first four portfolios examine the retirement timing of Michigan City Unit 12, including bookend concepts that evaluate retention of the plant beyond its announced retirement date to the end of its book life in 2032 and an early retirement by 2024, a portfolio concept that is not viable from an implementation perspective.

- Portfolios 5 and 6 vary the retirement timing of Schahfer Units 16A/B between 2025 and the expected end of the units' useful operational life in 2028.

- Portfolios 7 and 7H evaluate long-term concepts for potential Sugar Creek retirement and hydrogen conversion, respectively. These portfolios were developed to provide a long-term view towards net-zero decarbonization pathways, although key implementation actions would be made more than a decade into the future.

Figure 9-1: Overview of Existing Fleet Portfolios



9.1.4 Existing Fleet Cost Assumptions

The evaluation of each existing fleet portfolio was performed through a full portfolio analysis that included dispatch in Aurora and financial accounting in PERFORM (*See* Section 2 for more detail on the overall modeling process). Market assumptions were consistent with those outlined earlier in Section 8 for the Reference Case and the three alternative scenarios. In addition to the major market inputs and the costs of replacement resources (see next section below), several relevant assumptions were made regarding the ongoing costs of the existing coal fleet.

Ongoing costs include fuel, fixed O&M costs, and maintenance capital, as well as the recovery of remaining book value associated with each plant as of April 2021. This recovery includes return of (depreciation), return on, and income and property taxes associated with the remaining net book value of NIPSCO's existing fleet.

Fixed O&M costs included all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. For all units, projections of fixed O&M costs were obtained for each year within 2021-2040. These costs were then escalated at 2.1% per year[100] for the 2041-2050 end effects modeling period. Additional detail is provided in Confidential Appendix

[100] The EIA's AEO assumes a 2.1% rate of inflation for "All Commodities," which is used as a long-term proxy of general cost inflation for the end effects extrapolation.

D. As an existing unit's projected retirement date moves up, the relative fixed O&M spend tended to decrease during the years leading up to retirement.

Maintenance capital costs included the projected capital expenditures necessary to keep the units running through the analysis period at the projected level of operations. For all units, projections of maintenance capital costs were obtained for each year within 2021-2040. These costs were then escalated at 2.1% per year 2041-2050 end effects modeling period. Additional detail is provided in Confidential Appendix D. Similar to fixed O&M costs, as an existing unit's projected retirement date moves up, the relative capital spend tended to decrease during the years leading up to retirement.

NIPSCO also included estimated transmission upgrade costs associated with Schahfer and Michigan City's retirements. An additional $6.7 million of capital expenditures was incorporated for transmission upgrades at the time Schahfer 16A/B retires in any existing fleet portfolio. An additional $82.9 million of capital expenditures was incorporated for transmission upgrades at the time Michigan City retires in any existing fleet portfolio.

Recovery of depreciation expenses on existing capital by 2033 has also been incorporated in the existing fleet analysis. NIPSCO assumes that each unit continues to depreciate at the same rate of 3.88% until 2033, regardless of whether the unit has been retired or not. This means that each retirement portfolio has the same depreciation schedule for existing capital. At 2033, the sum of all coal plants' NBV on existing capital is equal to the negative "cost of removal" for all the coal plants. The negative NBV on existing capital in 2033 lowers rate base in perpetuity. The cost of removal was estimated by John J. Spanos, an expert witness supporting NIPSCO's 2019 Electric Rate Case[101] In addition to the "return of" (depreciation) the net book value, NIPSCO continues to earn a "return on" the net book value equal to NIPSCO's assumed weighted average cost of capital. NIPSCO assumes that property and income tax will *not* be collected on the remaining NBV of the plant if it is retired.

9.1.5 Identification of Least-Cost Replacement Capacity

As in the 2018 IRP, NIPSCO's All-Source RFP provided insight into the supply and pricing of resource alternatives available to NIPSCO (*See* Section 4 for details on the process and the costs and operational parameters of the individual tranches used for evaluation). In addition, NIPSCO identified other resource options, including DERs (*See* Section 4), an uprate at the existing Sugar Creek facility (*See* Section 4), and bundles of DSM resource options over time (*See* Section 5).

With these resource options, a portfolio optimization was performed within Aurora's portfolio optimization tool under each of the eight retirement portfolio concepts to identify least-cost sets of replacement resources under Reference Case market conditions. The portfolio optimization modeling was performed for both the winter and summer peak seasons and was

[101] See Cause No. 45159.

designed to minimize the net present value of revenue requirements, with certain constraints for reserve margins, maximum off-system energy sales, and resource eligibility.[102]

Overall, the economic optimization model selected a diverse set of resources. Driven by a binding winter reserve margin and the energy resources already obtained from the 2018 IRP Preferred Plan, the indicative ordering of model selection preference tends to favor resources that offer greater levels of firm capacity relative to their energy contributions. When available for selection, the resources universally selected through 2027 included (all values in ICAP) included the following:

- Approximately 10 MW of NIPSCO-owned DERs with the largest distribution cost deferrals;
- The uprate to the existing Sugar Creek CCGT at the modeled level of 53 MW;
- Approximately 68 MW (summer peak credit)[103] of DSM resources by 2027, which includes the cumulative impact of both Tier 1 Residential and Commercial programs by 2027, with Commercial programs being most cost effective;[104]
- Thermal capacity contracts from the 2021 RFP up to 150 MW;

In addition, several different resource types were consistently selected at various sizes and timings based on retirement dates and resource eligibility. These included:

- A natural gas peaker up to 300 MW (hydrogen-enabled in Portfolio 7H);
- Various levels of stand-alone storage between 135 MW and 570 MW;
- Solar capacity up to 250 MW;
- Wind capacity up to 200 MW;
- A 20 MW electrolyzer pilot at Sugar Creek in Portfolio 7H.

Figure 9-2 provides a summary of the capacity resources that were selected under Portfolios 1-6, and Figure 9-3 provides a summary of the capacity resources that were selected under Portfolios 7 and 7H. Note that these portfolios do not represent NIPSCO's preferred replacement strategy, but only least-cost optimization outcomes that are used to evaluate retirement implications associated with the existing fleet.

[102] Portfolios were optimized against winter reserve margin constraints (9.4%), followed by summer to ensure compliance with both. A maximum net energy sales limit of 30% during the fleet transition (2023-2026), falling to 25% in 2030+, was enforced. Portfolios 7 and 7H are designed to achieve net zero emissions over the study horizon, so eligible resources were restricted. Portfolio 7 did not allow for new fossil resources, and Portfolio 7H "forced in" hydrogen-enabled resources

[103] Note that the winter peak impact of the selected DSM resources is approximately 46MW.

[104] Note that the Tier 1 Residential and Commercial DSM bundles were selected across all time horizons in the fundamental modeling period. Additional detail on bundle costs and savings is provided in Section 5.

Figure 9-2: Summary of Least-Cost Replacement Capacity: Portfolios 1-6



Portfolio 1

MC12 Through Book Life

Technology	ICAP MW	Year
NIPSCO DER	10	2026
Sugar Creek Uprate	53	2027
DSM*	68	2027*
Thermal Contract	50	2024
Thermal Contract	100	2026
Gas Peaker	300	2032
Storage	135	2027
Total	**693**	

Portfolios 2 | 3 | 4

2018 IRP (MC 2028) | MC 2026 | MC 2028

Technology	ICAP MW	Year P2	Year P3	Year P4
NIPSCO DER	10	2026	2026	2026
Sugar Creek Uprate	53	2027	2027	2027
DSM*	68	2027*	2027*	2027*
Thermal Contract	50	2024	2024	2024
Thermal Contract	100	2026	2026	2026
Gas Peaker	300	2028	2026	2024
Storage	135	2027	2027	2025
Solar	100 / 200^	2026	2026	2026
Total	**793 / 893^**			

Portfolios 5 | 6

Portfolio 2 w/ 16AB 2025 | Portfolio 3 w/ 16AB 2025

Technology	ICAP MW	Year P5	Year P6
NIPSCO DER	10	2026	2026
Sugar Creek Uprate	53	2027	2027
DSM*	68	2027*	2027*
Thermal Contract	50	2024	2024
Thermal Contract	100	2026	2026
Gas Peaker	300	2028	2026
Storage	135	2025	2025
Solar	100	2026	2026
Wind	200	N/A	2026
Total	**993**		

^ P2/3 have 100 MW of solar; P4 has 200 MW

Figure 9-3: Summary of Least-Cost Replacement Capacity: Portfolios 7 & 7H

Portfolio 7

Fossil Free By 2032

Technology	ICAP MW	Year
NIPSCO DER	10	2026
DSM*	68	2027*
Storage	235	2025
Storage	100	2026
Storage	235	2027
Solar	250	2026
Wind	200	2026
Total	**1,020**	

Portfolio 7H

Fossil Free Option by 2032 w/ SC Conversion (incl. capital costs)

Technology	ICAP MW	Year
NIPSCO DER	10	2026
Sugar Creek Uprate	53	2027
DSM*	68	2027*
Storage	235	2025
Storage	135	2027
Solar	250	2026
Wind	200	2026
Hydrogen-Enabled Gas Peaker	193	2025
SC Electrolyzer Pilot	20	2026
Total	**1,131**	

9.1.6 Evaluation of Each Existing Fleet Portfolio – Scorecard Metrics

NIPSCO developed a set of decision criteria objectives and metrics against which to evaluate the full set of existing fleet portfolios. The analysis was then conducted to quantify the performance of each portfolio against each scorecard metric. The following section describes each of the key objectives and metrics in more detail:

- Cost to Customer is measured by the overall NPVRR under Reference Case Conditions.

- Cost Certainty measures the certainty that the net present value of revenue requirements falls within the range of the scenario outcomes and is quantified by the range in NPVRR across scenarios.

- Cost Risk measures the risk of unacceptable, high-cost outcomes and is quantified by the highest scenario NPVRR.

- Lower Cost Opportunity measures the potential for lower cost outcomes and is quantified by the lowest scenario NPVRR.[105]

- Carbon Emissions measures the carbon intensity of the portfolio and is quantified by the cumulative short tons of CO2 emitted from the generation portfolio from 2024 through 2040.[106]

- Employees and Local Economy measures the positive social and economic impacts of NIPSCO's existing generation fleet and are measured by the net impact on permanent jobs associated with the current generation fleet and the net present value of property taxes associated with the current fleet relative to the 2018 IRP's conclusions, respectively.

A summary of the decision criteria metrics for the existing fleet analysis is provided in Figure 9-4, noting that reliability metrics are addressed more fully in the replacement analysis that seeks to evaluate the tradeoffs of different replacement resources more comprehensively.

[105] Note that additional rate stability and risk metrics are included in the Replacement Analysis phase, including those associated with the stochastic analysis.

[106] These years represent the fundamental modeling horizon after the retirement of the Schahfer coal units, which is common to all portfolios.

Figure 9-4: Scorecard Metrics for Existing Fleet Analysis

Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	**Reliability**	• *To be addressed in Replacement Analysis stage*
	Resource Optionality	
Positive Social & Economic Impacts	**Employees**	• Net impact on NiSource jobs • Metric: Approx. number of permanent NiSource jobs associated with generation
	Local Economy	• Net effect on the local economy (relative to 2018 IRP) from new projects and ongoing property taxes • Metric: NPV of existing fleet property tax relative to 2018 IRP

Additional risk metrics will be included in the Replacement Analysis, when broader set of resource types are evaluated

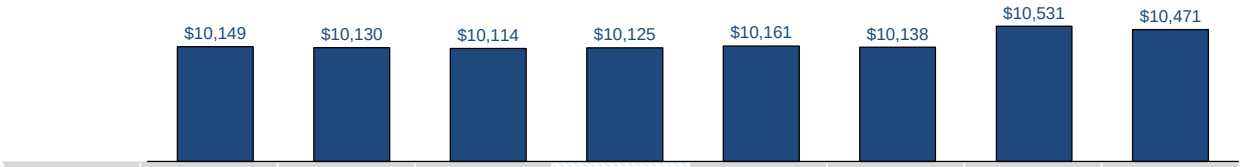
9.1.7 Evaluation of Each Existing Fleet Portfolio – Results

Reference Case Cost Results

The eight existing fleet portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail) to estimate revenue requirements for each over time. The assessment was first performed across the Reference Case set of market assumptions and inputs to calculate baseline projections of the NPVRR over the thirty-year planning horizon, which are summarized in Figure 9-5.

Under the Reference Case market conditions, the difference in NPVRR from the highest cost to lowest cost portfolio is approximately $430 million. Consistent with NIPSCO's prior IRP findings, early retirement of coal is generally cost effective for customers, with Portfolio 3 (retirement of Michigan City 12 in 2026) having the lowest cost overall. However, the difference in cost across several portfolios is small, since much of the remaining portfolio is fixed and small changes in retirement dates are now being assessed. In addition, the analysis suggests that retaining Units 16A/B until 2028 may be cost effective, given the portfolio's capacity needs. However, this is contingent on the operational condition of these older vintage units, and the cost impacts of earlier retirement are well less than 1% in NPVRR.

Figure 9-5: Cost to Customer Impacts – Existing Fleet Portfolios



Portfolio Transition Target:	15% Coal through 2032 (1)	15% Coal through 2028 (2)	15% Coal through 2026 (3)	15% Coal through 2024 (4)	15% Coal through 2028 (5)	15% Coal through 2026 (6)	15% Coal through 2028 Fossil Free by 2032 (7)	15% Coal through 2028 Option for Fossil Free by 2032 (7H)
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Rank (1=Least Cost)	5	3	1	2	6	4	8	7
Delta from Least Cost	$35M 0.3%	$16M 0.2%	-	$10M 0.1%	$47M 0.5%	$24M 0.2%	$417M 4.1%	$357M 3.5%

Not a viable pathway due to implementation timing

Scenario Cost Results

In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each existing fleet portfolio against each scenario described earlier in Section 8. The NPVRR for each retirement portfolio across each scenario is summarized in Figure 9-6, with additional details regarding the scenario results described below.

Under the SQE scenario, all portfolio costs are projected to decline due to no carbon price and lower gas and power prices. Given that the lower natural gas price outlook harms near-term coal plant performance, earlier retirement of Michigan City 12 is slightly lower cost than retaining the unit longer, although Portfolios 2-4 are all within $20 million on an NPVRR basis. The cost premium associated with moving towards a net zero strategy (Portfolios 7 and 7H) is highest under this scenario.

Under the AER scenario, higher carbon prices and higher gas prices drive higher portfolio costs, particularly for Portfolio 1, which retains Michigan City 12 until 2032. However, Portfolios 2 and 3 are lower cost than Portfolio 4, as the higher gas prices benefit Michigan City's performance for a few years until replacement resources can enter as the carbon price increases over time. Under this scenario, Portfolio 7 has the lowest NPVRR.

Under the EWD scenario, portfolio costs are the highest, given the highest load growth expectations and growing clean energy requirements. The relative ordering of Portfolios 1-4 is the same as in the Reference Case, but Portfolio 6 has the lowest NPVRR of the first six due to the benefit realized by higher levels of renewable energy additions taking advantage of the clean

energy standard construct. In addition, Portfolios 7 and 7H are the lowest cost under this scenario, with the value of hydrogen energy providing 7H a significant cost benefit.

Figure 9-6: Cost to Customer across All Scenarios – Existing Fleet Portfolios (30-year NPVRR – millions of $)



	Portfolio Transition Target:	15% Coal through 2032	15% Coal through 2028	15% Coal through 2026	15% Coal through 2024	15% Coal through 2028	15% Coal through 2026	15% Coal through 2028 Fossil Free by 2032	15% Coal through 2028; Option for Fossil Free by 2032
	Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
	Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Reference Case	Delta from Lowest	$35	$16	-	$10	$47	$24	$417	$357
	Cost to Customer	0.3%	0.2%	-	0.1%	0.5%	0.2%	4.1%	3.5%
Status Quo Extended	Delta from Lowest	$36	$18	$2	-	$49	$108	$720	$492
	Cost to Customer	0.4%	0.2%	0.0%	-	0.5%	1.2%	7.8%	5.4%
Aggressive Env. Reg.	Delta from Lowest	$336	$269	$259	$277	$292	$157	-	$303
	Cost to Customer	3.1%	2.5%	2.4%	2.5%	2.7%	1.4%	-	2.8%
Econ-Wide Decarbonization	Delta from Lowest	$477	$454	$449	$459	$478	$276	-	$29
	Cost to Customer	4.1%	3.9%	3.9%	4.0%	4.2%	2.4%	-	0.3%

*Note that a $0.50/kg H2 subsidy is assumed in AER and EWD

Not a viable pathway due to implementation timing

Overall, across scenarios, the following key observations were made:

- Retirement of Michigan City 12 in 2026 has a slightly lower NPVRR (less than $20 million) relative to retirement in 2028 across all scenarios.
- Retirement of Michigan City 12 in 2032 is always higher cost than earlier retirement, with the largest difference in the AER scenario.
- Portfolio 2 (retirement of Schahfer 16AB in 2028) is slightly lower cost than Portfolio 5 (retirement of Schahfer 16AB in 2025), although additional renewable additions with early 16AB retirement (Portfolio 6) results in a lower NPVRR under the two high carbon regulation scenarios.
- Portfolios 7 and 7H have the smallest range, as their future renewable, hydrogen, and storage investments hedge against high-cost power market outcomes.

CO2 Emissions

The retirement timing for Michigan City 12 is the major driver of CO2 emission differences across the eight portfolios, with Sugar Creek remaining the largest source of emissions into the 2030s. Therefore, earlier retirement of either unit results in lower overall CO2 emissions for the portfolio. Figure 9-7 illustrates the projected CO2 emissions by portfolio over time for the Reference Case, while Figure 9-8 presents the cumulative emissions over the 2024-2040 period for each scenario, along with a reporting of the scenario average. Emissions vary across scenarios based on different dispatch projections for the fossil units and the potential for hydrogen blending at Sugar Creek in the AER and EWD scenarios in Portfolio 7H.

Figure 9-7: Annual CO2 Emissions for Existing Fleet Portfolios – Reference Case

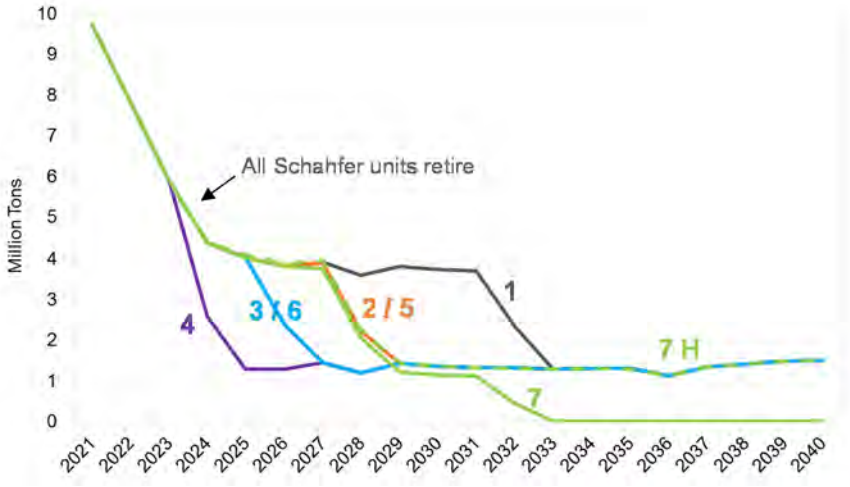
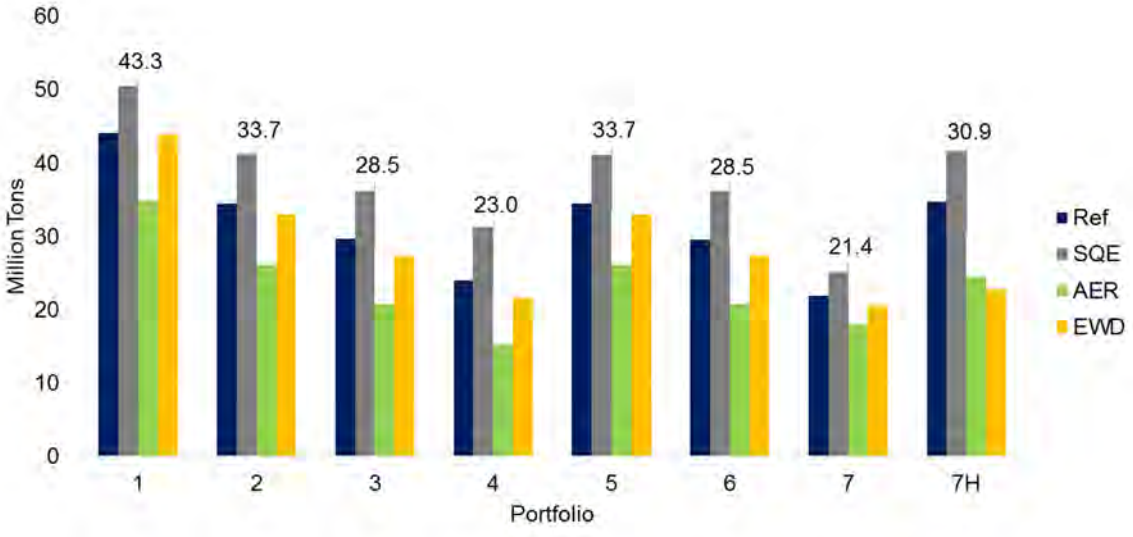


Figure 9-8: 2024-2040 Cumulative Tons of CO2 Emissions for Existing Fleet Analysis – All Scenarios with Average



9.1.8 Existing Fleet Analysis Scorecard Summary

Figure 9-9 presents a summary of all scorecard metrics for each of the eight existing fleet portfolios. This includes the cost metrics associated with the Reference Case NPVRR, the risk metrics associated with the scenario analysis, carbon emissions, NIPSCO employees, and the local economy, as described above.

Figure 9-9: Retirement Portfolio Scorecard

	1	2	3	4	5	6	7	7H
Portfolio Transition Target:	**15% Coal through 2032**	**15% Coal through 2028**	**15% Coal through 2026**	**15% Coal through 2024**	**15% Coal through 2028**	**15% Coal through 2026**	**15% Coal through 2028 Fossil Free by 2032**	**15% Coal through 2028 Fossil Free by 2032**
Retire:	MC: 12 (2032) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16AB (2028)	MC: 12 (2026) Schfr: 16AB (2028)	MC: 12 (2024) Schfr: 16AB (2028)	MC: 12 (2028) Schfr: 16 AB (2025)	MC: 12 (2026) Schfr: 16AB (2025)	MC: 12 (2028) Schfr: 16AB (2025) SC: (2032)	MC: 12 (2028) Schfr: 16AB (2025) SC to H2: (2032)
Retain beyond 2032:	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	Sugar Creek	None	Sugar Creek converts to H2 (2032)
Cost To Customer 30-year NPV of revenue requirement (Ref Case)	$10,149 +$35 0.3%	$10,130 +$16 0.2%	$10,114 - -	$10,125 $10 0.1%	$10,161 +$47 0.5%	$10,138 +$24 0.2%	$10,531 +$417 4.1%	$10,471 +$357 3.5%
Cost Certainty Scenario Range (NPVRR)	$2,759 +$1,161 72.6%	$2,754 +$1,156 72.3%	$2,766 +$1,167 73.0%	$2,777 +$1,179 73.8%	$2,747 +$1,149 71.9%	$2,487 +$889 55.6%	$1,598 - -	$1,855 +$257 16.1%
Cost Risk Highest Scenario NPVRR	$11,974 +$477 4.1%	$11,951 $454 3.9%	$11,947 +$449 3.9%	$11,957 +$459 4.0%	$11,976 +$478 4.2%	$11,773 +$276 2.4%	$11,498 - -	$11,527 +$29 0.3%
Lower Cost Opportunity Lowest Scenario NPVRR	$9,215 +$36 0.4%	$9,197 +$18 0.2%	$9,181 +$2 0.0%	$9,179 - -	$9,229 +$49 0.5%	$9,287 +$108 1.2%	$9,899 +$720 7.8%	$9,671 +$492 5.3%
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	43.3 +22 102%	33.7 +12 57%	28.5 +7 33%	23.0 +2 8%	33.7 +12 57%	28.5 +7 33%	21.4 - -	30.9 +9 44%
Employees Approx. existing gen. jobs compared to 2018 IRP*	+127	0	-127	-127	-4	-131	-34	-4
Local Economy NPV of existing fleet property tax relative to 2018 IRP	+$13	$0	-$10	-$23	$0	-$10	-$16	+$13

*Adding replacement projects could have an impact on net jobs

Not a viable pathway due to implementation timing

The following key observations were made:

- Retaining Michigan City 12 beyond the currently planned retirement date of 2028 (Portfolio 1) is higher cost than the alternatives across all four scenarios.
- Retirement of Michigan City 12 in 2024 (Portfolio 4) is higher cost than later retirement in three out of the four scenarios and is not a viable pathway given insufficient timing to secure replacement capacity.
- Retirement of Michigan City 12 in 2026 (Portfolio 3) has the lowest Cost to Customer under the Reference Case and in three out of four scenarios and achieves the most significant CO2 reductions of the viable portfolios testing coal retirement.

- Retirement of Michigan City in 2028 (Portfolio 2) is very close to Portfolio 3 on all cost metrics, while also preserving jobs for NIPSCO employees and local property tax benefits for two additional years.

- Acceleration of the Schahfer 16A/B retirement to 2025 (Portfolios 5 and 6) is slightly higher cost than retaining the units until 2028, but early retirement could be influenced by unit operational condition and other external policy and technology factors, since additional renewable energy replacement (Portfolios 6) provides lower costs under scenarios with significant carbon regulation (AER and EWD).

- A retirement of Sugar Creek in the 2030s (Portfolio 7) offers the lowest carbon emission profile and, along with potential retrofit to reduce CO2 emissions (Portfolio 7H), provides a hedge against significant environmental regulations that would otherwise raise portfolio costs.

9.1.9 Preferred Existing Fleet Portfolio

NIPSCO's preferred existing fleet portfolio strategy is to retire Michigan City 12 between 2026 and 2028 , to optimize the retirement timing of Schahfer 16A/B between 2025 and 2028, and to keep open the option of retiring or retrofitting the Sugar Creek plant in the 2030s based on environmental policy evolution and technology advancement.

Overall, Portfolio 2 (2028 Michigan City 12 retirement) and Portfolio 3 (2026 Michigan City 12 retirement) were the lowest cost, viable existing fleet portfolio options, and preserving optionality for the Michigan City 12 retirement date will allow NIPSCO to perform full due diligence on RFP projects to confirm timing and costs, monitor ongoing market design and environmental policy changes, and react to technology evolution.

In addition, although Schahfer 16A/B may provide relatively low-cost capacity through 2028, NIPSCO will retain flexibility with retirement timing based on the ultimate Michigan City 12 retirement timing and associated replacement opportunities, Schahfer 16A/B's operational performance, and policy and technology developments.

Finally, while Portfolios 7 and 7H are higher cost under currently expected conditions, retirement or conversion of Sugar Creek in the 2030s, with additional early renewable additions, would be lower cost than continuing to operate the unit fully on natural gas in the event of a high carbon price or other aggressive clean energy policy implementation. Therefore, NIPSCO's preferred existing fleet portfolio strategy explicitly keeps such long-term options open regardless of the retirement dates for Michigan City and Schahfer 16A/B. As a result, the replacement analysis (described in more detail below) continued to evaluate such strategies in more detail.

It is anticipated that NIPSCO's 2021 IRP preferred retirement strategy will require certain upgrades to the transmission system in order to maintain system reliability and remain compliant with NERC transmission planning standards, NIPSCO Planning criteria, and MISO requirements. As noted above, nearly $90 million in costs was assessed with the retirement of Michigan City 12

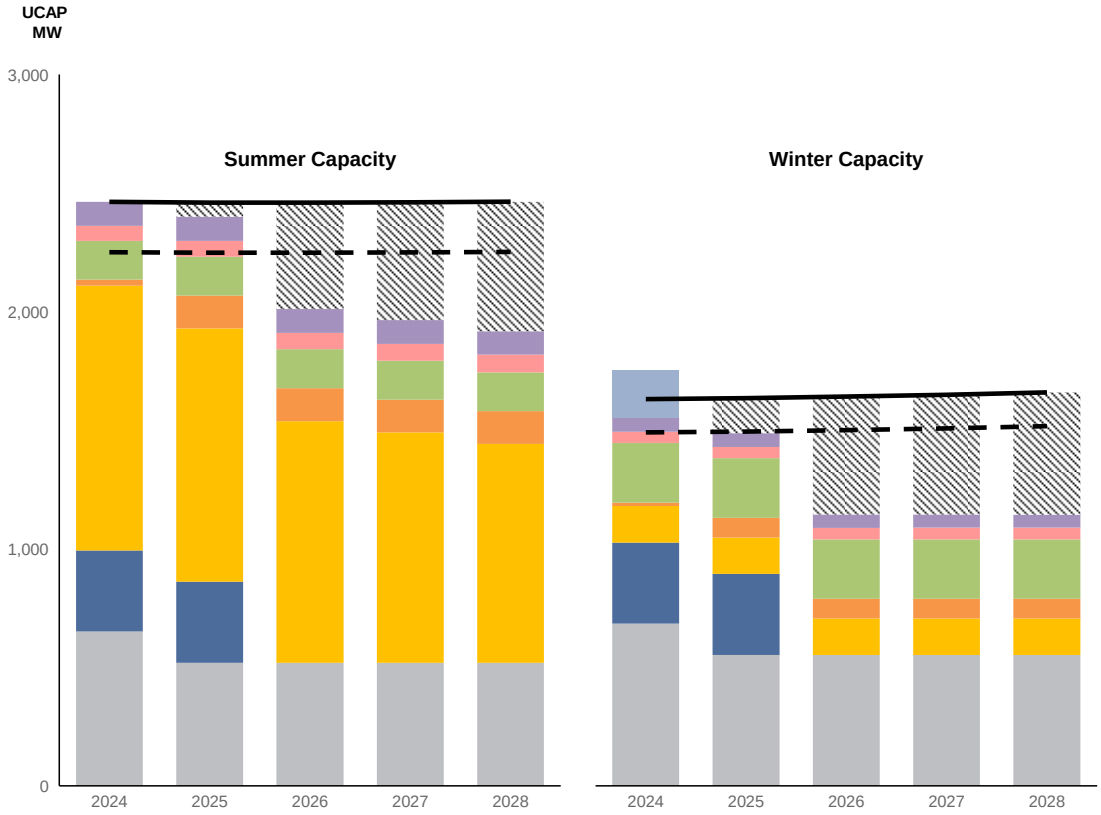
and the Schahfer 16 A/B units in the IRP analysis. This assumption will be validated once NIPSCO proceeds with filing the required forms with MISO (Attachment Y).

With its preferred existing fleet portfolio strategy, NIPSCO has balanced customer cost and cost risk, with portfolio flexibility and the ability to successfully and reliability transform its supply resources to meet its customers' needs. This option also balances other non-economic considerations such as environmental sustainability, portfolio flexibility, employee considerations, and property tax impacts.

Under such a portfolio, a capacity gap of up to 547 MW in the summer and up to 515 MW in the winter will open up by 2028,[107] as shown in Figure 9-10, which summarizes current and expected capacity resources against NIPSCO's Reference Case load forecast, inclusive of planning reserve margin requirements, and assuming the *earliest potential resource retirements* studied in the existing fleet analysis (Schahfer 16A/B in 2025 and Michigan City 12 in 2026). Uncertainty in the future capacity gap will be driven by load growth, MISO planning reserve margin targets, and realized renewable resource capacity credit over time. This capacity gap is the subject of the replacement analysis that is described next.

[107] The capacity gap would be slightly smaller in 2025 or 2026 if the Michigan City 12 and Schahfer 16AB units are retired at points in time prior to 2028. However, this represents the resulting gap by 2028 of any retirement strategy, as illustrated in Figure 9-10.

Figure 9-10: Earliest Future Capacity Need Based on Unit Retirements



9.2 Replacement Analysis

9.2.1 Process Overview

NIPSCO evaluated a range of potential resource replacement options to fill the capacity gap that would develop as the Michigan City 12 and Schahfer 16A/B units retire. For the replacement analysis, Portfolio 3 from the existing fleet analysis was used to assess portfolio selection under the earliest possible retirement of Michigan City 12, noting that Portfolio 2 (Michigan City 12 retirement in 2028) would have similar results, with small changes in resource addition timing.[108]

NIPSCO's replacement analysis was performed in a similar manner to the existing fleet analysis, with the following major steps:

- Identify replacement resource concepts for NIPSCO, primarily around considerations for CO2 emission intensity and resource dispatchability.

[108] This approach does not imply that NIPSCO has determined a specific Michigan City12 retirement date, but is useful for replacement resource selection, given that 2026 was deemed to be the earliest viable retirement date.

- Develop specific replacement portfolios within each concept using IRP optimization tools, bids from the RFPs, and expert judgment.

- Evaluate each replacement portfolio in the IRP tools for each scenario and across the full stochastic distribution of major market inputs (as discussed in detail in Section 8).

- Record costs, risks, and other metrics in the integrated scorecard to arrive at a preferred replacement portfolio strategy.

9.2.2 Identification of Replacement Resource Concepts

NIPSCO developed a matrix of replacement resource concepts based on two key planning considerations. The first consideration was structured around the "dispatchability" of the resource options. Broadly speaking, dispatchability refers to the ability of resources within the portfolio to provide energy "on demand," meaning that resources not reliant on external weather conditions and factors and resources with longer energy duration capabilities are considered more dispatchable. Across the dispatchability consideration, three categories were broadly defined:

- Portfolios that meet only the existing summer reserve margin requirements over time and tend to contain more solar capacity than other dispatchable resource types;[109]

- Portfolios that meet both winter and summer reserve margin requirements over time and tend to contain additional thermal or storage capacity;

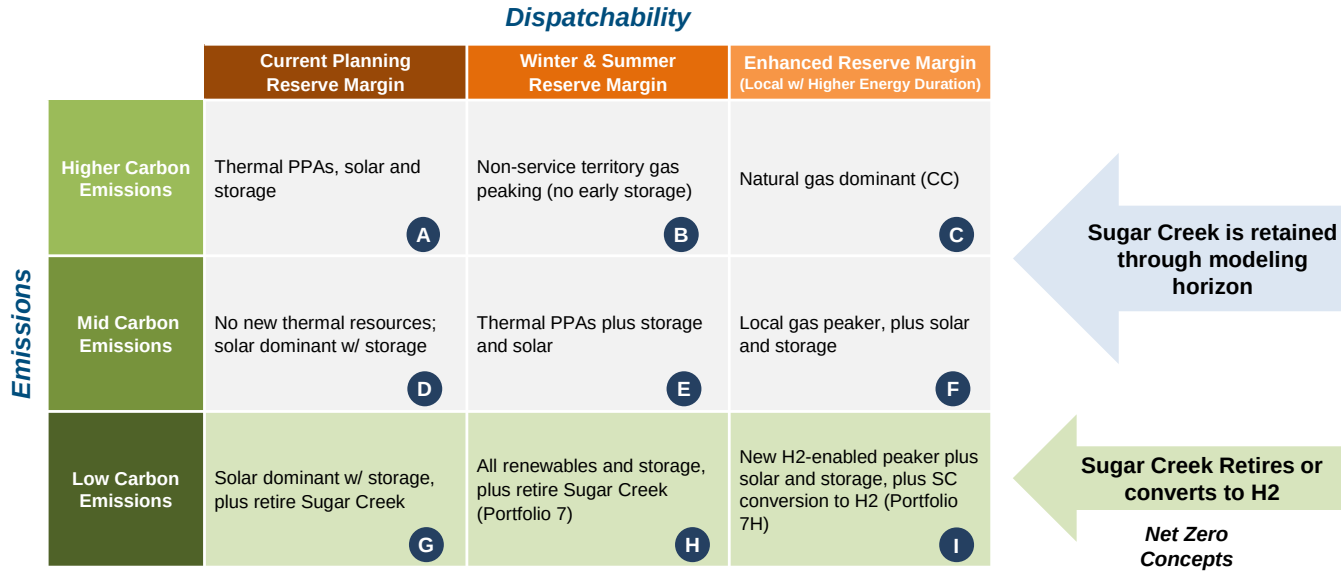
- "Enhanced" reserve margin portfolios that more fully rely on local resources with longer energy duration capabilities, especially thermal resources. Such a portfolio category recognizes the need for local resources during emergency conditions and anticipates future MISO market policy developments that may reduce the capacity credit for resources with limited energy durations, such as four-hour batteries.

The second consideration was structured around the CO2 emission intensity of each potential portfolio option. While no specific emission intensities were defined, portfolios with more fossil-fired resource capacity were considered to have higher emission intensities, while portfolios with more renewable and storage capacity were considered to have lower emission intensities. In addition, specific net-zero emission concepts based on retirement or conversion to hydrogen of all fossil resources in the portfolio were developed.

Overall, nine different concepts were identified for more detailed portfolio development, as shown in Figure 9-11. These portfolios are referred to as Portfolios A-I throughout the rest of this Section.

[109] Given expectations for MISO market rules changes, these portfolio concepts are not viable, but were evaluated to assess their costs across scenarios along with other tradeoffs. Certain stakeholders also expressed an interest in evaluating this theme.

Figure 9-11: Replacement Consideration Matrix



9.2.3 Development of Specific Replacement Portfolios

Based on the nine replacement concepts, NIPSCO then developed specific portfolios to fit each theme. This was done through a combination of the Aurora model's portfolio optimization capability and expert judgment to adjust portfolio concepts based on optimization analysis and available RFP bids.

DSM and DER Selection

Across all portfolio themes, the following DSM bundles were incorporated based on the economic optimization analysis: (i) Tier 1 residential EE for 2024-2029, 2030-2035, and 2036-2041; (ii) commercial and industrial EE for 2024-2029, 2030-2035, and 2036-2041; and (iii) the residential DR rates programs after 2030. (*See* Section 5 for additional detail on the specific energy and peak savings contributions of each bundle). In addition, 10 MW of NIPSCO DER was incorporated in all portfolio themes, reflecting the DER opportunities with the largest investment deferral benefit (*See* Section 4 for additional detail).

All-Source RFP Resource Selection

Beyond DSM and DER additions, NIPSCO used the following approach to select RFP project additions for each of the portfolio themes, which are summarized in Figure 9-12 with incremental ICAP additions and in Figure 9-13 with new resource UCAP contributions shown in the context of the remaining portfolio and expected seasonal reserve margin requirements for 2027:

- Portfolios B, E, and F were based on the optimized portfolio themes from the existing fleet analysis, with specific RFP tranches to identify local versus remote gas peaking options (in Portfolios B and F) and to adjust the amount of gas peaking, storage, and solar capacity to fit the themes and meet reserve margin requirements.

- The net energy sales constraint enforced in the existing fleer analysis phase was relaxed to allow for fossil resources with higher energy contributions for Portfolio C, allowing for the inclusion of a combined cycle.

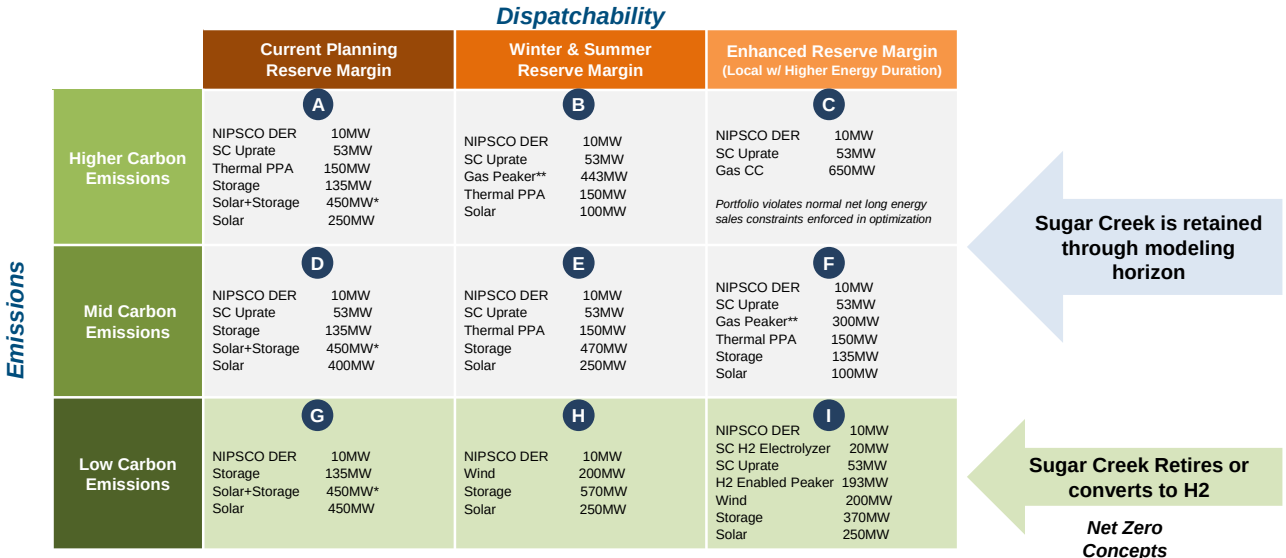
- Optimization testing was evaluated across Reference and high environmental regulation scenarios under summer reserve margin targets only to develop Portfolios A, D, and G with higher levels of solar and solar plus storage.

- Portfolios H and I were mapped to Portfolios 7 and 7H, respectively from the existing fleet analysis to capture the net zero concepts with Michigan City retirement in 2026.

Beyond the RFP selection period, NIPSCO relied upon the optimization analysis results from the existing fleet analysis phase, which suggested that generic solar and storage resources were most cost-effective additions over time to meet capacity needs and energy requirements associated with expectations for declining capacity factors for the Sugar Creek unit, expiring wind contracts, and solar degradation over time. Solar and storage addition amounts were adjusted to ensure reserve margin targets were met across each of the portfolio themes.[110] A summary of the total capacity additions through 2040 for all nine portfolios is shown in Figure 9-14, with a 2040 supply-demand balance on a UCAP basis summarized in Figure 9-15.

[110] Note that for portfolio development purposes, a mix of PPA and owned resources was assumed over the long-term, as opposed to a generic PPA least cost solution that was identified by the optimizer. This is consistent with NIPSCO's 2018 IRP preferred portfolio and does not necessarily represent NIPSCO's preferred procurement strategy for projects into the 2030s. Future IRPs will assess ongoing needs on a regular basis.

Figure 9-12: Replacement Portfolio Resource Additions through 2027 (ICAP MW)



Note: Residential/Commercial DSM universally selected across portfolios
**Represents 300 MW of solar and 150 MW of storage*
***Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

Figure 9-13: 2027 Supply Mix by Replacement Portfolio (UCAP MW) – without Michigan City 12 and Schahfer 16AB

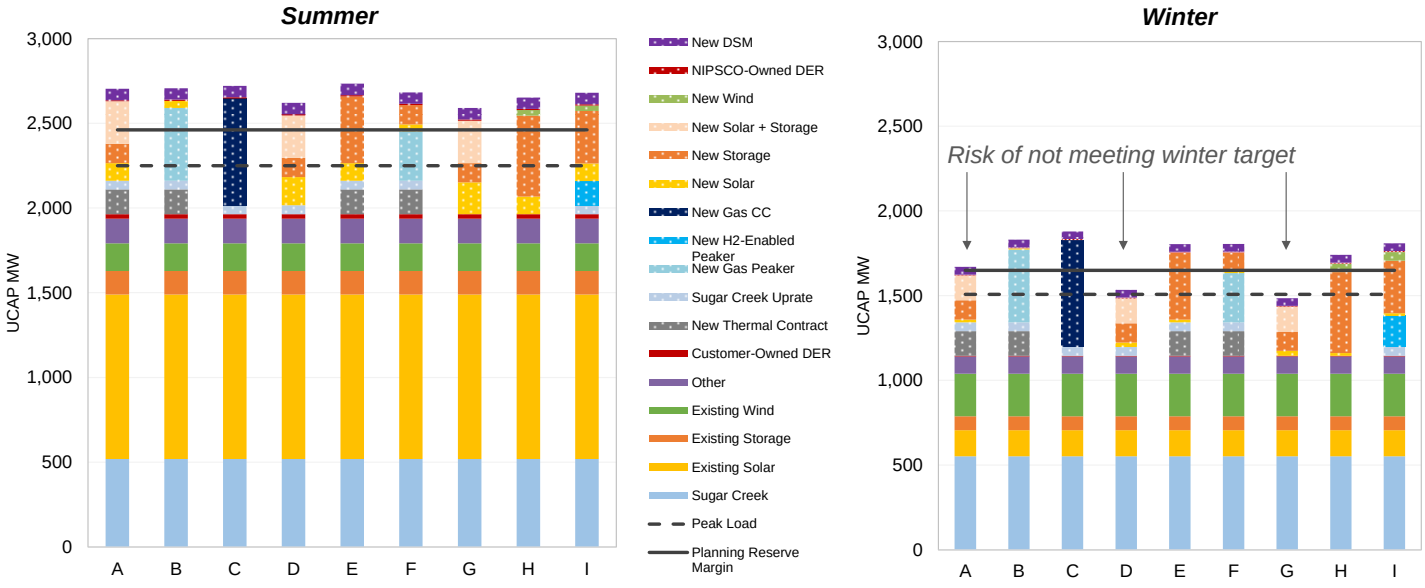
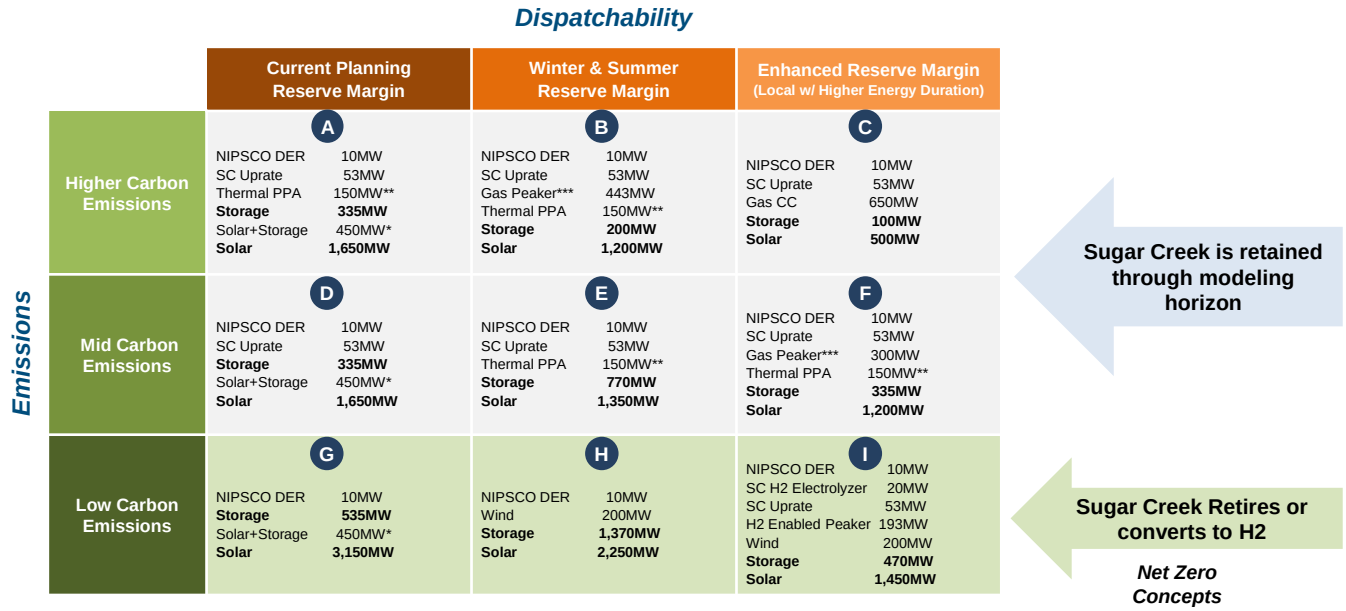
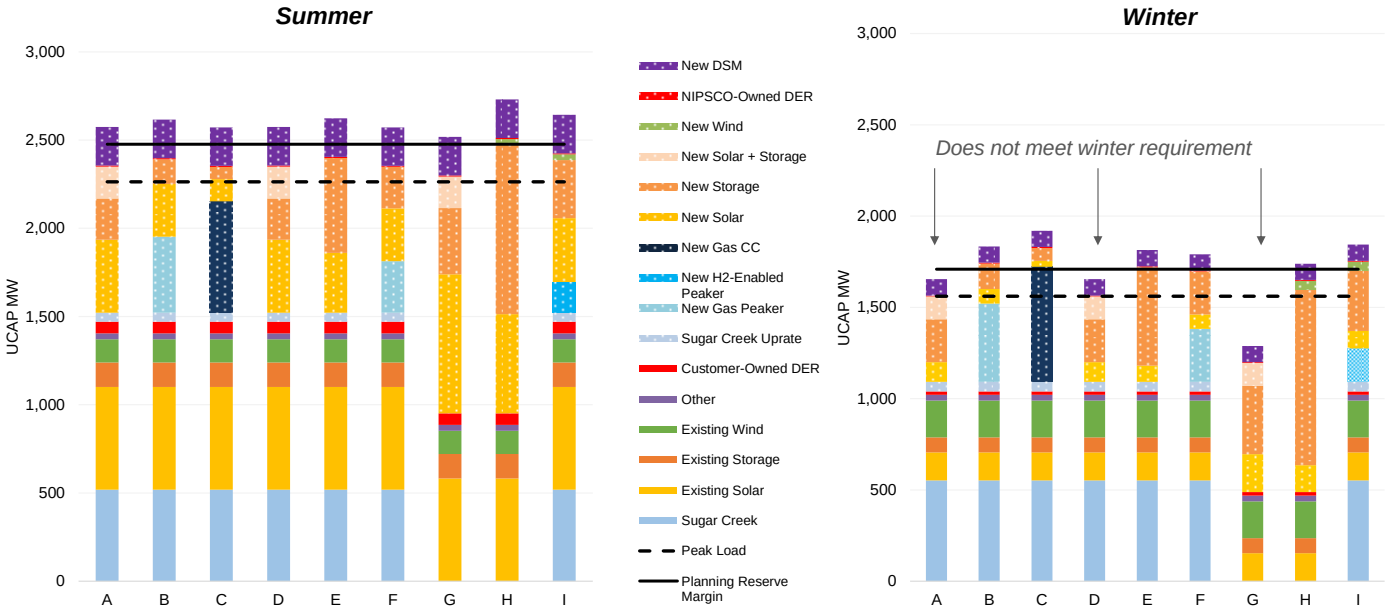


Figure 9-14: Replacement Portfolio Resource Additions through 2040 (ICAP MW)



Note: Residential/Commercial DSM plus a DR Rates program universally selected across portfolios
**Represents 300 MW of solar and 150 MW of storage*
***Ten-year PPA term would have this resource expire by mid-2030s*
****Gas peaker in Portfolio B represents an out-of-service territory PPA; Gas peaker in Portfolio F represents asset sale proposal*

Figure 9-15: 2040 Supply Mix by Replacement Portfolio (UCAP MW)



9.2.4 Evaluation of Each Replacement Portfolio – Scorecard Metrics

Similar to the scorecard developed for the existing fleet analysis, NIPSCO developed a scorecard of objectives, indicators, and key metrics associated with the replacement analysis (*See* Figure 9-16). While major objectives remained consistent across stages of the analysis, some changes were made for the replacement scorecard relative to the existing fleet scorecard:

- Risk metrics associated with the stochastic analysis were added, which included several measurements of points on the stochastic distribution of revenue requirement outcomes relative to the median: (i) cost certainty was measured at the 75th percentile; (ii) cost risk was measured with the 95th percentile conditional value at risk, or the average of all outcomes above the 95th percentile; and (iii) lower cost opportunity was measured at the 5th percentile.

- Reliability was measured in an economic fashion through the potential value upside in the ancillary services markets and through the Reliability Assessment scoring (see additional detail later in this section).

- Resource optionality was measured through the MW-weighted commitment duration of generation commitments in the year 2027.

- Employee count was not recorded, given uncertainty with future project details.

Figure 9-16: Scorecard Metrics for Replacement Analysis

Objective	Indicator	Description and Metrics
Affordability	**Cost to Customer**	• Impact to customer bills • Metric: 30-year NPV of revenue requirement (Reference Case scenario deterministic results)
Rate Stability	**Cost Certainty**	• Certainty that revenue requirement within the most likely range of outcomes • Metric: Scenario range NPVRR and 75th % range vs. median
	Cost Risk	• Risk of unacceptable, high-cost outcomes • Metric: Highest scenario NPVRR and 95th % conditional value at risk (average of all outcomes above 95th % vs. median)
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: Lowest scenario NPVRR and 5th % range vs. median
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions (2024-40 short tons of CO_2) from the generation portfolio
Reliable, Flexible, and Resilient Supply	**Reliability**	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: Sub-hourly A/S value impact and Reliability Assessment scoring
	Resource Optionality	• The ability of the portfolio to flexibly respond to changes in NIPSCO load, technology, or market rules over time • Metric: MW weighted duration of generation commitments (UCAP – 2027)
Positive Social & Economic Impacts	**Employees**	• *Addressed in Existing Fleet Analysis for existing generation assets; employee numbers will be dependent on specific asset replacements*
	Local Economy	• Effect on the local economy from new projects and ongoing property taxes • Metric: NPV of property taxes from the entire portfolio

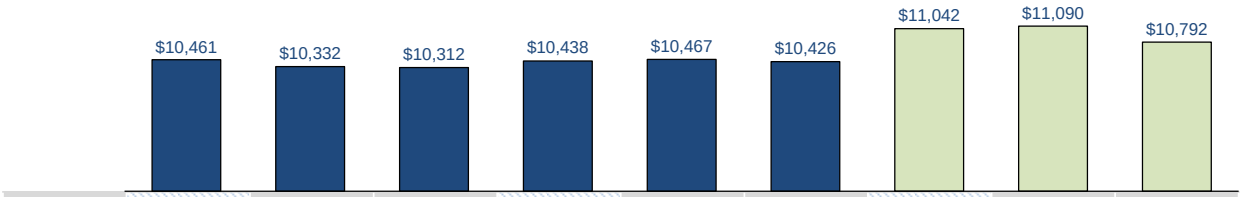
9.2.5 Evaluation of Replacement Portfolios – Core Analysis Results

Reference Case Cost Results

The nine replacement portfolios were all evaluated within the core IRP modeling tools (*See* Section 2 for more detail) to estimate revenue requirements for each over time. The assessment was first performed across the Reference Case set of market assumptions and inputs to calculate baseline projections of the NPVRR over the thirty-year planning horizon, which are summarized in Figure 9-17.

Under the Reference Case market conditions, Portfolios A through F are all within ~$150 million of each other on an NVPRR basis, with Portfolios B, C, and F (portfolios with natural gas capacity additions) having the lowest costs. Portfolio C has the lowest NPVRR, but develops a very net long position, with excess energy sales offsetting portfolio costs.[111] Portfolios G, H, and I (net zero concepts) are higher cost, with Portfolio I retaining the optionality to burn natural gas at Sugar Creek under Reference Case conditions.

Figure 9-17: Reference Case Cost to Customer Impacts – Replacement Portfolios (30-year NPVRR – millions of $)



Replacement Theme	**Thermal PPAs, solar and storage**	**Non-service territory gas peaking (no early storage)**	**Natural gas dominant (CC)**	**No new thermal resources; solar dominant w/ storage**	**Thermal PPAs plus storage and solar**	**Local gas peaker, plus solar and storage**	**Solar dominant w/ storage, plus retire Sugar Creek**	**All renewables and storage, plus retire Sugar Creek (Portfolio 7)**	**New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)**
	A	B	C	D	E	F	G	H	I
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Rank (1=Least Cost)	5	2	1	4	6	3	8	9	7
Delta from Least Cost	$150 1.5%	$21 0.2%	-	$126 1.2%	$156 1.5%	$115 1.1%	$730 7.1%	$778 7.5%	$480 4.7%

Not a viable pathway due to not meeting winter planning reserve margins

Scenario Cost Results

In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each replacement portfolio against each scenario described earlier in Section 8. The NPVRR for each replacement portfolio across each scenario is summarized in Figure 9-18, with additional details regarding the scenario results described below.

[111] This portfolio is also higher than several alternatives over a 20-year period, indicating that the long-term merchant energy margins contribute to the overall lower costs.

Figure 9-18: Cost to Customer across All Scenarios – Replacement Portfolios (30-year NPVRR – millions of $)

Replacement Portfolio	Reference Case	Status Quo Extended	Aggressive Environmental Regulation	Economy-Wide Decarbonization
A	10,461	9,657	11,356	12,015
B	10,332	9,400	11,444	12,182
C	10,312	9,309	11,637	12,518
D	10,438	9,644	11,338	11,965
E	10,467	9,588	11,373	12,126
F	10,426	9,495	11,489	12,243
G	11,042	10,485	11,573	11,809
H	11,090	10,458	11,482	12,011
I	10,792	9,933	11,550	11,848

*Note that Portfolio I was assessed with a hydrogen subsidy of $0.50/kg in the AER and EWD scenarios.

Under the SQE Scenario, with no carbon regulation and low natural gas prices, portfolios with more gas generation (particularly Portfolio C) are lower in cost. In addition, under this scenario, the cost of pursuing a net zero strategy increases, with the spread from the lowest to highest cost portfolios widening to over $1 billion in NPVRR

On the other hand, under a scenario with rising gas prices and strict environmental regulation (through a carbon price in the AER scenario), portfolios with more gas generation (particularly Portfolio C) are higher cost. Among viable options that meet expected summer and winter reserve margin requirements, Portfolio E (storage and solar, with no new gas capacity additions) is lowest cost

Finally, under the EWD scenario, similar trends as those observed in the AER scenario are also evident. However, clean energy resources have more value in this scenario, given the Clean Energy Standard construct and long-term extensions in federal tax credits, resulting in Portfolio I (assuming a future hydrogen subsidy)[112] having lowest costs among viable portfolios.

Overall, across scenarios, the following key observations were made:

- Portfolios that have the highest solar additions and meet only the summer reserve margin target (Portfolios A, D, G) perform best under high environmental regulation scenarios (AER and EWD), but are higher cost than alternatives in other scenarios and are not viable options, given expected market rule changes.

- Adding new combined cycle capacity (Portfolio C) results in the lowest costs under the Reference and SQE scenarios, but is highest cost in the AER and EWD

[112] As noted in Section 8, environmental regulation, particularly in the EWD scenario, could include subsidies for emerging technologies such as hydrogen. Section 4.6.4.1 discusses the development of green hydrogen costs for the 2021, including the $0.50/kg subsidy sensitivity evaluated here.

scenarios, illustrating how adding significant amounts of additional natural gas-fired energy to the portfolio contributes to higher levels of scenario risk.

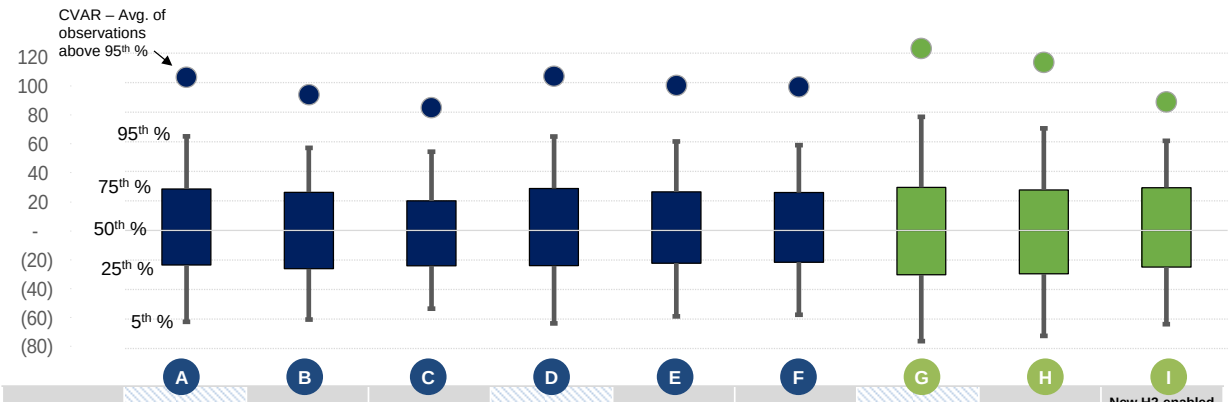
- While a portfolio approach that retires all thermal resources by 2032 and relies solely on renewables and storage (Portfolio H) provides a high level of scenario cost certainty, it is highest cost under Reference Case conditions.

Stochastic Analysis Results

In addition to assessing each replacement portfolio against each market scenario, NIPSCO has also evaluated the replacement options against the full stochastic distribution of potential outcomes for commodity prices and renewable output, as described in more detail in Section 8. The stochastic assessment is used to further evaluate the risk of each of the portfolios against a framework that is focused on short-term price and renewable output volatility as opposed to the long-term movement in macroeconomic or policy trends that are assessed across scenarios.

Figure 9-19 presents a summary of the stochastic results for each of the replacement portfolios, with the graphics highlighting the spread in NPVRR relative to the median (50^{th} percentile) cost for each portfolio. The 25^{th} to 75^{th} percentile range is shown in the shaded box are, while the 5^{th} and 95^{th} percentiles are marked by the tails or "whiskers" shown below and above the box, respectively. The CVAR or average of the observations above the 95^{th} percentile is indicated with a dot. The key risk metrics associated with NIPSCO's integrated scorecard framework are shown in the table below the graphic.

Figure 9-19: Summary of Stochastic Results – Replacement Portfolios (30-year NPVRR – millions of $)



Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
95th % CVAR Delta from Low	21	9	-	21	15	14	40	31	4
75th % Delta from Low	8	6	-	8	6	6	9	7	9
5th % Delta from Low	13	15	22	12	17	18	-	4	11

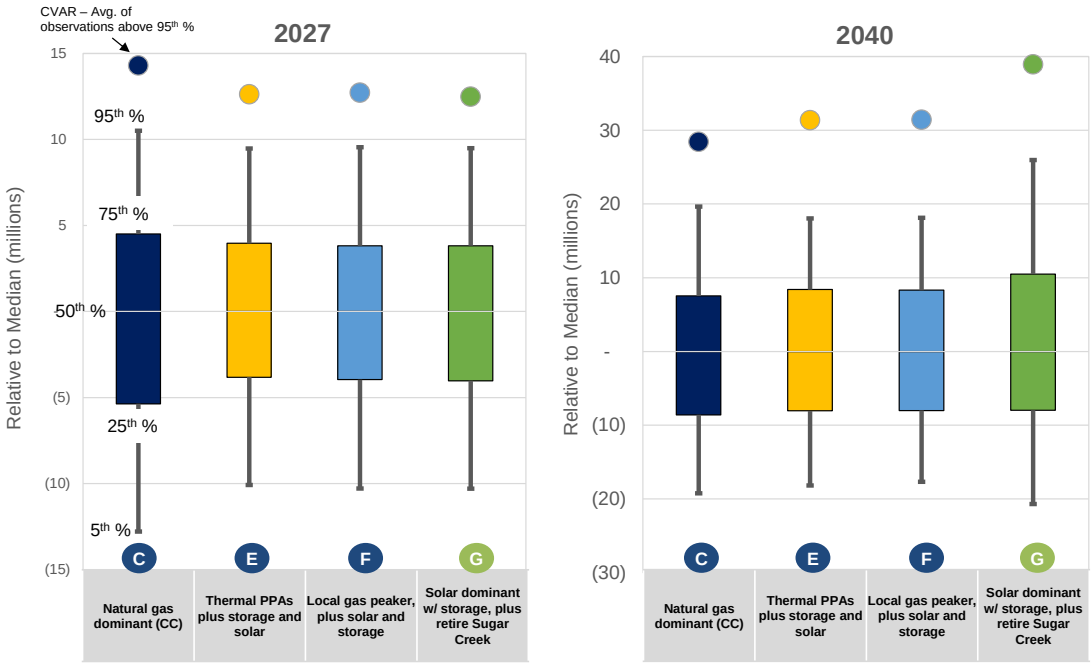
Overall, the magnitude of cost distributions across portfolios is narrower than the scenario range, suggesting that stochastic risk for these portfolio options is less impactful than the major policy or market shifts evaluated across scenarios. However, the stochastic analysis results do indicate that over the 30-year time horizon, dispatchability serves to mitigate tail risk, as portfolios that retain Sugar Creek or add natural gas, including with hydrogen enablement, or storage capacity (Portfolios B, C, E, F, and I) perform best at minimizing upside cost risk by resulting in the lowest difference in the 95th CVAR relative to the median. Meanwhile, the lowest downside range is observed in renewable-dominant portfolios, showcasing that such portfolio strategies (illustrated through Portfolios A, D, G, and H) have the broadest range of outcomes.

The stochastic analysis also illustrates the changing risks likely to be faced by NIPSCO's portfolio over time. Under current market conditions, portfolios with larger amounts of natural gas energy are likely to be highly exposed to market price and dispatch risk. As a result, over the next several years, Portfolio C is likely to have a broader range of cost outcomes and higher tail risk. However, over time, as the market becomes more dominated by intermittent resources, renewable output uncertainty becomes more correlated to power prices, and NIPSCO portfolio strategies that rely most on intermittent renewable resources (Portfolio G, for example) have the greatest tail risk. This is because they expose the portfolio to high costs associated with low renewable output/high market price events.

This phenomenon is illustrated in Figure 9-20, which show the range of stochastic cost outcomes for a selection of four portfolios in the years 2027 and 2040. While Portfolio C has the

greatest risk exposure in 2027 and Portfolio G has the greatest risk exposure in 2040, portfolios that integrate some level of dispatchable capacity in the form of peaking or storage resources (Portfolios E and F) perform similarly from a risk perspective over time and hedge against both near-term and long-term stochastic risk exposure.

Figure 9-20: Risk Profile Evolution for a Sample of Replacement Portfolios



This conclusion can also be illustrated by evaluating a sample of daily outcomes from the stochastic analysis across seasons. As shown in Figure 9-21, during summer days, power prices are likely to be negatively correlated to solar output, with price dips during mid-day hours (when solar output is high) and price spikes in the evenings and overnight (when solar output is low). As a result, a portfolio dominated by solar capacity will have excess energy during low-priced hours and could be exposed to market purchases during high-priced hours. Portfolios that integrate storage or other dispatchable resources could mitigate this risk, which may be even more pronounced on days with low solar output (right graphic).

Figure 9-22 provides additional examples during the winter season, a time of year when solar output will be lower and potentially more volatile. As a result, during days with low solar output, significant market exposure is possible for portfolios without sufficient dispatchable capacity, particularly during the morning and evening peak load periods.

Figure 9-21: Sample Stochastic Iterations for Summer Day Solar and Storage Output

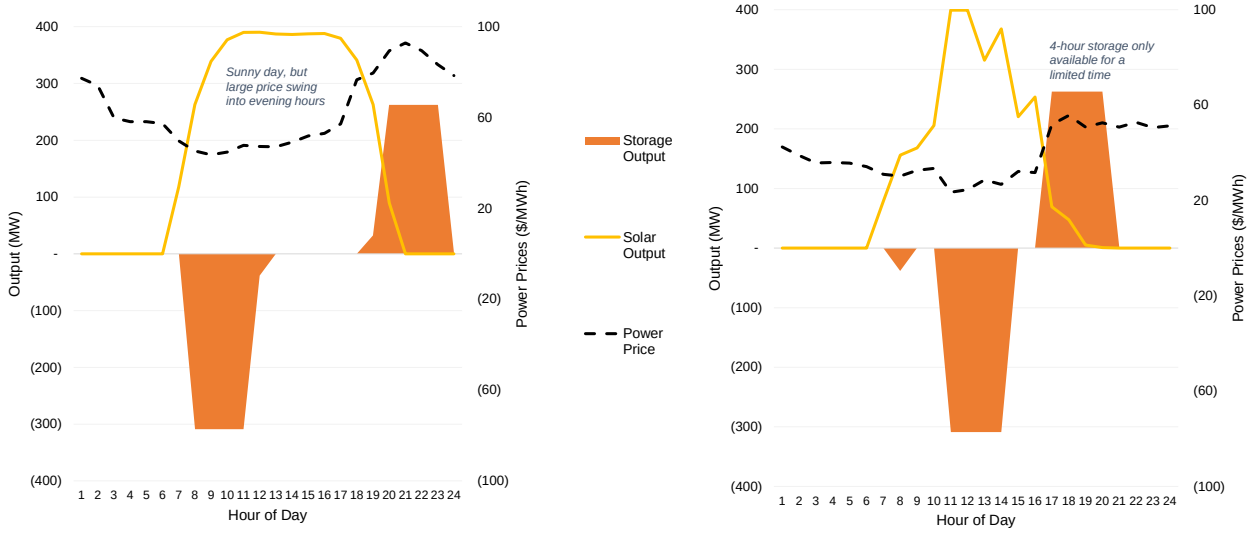
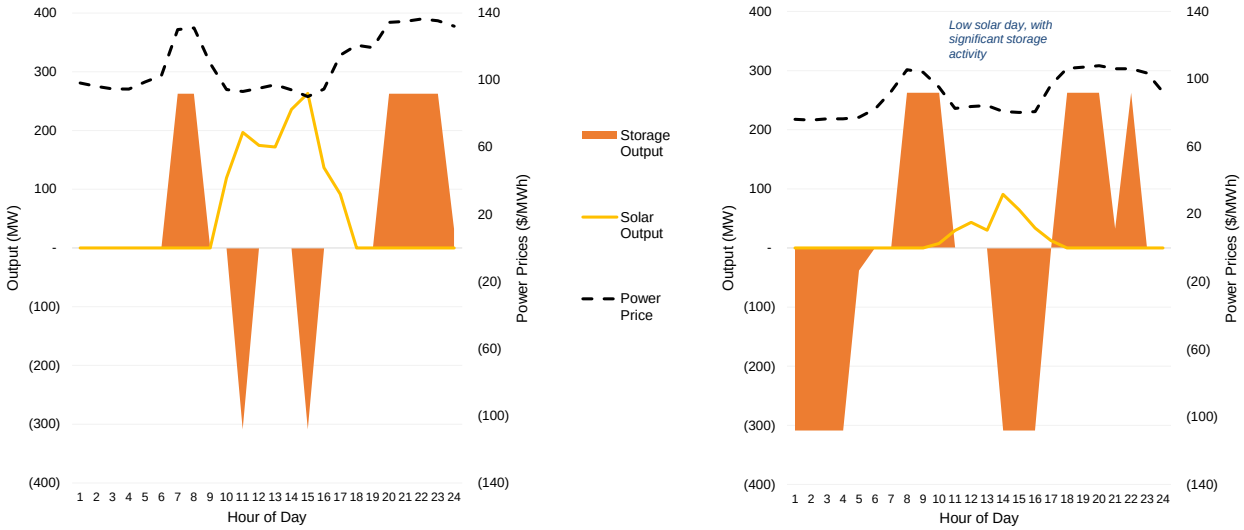


Figure 9-22: Sample Stochastic Iterations for Winter Day Solar and Storage Output



CO2 Emissions

Across replacement portfolios, the biggest drivers of future CO2 emissions are whether the portfolio adds a significant new source of CO2 emissions in the form of a combined cycle (Portfolio C) and how Sugar Creek operates into the 2030s.[113] Therefore, Portfolio C has the highest emission profile over time, and Portfolios G and H (and Portfolio I if Sugar Creek converts to hydrogen) have the lowest emission profile. Figure 9-23 illustrates the projected CO2 emissions by portfolio over time for the Reference Case, while Figure 9-24 presents the cumulative emissions over the 2024-2040 period for each scenario, along with a reporting of the scenario average. As

[113] Note that the replacement portfolios were all evaluated under the assumption of a 2026 retirement date for Michigan City 12, which is not necessarily NIPSCO's preferred portfolio. See Figure 9-7 for the impact of retirement in 2026 versus 2028 on CO_2 emissions.

in the existing fleet analysis, emissions vary across scenarios based on different dispatch projections for the fossil units and the potential for hydrogen blending at Sugar Creek in the AER and EWD scenarios in Portfolio I.

Figure 9-23: Annual CO2 Emissions for Existing Fleet Portfolios – Reference Case

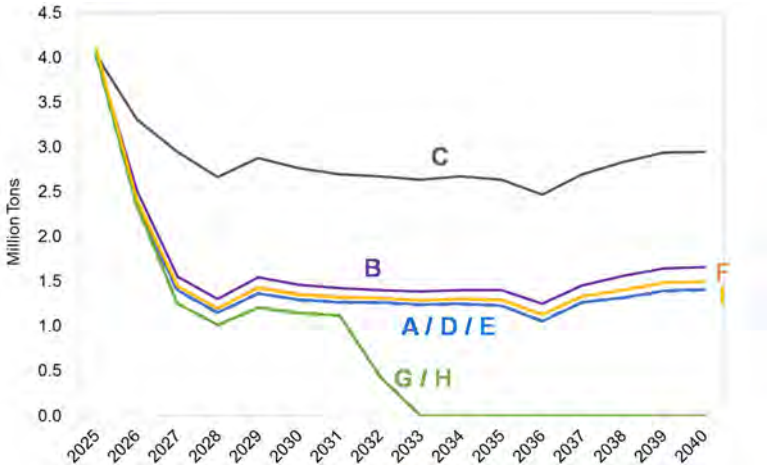
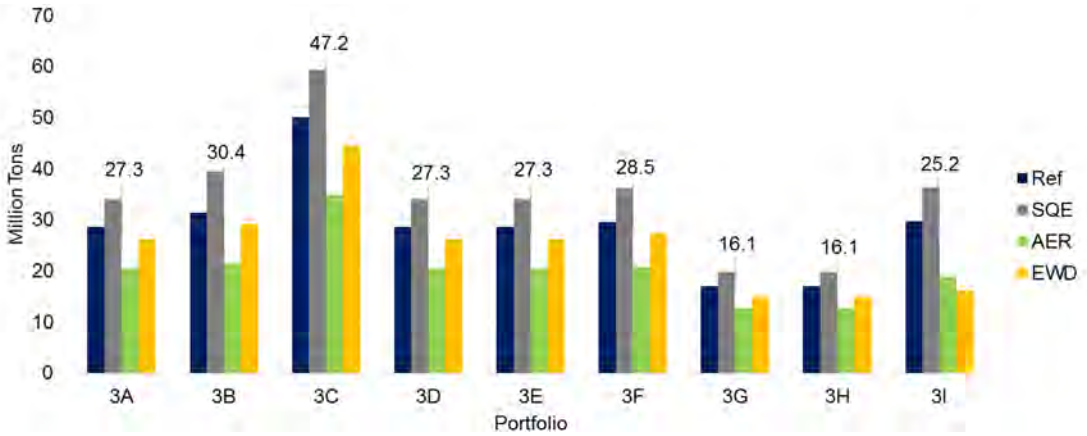


Figure 9-24: 2024-2040 Cumulative Tons of CO2 Emissions for Existing Fleet Analysis – All Scenarios with Average



Additional DSM Analysis

As noted earlier, all of NIPSCO's replacement portfolios contain several DSM measures that were found to be cost-effective in the optimization analysis. These included: (i) Tier 1 residential EE for 2024-2029, 2030-2035, and 2036-2041; (ii) commercial and industrial energy efficiency for 2024-2029, 2030-2035, and 2036-2041; and (iii) the residential DR rates programs after 2030. As discussed in Section 5, the core portfolio analysis was performed for RAP levels of DSM, although NIPSCO also evaluated the impact of using MAP levels, which includes

additional savings available at higher costs, as summarized in Figure 9-25 and Figure 9-26,[114] respectively.

Figure 9-25: MAP vs. RAP Annual GWh Savings – Residential Tier 1 and Commercial and Industrial Programs

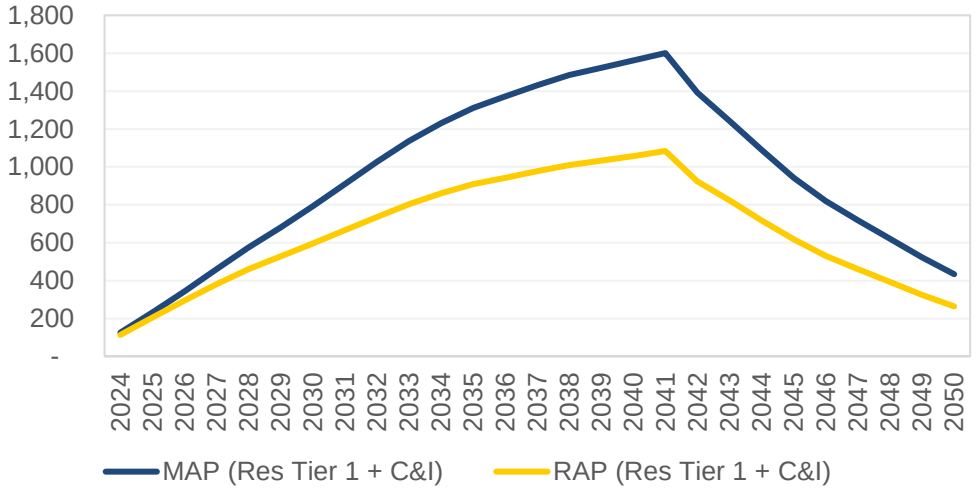


Figure 9-26 : Levelized Costs ($/MWh) by DSM Bundle – RAP vs. MAP

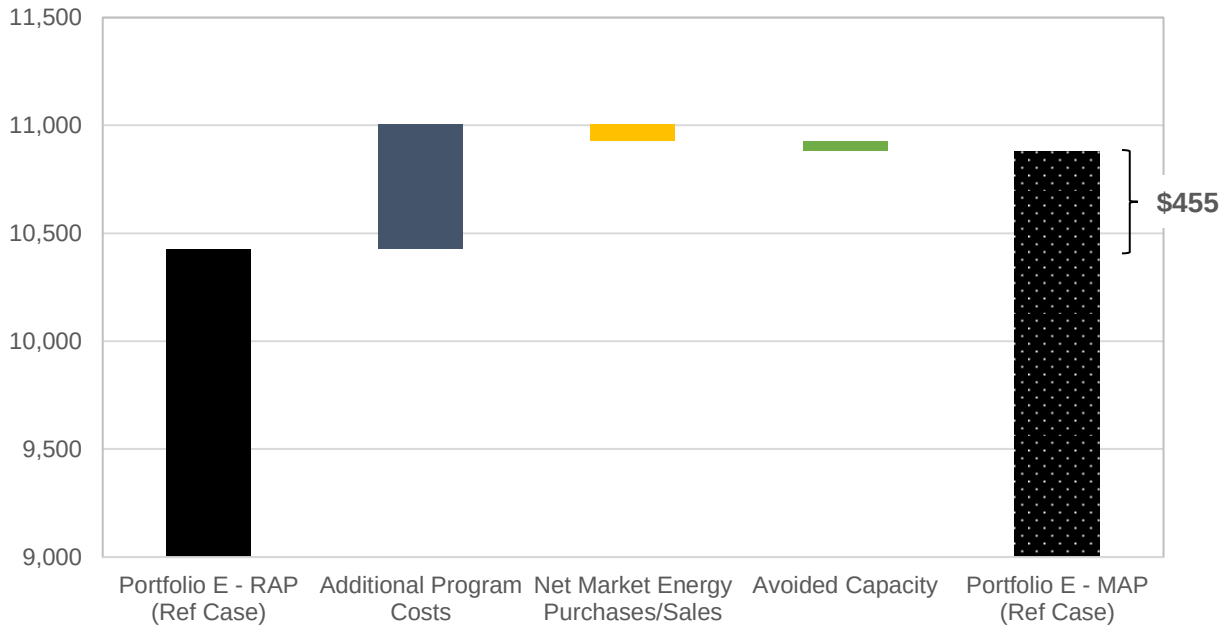
		RAP	MAP
2024-2029	Res Tier 1	53	140
	C&I	26	86
2030-2035	Res Tier 1	60	160
	C&I	30	90
2036-2041	Res Tier 1	65	165
	C&I	32	91

Using these inputs, NIPSCO evaluated the impact of moving to the MAP DSM bundles for a selection of replacement portfolios. This was done by effectively "forcing in" the same residential and commercial/industrial energy efficiency programs identified in the original optimization analysis, but at the MAP level instead of at the RAP level. This has the impact of both reducing energy requirements and mitigating the need for some long-term capacity additions. The impact of reduced energy requirements was evaluated through a re-dispatch of the portfolios in the Aurora portfolio model, while 100 MW of future storage additions in the 2030s were removed to reflect the reduced capacity obligation.

[114] Note that levelized costs are presented prior to cost adjustments for avoided T&D investment.

Under Reference Case conditions, NIPSCO's analysis found that moving from the RAP to the MAP DSM bundles would increase the 30-year NPVRR by $455 million for Portfolio F.[115] As illustrated in Figure 9-27, the additional program costs represent $578 million in NPVRR, while the value of saved energy associated with fewer net market purchases represented $78 million in NPVRR and the savings associated with avoided storage capacity additions represented $45 million in NPVRR. Alternative scenarios with higher costs of energy (especially the AER scenario) would increase the savings associated with net market energy purchases/sales, but still would not offset additional program costs. This analysis confirmed that the DSM programs contained in NIPSCO's preferred portfolio will be based on the RAP assumptions.

Figure 9-27: 30-year NPVRR Impact of Shifting from RAP to MAP – Portfolio F Example



9.2.6 Sub-Hourly Modeling with Ancillary Services

9.2.6.1 Background

Although the IRP's core economic analysis captures most portfolio cost elements, NIPSCO has broadened the scope of the 2021 IRP to assess additional elements of reliability, including Operating Reliability, as defined in MISO's RIIA report and summarized in Figure 9-28. Although all Operating Reliability elements cannot be evaluated in an economic fashion, MISO does operate markets for ancillary services which aim to enhance reliability at a very granular level and in real time.

[115] NIPSCO also tested the impact on Portfolio E and found that moving from the RAP to the MAP DSM bundles would increase the 30-year NPVRR by $429 million.

Figure 9-28: Overview of Different Elements of Reliability and IRP Modeling Approach

	Resource Adequacy	Energy Adequacy	Operating Reliability
Definition:	Having sufficient resources to reliably serve demand	Ability to provide energy in all operating hours continuously throughout the year	Ability to withstand unanticipated component losses or disturbances
Forward Planning Horizon:	Year-ahead	Day-ahead	Real-time or Emergency
Reliability Factors:	Reserve margin, ELCC and energy duration	Dispatchability, energy market risk exposure	Real Time Balancing System
IRP Modeling Approach:	Portfolio development constraints, with ELCC and seasonal accounting	Hourly dispatch analysis, including stochastic risk	**Ancillary services analysis (regulation, reserves), with sub-hourly granularity**

MISO Ancillary Services Market Overview

MISO operates two energy and operating reserve markets: day-ahead and real-time. The day-ahead clears every hour, on the eve of the day of operations, on a co-optimized basis using SCUC, SCED, and SCED-pricing computer programs. On the day of operations, the real-time clears every 5-minutes on a co-optimized basis using SCED. The operating reserve market is composed of regulating reserves and contingency reserves. Resources are permitted to switch between markets, and there is no minimum threshold for continuous provision into a single market.[116] Currently, storage resources are only permitted to participate in the regulation market, but MISO is underway with tariff filings to allow them to participate in energy and other ancillary services markets.[117]

Resources participating in the day-ahead and real-time markets have the ability to specify, along other offer parameters, a commitment status which describes the ability or inability to dispatch. The five statuses are: economic, must-run (self-commit), outage, emergency, and not participating. “Economic” designates a resource available for commitment by the operator. “Must-run” designates a resource committed per market participant request and available for dispatch by MISO. “Outage” designates a resource not available in the energy or operating reserve markets because it is undergoing a planned or forced outage. “Emergency” designates a resource available for only emergency situations. “Not participating” designates a resource which will not participate in day-ahead or real-time energy market but is available.

Frequency regulation is used to address small mismatches between supply and demand. Regulating generators cleared in the day-ahead or real-time market must be fully deployable in regulation-up and regulation-down directions within a specified time period. Unlike some other

[116] MISO BPM 002 – p. 142
[117] BPM002 – p. 132, 170

RTOs that have separate markets for regulation-up and regulation-down, MISO has a single regulation market.

Contingency reserves are used to address unforeseen events such as a large generator tripping offline. Contingency reserves are composed of spinning and supplemental reserves. Spinning reserves are provided by units that are synchronized to grid, not generating at their maximum output, and able to ramp up their generation. Supplemental reserves are also provided by units that are not synchronized to the grid but are able to come online quickly if needed.

FERC Order 841 Implications for Storage Market Participation

The role of storage in the energy and ancillary services markets is likely to continue to evolve as the electricity markets comprise more intermittent resources. As a result, FERC issued Order No. 841 to boost competition in the storage sector and ensure that markets like MISO provide just and reasonable rates. Order No. 841 requires each RTO and ISO to revise its tariff to establish a participation model for electric storage resources consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, will help facilitate their participation in the RTO/ISO markets.

MISO is responsible for implementing this order and has been granted an extension for compliance through 2022. Some key elements of MISO's market design changes are likely to include the following:

- A proposal to establish a unique offer structure for ESR in both the Day-Ahead Market and the Real-Time Market and to provide flexibility to ESR owners by establishing a Commitment Status to communicate how the resource will be available to the markets.

- Enablement of ESR to provide energy and ancillary services, blackstart service, and reactive supply and voltage control.

- Allowance of ESR to qualify as Use Limited Resources to accommodate resources that may need or desire their commitment to be limited to four hours per day in order to reliably provide a service.

- Allowance for ESR to both receive and inject electric energy in a way that recognizes physical and operational characteristics and optimizes benefits to MISO and prevents conflicting dispatch instructions through a single offer curve made up of both discharge segments (i.e., price/MW pairs for positive values or injections) and charge segments (i.e., price/MW pairs for negative values or withdrawals). Resources will be paid or pay the LMP at the pricing node for, respectively, injections to discharge and withdrawals to charge. Efficiency losses will not be considered load or station power but will be included in energy schedules.

- Ability of ESR to participate and set prices in the Planning Reserve Auction, submit wholesale bids to buy energy though the Day-Ahead and Real-Time Energy Offer

Curves, participate in MISO's markets as price takers, self-schedule, and manage their State of Charge.

9.2.6.2 Energy Storage Resource Operations Model Overview

Since the core Aurora market and portfolio model is fundamentally based on a day-ahead simulation, NIPSCO has performed additional analysis to estimate the incremental value streams that flexible resources can achieve by participating in markets beyond day-ahead energy. To do this, CRA employed its proprietary ESOP model,[118] an optimization model that computes revenues through participation in energy and A/S markets with five-minute granularity. Given simulated energy and ancillary services pricing information, ESOP solves for optimal dispatch decisions unique to a price-taking resource's technological characteristics and a regional market's participation rules. A comparison of the Aurora portfolio tool and the ESOP model is summarized in Figure 9-29.

Figure 9-29: Comparison of Aurora Portfolio Tool and ESOP

Category	Aurora Portfolio Tool	ESOP
Market Coverage	Day-ahead energy	Energy plus ancillary services ("A/S") (frequency regulation and spinning reserves)
Time Granularity	Hourly, chronological	5-minute intervals, chronological
Time Horizon	20 years	Sample years (ie, 2025, 2030, 2035, 2040)
Pricing Inputs	MISO-wide fundamental analysis feed NIPSCO-specific portfolio dispatch	Historical data drives real-time and A/S pricing; specific asset types dispatched against price
Asset Parameters Used	Hourly ramp rate, storage cycle and depth of dispatch limits, storage efficiency	Sub-hourly ramp rate, storage cycle and depth of discharge limits, storage efficiency
Outputs	Portfolio-wide cost of service	Incremental value for specific asset type

For the 2021 IRP, the MISO five-minute real-time markets for energy, frequency regulation,[119] and spinning reserves were evaluated, with a focus on the performance of storage, paired solar plus storage, and natural gas peaking resources in order to evaluate specific tradeoffs of these capacity-advantaged resource options in NIPSCO's portfolio.

[118] Note that while the ESOP model was originally designed for storage evaluation, modified versions simulate the operations of other fast response resources such as natural gas peakers.

[119] MISO has a single market for regulation up and regulation down services. When providing regulation services, a unit will follow a signal from the system operator. Since it is impossible to know whether the regulation signal will dispatch a unit up or down and by how much ahead of time, ESOP assumes that a unit will be dispatched in both directions while participating in the regulation market. For battery storage, regulation down services can be provided when backing down from a discharge cycle or charging. Since the analysis has assumed that paired solar plus storage resources receive the investment tax credit, in order to participate in the regulation market, it was assumed that a battery resource must have sufficient ability to either back down from a discharge cycle or charge from the paired solar resource. Although such behavior is only required for the first five years of resource operation, for modeling simplicity, this assumption was maintained throughout the analysis.

9.2.6.3 Development of Sub-Hourly Prices for Energy and Ancillary Services

ESOP is run with five-minute price streams for real-time energy, regulation, and spinning reserves prices. As Aurora's long-term capacity expansion tool is used to generate hourly price trajectories representative of the day-ahead energy market, CRA developed a methodology to estimate real-time price trajectories based on historical relationships between day-ahead energy and real-time energy and ancillary services prices, applied to the day-ahead energy prices forecasts developed for each of the four planning scenarios (*See* Section 8 for more detail on the MISO market scenario development process). As part of this process, the following historical data was gathered, based on the period June 1, 2018 to May 31, 2019:

- NIPS.AZ day-ahead hourly LMP[120]
- NIPS.AZ real-time five-minute LMP[121]
- MISO real-time hourly regulation and spinning reserve prices[122]
- Real-time five-minute LMP from NIPSCO node[123]

The relationship between historical hourly day-ahead LMP and five-minute real-time LMP was used to shape the MISO-scenario driven price forecasts to real-time five-minute LMP inputs for ESOP. Because historical regulation and spinning reserve prices services were unavailable at a five-minute granularity, a proxy for a five-minute price shape was taken from the neighboring PJM interface for the same historical period. Similarly, a relationship between hourly day-ahead LMP and sub-hourly ancillary service prices was taken to determine real-time inputs into ESOP.

ESOP was run for the following test years using five-minute real-time price inputs:

- June 1, 2025 to May 31, 2026
- June 1, 2030 to May 31, 2031
- June 1, 2035 to May 31, 2036
- June 1, 2040 to May 31, 2041

9.2.6.4 Operational Parameters for Technology Options

While Section 4 of this report provides a summary of all key cost and operational inputs associated with the RFP bid resource tranches and used in the core economic portfolio analysis,

[120] ABB Energy Velocity Suite. ABB
[121] ABB Energy Velocity Suite. ABB
[122] MISO has one clearing price for regulation up and down. Prices gathered from ABB Energy Velocity Suite. Only hourly ancillary service clearing prices were available.
[123] PJM. PJM Data Miner 2 Tool. Five-minute RT LMP, NIPSCO node. http://dataminer2.pjm.com/feed/rt_fivemin_hrl_lmps.

evaluation in ESOP requires more granular operational input assumption development to assess sub-hourly ramp rates and other constraints. Therefore, CRA and NIPSCO reviewed individual bids to assess bidder expectations for key storage and gas peaker parameters and to develop assumptions for ESOP modeling, which are summarized in Figure 9-30.

Figure 9-30: Resource Operational Parameter Input Assumptions for ESOP Analysis

Lithium-Ion	Units	Value
Duration (Energy/Power Ratio)	hours	4
Roundtrip Efficiency	%	87%
Cycles per Year	#	365
Parasitic Load	%/hr	0.50%
Ramp Rate	%/min	100%
State of Charge Lower Bound[124]	%	0%
State of Charge Upper Bound	%	100%
VOM	$/MWh	0

Gas Combustion Turbine	Units	Value
Heat Rate (Average Realized)	Btu/kWh	10,000
Ramp Rate	%/min	17%
Forced Outage	%	5.00%
Minimum Generation Percentage	%	50%
Max hours of operation / year	Hrs/yr	3,000
Min Downtime	Hrs	4
Min Runtime	Hrs	2
Emission Rate	lb CO2/MMBtu	119
Start Costs	$/MW/start	18
VOM	$/MWh	2

[124] Note that multiple bidders indicated no limits to state of charge boundaries, although other sources suggest that lower and upper bounds of between 10-20% and 80-90%, respectively might be expected for lithium-ion battery technology. As a result, multiple assumptions were tested in the ESOP modeling, and it was determined that this parameter is not a significant driver of results.

9.2.6.5 Key Findings from ESOP Analysis

Based on the resource types that comprise NIPSCO's portfolio options (see discussion of portfolio composition and definition in the earlier sub-sections of this Section) and the types of resources likely to have opportunities for additional value in the sub-hourly energy and ancillary services markets beyond what is accounted for in the core portfolio analysis, CRA evaluated three distinct technology options in ESOP:

- Lithium-ion four-hour duration battery storage;
- Paired solar plus storage (lithium-ion four-hour duration) at a 2:1 ratio;[125] and
- Natural gas-fired combustion turbine peaker

As noted above, the three resource types were assessed over four sample future years in order to estimate the incremental value that might be available in the sub-hourly energy and ancillary services markets above what is captured in the Aurora model's day ahead hourly assessment. The analysis found that the most significant upside is for battery technology, particularly in the regulation market, as illustrated in the Reference Case margin projections summarized in Figure 9-31. Key findings by technology included:

- **Lithium-Ion battery**: As the most highly flexible resource option, the battery can respond rapidly in real time to changing price signals at five-minute granularity. Most notably, the resource can participate regularly in the regulation market, providing up and down service given its unique ability to charge or discharge. An illustration of simulated charging and discharging behavior along with energy and regulation price behavior is shown for a sample summer day in Figure 9-32. This shows how the battery can adjust its state of charge very rapidly to respond to 5-minute price signals, while also participating in the regulation market.
- **Paired solar plus storage**: As in the hourly Aurora modeling, the solar component provides significant energy value, while the upside from the ESOP analysis is primarily limited to participation in the regulation market. It is important to note that current ITC rules limit the battery's flexibility and ability to take advantage of the regulation market, given that the battery resource must charge predominantly from the solar component.
- **Natural gas-fired combustion turbine**: The gas peaking resource is able to monetize real-time sub-hourly volatility, providing value upside compared to the Aurora day ahead hourly modeling. However, regulation opportunities are only available when the unit is already operating for energy, limiting the upside when compared to the battery storage projections. Spinning reserve revenues are also likely to be available, but these are less valuable than regulation.

[125] Note that the most attractive RFP tranches, including those selected in the portfolio development phase, were at ratios of approximately 2:1 (solar:storage), so this configuration was analyzed in the ESOP analysis.

Figure 9-31: Reference Case Annual Margin Comparison by Technology: Aurora Day Ahead Energy vs. ESOP Sub-Hourly Energy Plus Ancillary Services

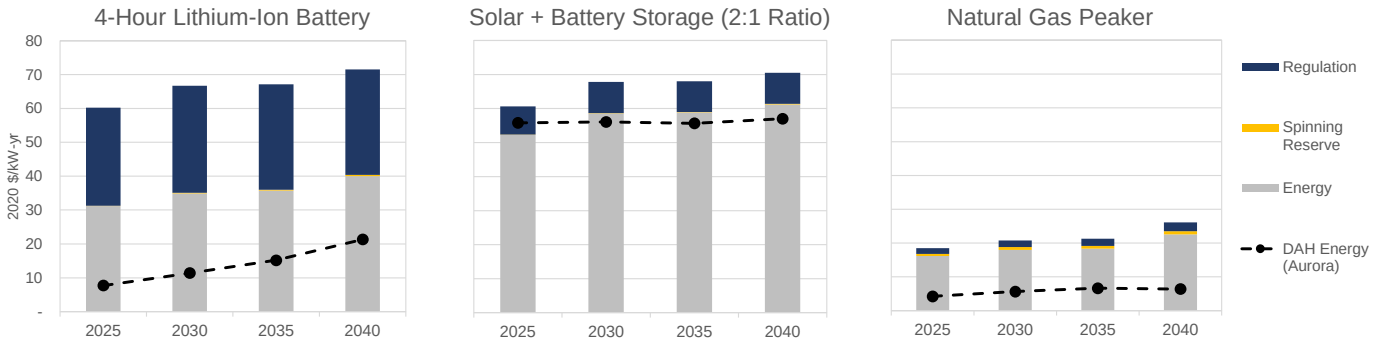
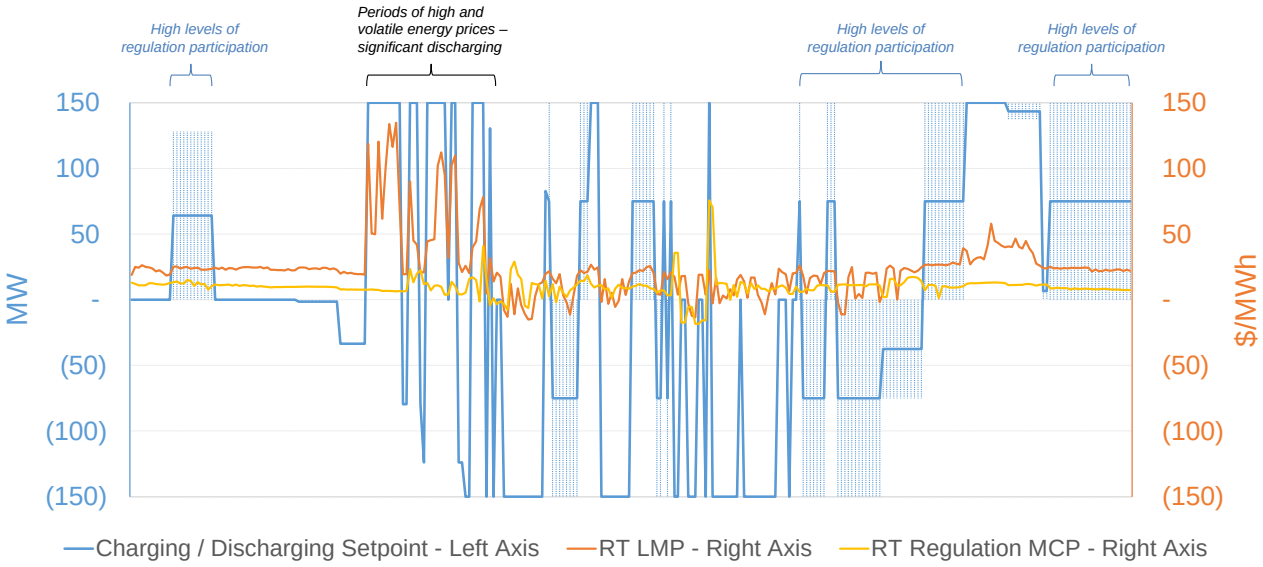


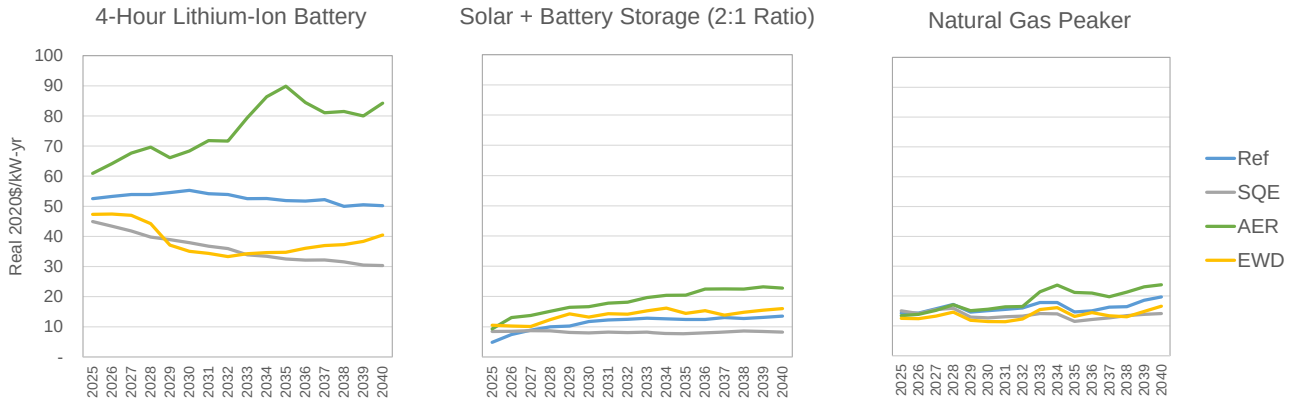
Figure 9-32: Sample Summer Day of Battery Dispatch



In addition to the Reference Case analysis, CRA evaluated the performance of the three resource options across the three alternative market scenarios (see Section 8 for more detail). Across all scenarios, the incremental value associated with the sub-hourly energy and ancillary services markets was projected to be greatest for the battery. This was especially the case in the AER, with high energy prices due to high carbon and natural gas prices, and high levels of

renewable penetration driving larger price spreads across hours. A summary of the simulated incremental value by technology and scenario is shown in Figure 9-33.[126]

Figure 9-33: Incremental Sub-Hourly Energy and Ancillary Services Value by Technology across Scenarios



9.2.6.6 Portfolio Cost Implications

After performing the core ESOP analysis at the resource level, CRA and NIPSCO built up portfolio-level impacts according to the amounts of lithium-ion battery storage, paired solar plus storage, and natural gas peaking capacity in each of the nine replacement portfolios. This was accomplished by attributing the annual $/kW-yr incremental value shown in Figure 9-33 to each MW of storage, solar plus storage, or gas peaker in the portfolios to arrive at an aggregate total net present value impact. This is summarized by portfolio and across all scenarios in Figure 9-34 Overall, the analysis reached the following conclusions:

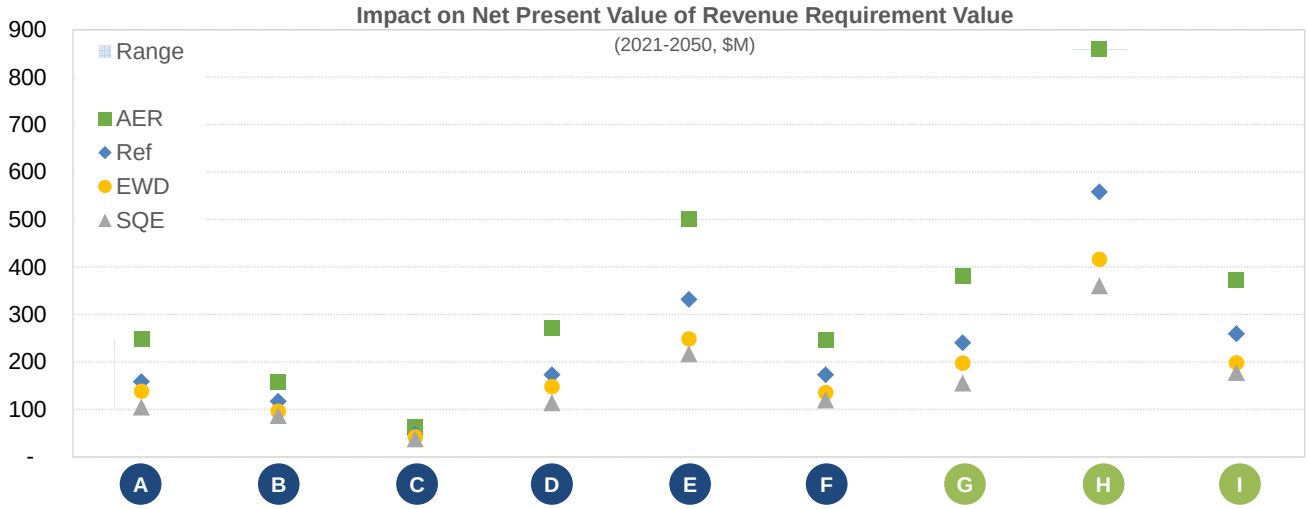
- Portfolios with the largest amounts of storage (Portfolios E and H) have the greatest potential to lower the NPVRR by capturing flexibility value that may manifest in the sub-hourly energy and ancillary services markets.

- A wide range of value is possible, with higher prices and price spreads in the AER scenario driving higher estimates and lower prices and lower price spreads in the SQE scenario driving lower estimates.

- While these estimates provide perspective on the relative performance of various portfolio strategies, significant uncertainty exists and the realization of such benefits is dependent on market rules evolution, MISO generation mix changes, and market participant behavior.

[126] Note that since the ESOP analysis was only performed for five sample years, estimates for the other model years were made through interpolation.

Figure 9-34: Range of Additional Value Opportunity by Replacement Portfolio



9.2.7 Non-Economic Reliability Assessment

Economic analysis alone does not capture the full suite of reliability attributes offered by various resources. As outlined in Section 6, NIPSCO participates in MISO in a variety of roles with various compliance standards and responsibilities, and any future resource decisions (retirement or replacement) will need to consider the non-economic implications for NIPSCO's ability to comply with both NERC and MISO standards and procedures now and into future.

Under normal system operating conditions, NIPSCO is tied to MISO and PJM's systems for dispatch of its resources and the balancing of energy. However, under emergency or blackout conditions ("islanded operation"), NIPSCO's resources should have the capability to reliably serve the critical demand of its customers.

With the goal of understanding the relative ability of replacement portfolios to support the reliable operation of the system, NIPSCO engaged Quanta Technology, a third-party technical expert, to perform a planning-level reliability assessment of all replacement generation resources under consideration. The Quanta Technology Reliability Assessment Final Report is attached as Confidential Appendix E. In this assessment, Quanta Technology identified reliability criteria and metrics that individually and collectively serve to enhance the reliability attributes of a given portfolio, developed a scoring methodology for individual technologies, and scored and ranked portfolios across these metrics. The results of the assessment were then incorporated into the Replacement scorecard to support overall portfolio evaluation.

9.2.7.1 Study Methodology

The reliability assessment study was performed according to the steps outlined in Figure 9-35. The first two steps assessed NIPSCO's reliability needs and then reviewed, refined, and augmented the initial set of reliability metrics identified by NIPSCO.

The study then proceeded to conduct a series of system analyses, each quantifying the performance of each of the nine replacement portfolios against each measure, and where appropriate, determining the required mitigations to address any performance gaps. The nature of the study is akin to a series of analysis filters that ultimately help identify reliability concerns that would need mitigation.

Finally, a scoring matrix was developed with acceptable performance thresholds to provide a quantifiable score for each reliability measure. These scores were aggregated for each metric, and eventually for each portfolio. Portfolios were then ranked according to their reliability attributes with the highest scores to those with the least reliability concerns.

Figure 9-35: Reliability Study Methodology



9.2.7.2 Reliability Criteria and Metrics

NIPSCO developed an initial set of reliability criteria that are important to the continued reliable operation of the grid and that enable NIPSCO to fulfill its obligations under NERC and MISO standards. Quanta Technology performed a critical assessment of these metrics, resulting in a final list of reliability and resilience criteria summarized in Figure 9-36.

Figure 9-36: Reliability Criteria

	Criteria	Description	Rationale
1	Blackstart	Resource has the ability to be started without support from the wider system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, supply real and reactive power, frequency, and voltage control	In the event of a black out condition, NIPSCO must have a blackstart plan to restore its local electric system. The plan can either rely on MISO to energize a cranking path or on internal resources within the NIPSCO service territory.
2	Energy Adequacy	Portfolio resources are able to supply the energy demand of customers during MISO's emergency max gen events, and also to supply the energy needs of critical loads during islanded operation events.	NIPSCO must have long duration resources to serve the needs of its customers during emergency and islanded operation events.
3	Dispatchability and Automatic Generation Control	Resources will respond to directives from system operators regarding its status, output, and timing. The unit has the ability to be placed on Automatic Generation Control (AGC) allowing its output to be ramped up or down automatically to respond immediately to changes on the system.	MISO provides dispatch signals under normal conditions, but NIPSCO requires AGC attributes under emergency restoration procedures or other operational considerations
4	Operational Flexibility and Frequency Support	Resources are able to provide inertial energy reservoir or a sink to stabilize the system. The resource can adjust its output to provide frequency support or stabilization in response to frequency deviations with a droop of 5% or better	MISO provides market construct under normal conditions, but preferable that NIPSCO possess the ability to maintain operation during under-frequency conditions in emergencies
5	VAR Support	Resources can deliver VARs out onto the system or absorb excess VARs to control system voltage under steady-state and dynamic/transient conditions. Resources can provide dynamic reactive capability (VARs) even when not producing energy and have Automatic voltage regulation (AVR) capability ranging from 0.85 lagging (producing) to 0.95 leading (absorbing) power factor	NIPSCO must retain resources electrically close to load centers to provide this attribute in accordance with NERC and IEEE Standards
6	Geographic Location Relative to Load	Resources are located in NIPSCO's footprint (electric Transmission Operator Area) in Northern Indiana near existing NIPSCO 138kV or 345kV facilities and are not restricted by fuel infrastructure. Preferred locations are ones that have multiple power evacuation/deliverability paths and are close to major load centers.	Although MISO runs markets that value location, resources that are interconnected to buses with multiple power evacuation paths and those close to load centers are more resilient to transmission system outages and provide better assistance in the blackstart restoration process.
7	Predictability and Firmness of Supply	Ability to predict/forecast the output of resources and to counteract forecast errors.	Energy is scheduled with MISO in the day-ahead (DAH) hourly market and in the real-time (RT) 5-minute market. Deviations from these schedules have financial consequences, and the ability to accurately forecast the output of a resource up to 38 hours ahead of time for DAH and 30 minutes for RT is advantageous.
8	Short Circuit Strength Requirement	Resources help ensure the strength of the system to enable the stable integration of all inverter-based resources (IBRs) within a portfolio.	The retirement of synchronous generators within NIPSCO's footprint and across MISO and replacements with increasing levels of IBRs will lower the short circuit strength of the system. Resources that provide higher short circuit current provide a better future proofing without the need for expensive mitigation measures.

After establishing the criteria, a set of quantified metrics were developed to measure the technical ability of resources to enhance a given criterion, as summarized in Figure 9-37. Quanta Technology performed detailed analysis at the resource level to evaluate each metric.

Figure 9-37: Reliability Metrics

	Metric	Measure
1	Blackstart	Qualitative Assessment of Risk of not Starting
2	Energy Adequacy	Energy not Served during market emergencies (% of load consumption increase)
		Energy Not Served when Islanded (Worst 1-week) %
3	Dispatchability and Automatic Generation Control	Dispatchable (%CAP, unavoidable VER Penetration)
		Increased Freq Regulation Requirements (MW)
		1-min Ramp Capability (MW)
		10-min Ramp Capability (MW)
4	Operational Flexibility and Frequency Support	Inertia MVA-s
		Inertial Gap FFR MW (islanded operation)
		Primary Gap PFR MW (islanded operation)
5	VAR Support	Dynamic VAR to load Center Capability (MVAr)
6	Location	Average Number of Evacuation Paths
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW
8	Short Circuit Strength	Required Additional Synchronous Condensers MVA

9.2.7.3 Reliability Assessment Details

Based on the criteria and metrics summarized above, the study evaluated all nine replacement portfolios for the year 2030 across a variety of assessments summarized in Figure 9-38. Given the dynamic and uncertain nature of renewable energy developments associated with technology mix, sites, and sizes, as well as the future state of the transmission grid that will be required to enable the integration of these resources, this study attempted to provide an envelope of outcomes (and in many cases, best or optimistic outcomes) under a regime of well-coordinated or guided project development processes.

Figure 9-38: Metrics and Measures Results – Raw Scores

System Condition	Reliability Assessment
Normal	• deliverability of dynamic reactive power to load centers • short circuit strength • predictability of portfolio output • increased need for regulation reserves • geographic location and ability to evacuate the power
Emergency – Max Gen	• energy adequacy – Need for market purchases
Isolated	• black start and restoration • short circuit strength • ability to control frequency (inertial and primary frequency response) • power ramping capability • energy adequacy to serve the critical demand of customers.

Several assumptions were made in the study. For example, operating renewable resources economically require them to generate all the time at their maximum potential power levels as allowed by solar irradiance and wind speeds. This mode of economic operation precludes these resources from providing frequency response in the upward direction, as will be required when a generator or import is suddenly lost. Reducing the power output to enable participation in frequency response in the upward direction is very expensive. However, the speed of control of the IBRs makes them perfectly suited for participating in frequency response in the downward direction (i.e., curtailment), as will be required when a large load or export is suddenly lost.

Given that this was a planning level assessment, screening-level quantitative studies were conducted for a set of reliability standards, including inertial response, primary frequency response, secondary frequency response, short circuit strength, system ramping requirements, dynamic reactive support, and energy adequacy along with a qualitative assessment of blackstart and system restoration capability. Other areas of reliability assessment are outside the scope of this study, but might include system protection, power quality, flicker, and control interactions. Detailed system studies will be required to ascertain the reliability of the system once a portfolio is selected and the location, size, and technology of all portfolio resources are available.

9.2.7.4 Summary of Results

The technical reliability assessment included a quantitative analysis of each measure, (except blackstart), using information associated with resource technology, size, location, and expected production. Blackstart was scored qualitatively by assessing the risk of successfully restoring the system based on a strategy of using standalone energy storage and synchronous generation within NIPSCO's service territory to start existing synchronous condensers and then other nearby resources of solar plus storage, solar PV, and wind technologies, in that order.

The assessment identified potential reliability gaps for each of the nine replacement portfolios and also suggested potential mitigations to these gaps. The mitigations take the form of grid-forming inverter technology, additional blackstart capability, additional fast power resources

such as battery storage, super capacitors, or combustion turbines, and additional synchronous condensers. The key findings of this study included the following:

- Reliability concerns were identified for each portfolio, especially under emergency and islanded conditions, and mitigation measures were identified as follows:
    - Stand-alone energy storage should have grid-forming inverters (GFM) with additional capabilities including black start and fast frequency response (FFR). GFM inverters are not widely used today in the US market, but the technology is available and is recommended for portfolios with high penetration of IBRs.
    - Gas peakers and combined cycle units in portfolios C, F, and I should have blackstart capability.
    - Additional fast power resources may be needed in some portfolios. These have been quantified for energy storage technology. However, super capacitors or combustion turbines can also provide the same function, but the size should be determined for these technologies.
    - Specifications of short circuit ratio (SCR) of inverters should not exceed 3.
    - Provision of additional synchronous condensers should be considered to increase the grid's short circuit strength ranging from 0 to 802 MVAr.
- Many reliability areas were not covered by this study including:
    - The study assumed that any required grid upgrades will be implemented as part of MISO interconnection process.
    - Given that all IRP portfolios were designed to meet MISO's reserve margin targets, a separate portfolio-level resource adequacy study was not conducted.
    - All reliability assessments in this study applied screening-level indicative analyses. Detailed system studies are essential and should be conducted to properly assess system reliability of the preferred portfolio options.

9.2.7.5 Scoring Methodology and Performance Thresholds

Figure 9-39 summarizes the thresholds that were used in the study to score each measure, along with the rationale for setting the threshold values. Measures that exceeded the upper threshold were deemed satisfactory (Pass) and given a score of 1, while those measures below the lower threshold were deemed problematic and given a score of 0. Measures in between were considered cautionary and given a score of ½. The scores of measures within each of the eight individual metrics were averaged to yield a single score for each metric. Metric scores were then added for each portfolio and compared. The maximum score of each portfolio was eight.

Figure 9-39: Scoring Thresholds

	Year 2030		1 (Pass)	½ (Caution)	0 (Problem)	Rationale
1	Blackstart	Ability to blackstart using Storage & Synchronous Condensers	>50%	25-50%	<25%	System requires real and reactive power sources with sufficient rating to start other resources. Higher rated resources lower the risk
2	Energy Adequacy	Energy not Served during market emergencies (% of load consumption increase)	<5%	5-20%	>20%	Ability of portfolio resources to serve unanticipated growth in load consumption during MISO emergency max-gen events.
		Energy Not Served when Islanded (Worst 1-week) %	<70%	70-85%	>85%	Ability of Resources to serve critical loads for 1 week, estimated at 15% of total load. Adding other important loads brings the total to 30%
3	Dispatchability	Dispatchable (VER Penetration %)	<50%	50-60%	>60%	Intermittent Power Penetration above 60% is problematic when islanded
		Increased Freq Regulation Requirements	<2% of peak load	2-3% of Peak Load	>3% of peak load	Regulation of Conventional Systems ≈1%
		1-min Ramp Capability	>15% of CAP	10-15% of CAP	<10% of CAP	10% per minute was the norm for conventional systems. Renewable portfolios require more ramping capability
		10-min Ramp Capability	>65% of CAP	50-65% of CAP	<50% of CAP	10% per minute was the norm for conventional systems. But with 50% min loading, that will be 50% in 10 min. Renewable portfolios require more ramping capability
4	Operational Flexibility and Frequency Support	Inertia (seconds)	>3xMVA rating	2-3xMVA rating	<2xMVA rating	Synchronous machine has inertia of 2-5xMVA rating.
		Inertial Gap FFR (assuming storage systems will have GFM inverters)	0	0-10% of CAP	>10% of CAP	System should have enough inertial response, so gap should be 0. Inertial response of synch machine ≈ 10% of CAP
		Primary Gap PFR MW	0	0 - 2% of CAP	2% of CAP	System should have enough primary response, so gap should be 0. Primary response of synch machine ≈ 3.3%of CAP/0.1Hz (Droop 5%)
5	VAR Support	VAR Capability	≥41% of ICAP	31-41% of ICAP	<31% of ICAP	Power factor higher than 95% (or VAR less than 31%) not acceptable. Less than 0.91 (or VAR greater than 41.5%) is good
6	Location	Average Number of Evacuation Paths	>3	2-3	<2	More power evacuation paths increases system resilience
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) MW	≥ 0	-10% - 0% of CAP	<-10% of CAP	Excess ramping capability to offset higher levels of intermittent resource output variability is desired
8	Short Circuit Strength	Required Additional Synch Condensers MVA	0	0-21.9% of CAP	>21.9% of CAP	Portfolio should not require additional synchronous condensers. 500MVAr is a threshold (same size as one at Babcock)

9.2.7.6 Reliability Ranking of IRP Portfolios

Figure 9-40 presents the normalized resources for each replacement portfolio across each of the eight metrics, and Figure 9-41 summarizes the resulting portfolio scores and rankings.

Figure 9-40: Normalized Results

	Year 2030		A	B	C	D	E	F	G	H	I
1	Blackstart	Qualitative Assessment of Risk of not Starting	25%	0%	75%	25%	50%	100%	25%	50%	100%
2	Energy Adequacy	Energy not Served during market emergencies (% of load consumption increase)	10%	2%	2%	21%	2%	3%	26%	3%	2%
		Energy Not Served when Islanded (Worst 1-week) %	76%	79%	32%	75%	78%	56%	74%	73%	58%
3	Dispatchability and Automatic Generation Control	Dispatchable (%CAP, unavoidable VER penetration%)	28%	18%	55%	27%	44%	45%	26%	47%	47%
			58%	45%	42%	63%	50%	45%	65%	51%	51%
		Increased Freq Regulation Requirement (% Peak Load)	2.3%	1.6%	1.5%	2.5%	1.8%	1.6%	2.6%	2.0%	2.0%
		1-min Ramp Capability (%CAP)	24.0%	22.6%	17.8%	22.8%	47.2%	29.4%	22.1%	49.3%	39.0%
		10-min Ramp Capability (%CAP)	41.7%	50.7%	52.1%	39.6%	64.4%	60.3%	37.1%	63.7%	61.5%
4	Operational Flexibility and Frequency Support	Inertia (seconds)	2.13	3.38	4.17	2.02	2.07	3.58	1.81	1.73	2.60
		Inertial Gap FFR (%CAP)	11.2%	32.1%	10.7%	11.0%	0.0%	6.1%	11.6%	0.0%	0.0%
		Primary Gap PFR (%CAP)	18.8%	44.7%	25.9%	17.9%	0.0%	19.1%	17.7%	0.0%	1.3%
5	VAR Support	Dynamic VAR to load Center Capability (%CAP)	47.8%	47.8%	35.1%	48.5%	44.7%	43.6%	49.1%	47.4%	47.1%
6	Location	Average Number of Evacuation Paths	5	2.5	N/A	4.6	4.7	4.7	4.8	5.6	5.1
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	-4.1%	-8.0%	11.4%	-5.0%	14.9%	15.8%	-5.3%	17.4%	17.1%
8	Short Circuit Strength	Required Additional Synch	25%	11%	0%	33%	15%	0%	35%	21%	11%

		Condensers (%Peak Load)										

VER: Variable Energy Resources (e.g., solar, wind)
CAP: Capacity credit of all resources including existing, planned, and portfolio

Figure 9-41: Portfolio Scores and Ranking

	Year 2030		A	B	C	D	E	F	G	H	I	Weight
1	Blackstart	Qualitative Assessment of Risk of not Starting	1/2	0	1	1/2	1/2	1	1/2	1/2	1	12.5%
2	Energy Adequacy	Energy not Served during market emergencies (% of consumption increase)	1/2	1	1	0	1	1	0	1	1	6.3%
		Energy Not Served when Islanded (Worst 1-week) %	1/2	1/2	1	1/2	1/2	1	1/2	1/2	1	6.3%
3	Dispatchability and Automatic Generation Control	Dispatchable (VER Power Penetration %)	1/2	1	1	0	1/2	1	0	1/2	1/2	3.1%
		Increased Freq Regulation Requirement (% Peak Load)	1/2	1	1	1/2	1	1	1/2	1/2	1/2	3.1%
		1-min Ramp Capability (%CAP)	1	1	1	1	1	1	1	1	1	3.1%
		10-min Ramp Capability (%CAP)	0	1/2	1/2	0	1/2	1/2	0	1/2	1/2	3.1%
4	Operational Flexibility and Frequency Support	Inertia (seconds)	1/2	1	1	1/2	1/2	1	0	0	1/2	4.2%
		Inertial Gap FFR (%CAP)	0	0	0	0	1	1/2	0	1	1	4.2%
		Primary Gap PFR (%CAP)	0	0	0	0	1	0	0	1	1/2	4.2%
5	VAR Support	Dynamic VAR to load Center Capability (%CAP)	1	1	1/2	1	1	1	1	1	1	12.5%
6	Location	Average Number of Evacuation Paths	1	1/2	1	1	1	1	1	1	1	12.5%
7	Predictability and Firmness	Ramping Capability to Mitigate Forecast Errors (+Excess/-Deficit) (%VER MW)	1/2	1/2	1	1/2	1	1	1/2	1	1	12.5%
8	Short Circuit Strength	Required Additional Synch Condensers (%Peak Load)	0	1/2	1	0	1/2	1	0	1/2	1/2	12.5%
	Portfolio Scores		**52%**	**56%**	**84%**	**47%**	**79%**	**92%**	**45%**	**76%**	**85%**	

	# 0	4	3	2	6	0	1	7	1	0
	# 1/2	7	5	2	5	6	2	4	6	6
	# 1	3	6	10	3	8	11	3	7	8
	Total Measures	14	14	14	14	14	14	14	14	14

The highest ranked portfolios across the eight reliability metrics are:

1. F (Score 92%)
2. I (Score 85%)

3. C (Score 84%)
4. E (Score 79%)
5. H (Score 76%)

Replacement Analysis Scorecard Summary

Figure 9-42 presents a summary of all scorecard metrics for each of the nine replacement portfolios. This includes the cost metrics associated with the Reference Case NPVRR, the risk metrics associated with the major outcomes from the scenario and stochastic analyses, carbon emissions, reliability, resource optionality, and impacts on the local economy, as described above. The following key observations were made:

- Portfolios that have the highest solar additions and meet only the summer reserve margin target (Portfolios A, D, and G) are not viable options for NIPSCO, given expected MISO ruls changes, even though they perform best under high environmental regulation scenarios (AER and EWD).

- Although adding new combined cycle capacity (Portfolio C) results in lowest costs under the Reference and SQE scenarios and provides a new dispatchable energy resource to mitigate future intermittency risk, this strategy carries the highest scenario cost exposure and uncertainty, results in the highest CO2 emissions, and reduces future resource optionality.

- While a portfolio approach that retires all thermal resources by 2032 and relies solely on renewables and storage (Portfolio H) provides a high level of scenario cost certainty, the lowest emission profile, significant upside value opportunity associated with ancillary service markets, and significant additional local economic investment, it has the highest cost under Reference scenario conditions and exposes the portfolio to high stochastic tail risk, given high levels of intermittent resources.

- While portfolios that retain Sugar Creek and add some amount of new peaking and storage resources (Portfolios B, E, and F) do not score best on any single metric, they minimize cost risks, continue NIPSCO down a path of significant CO2 emission reductions, and allow for flexibility and optionality.

- A portfolio that includes additional renewables and storage, as well as options to pursue hydrogen at existing and new thermal facilities (Portfolio I), produces lower CO2 emissions than Portfolios B, E, and F, performs better under scenarios with high environmental regulation/incentives (particularly EWD), and mitigates stochastic tail risk.

- Portfolios with local thermal peaker and storage resources (particularly Portfolios F and I and to a lesser extent Portfolio E) provide the most reliability attributes and perform best on the composite reliability score.

Figure 9-42: Replacement Portfolio Scorecard

	A	B	C	D	E	F	G	H	I
Replacement Theme	Thermal PPAs, solar and storage	Non-service territory gas peaking (no early storage)	Natural gas dominant (CC)	No new thermal resources; solar dominant w/ storage	Thermal PPAs plus storage and solar	Local gas peaker, plus solar and storage	Solar dominant w/ storage, plus retire Sugar Creek	All renewables and storage, plus retire Sugar Creek (Portfolio 7)	New H2-enabled peaker plus solar and storage, plus SC conversion to H2 (Portfolio 7H)
Carbon Emissions	Higher	Higher	Higher	Mid	Mid	Mid	Low	Low	Low
Dispatchability	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)	Current Planning Reserve Margin	Winter & Summer Reserve Margin	Enhanced Reserve Margin (Local w/ Higher Energy Duration)
Cost To Customer 30-year NPVRR (Ref Case) $M	$10,461 +$149	$10,332 +$20	$10,312 -	$10,438 +$126	$10,467 +$155	$10,426 +$114	$11,042 +$730	$11,090 +$778	$10,792 +$480
Cost Certainty Scenario Range NPVRR $M	$2,359 +$1,035	$2,782 +$1,458	$3,208 +1,884	$2,322 +$998	$2,538 +$1,214	$2,748 +$1,424	$1,324 -	$1,553 +$229	$1,855 +$531
Cost Risk High Scenario NPVRR $M	$12,015 +$206	$12,182 +$373	$12,518 +$709	$11,965 +$156	$12,126 +$317	$12,243 +$434	$11,809 -	$12,011 +$202	$11,848 +$39
Cost Risk Stochastic 95% CVAR – 50%	$104 +$21	$92 +$9	$83 -	$104 +$21	$98 +$15	$97 +$14	$123 +$40	$114 +$31	$87 +$4
Lower Cost Opp. Lowest Scenario NPVRR $M	$9,657 +$348	$9,400 +$91	$9,309 -	$9,644 +$335	$9,588 +$279	$9,495 +$186	$10,485 +$1,176	$10,458 +$1,149	$9,933 +$684
Carbon Emissions M of tons 2024-40 Cum. (Scenario Avg.)	27.3 +11.2	30.4 +14.3	47.2 +31.1	27.3 +11.2	27.3 +11.2	28.5 +12.4	16.1 -	16.1 -	25.2 +9.1
Reliability Composite reliability score (out of 8 possible points)	3.67 -3.71	4.46 -2.92	5.21 -2.17	3.54 -3.84	6.08 -1.30	7.38 -	3.38 -4.00	5.79 -1.59	6.79 -0.59
Reliability Reduction to 30-Year NPVRR (Ref Case) $M	($158) +$400	($117) +$441	($48) +$510	($173) +$385	($332) +$226	($173) +$385	($240) +$318	($558) -	($259) +$299
Resource Optionality MW-weighted duration of 2027 gen. commitments (yrs.)	20.01 +3.01	20.53 +3.53	23.55 +6.55	20.37 +3.37	21.15 +4.15	22.12 +5.12	17.00 -	18.19 +1.19	21.46 +4.46
Local Economy NPV of property taxes	$420 -$66	$388 -$98	$451 -$35	$417 -$69	$413 -$73	$416 -$70	$486 -	$477 -$9	$421 -$65

9.3 Preferred Replacement Portfolio

NIPSCO has identified Portfolio F as a preferred near term replacement portfolio concept, with the potential to pivot towards Portfolio I based on continued RFP bid diligence, technology evolution, and potential federal policy changes. Across each of these preferred concepts, NIPSCO has concluded that certain resources that provide near-term capacity (the Sugar Creek uprate, attractive DER opportunities, thermal capacity contracts, and demand side management programs) appear to be cost-effective additions to the portfolio and should be pursued in order to firm up the capacity position of the portfolio in the near-term and in anticipation of future retirements.

Beyond those capacity additions common to all candidate portfolios, solar, storage and natural gas peaking resources appear to be economic replacement options for Michigan City and Schahfer 16A/B.[127] Integrating dispatchable capacity into the portfolio over the long term (without materially increasing gas-fired energy exposure and CO2 emissions through a CCGT) tends to mitigate cost risk associated with intermittent resources and will help meet pending seasonal reserve margin requirements. However, the quantities and characteristics of storage and gas peaking resource additions require further study to confirm reliability can be maintained and to understand the value of each resource type given ongoing and potential market and policy changes.

Near-term capacity additions, including the Sugar Creek uprate, attractive DER, thermal capacity contracts, DSM, solar, storage, and a natural gas peaker, preserve flexibility in an environment of market, policy, and technology uncertainty. NIPSCO's preferred portfolio allows

[127] Portfolio I also contains some wind capacity, which NIPSCO may consider depending on future federal policy developments.

the Company to monitor technology and policy trends that will inform future action and maintain a pathway to a Net Zero emissions portfolio over the long term, including with emerging technology such as hydrogen.

Figure 9-43 summarizes the elements of NIPSCO's preferred plan, including the expected ranges of capacity additions by resource type through the 2027 period. As additional diligence is performed and as more information is obtained regarding market, policy, and technology change, NIPSCO will refine the specific capacity addition numbers.

Figure 9-43: Preferred Portfolio Capacity Addition Ranges by 2027

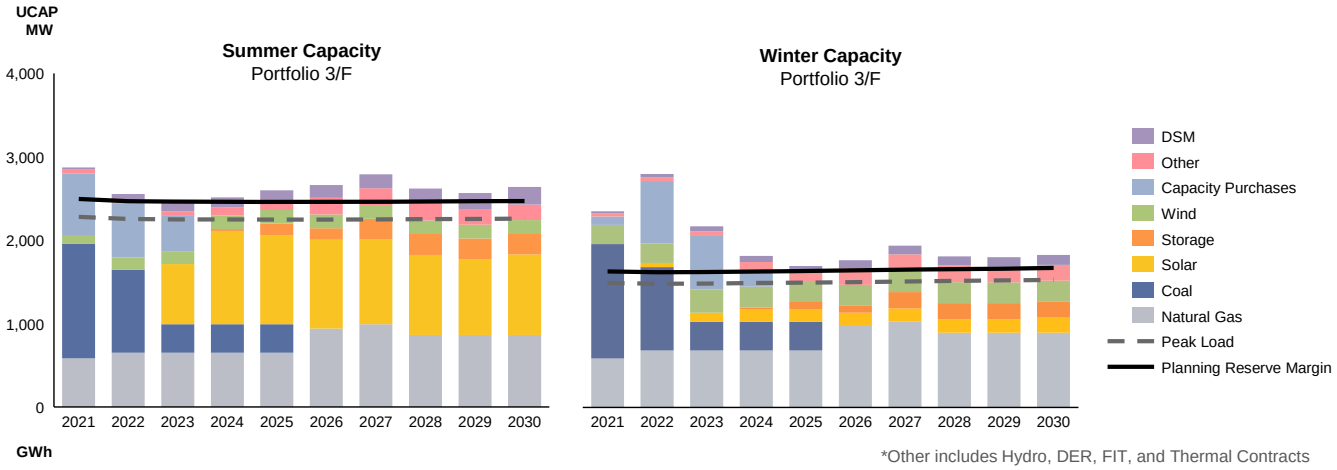
Resource	MW by 2027	Notes
Sugar Creek Uprate	30-53 MW	Two options offered by the manufacturer; additional diligence will confirm pricing and timing
Solar + Storage DER Opportunities	~10 MW	Specific projects to be identified, with distribution deferral opportunities consistent with attractive IRP tranche assumptions
Thermal Capacity Contracts	150 MW	Likely up to 10-year term
DSM	~68 MW	Represents Tier 1 residential plus all commercial energy efficiency programs (46 MW of winter peak)
Solar	100-250 MW	Dependent on specific asset attributes and further bid diligence; Natural gas peaking capacity may be hydrogen-enabled.
Storage	135-370 MW	
Natural Gas Peaker	Up to 300 MW	

This preferred portfolio maintains NIPSCO on a trajectory that significantly shifts its generation mix from coal towards renewables and adds capacity-advantaged resources that are needed to meet future reserve margin requirements, protect against hourly energy market exposure, and preserve reliability for customers. As shown in Figure 9-44,[128] NIPSCO's preferred plan anticipates new capacity-advantaged resources entering into service by the middle of the decade, including storage, natural gas (the Sugar Creek uprate and new peaking capacity), and thermal capacity contracts. It also includes additional solar and new DSM programs.

As shown in Figure 9-45, total energy from the preferred portfolio is projected to be roughly in balance with NIPSCO's load requirements, with flexibility around the ultimate timing of the Michigan City 12 retirement. Although new storage and gas peaking resources provide limited net energy contribution on an annual basis, they support the portfolio's energy adequacy when intermittent resources are unavailable.

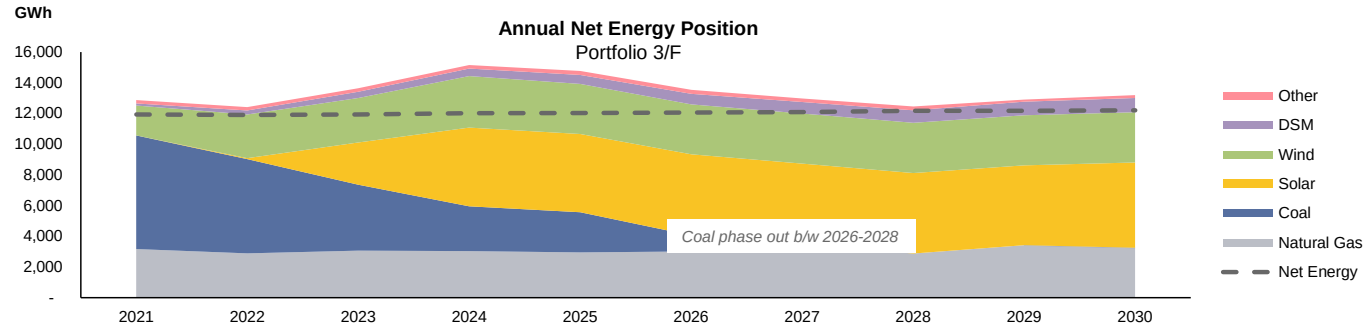
[128] For illustrative purposes, Figure 9-44 and Figure 9-45 show Replacement Portfolio F based on Portfolio 3 from the Existing Fleet analysis.

Figure 9-44: Preferred Portfolio Summer and Winter Capacity Mix



*Other includes Hydro, DER, FIT, and Thermal Contracts

Figure 9-45: Preferred Portfolio Energy Mix



*Other includes Storage, Hydro, DER, FIT, and Thermal Contracts

Note that storage has a net negative contribution to annual energy and reduces the size of the "Other" area in the net energy graphic

9.3.1 Preferred Portfolio Summary

NIPSCO's preferred portfolio was developed to ensure that a reliable, compliant, flexible, diverse and affordable set of resources is available to meet future customer needs. As part of the portfolio selection process, NIPSCO also considered the impacts to its employees, the environment, reliability, and impacts on the local economy. The major components of the NIPSCO resource strategy are expected to:

- Continue to implement NIPSCO's portfolio transition by integrating new renewable projects and taking the necessary steps to retire the Michigan City coal plant by 2028;

- Continue the Company's commitment to EE and DR by executing the current filed DSM plan and continuing to plan for significant residential and commercial DSM programs over time;

- Provide a cost-effective portfolio for customers while also balancing other objectives associated with rate stability, environmental sustainability, and positive social and economic impacts;

- Ensure that system reliability is preserved as NIPSCO and the broader MISO market increase the amount of intermittent resource capacity;

- Reduce customer and NIPSCO exposure to market, policy, and technology risks by intentionally integrating modular, highly diverse new resource alternatives over the next several years;

- Preserve flexibility in resource procurement, particularly over the long-term;

- Continue to actively monitor federal policy, technology, and MISO market trends, while staying engaged with project developers and asset owners to understand the landscape of new resource options;

- Continue to invest in infrastructure modernization to maintain safe and reliable delivery of energy services;

- Continue to comply with NERC, MISO, and EPA standards and regulations.

It is important to remember that this preferred portfolio as part of the 2021 IRP is a snapshot in time and while it establishes a direction for NIPSCO, it is subject to change as the external operating environment changes. In addition, the submission of this plan and its resulting preferred portfolio does not stop the transparency of the process or engagement with stakeholders.

9.3.2 Financial Impact

Figure 9-46 shows NIPSCO's financial impact of Replacement Portfolio F under the retirement dates from Existing Fleet Portfolio 3 over the planning period. While NIPSCO's preferred portfolio intentionally retains flexibility to incorporate elements of Portfolios 3 and 5 from the Existing Fleet analysis, as well as Portfolios F and I from the Replacement analysis, this summary is being provided as a baseline benchmark.

The 30-year NPVRR is broken down into operating and capital costs. The operating costs include the fixed and variable costs associated with both existing units and future resources, as well as contract costs and net market purchases. The capital costs include all capital related costs for existing units and costs related to the acquisition of new resources in the preferred portfolio. These costs include depreciation expenses, capital charges, and taxes. In order to present a levelized net present value rate summary, the total energy forecast for NIPSCO is also discounted over the 30-year period at the same rate.

Figure 9-46: Financial Impact Summary[129]

Financial Impact Summary	
Operating Costs ($000)	5,195,199
Capital Costs ($000)	5,231,167
Total Revenue Requirement ($000)	10,426,365
Total Energy Requirement (GWh)	146,316
Cents/kWh	7.13

Note that Total Energy Requirement is the discounted value of 30 years of energy forecasts, rather than a total sum. This is done to allow for the cents per kWh summary to be reflective of a levelized net present value calculation.

NIPSCO expects that existing cash balances, cash generated from operating activities, and funding through inter-company loan arrangements with its parent company will meet anticipated operating expenses and capital expenditures associated with NIPSCO's short-term action plan.

In the long term, future operating expenses as well as recurring and nonrecurring capital expenditures are expected to be obtained from a number of sources including: (i) existing cash balances; (ii) cash generated from operating activities; (iii) inter-company loan arrangement; (iv) additional external debt financing with unaffiliated parties; (v) new equity capital and (vi) tax equity financing. NiSource, Inc. procures external funding from the bank and capital markets (debt and equity). NiSource's long-term debt ratings are currently BBB at Fitch and Baa2 at Moody's.

9.3.3 Developments That Will Shape NIPSCO's Preferred Portfolio Implementation

As summarized in Section 2, NIPSCO identified several key themes that have influenced the development of this 2021 IRP and that will shape the ultimate implementation of NIPSCO's short-term action plan. As noted above, NIPSCO's preferred portfolio incorporates ranges of new resource additions to reflect the fact that several evolving external factors will influence final procurement decisions. These can broadly be categorized into factors associated with RFP bid negotiations and follow-up, MISO market rules changes, federal policy changes, and technology development.

RFP Bid Negotiations

Although the 2021 IRP involves smaller overall capacity changes than the 2018 IRP, in many ways the resource implementation will be more complex. This is largely due to the fact that specific diligence needs to be completed on a smaller sub-set of discrete projects, as opposed to

[129] The information is based on Replacement Portfolio F under the retirement date assumptions from Portfolio 3 from the Existing Fleet analysis. As discussed throughout this section, to preserve flexibility, NIPSCO's ultimate preferred portfolio may incorporate elements of Portfolios 3 and 5 from the Existing Fleet analysis and Portfolios F and I from the Replacement analysis.

the greater flexibility afforded NIPSCO in 2018 associated with identifying many renewable projects to fill a relatively large capacity target.

As NIPSCO proceeds with its short-term implementation plan, the following RFP bid diligence will be required:

- Review the best-performing gas peaker bids to confirm consistency with Reliability Assessment conclusions, assess opportunities for hydrogen enablement, and evaluate overall project viability and feasibility;

- Assess characteristics of storage bids to confirm consistency with Reliability Assessment, such as a preference for grid forming inverter technology, and other operational requirements; and

- Consider additional RFPs for capacity resources if needed to re-assess the landscape and ensure consistency with all IRP preferred portfolio requirements.

MISO Market Rules Changes

At the outset of its 2021 IRP process, NIPSCO identified several regulatory developments at the MISO level that would impact portfolio performance and ultimate implementation of the preferred plan. While MISO has advanced policy development implementation in many areas over the last year, several areas of uncertainty remain, requiring NIPSCO to ensure portfolio decisions are flexible enough to adapt to the changing environment. These include:

- Ongoing activities associated with MISO's RAN framework and the pending implementation of a seasonal capacity construct: Throughout 2021, MISO engaged with stakeholders regarding the implementation of a four-season capacity construct. While still not final, NIPSCO expects a filing on this proposal with FERC to be followed by implementation over the next few years. NIPSCO's 2021 IRP has explicitly planned for this, but portfolio adjustments may be needed in the event of different reserve margin targets (for example, a higher winter standard than modeled in the IRP) and evolving capacity accreditation rules.

- MISO's transition to an ELCC methodology to assess capacity credit for wind and solar resources over time and by season: NIPSCO's 2021 IRP incorporated a range of ELCC trajectories over time by scenario (*See* Section 8 for details across scenarios and earlier parts of this section for the impacts on NIPSCO's supply-demand balance) and assumed different summer and winter capacity credit ratings for intermittent technologies. However, as MISO implements new ELCC accounting procedures and the seasonal capacity construct, and as the amount of intermittent capacity in the broader market increases, credit values may evolve differently than what NIPSCO has assumed in the IRP. Therefore, resource procurement will need to remain flexible in order to ensure planning reserve margins are maintained.

- MISO's ongoing RIIA study: Although the 2021 IRP was designed specifically to evaluate reliability across the many dimensions identified in recent RIIA reports, NIPSCO will continue to track developments and their impact on the portfolio.

- MISO's implementation of market rules associated with FERC No. Order 841, which requires ISOs and RTOs to establish a participation model for storage resources in energy, capacity, and ancillary services markets: The 2021 IRP has identified significant value opportunities for storage resources in the sub-hourly energy and ancillary services markets. However, rules for storage implementation are not fully established, with MISO requesting implementation delays until 2022. As these rules are formalized, including for capacity accreditation and energy and ancillary services participation, NIPSCO will continue to track developments and adapt its resource procurement plans (particularly around storage) accordingly.

Federal Energy and Environmental Policy Changes

As of the time of the development of NIPSCO's 2021 IRP preferred portfolio, federal policymakers were debating significant changes to energy and environmental policy. While NIPSCO's scenarios have contemplated a broad range of policy outcomes largely consistent with the state of the debate (*See* Section 8 for more detail), certain outcomes could impact portfolio implementation decisions. The most relevant include:

- The potential implementation of a stand-alone storage ITC: NIPSCO's preferred portfolio contains a wide range of potential storage additions, and NIPSCO's scenario analysis indicated that storage resources perform better in scenarios that assume the implementation of a storage ITC. Therefore, if implemented, NIPSCO's preferred portfolio retains the flexibility to pivot towards higher levels of storage additions.

- Changes to current implementation of the ITC including, potential "direct-pay" provisions and Internal Revenue Service normalization rules.

- The potential implementation of a hydrogen PTC or other federal incentives for hydrogen development: NIPSCO's portfolio analysis suggested that federal subsidies for hydrogen production would improve the performance of portfolios that integrate this resource type into the mix. Therefore, if federal legislation includes direct subsidies or other incentives associated with hydrogen production or use, NIPSCO may adapt by exploring pilot programs or other initiatives designed to test and integrate hydrogen into its generation mix.

- The potential implementation of a carbon tax, clean energy standard or CEPP: Various recent policy proposals have offered several alternative means of incentivizing clean energy additions, and certain policy outcomes may influence the amount of new renewable capacity (both solar and wind) that NIPSCO ultimately adds to its portfolio through the short-term implementation plan.

Technology Change

As the power sector continues to navigate a period of significant change, NIPSCO expects that technology evolution will be rapid, requiring regular review of the supply-side resource marketplace and flexibility in the preferred portfolio. For example, as NIPSCO implemented the short-term action plan from its 2018 IRP, additional paired solar plus storage additions were made in response to improving technology and declining costs for lithium-ion battery storage. Going forward, NIPSCO expects power sector technology evolution to continue to impact both short-term procurement activities and long-term resource decisions. In particular, NIPSCO will continue to monitor the following:

- Stand-alone storage resource costs, efficiencies, and operational parameters, such as cycle limits, depth of discharge specifications, and ongoing expenses;
- Grid-forming inverter technology that could provide reliability benefits, such as blackstart, fast frequency response, and inertial response, to NIPSCO's system as it becomes more inverter-based;
- Hydrogen production developments, particularly associated with electrolysis of water with clean electricity sources ("green hydrogen") and the costs and capabilities of turbines and other thermal resources to burn hydrogen or blend hydrogen with natural gas;
- CCS costs and sequestration opportunities, particularly associated with the Sugar Creek facility;
- Long-duration storage technologies, including gravity storage, and their associated costs, efficiencies, and other value drivers;
- Other technologies that may emerge over the long term, including small modular reactors and other nuclear technology.

Other Factors

As with the implementation of NIPSCO's 2018 IRP, NIPSCO will again continue to perform project-specific analyses for any new resources that may enter the portfolio to evaluate items such as congestion and nodal price risk, energy deliverability, and other reliability topics. This may include detailed nodal and power flow modeling and other local transmission and distribution system analyses.

9.4 Short-Term Action Plan

NIPSCO's short-term action plan covers the period 2022 to 2027 and includes several elements, as summarized in

Figure 9-47. NIPSCO will initiate the planning process for the retirement of the Michigan City 12 and Schahfer 16AB units, leaving flexibility in ultimate timing, as described in the preferred existing fleet portfolio section above. During the retirement implementation period, NIPSCO will make the required notifications to MISO, NERC and other relevant organizations of its intention to retire units, and NIPSCO will also identify and implement reliability and transmission upgrades resulting from the retirements.

NIPSCO will also select replacement resources identified through the 2021 RFP evaluation process, prioritizing resources that were common across all portfolios that influenced the preferred portfolio selection. These include short-term thermal contracts and some solar resources. NIPSCO will also take the necessary steps to proceed with uprates to the Sugar Creek CCGT facility and identify opportunities for DER projects with distribution deferral costs consistent with the attractive tranche selected in the preferred portfolio. NIPSCO will also continue to implement the filed DSM plan for 2022 to 2024 and will continue to pursue longer-term DSM implementation consistent with the bundles selected in the preferred portfolio.

In addition, NIPSCO will perform due diligence on the short-list of gas peaker and storage bids and will conduct additional targeted RFP solicitations and associated portfolio analysis if current projects do not meet all reliability and other considerations inherent in the preferred portfolio. For the projects selected, NIPSCO will pursue the required approvals from the Commission to acquire those projects. Finally, to fill any short-term capacity needs during this period, NIPSCO will rely on MISO market purchases or short-term bilateral capacity contracts.

9.5 Conclusion

The NIPSCO Integrated Resource Plan seeks to ensure reliable, cost-effective electric service for customers while maintaining a robust and diverse pool of supply-side generation and demand-side options. This 2021 IRP incorporated several emerging trends and greatly expanded the analysis of risk and reliability to identify a preferred portfolio that is highly flexible to changing external conditions. It is no longer possible to view the world in terms of choosing a simple least cost option, and NIPSCO has identified an implementation roadmap that reflects the need to minimize future environmental impacts, maximize resource diversification, and preserve optionality over the long-term.

Figure 9-47: Short-Term Action Plan Summary

Complete and place in service 12 remaining renewable facilities approved by the IURC
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by 2023
Refine the retirement of Michigan City 12 to be between 2026 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate
Monitor the operating condition of the Schahfer 16A/B and plan for their retirement between 2025 and 2028 by making required notifications to MISO, NERC, and other organizations as appropriate, including preserving the optionality to use existing interconnection rights at the site through the MISO generator replacement process
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Confirm Sugar Creek uprate options in more detail with the plant's turbine manufacturer and schedule the uprate in accordance with the plant's maintenance cycles
Identify candidate DER projects as part of NIPSCO's distribution planning activities and consistent with planning-level assumptions developed in the IRP; implement identified projects after additional project-specific diligence
Continue implementation of filed DSM Plan for 2022 through 2023
Select replacement projects identified from the 2021 RFPs, initially prioritizing thermal PPA and solar resources
Perform deeper diligence on gas peaker and storage projects from the 2021 RFPs, selecting projects that conform to the preferred portfolio's requirements as NIPSCO tracks MISO guidelines, Commission requirements, and system reliability needs
As needed, conduct a subsequent RFP(s) to identify additional resources that may be available with attributes that are consistent with those required to implement the preferred portfolio
Explore potential pilot projects from the RFP associated with emerging technologies, such as long duration storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
Procure short-term capacity as needed from the MISO market or through short-term bilateral capacity transactions
Continue to actively monitor technology and MISO market trends, while staying engaged with project developers and asset owners to understand landscape

Perform additional reliability analysis within the NIPSCO system as needed to ensure evolving portfolio meets all reliability needs and requirements
Comply with NERC, EPA, and other regulations
Continue planned investments in infrastructure modernization to maintain the safe and reliable delivery of energy services

Section 10. Customer Engagement

10.1 Enhancing Customer Engagement

People must be at the center of a sustainable energy future. Understanding and incorporating the diverse needs and perspectives of NIPSCO's customers is important, and the Company is focused on continuously improving how it serves and engages with its customers. Whether it is transitioning to lower-cost and cleaner energy sources, helping customers understand changes and enhancements to their service, or listening to customer feedback about how they want to interact with NIPSCO, customers have been and continue to be the central focus.

10.1.1 Leveraging Customer and Stakeholder Feedback

NIPSCO relies on customer feedback to uncover service improvement opportunities. Those feedback mechanisms include the Customer Advisory Panel, J.D. Power customer satisfaction surveys, customer surveys administered by the MSR Group, online customer panels, and comments and complaints that are emailed or called in to NIPSCO's customer care center, as well as the IURC Consumer Affairs Division. NIPSCO also surveys customers to determine customer satisfaction with its customer care center and interactions with field personnel, as well as with other interactions, such as mobile, integrated voice responses and the website. The company also researches best practices that have been demonstrated by those within the utility sector as well as those outside of the industry. Customer feedback is the primary driver behind many of the changes to operations, improvements to customer communications, enhancements to services, and other offerings that have been instituted in recent years.

In 2020, NIPSCO also partnered with E Source, a company with 30+ years of industry expertise, to perform a market research study gathering voice-of-customer insights that shed a unique light on their experiences and expectations of NIPSCO, utilities, and energy. The study was designed to determine a baseline on NIPSCO customer wants and needs while identifying ways to bridge gaps between those wants and needs and NIPSCO's brand promise. The customer insights provided a fresh perspective on ways NIPSCO can best meet the expectations of today's customers, which will include updating brand messaging and validating in-flight customer experience investments and enhancements, while also potentially providing business case data for future customer-focused initiatives.

Direct customer feedback has been critical in helping NIPSCO and its parent company, NiSource, to better understand and prioritize customer needs. Based on customer feedback, the following features and capabilities have been implemented – or are currently being implemented – at NIPSCO and its five sister utilities:

- Service Request Management: Allowing customers to start, stop and transfer service digitally;
- Mobile Application: Delivering a mobile application so customers can directly conduct utility business via a native mobile application; and

- Chatbot and Live Chat: Allowing customers to receive support via a chatbot or via online chat with a live agent.

Customer feedback also allows NIPSCO to drive continuous incremental improvements across existing initiatives, including paperless enrollments and ongoing website enhancements, and helps NIPSCO better understand areas in which customers are satisfied with their interactions and areas in which the Company can continue to improve across technologies, processes and experiences.

10.1.2 Customer Education – Your Energy, Your Future

As NIPSCO transitions away from coal generation and toward lower-cost, cleaner generation options, it is important for customers to understand why and how this transition will occur so NIPSCO can maintain customer trust and confidence in the essential, reliable energy it provides.

One of the ways NIPSCO has been able to help educate customers about its "Your Energy, Your Future" generation transition plan is through a robust awareness campaign. The campaign – which included advertising and public relations efforts to communicate this message – started in 2019, was refreshed in 2020, and has continued in 2021. The goal of the NIPSCO public education efforts is to generate awareness about the generation transition by helping customers understand the customer, economic, and environmental benefits of these changes.

Part of the campaign included the creation of a dedicated website, or microsite, to house all information related to NIPSCO's Your Energy, Your Future generation transition, which can be found at NIPSCO.com/future.

New in 2020 was an "explainer" video prominently featured on the microsite that breaks down the basics of NIPSCO's generation transition in three minutes – highlighting customer cost savings, continued reliability, lower emissions, and additional economic benefits to the communities NIPSCO serves. The video was viewed by nearly 30,000 customers between NIPSCO's website and Facebook page over a 22-week period, when the advertising campaign was in flight.

Along with the microsite and video, NIPSCO utilized television, radio and print advertising, bill inserts, customer emails, and social media to reach customers and educate them about the generation transition. Press releases were also utilized to announce the latest renewable energy project news.

In 2020, NIPSCO partnered with the Center for Innovation through Visualization and Simulation through Purdue University Northwest to create a virtual simulation of a wind farm showing how wind energy is captured and delivered to customers' homes through the distribution system. The simulation will be featured on the Your Energy, Your Future microsite, along with being loaded into virtual reality goggles that NIPSCO representatives will bring to community events once COVID-19 restrictions are fully lifted.

NIPSCO's 2020 Your Energy, Your Future ad campaign's "Leaving It Better" story featuring Gary, Indiana resident and community leader LaJuan Clemons was nominated and won an Emmy award in June 2021. The Lower Lakes Chapter of the National Academy of Television Arts & Sciences awards Emmys to stations, studios, and production companies, and the LaJuan video story was entered in partnership with NIPSCO's advertising agency, Borshoff, and its production partner, Bayonet Media. The winning video featured LaJuan's inspiring story of how he helps Leave It Better in his Gary, Indiana, community. The video won in the Branded Content–Short-Form Content category.

Annually, NIPSCO garners customer feedback through a sentiment and awareness study from the Your Energy, Your Future campaign. The most recent study, conducted at the end of 2020, showed 67% of customers have a favorable view of NIPSCO's generation transition plan. Feedback showed customers associated NIPSCO's generation transition with cleaner energy, reducing emissions and improving the environment, while also demonstrating that they understand NIPSCO will continue to provide reliable energy into the future. Customer feedback on external campaigns helps NIPSCO learn which parts of its plan may need more consumer education in the future.

10.1.3 NIPSCO's Customer Workshop Series

NIPSCO has kicked off the ninth season of its Customer Workshop Series in partnership with Purdue University. Due to the COVID-19 pandemic, NIPSCO Major Accounts elected not to host the Customer Workshop Series in 2020. Other than this one-year break, hundreds of NIPSCO Transmission and C&I customers from all over northern Indiana have attended the various workshops since 2011. The series includes workshops ranging from the technical (Understanding HVAC, Fundamentals of Compressed Air, Energy Savings 101, Demand Management, Lighting, etc.) to the interpersonal (Six Sigma, Managing Time & Stress, Becoming a Leader, Managing Across Generations, etc.), and customers are able to pick which workshops are valuable to their businesses and reserve openings for themselves and/or their colleagues at no expense.

Attendees are able to interact with industry experts and representatives from the NIPSCO Major Accounts team, as well as their peers at other companies, learning best practices and voicing their current challenges and solutions in an open, classroom setting. Each season, customers complete surveys, and the feedback is used to improve the subsequent season. During the 2021 season, NIPSCO continued to host classes throughout the service territory while abiding by Centers for Disease Control and Prevention guidelines for social distancing to protect the health and well-being of customers, Purdue employees, and NIPSCO team members.

10.2 Community Partnerships

10.2.1 Community Advisory Panels

Another avenue used by NIPSCO to engage with its customers and stakeholders is the use of Community Advisory Panels (CAPs), which serve as a forum to discuss new company initiatives and programs as well as to educate and facilitate feedback regarding service and other NIPSCO-related matters in our communities. NIPSCO has five regional CAPs across the

Company's northern Indiana footprint. CAPs are composed of individual customers, as well as local government and community leaders representing a diverse, broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues. In 2019, NIPSCO adjusted the CAP territories slightly to reflect changes made to the areas that its Public Affairs managers serve. During 2020, NIPSCO was able to conduct three annual meetings virtually to maintain the integrity of the program. CAP members received updated information on NIPSCO's Your Energy, Your Future generation transition plan, as well as background on how the MISO operates in connection with NIPSCO and other states. In addition, NIPSCO utilized the CAP relationships throughout 2020 to communicate operational updates NIPSCO initiated as a result of COVID-19.

10.2.2 Partners For Clean Air

NIPSCO is a Gold Member of the Northwest Indiana Partners for Clean Air, a coalition of businesses, industries, local governments, and community groups committed to improving overall air quality and public health through voluntary actions. NIPSCO's voluntary actions include implementing energy-efficiency programs for customers and the Your Energy, Your Future generation transition. On April 30, 2021, NIPSCO received the Business Award at the annual Partners for Clean Air virtual award ceremony. To win this award, NIPSCO partnered with South Shore Clean Cities to support the construction of 24 new, public electric vehicle charging stations by matching funds for grant projects with $500 donations for eligible participants. Level 2 electric vehicle charging stations have been installed in 18 communities across northern Indiana.

10.3 Customer Programs

10.3.1 Feed-in Tariff

NIPSCO's FIT Phase I was approved on July 13, 2011, in Cause No. 43922. Implementation began immediately as a three-year pilot program with a 30 MW capacity cap. Phase I offered a higher rate to participants selling electricity than the retail electric rate in the current approved sales tariffs and provided an incentive to encourage development of renewable generating resources. The pilot program was designed to help maximize the development of renewable energy in Indiana, which welcomed biomass, wind, hydro and solar resources. The FIT provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a RPPA. Participating customers receive payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- An IA and RPPA are required to reserve capacity or enter the queue.

- The customer is responsible for interconnection fees and installation costs in accordance with the Indiana Administrative Code.

- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with the IA.

Phase I concluded in March 2015 with a total subscription of 29.7 MW and is summarized in Table 10-1.

Table 10-1: FIT Phase I In-Service

Technology	Total FIT (kW)
Biomass	14,348
Solar (large)	14,500
Solar (small)	690
Wind (large)	150
Wind (small)	10
New Hydro	0
Total	**29,698**

NIPSCO's FIT Phase II was approved on February 4, 2015, in Cause No. 44393. NIPSCO released Phase II, Allocation I of the FIT program in March 2015 and Phase II, Allocation II in March 2017. Phase II allows for an additional 16 MW of renewable capacity, bringing the total FIT capacity cap up to 46 MW. Table 10-2shows the subscription for Phase II as of July 2020.

Table 10-2: FIT Phase II Project Totals

Technology	In-service (kW)	Queue (kW)	Total FIT (kW)
Micro Solar	229	80	309
Intermediate Solar	6,170	1,800	7,970
Micro Wind	20	0	20
Intermediate Wind	0	0	0
Biomass	0	0	0
Total	6,419	1,880	8,299

With over 36 MW of capacity currently interconnected in the FIT program, as of December 31, 2020, NIPSCO had a total metered generation from customers selling electricity of 904,806 MWh. Micro solar, micro wind, intermediate wind and biomass all have remaining capacity; however, there is an existing queue for the limited amount of remaining intermediate solar capacity. Despite continued interest in the FIT program, especially the intermediate solar technology, there are no plans to offer another FIT program in the future. Table 10-3 shows the annual production and growth by technology segment.

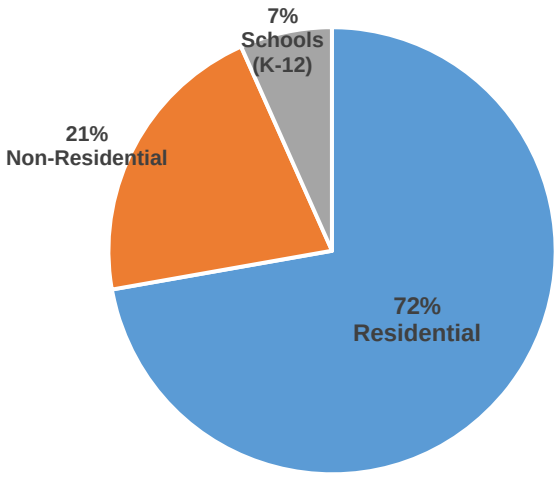
Table 10-3: Annual Production by Technology – Generation (MWh)

Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Biomass	6,220	19,152	31,603	49,917	81,370	83,552	89,486	94,942	94,552	96,144	646,938
Intermediate Solar	-	434	15,789	21,665	22,436	22,697	24,391	27,450	16,707	30,345	181,914
Micro Solar	-	119	472	719	818	825	849	849	857	899	6,407
Intermediate Wind	-	-	90	166	218	166	168	180	143	115	1,246
Micro Wind	-	4	16	12	9	8	8	8	8	8	81
Total	**6,220**	**19,709**	**47,970**	**72,479**	**104,851**	**107,248**	**114,902**	**123,429**	**112,267**	**127,511**	**836,586**

10.3.2 Net Metering

NIPSCO's Net Metering Rider allows customers to install renewable energy generation to offset all or part of their own electricity requirements. Net metering is the measurement of the difference between the electricity that is supplied by NIPSCO and the electricity that is supplied back to NIPSCO by an eligible net metering customer. Production is measured on a kWh basis. To be eligible, a customer must be in good standing and operate a solar, wind, biomass or hydro generating facility that has a nameplate capacity of less than or equal to 1 MW. NIPSCO follows the rules and guidelines set forth in the Indiana Administrative Code with respect to Net Metering and the interconnection process. Customers with a fully executed Net Metering Agreement and IA receive a credit for each kWh provided to NIPSCO above their own usage requirements. NIPSCO's Net Metering program capacity as of December 31, 2020 was 30.4 MW. The total measured generation by the Net Metering customers for 2020 was 20,483,454 kWh. The current classification of NIPSCO's 779 Net Metering customers is shown in Figure 10-1.

Figure 10-1 : Classification of Net Metering Customers



To be guaranteed to participate in the nonresidential Net Metering program, a customer interconnection application had to be submitted by October 1, 2021. Nonresidential applications approved by December 31, 2021 will also be allowed to participate. Residential and biomass interconnection applications will continue to be accepted until July 1, 2022, or until there is no remaining capacity available, as outlined in Senate Enrolled Act 309. Once the Net Metering program is no longer available for any classification of customer, a customer can elect to submit an interconnection application for the EDG Rider, if approved by the Commission.[130] In 2020, NIPSCO implemented the use of DocuSign to expedite contract execution and provide convenience for customers.

10.3.3 Green Power Rider Program

NIPSCO's GPR program was approved on December 19, 2012, in Cause No. 44198. NIPSCO's request for an extension of its GPR program, with certain modifications and as a component of NIPSCO's approved tariff on a non-pilot basis, was approved on December 30, 2014, in Cause No. 44520. The GPR Program is a voluntary program that allows customers to designate a portion or all of their monthly electric usage that they want to be renewable energy. Customers can enroll online or by calling NIPSCO.

Green power is energy generated from renewable and/or environmentally friendly sources or a combination of both, which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of green power include solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green power includes the purchase of RECs from the sources described above. For the GPR program, NIPSCO's residential electric customers can designate 25%, 50% or 100% of their total electricity usage they would like to be renewable energy. In addition to those options, NIPSCO's nonresidential customers also have the option to designate 5% or 10% of their total electricity usage they would like to be renewable energy. As of December 31, 2020, 1,496 customers were participating in the GPR Program. Figure 10-2 shows the breakdown among residential customers as of December 31, 2020.

[130] As of the submission of this report, NIPSCO's EDG Rider was pending before the Commission in Cause No. 45505.

Figure 10-2 GPR Program Residential Customer Count[131]

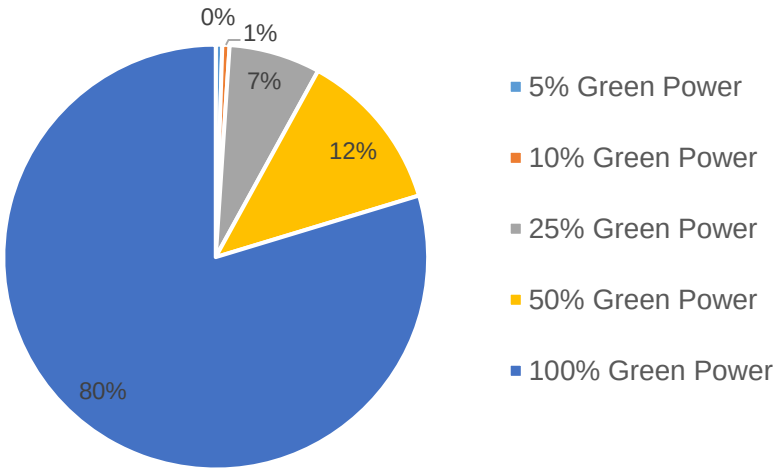
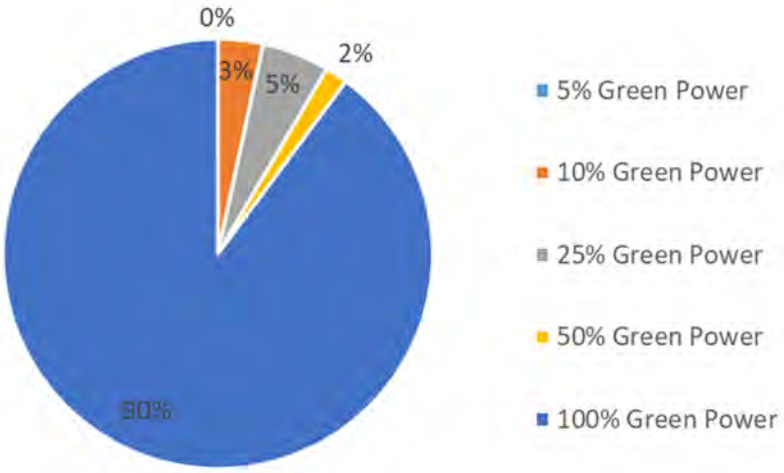


Figure 10-3 shows the breakdown of commercial and industrial customers as of December 31, 2020.

Figure 10-3: GPR Program Commercial Customer Count



[131] Previously residential customers had the option to enroll at 5% or 10%. Customers who elected one of those options were grandfathered in when those levels were discontinued for residential customers.

NIPSCO's GPR program for the period of January 1 through December 31, 2020, accounted for 21,308,200 kWh of energy consumption designated as green power. Residential customers accounted for 11,060,703 kWh of energy consumption, and C&I customers accounted for 10,247,497 kWh of energy consumption of designated green power. For both residential and commercial customers, the majority of the GPR program enrollments designate 100% of their energy as green power. Table 10-4 shows the energy consumption designated as Green Power for participating customers, by rate type, for the period January 1 through December 31, 2020.

Table 10-4 2020 Green Power Customers by Rate Type (kWh)

Rate Type	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Commercial	893,256	892,359	927,167	846,381	758,117	992,134	1,168,867	1,048,591	1,029,012	901,414	787,791	815,614	11,060,703
Residential	860,081	765,934	724,971	697,433	643,985	898,306	1,319,713	1,166,669	1,072,389	665,051	631,954	801,011	10,247,497
Total	**1,753,337**	**1,658,293**	**1,652,138**	**1,543,814**	**1,402,102**	**1,890,440**	**2,488,580**	**2,215,260**	**2,101,401**	**1,566,465**	**1,419,745**	**1,616,625**	**21,308,200**

Participating customers are billed under their current applicable rates, with a separate line item showing the premium to participate in the GPR program. This premium is calculated by multiplying the GPR rate by the kWhs the customer specifies to be subject to the GPR. Table 10-5 shows the green power premiums applicable during the period January 1, 2017, through December 31, 2020.

Table 10-5: Green Power Rates

July 2017 to June 2018	July 2018 to June 2019	July 2019 to June 2020	July 2020 to June 2021
$0.002940	$0.001805	$0.001657	$0.002860

10.3.4 Transportation Decarbonization: DC Fast charging stations & IDEM Grant

The Indiana Volkswagen Environmental Mitigation Trust Fund Committee was formed to manage the disbursement of Indiana's share of funds from the Environmental Mitigation Trust created as part of Volkswagen's settlement of Clean Air Act violations regarding diesel emissions from its vehicles. IDEM is the lead agency for the state of Indiana's participation in the Environmental Mitigation Trust. In late 2020, NIPSCO joined the Indiana Utility Group, a consortium of eight Indiana utilities, to apply for Electric Vehicle DC Fast Charging funding. In March 2021, the Indiana Utilities Group submitted a coordinated grant application for 61 DC fast-charging stations, 10 of which were for NIPSCO's service territory. Along with the IDEM grant of more than $900,000, NIPSCO is investing more than $1.4 million in constructing these charging stations. NIPSCO has a goal of having all 10 stations in operation by late 2022.

10.3.5 Advanced Metering Infrastructure

NIPSCO has proposed to implement AMI meter technology for its electric customers, and this proposal is still pending in a proceeding before the Commission.[132] AMI is central to NIPSCO's efforts to enable modern energy capabilities. These capabilities include integration of electric vehicle charging and customer-owned generation resources into the distribution grid, improved forecasting of electricity demand thus enabling better planning for the future, and access to data that helps NIPSCO to both understand impacts to and anticipate issues with the distribution system as generation technology and usage patterns evolve to maintain reliability.

10.4 Corporate Development and Community Support

10.4.1 Supporting Economic Growth

NIPSCO partners with community leaders and state, regional, and local economic development organizations to attract and support the expansion of new and existing businesses and to help create more jobs across the NIPSCO service territory. In addition to being one of the largest employers in the region, NIPSCO spends $1.1 million in economic development efforts each year, which has resulted in 85 new businesses or expansions and 8,700 local jobs in the past 10 years.

NIPSCO's Rider 877 – Economic Development Rider offers discounts on existing tariff services for qualifying projects that bring new jobs and investment from outside the NIPSCO service territory. When coupled with local and state incentives, a powerful package is created with often positive results.

NIPSCO's Your Energy, Your Future generation transition will help save Indiana's businesses and families money and also make northern Indiana more economically competitive. The generation transition positions Indiana as a more attractive location to employers, as well as residents, as NIPSCO brings a sustainable balance of cleaner, lower-cost renewable energy to its portfolio. For example, in 2019, the Digital Crossroads Data Center – a more than $50 million facility bringing jobs and revenue to the area – decided to open in Hammond, Indiana. NIPSCO's generation transition commitment was part of what attracted the business to the area, as it looked to be the most energy-efficient, lowest-latency urban data center in the United States.

10.4.2 Supplier Diversity

Cultivating a diverse pipeline of suppliers helps bring innovative ideas and processes, a competitive advantage, and other benefits to NIPSCO's communities. NIPSCO has created a supplier diversity program that strengthens and widens the playing field for qualified suppliers who are typically underutilized in the supply chain of a large corporation.

In 2020, NIPSCO's direct supplier spending in Indiana was $1.057 billion. Of that, $95.9 million was spent on diverse businesses and $19.6 million was spent on diverse subcontractors.

[132] See Cause No. 45557, NIPSCO's TDSIC Plan further discussed in Section 6.

10.4.3 Workforce Development

NIPSCO continues to lead efforts and partnerships focused on workforce development – both for the current and future workforce generations. Some of the highlights include:

- **Ivy Tech Partnership for Energy Industry Training Program:** This program began in 2009 and provides training in electric-line, power plant technology, and gas technology areas. NIPSCO has hired more than 60 students from the program, and graduates are guaranteed an interview opportunity. Additionally, NIPSCO provides instructors for these training classes and, in 2017, provided a full-scale electric distribution system for training purposes built within the Ivy Tech Valparaiso campus energy technology lab – the only such facility in an educational setting in Indiana. NIPSCO is currently working with Ivy Tech to review the entire program and update the curriculum to meet the training needs for renewable energy generation operation and maintenance.

- **NIPSCO Energy Academy:** Started in 2014, the NIPSCO Energy Academy program is a partnership designed to prepare area students for high-demand jobs in the electronics, energy, and utility industries. It is the first initiative of its kind in Indiana, and it will serve students from Michigan City High School, LaPorte High School, New Prairie High School, South Central High School, LaCrosse High School, and Westville High School. More than 100 students that have gone through the program. NIPSCO is currently looking to add a similar Energy Academy in Lake County.

- **IN-POWER Youth Mentoring Program:** In 2010, NIPSCO introduced the IN-POWER Youth Mentoring Program – a unique mentoring program for local high school students that takes a holistic approach to developing a more highly skilled future workforce in the energy sector. The program was expanded with IN-POWER STEM PLUS, designed to give 7th and 8th grade students a firsthand experience on gas and electric safety while teaching them about the various aspects of STEM needed in the energy sector. NIPSCO employees and American Association of Blacks in Energy Indiana members serve as mentors and instructors. Participants receive college credits, unique mentoring and internships, among other opportunities.

- **NIPSCO Energy Ambassador Program:** The NIPSCO Energy Ambassador program, in partnership with the Urban League, is a college- and career- readiness program initiated in 2019. This opportunity invites 11th and 12th grade students throughout northwest Indiana to participate in virtual workshops and activities designed to educate students about NIPSCO's operations and encourage STEM learning. In this, the program's third year, NIPSCO donated $60,000 to the Urban League to support the 2021 summer internship. Other goals of the program include reducing social-emotional barriers for students, increasing students' interest in STEM careers, boosting self-esteem and supporting educations goals. Approximately 45 students participate annually and:

- Receive informational training from NIPSCO representatives
- Disseminate NIPSCO customer-centric information to their respective communities to provide awareness
- Participate in career exploration experiences
- Participate in community service outreach activities
- Attend workshops to become college or career ready

- **JA Support:** NIPSCO provides annual support for classroom business education programs through both contributions and volunteer instructors across NIPSCO's service area. For the past several years, NIPSCO has supported a "JA Day" in a local Hammond and East Chicago school systems. In 2021, NIPSCO partnered with JA to offer a virtual platform that taught participating students about different job sectors.

- **City of Gary Summer of Opportunity Job Program:** The Summer of Opportunity places youth in meaningful work opportunities throughout Gary, with lunch-and-learn workshops featuring local professionals, with every other session focusing on financial literacy. Local youth staff six summer program sites that offer summer meals and learning. NIPSCO partners with the mayor's office, Gary Youth Services Bureau, Urban League, and the Gary Chamber of Commerce to create a set of supports that enable strong transitions from school year to school year and from high school to college and career.

- **Girl Scouts Engineering Day:** For more than five years, NIPSCO has hosted approximately 125 girls from kindergarten to 4th grade for the annual Introduce a Girl to Engineering Day. The girls come from local Girl Scout troops along with some young relatives of NIPSCO and NiSource employees. The four-hour event is part of the company's efforts to help build the next generation of female leaders, support local communities and provide opportunities for local students interested in STEM-related careers. The event is organized by the employee resource group Developing and Advancing Women (DAWN) at NiSource.

- **On My Way Pre-K:** NIPSCO was a lead sponsor of the Pilot Pre-K Program, which began in 2016, and has been shown to be a successful early education program to improve children's chances of being ready to learn when they reach kindergarten and throughout their educational experiences, a key factor in breaking the cycle of poverty.

10.4.4 Corporate Citizenship

NIPSCO believes that reinvesting in the communities where its employees live and work will enhance the quality of life for everyone. Each year, NIPSCO donates time, money, and other

resources to hundreds of local philanthropic programs and organizations across its 30-county service area, focusing on:

- Safety
- Economic and workforce development
- Environmental stewardship
- STEM and energy education
- Basic needs and hardship assistance

Through these programs and partnerships, NIPSCO is working hard with its communities to build a brighter future for years to come.

In 2020, NIPSCO and the NiSource Charitable Foundation contributed approximately $1 million to local organizations throughout the NIPSCO service territory.

A highlight of that effort includes NIPSCO's annual Charity of Choice campaign, during which employees select one nonprofit organization or an area of need to support. Fundraisers, volunteerism, and other activities are planned throughout a summer-long, employee-led campaign. Recent benefactors and causes selected by employees have included autism, veterans, Boys & Girls Clubs, the American Heart Association, the American Red Cross, and organizations supporting the community through the COVID-19 pandemic. The 2021 Charity of Choice campaign supported mental health awareness and education.

10.4.5 Volunteerism

NIPSCO employees have a passion for volunteering and giving back to their local communities. Through a program called Dollars for Doers, cultivated by NIPSCO's parent company, NiSource Inc., employees translate their community service into financial support for organizations they care about most. The program contributes up to $500 per employee to an organization in return for volunteer time. In 2019, NIPSCO employees volunteered more than 2,100 hours, which resulted in more than $56,000 of contribution to local organizations. In 2020, while the COVID-19 pandemic limited how NIPSCO employees could safely volunteer time across the service area, NIPSCO employees contributed more than 1,000 volunteer hours, equating to an additional impact of $30,953 to various charities.

Additionally, NIPSCO employees volunteer their personal time and resources with more than 100 local nonprofit boards, local associations and other local community efforts each year.

Section 11. Compliance with IRP Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(d) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents: (1) The integrated resource plan.	Submitted via email on November 15, 2021
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP.	Confidential Appendix D
(3) An IRP summary that communicates core IRP concepts and results to non-technical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) the IRP public advisory process; and (vi) any additional details the commission staff may request. (B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	Executive Summary
(e) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following: (1) The name and address of each known entity considered by the utility to be an interested party. (2) A statement that the utility has sent each known interested party, electronically or by deposit in the United States mail, First Class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information: (A) A general description of the subject matter of the submitted IRP. (B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within 90 days of the IRP submittal.	Transmittal Letter

Rule	Section(s)
An interested party includes any business, organization, or customer that participated in the utility's previous public advisory process. A utility is not required to separately notify all of its customers. (3) A statement that the utility has served a copy of the documents submitted under subsection (d) above on the office of the consumer counselor.	
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) A municipally owned utility; (2) A cooperatively owned utility; and (3) A utility submitting an IRP under subsection 2(b) of this rule. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by interested parties, the commission, and its staff. (d) The utility retains full responsibility for the content of its IRP.	N/A
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable energy and non-energy benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and its rationale. (2) The utility is encouraged to hold additional meetings as appropriate. (3) The schedule for meetings shall be determined by the utility and shall:	Section 2.1 Appendix A

Rule	Section(s)
(A) be consistent with its internal IRP development schedule; and (B) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP. (4) The utility or its designee shall: (A) chair the participation process (B) schedule meetings; and (C) develop and publish to its website agendas and relevant material for those meetings at least seven calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen calendar days following each meeting; (5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility. (6) The utility shall take reasonable steps to notify its customers; the commission; and interested parties of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	
(a) The commission or its staff may host an annual technical conference to facilitate: (1) identifying contemporary issues; (2) identifying best practices to manage contemporary issues; and (3) instituting a standardized IRP format. (b) The agenda of the technical conference shall be set by the commission staff. Utilities and interested parties may request commission staff include specific contemporary issues and presenters. (c) The director may designate specific contemporary issues for utilities to address in the next IRPs by providing the utilities and interested parties with the contemporary issues to be addressed. The utility shall address the designated contemporary issues in its next IRP. In addition, prior to its next IRP the utility shall provide to interested parties either a discussion of the impacts of such issues on its IRP or describe how it has taken the contemporary issues into account.	N/A
(d) A utility shall address new issues raised in a contemporary issues technical conference if the contemporary issues technical conference occurred at least one (1) year prior to the submittal date of a utility's IRP.	Section 2
170 IAC 4-7-4: Integrated Resource Plan Contents	

Rule	Section(s)
An IRP must include the following:	
(1) At least a 20 year future period for a predicted or forecasted analysis.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with subsection 5(a) of this rule.	Section 3.2 Section 3.3 Section 3.4 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.9 Section 3.10 Section 3.11
(3) At least three alternative forecast scenarios of peak demand and energy usage in compliance with subsection 5(b) of this rule.	Section 3.7
(4) A description of the utility's existing resources in compliance with subsection 6(a) of this rule.	Section 4.3 Section 4.4 Section 4.5 Section 5.1
(5) A description of possible alternative methods of meeting future demand for electric service in compliance with subsection 6(b) of this rule.	Section 5
(6) The resource screening analysis and resource summary table required in subsection 7(a) of this rule.	Section 4.6
(7) The information and calculation of tests required for potential resources in compliance with subsections 7(b)-7(e) of this rule.	Appendix B
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with subsection 8(a) and 8(b) of this rule.	Section 8.1 Section 9.2 Section 9.3 Confidential Appendix D
(9) A description of the utility's preferred resource portfolio and the information required in compliance with subsection 8(b) of this rule.	Section 9.2 Section 9.3
(10) A short term action plan listing plans for the next three year period to implement the utility's preferred resource portfolio and its workable strategy. The short term action plan shall comply with section 9 of this rule.	Section 1.1 Section 9.4
(11) A discussion of the inputs; methods; and definitions used by the utility in the IRP.	Section 2 Section 3.3 Section 4.4 Section 4.9

Rule	Section(s)
	Section 5.1 Section 5.2 Section 5.3 Section 7.3 Section 8.1 Section 8.2 Section 8.4 Section 9.2 Section 9.3 Appendix A Confidential Appendix D
(12) Appendices of the data sets and data sources used to establish alternative forecasts in subsection 9(b) of this rule. If the IRP references a third party data source, the IRP must include the following for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of any adjustments made to the data. The data must be submitted with the IRP in a manipulable format.	Confidential Appendix D
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by the following: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Section 3 See Note 1
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Section 3
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	See Note 2

Rule	Section(s)
(16) A discussion detailing how information from Advanced Metering Infrastructure (AMI) and smart grid will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 3 Section 5.2 Appendix B
(17) A discussion of distributed generation within the service territory and its potential effects on generation, transmission, and distribution planning and load forecasting.	Section 9 Section 6.2 Section 10.3.1
(18) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Appendix A
(19) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 4.1
(20) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission have been taken into account and influenced the IRP development.	Section 7.3.5
(21) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(22) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 7.3 Section 8.2.3
(23) A discussion of how the utilities' resource planning objectives, such as cost effectiveness, rate impacts, risks and uncertainty, were balanced in selecting its preferred resource plan.	Section 9.3
(24) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include existing federal environmental laws; existing state laws, such as renewable energy requirements and energy efficiency laws; and existing policies, such as tax incentives for renewable resources that are certain. Existing laws or policies continuing throughout at least some portion of the planning horizon with a high	Section 9.3

Rule	Section(s)
probability of expiration or repeal must be eliminated or altered when applicable. (C) Not include future resources, laws, or policies unless the utility receives stakeholder input on the inclusion and it meets the following conditions: (i) Future resources have obtained regulatory approvals. (ii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	
(25) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 9.3
(26) A brief description, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. This description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) the limits of the utility's transmission use; (ii) the utility's assessment practices developed through experience and study; and (iii) operating restrictions and limitations particular to the utility.	Confidential Appendix C
(27) A list and description of the contemporary methods utilized by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and	Section 2.2 Section 3.2 Section 8.1 Section 9.3 Appendix B

Rule	Section(s)
(iv) analysis of risk and uncertainty.	
(28) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Section 5.2 Appendix B
(29) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically in a manipulable format. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Section 3.1 Confidential Appendix D
(30) A summary of the utility's most recent public advisory process, including: (A) Key issues discussed. (B) How the utility responded to the issues (C) A description of how stakeholder input was used in developing the IRP.	Section 2.1 Appendix A
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 4.6 Section 5 Appendix B
170 IAC 4-7-5: Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Section 3 Confidential Appendix D

Rule	Section(s)
(2) Disaggregation of historical data and forecasts by customer class, interruptible load, end-use where information permits.	Section 3
(3) Actual and weather normalized energy and demand levels.	Section 3.7
(4) A discussion of methods and processes used to weather normalize.	Section 3.3.1
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Section 3.7
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes, rate classes, or both. (C) Firm wholesale power sales.	Section 3.7
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2
(8) Justification for the selected forecasting methodology.	Section 3
(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data, such as described in subdivision 4(10) of this rule.	No Response Needed
(b) In providing at least three (3) alternative forecasts of peak demand and energy usage the utility shall include high, low, and most probable peak demand and energy use forecasts to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most likely based on alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices, including competition. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Section 3.7
(c) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, analysis as part of the on-going efforts to improve the credibility of the load forecasting process.	Section 3.2
170 IAC 4-7-6: Resource Assessment	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information:	Section 4.4 Section 4.5

Rule	Section(s)
(1) The net dependable generating capacity of the system and each generating unit.	
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.5 Section 4.6.5 Section 9.1
(3) A fuel price forecast by generating unit.	Section 8.2
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at each existing fossil fueled generating unit.	Section 4.1
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network. (D) An assessment of the transmission component of avoided cost.	Section 5.2 Section 6.1
(6) A discussion of DSM programs and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Section 3.2 Section 5.1 Section 5.3 Appendix B
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Innovative rate design as a resource in meeting future electric service requirements.	Section 5.2
(2) Demand-side resources, including Demand response programs, and Energy efficiency programs.	Section 5.2 Section 5.4 Appendix B

Rule	Section(s)
For a demand-side resource identified in the IRP, the utility shall, include the following: (A) A description of the program considered. (B) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to programs under consideration such as project life and seasonal operation. (C) The customer class or end-use, or both, affected by the program. (D) A participant bill impact projection and participation incentive to be provided in the program. (E) A projection of the program costs to be borne by the participant. (F) Estimated annual and lifetime energy (kWh) and demand (kW) savings per participant for each program. (G) The estimated program penetration rate and the basis of the estimate. (H) The estimated impact of a DSM program on the utility's load, generating capacity, and transmission and distribution requirements. (I) whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	See Note 3
(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including: (i) Size (MW). (ii) Utilized technology and fuel type. (iii) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Section 4.1 Section 4.5 Section 4.6
(4) transmission facilities as a resource including new projects, upgrades to transmission facilities, efficiency improvements, and smart grid technology.	Section 6.1 Section 6.2
In analyzing transmission resources, the utility shall include the following: (A) A description of the timing, types of expansion, and alternative options considered.	Section 6.1 Section 6.2

Rule	Section(s)
(B) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.6
(C) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 6.1
(D) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Section 6.1
170 IAC 4-7-7: Selection of Resources	
(a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 4.6 Section 5.2 Section 5.3 Appendix B
(b) The following information must be provided for a resource selected for further analysis: (1) A description of significant environmental effects, including the following: (A) Air emissions. (B) Solid waste disposal. (C) Hazardous waste and subsequent disposal. (D) Water consumption and discharge. (2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan and the commission analysis to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	Section 9.2
(c) For each DSM program analyzed under this section, the IRP must include one (1) or more of the following tests to evaluate the cost-effectiveness of the program. (1) Participant cost test. (2) Ratepayer impact measure. (3) Utility cost test. (4) Total resource cost test.	Section 5.2 Appendix B

Rule	Section(s)
(5) Other reasonable tests accepted by the commission.	
(d) A utility is not required to calculate a test result in a specific format.	N/A
(e) For each program in subsection (c), a utility must calculate the net present value of the program's impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the interest rate used in the net present value calculation.	Section 5.2 Appendix B
(f) For a test performed under subsection (c), an IRP must: (1) specify the components of the benefit and the cost for the test; and (2) identify the equation used to calculate the result.	Appendix B
(g) If a reasonable cost-effectiveness analysis for a program cannot be performed using the tests in subsection (c), because it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	N/A
(h) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	N/A
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios. In selecting the candidate resource portfolios, the utility shall consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Section 8.4
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential futures. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metric(s). (3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Section 9.2 Confidential Appendix D

Rule	Section(s)
(c) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	Section 9.3
(2) Identification of the variables used.	Section 9.3
(3) Identification of the standards of reliability.	Section 9.3
(4) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.3
(5) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 9.2
(6) An analysis showing the preferred resource portfolio utilizes, to the extent practical, all economical supply-side resources and demand-side resources as sources of new supply.	Section 9.3
(7) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility including their impacts on the utility's transmission and distribution system for the first ten years of the planning period.	Section 5.3 Appendix B
(8) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Section 9.3
(9) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance;	Section 9.3

Rule	Section(s)
(ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (x) operating costs; (v) construction costs; (vi) resource performance; (vii) load requirements; (viii) wholesale electricity and transmission prices; (ix) RTO requirements; and (x) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(10) A description of the utility's workable strategy allowing it to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including the following changes: (A) The demand for electric service. (B) The cost of a new supply-side resources or demand-side resources.. (C) Regulatory compliance requirements and costs. (D) Changes in wholesale market conditions. (E) Changes in fuel costs. (F) Changes in environmental compliance costs. (G) Changes in technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Section 9.3
(11) Utilities shall include a discussion of the potential changes under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 2.2
170 IAC 4-7-9: Short Term Action Plan	
(a) A short term action plan shall be prepared as part of the utility's IRP, and shall cover a three (3) year period beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. (b) The short term action plan must include, but is not limited to, the following:	Section 1.1 Section 9.4

Rule	Section(s)
(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective. (2) Identification of energy efficiency goals for implementation of energy efficiency that can be produced by reasonably achievable, cost effective plans developed in accordance with 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives. (3) The implementation schedule for the preferred resource portfolio. (4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts. (5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually transpired.	
Note 1: NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumption patterns by DSM program. The savings associated with DSM programs are gauged and claimed based on various TRMs, including the Indiana TRM, and the DSM programs are evaluated by program year by a third party EM&V administrator. NIPSCO will continue to consider its options. NIPSCO does not currently maintain and has no plans in the future to develop a database of electricity consumptions patterns by end use.	
Note 2: As part of its DSM functions, DSM programs are evaluated by program year by a third party EM&V administrator. As part of the EM&V process, the administrator surveys a sample of customers who have and have not participated in NIPSCO's DSM program. NIPSCO conducted an MPS (see Appendix B) that includes primary data. In addition, NIPSCO has previously completed lighting and market effect studies. NIPSCO used customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns as part of its updated MPS.	
Note 3: Customer bill impacts are calculated directly utilizing the customer rate and the savings of each measure/participant. Appropriate escalators and discount rates are used to determine the NPV of these savings and then Aggregated across all measures/participants. Incentives are also included in the cost benefit analysis as an input on a per participant/measure basis. Appropriate escalators and discount rates are applied and the NPV calculated.	

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 73
NIPSCO May 2022 Investor Call

NEWS

Wednesday, May 04, 2022

NiSource reports first quarter 2022 results

Share (https://www.facebook.com/sharer/sharer.php?u=https://www.nisource.com/news/article/nisource-reports-first-quarter-2022-results-20220504) (h

Posted In Financials

Need more info on this story? Contact our media relations team (mailto:media@NiSource.com).

We value your privacy
This website uses third-party cookies and tracking tools to enhance user experience, analyze website performance and traffic, and record user interactions. By accepting all cookies, your site usage information may also be shared with advertising and analytics partners. Learn more (/our-site/cookie-policy) about our cookie policy. By using our site, you agree to our Terms of Use (/our-site/terms-of-use) and Privacy Notice (/our-site/privacy-statement).

Decline Non-essential Cookies Accept All Cookies

Supplemental (https://investors.nisource.com/files/doc_financials/2022/q1/NI-Supplemental-Earnings-Slides-Q1-2022-Final.pdf)Supplemental Slides (https://investors.nisource.com/files/doc_financials/2022/q1/NI-Supplemental-Earnings-Slides-Q1-2022-Final.pdf) | Segment & Financial Information (https://investors.nisource.com/files/doc_financials/2022/q1/NI-Supplemental-Financial-Information-Q1-2022-Final.pdf) | Listen to Webcast (https://events.q4inc.com/attendee/307944441)

- 2022 guidance and long term earnings growth reaffirmed
- Generation transition from coal remains on track for 2026-2028; however, short term solar project delays expected
- Regulatory progress supporting enhanced safety and environmental performance continues, with a rate case settlement in Indiana and new cases filed in Pennsylvania and Virginia
- Investor Day, focused on extending NiSource's growth plan, will take place this fall
- Safety, reliability, customer affordability and sustainability remain top priorities

NiSource Inc. (NYSE: NI) today announced, on a GAAP basis, net income available to common shareholders for the three months ended March 31, 2022 of $413.0 million, or $0.94 diluted earnings per share, compared to net income available to common shareholders of $281.7 million, or $0.72 diluted earnings per share, for the same period of 2021.

NiSource also reported non-GAAP net operating earnings available to common shareholders of $328.7 million, or $0.75 diluted earnings per share, for the three months ended March31, 2022, compared to non-GAAP net operating earnings available to common shareholders of $304.8 million, or $0.77 diluted earnings per share, for the same period of 2021. Schedule 1 of this press release contains a complete reconciliation of GAAP measures to non-GAAP measures.

"The NiSource team continues to execute on plans for the growth and sustainability of our business while delivering safe and reliable service to our customers," said **Lloyd Yates**, President and CEO. "Despite the expected delays in solar projects, the resiliency and flexibility of our business plan continues to support our commitment to deliver 7 - 9% compound annual growth in non-GAAP NOEPS from 2021 through 2024. I also look forward to sharing details around the extension of this growth plan at our Investor Day event this fall."

Reaffirming 2022 and long-term financial guidance

Consistent with its near and long-term growth commitments, NiSource reaffirms its 2022 non-GAAP diluted net operating earnings per share (NOEPS) guidance of $1.42 to $1.48.

NiSource also continues to expect non-GAAP diluted NOEPS to grow by 7 to 9 percent, from 2021's full year results of $1.37 through 2024, on a compound annual growth rate basis, including near-term annual growth of 5 to 7 percent through 2023. NiSource reminds investors that it does not provide a GAAP equivalent of its earnings guidance due to the impact of unpredictable factors such as fluctuations in weather and other unusual and infrequent items included in GAAP results.

Renewable generation transition

We value your privacy
This website uses third-party cookies and tracking tools to enhance user experience, analyze website performance and traffic, and record user interactions. By continuing to use this website, your site usage information may also be shared with advertising and analytics partners. **Learn more (/our-site/cookie-policy)** about our cookie policy. By using our site, you agree to our **Terms of Use (/our-site/terms-of-use)** and **Privacy Notice (/our-site/privacy-statement)**.

The U.S. Commerce department circumvention investigation related to the import of solar components from select geographies has brought uncertainty and delays to the solar panel market. NiSource is working with its renewable generation developers to better understand the potential project impacts. The company anticipates that most solar projects originally scheduled for completion in 2022 and 2023 will experience delays of approximately 6 to 18 months. In connection with these delays, the company now expects to retire Schahfer Generating Station's remaining two coal units by the end of 2025. However, NiSource continues to expect that Michigan City Generating Station will retire on schedule between 2026-2028.

As NiSource evaluates potential adjustments to renewable generation project timing, the company remains on track to make capital investments totaling approximately $10 billion during the 2021-2024 period. Capital investments for renewable projects of approximately $2.0 billion are expected, primarily between 2022 and 2024, with any remainder expected in 2025. NiSource has flexibility in the timing of other gas and electric infrastructure capital investments that can allow adjustments to compensate for delays in renewable generation projects. In total, capital investments are expected to drive compound annual rate base growth of 10 to 12 percent for each of the company's businesses through 2024.

Environmental impact targets update

In addition to retiring all coal-fired generation by 2026-2028, NiSource is on track to achieve its environmental goals, including:

- Reduce scope 1 greenhouse gas emissions 90% (from 2005 levels) by 2030
- Achieve 50% reduction (from 2005 levels) in methane emissions from gas mains and services by 2025

In 2021, NiSource's energy efficiency programs enabled nearly 1.1 million customers to manage their energy use. Energy efficiency upgrades, home check-ups, weatherization services and other activities helped customers save about $18.5 million on their energy bills and reduce emissions.

Inaugural annual Safety Report

NiSource's inaugural annual Safety Report outlines the company's continued commitment to safety. The report highlights risk management and continuous improvement activities, continued safety investments and technology integration to enhance safety. It is available on the company's website, **nisource.com** (https://www.nisource.com/home).

Among the advances highlighted in the report is the launch of a collaborative effort among safety-focused energy companies, the Natural Gas Safety Management System Collaborative. Its aim is to drive progress and maturity of safety management systems at member companies. NiSource will benefit from sharing information and learning from the experiences of others.

First quarter 2022 and recent business highlights

Electric operations

We value your privacy
This website uses third-party cookies and tracking tools to enhance user experience, analyze website performance and traffic, and record user interactions. By accepting all cookies, your site usage information may also be shared with advertising and analytics partners. **Learn more (/our-site/cookie-policy)** about our cookie policy. By using our site, you agree to our **Terms of Use (/our-site/terms-of-use)** and **Privacy Notice (/our-site/privacy-statement)**.

Northern Indiana Public Service Company (NIPSCO)filed a petition with the Indiana Utility Regulatory Commission seeking approval of NIPSCO's federally mandated costs for remediation of the coal combustion residuals ash pond at Michigan City Generating Station. The federally mandated costs include a total estimated $40.0 million of retirement costs.

Gas distribution operations

Columbia Gas of Virginia filed a rate case on April 29 to continue its safety and modernization investments. The case seeks an increase in annual revenues of approximately $58.2 million.

Columbia Gas of Ohio is preparing its response to the Public Utilities Commission of Ohio staff report filed on April 6, 2022 in its rate case. The June 2021 filing requested a $221.4 million increase net of the Capital Expenditure Program (CEP) and Infrastructure Replacement Program (IRP) riders.

Columbia Gas of Pennsylvaniahas filed a rate case to further upgrade and replace gas lines for the long-term safety of customers and communities. The case requests additional revenues of $82.2 million. It also seeks to provide additional energy efficiency options while balancing costs.

NIPSCO has filed a proposed settlement in its gas rate case. The agreement would provide a revenue increase of approximately $72 million annually. In addition to infrastructure modernization, the proposal would enable NIPSCO to continue to serve customers with a safe, reliable supply of natural gas, while remaining in compliance with state and federal safety requirements.

NiSource has joined the Coalition for Renewable Natural Gas. The company believes natural gas infrastructure will play an important role in America's energy future, potentially carrying renewable natural gas as well as other low-carbon fuels such as hydrogen. As NiSource explores opportunities to further decarbonize its natural gas system, its local distribution companies are pursuing programs that would allow customers to reduce the carbon intensity of their natural gas usage through the renewable natural gas and carbon offsets. Regulatory filings seeking approval for these programs are under way, similar to the NIPSCO Green Power Rate program that has been in place for several years.

Additional information for the quarter ended March 31, 2022, is available on the Investors section of www.nisource.com (https://c212.net/c/link/?t=0&l=en&o=3525104-1&h=2186818682&u=https%3A%2F%2Fwww.nisource.com&a=www.nisource.com), including segment and financial information and our presentation to be discussed at the company's first quarter 2022 earnings conference call scheduled for May 4, 2022 at 11 a.m. ET.

Schedule 1 - Reconciliation of Consolidated Net Income Available to Common Shareholders to Net Operating Earnings Available to Common Shareholders (Non-GAAP) *(unaudited)*

	Three Months Ended March 31,	
(In millions, except per share amounts)	**2022**	2021
GAAP Net Income Available to Common Shareholders	**$ 413.0**	$ 28...

We value your privacy
This website uses third-party cookies and tracking tools to enhance user experience, analyze website performance and traffic, and record user interactions. By accepting all cookies, your site usage information may also be shared with advertising and analytics partners. **Learn more (/our-site/cookie-policy)** about our cookie policy. By using our site, you agree to our **Terms of Use (/our-site/terms-of-use)** and **Privacy Notice (/our-site/privacy-statement)**.

Adjustments to Operating Income:		
Operating Revenues:		
Weather - compared to normal	**(3.0)**	9.0
Operating Expenses:		
Greater Lawrence Incident		5.8
NiSource Next initiative[1]	**1.5**	9.7
Massachusetts Business related amounts[2]	**(105.0)**	6.9
Total adjustments to operating income	**(106.5)**	31.4
Income Taxes:		
Tax effect of above items[3]	**22.2**	(8.3)
Total adjustments to net income	**(84.3)**	23.1
Net Operating Earnings Available to Common Shareholders (Non-GAAP)	**$ 328.7**	$ 304.8
Diluted Average Common Shares	**441.4**	393.9
GAAP Diluted Earnings Per Share[4]	**$ 0.94**	$ 0.72
Adjustments to diluted earnings per share	**(0.19)**	0.05
Non-GAAP Diluted Net Operating Earnings Per Share[4]	**$ 0.75**	$ 0.77

[1]Represents incremental severance and third-party consulting costs incurred in connection with the NiSource Next initiative.

[2]2022 represents proceeds from a property insurance settlement related to the Greater Lawrence Incident.2021 primarily represents final net working capital adjustments to the purchase price for the loss incurred on the sale of the Massachusetts Business.

[3]Represents income tax expense calculated using the statutory tax rates by legal entity.

[4]The GAAP and Non-GAAP diluted NOEPS numerator for the three months ended March31, 2022 is equal to net operating earnings available to common shareholders adjusted for $0.5M add-back for interest expense incurred, net of tax, related to the Series A Equity Unit purchase contracts.

We value your privacy
This website uses third-party cookies and tracking tools to enhance user experience, analyze website performance and traffic, and record user interactions. By accepting all cookies, your site usage information may also be shared with advertising and analytics partners. **Learn more (/our-site/cookie-policy)** about our cookie policy. By using our site, you agree to our **Terms of Use (/our-site/terms-of-use)** and **Privacy Notice (/our-site/privacy-statement)**.

CORPORATE HEADQUARTERS
801 E 86th Ave
Merrillville, IN 46410
(https://www.google.com/maps/place/801+E+86th+Ave,+Merrillville,+IN+46410/@41.4614568,-87.3279006,17z/data=!3m1!4b1!4m5!3m4!1s0x8811eeedea44c869:0x17c752f05d34dfd5!8m2!3d41.4614568!4d-

87.3257066)

POPULAR LINKS

NiSource News (https://www.nisource.com/popular-links/nisource-news)

NiSource in the Community (https://www.nisource.com/popular-links/NiSource-in-the-community)

Find a Career at NiSource (https://www.nisource.com/popular-links/find-a-career-at-nisource)

Help (https://www.nisource.com/popular-links/help)

Contact Us (https://www.nisource.com/popular-links/contact-us)

SOCIAL MEDIA

(https://www.facebook.com/NiSource)

(https://twitter.com/NiSourceInc)

(https://www.linkedin.com/company/nisource/)

(https://www.instagram.com/nisourceinc/)

© 2026 NiSource Inc.

Terms of Use **(https://www.nisource.com/terms-of-use)** Privacy Notice **(https://www.nisource.com/privacy-notice)** Accessibility Statement **(https://www.nisource.com/accessibility-statement)**

We value your privacy
This website uses third-party cookies and tracking tools to enhance user experience, analyze website performance and traffic, and record user interactions. By accepting all cookies, your site usage information may also be shared with advertising and analytics partners. **Learn more (/our-site/cookie-policy)** about our cookie policy. By using our site, you agree to our **Terms of Use (/our-site/terms-of-use)** and **Privacy Notice (/our-site/privacy-statement)**.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 74
DOE 202(c) Webpage as of Jan. 22, 2026

An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

DOE's Use of Federal Power Act Emergency Authority

Under Federal Power Act (FPA) section 202(c), during the continuance of a war in which the United States is engaged or when 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, or of the fuel or water for generating facilities, or other causes, the Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c).

All public comments and requests related to FPA section 202(c) should be sent via email to AskCR@hq.doe.gov. Information that the sender deems sensitive and not eligible for public release should be marked accordingly, and both a public (redacted) and non-public version of such materials should be submitted. Additional information about 202(c) procedures, if necessary, will be announced on this page.

The provision of this process for submission of correspondence or comments on any pending application is for purposes of ensuring the receipt by the appropriate office and personnel within the Department. Establishment of this email address does not establish a "docket," and those submitting correspondence do not constitute parties or intervenors to any proceeding. Further, submission of correspondence to the Department does not in any way limit or prevent the ability of the Secretary to act on any application, or pursuant to section 202(c) without application, in any way and at any time as he or she deems appropriate.

202(c) Orders Issued to Date

2025 DOE 202(c) Orders

2024 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2025 to Dec. 31, 2025

Learn More

202(c) orders issued from Jan. 1, 2024 to Dec. 31, 2024

Learn More

2023 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2023 to Dec. 31, 2023

Learn More

2022 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2022 to Dec. 31, 2022

Learn More

2021 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2021 to Dec. 31, 2021

Learn More

2020 DOE 202(c) Orders

202(c) orders issued from Jan. 1, 2020 to Dec. 31, 2020

Learn More

DOE 202(c) Orders Issued Prior to 2020

DOE 202(c) orders issued prior to 2020

Learn More

Numbering Scheme Information

Beginning in 2022, the Department modified the numbering scheme associated with its section 202(c) emergency orders. Prior to 2022, emergency orders followed a fiscal year timeline, whereas since the beginning of 2022, emergency orders have aligned with the calendar year. For example, a 202(c) emergency order issued in November 2017 is identified as Order No. 202-18-1 and an order issued in December 2022 is identified as Order No. 202-22-3.

Privacy Program

Federal Government

USA.gov

The White House

Follow Us

Open Gov Accessibility Privacy Information Quality Web Policies Vulnerability Disclosure Program

Whistleblower Protection Equal Employment Opportunity

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

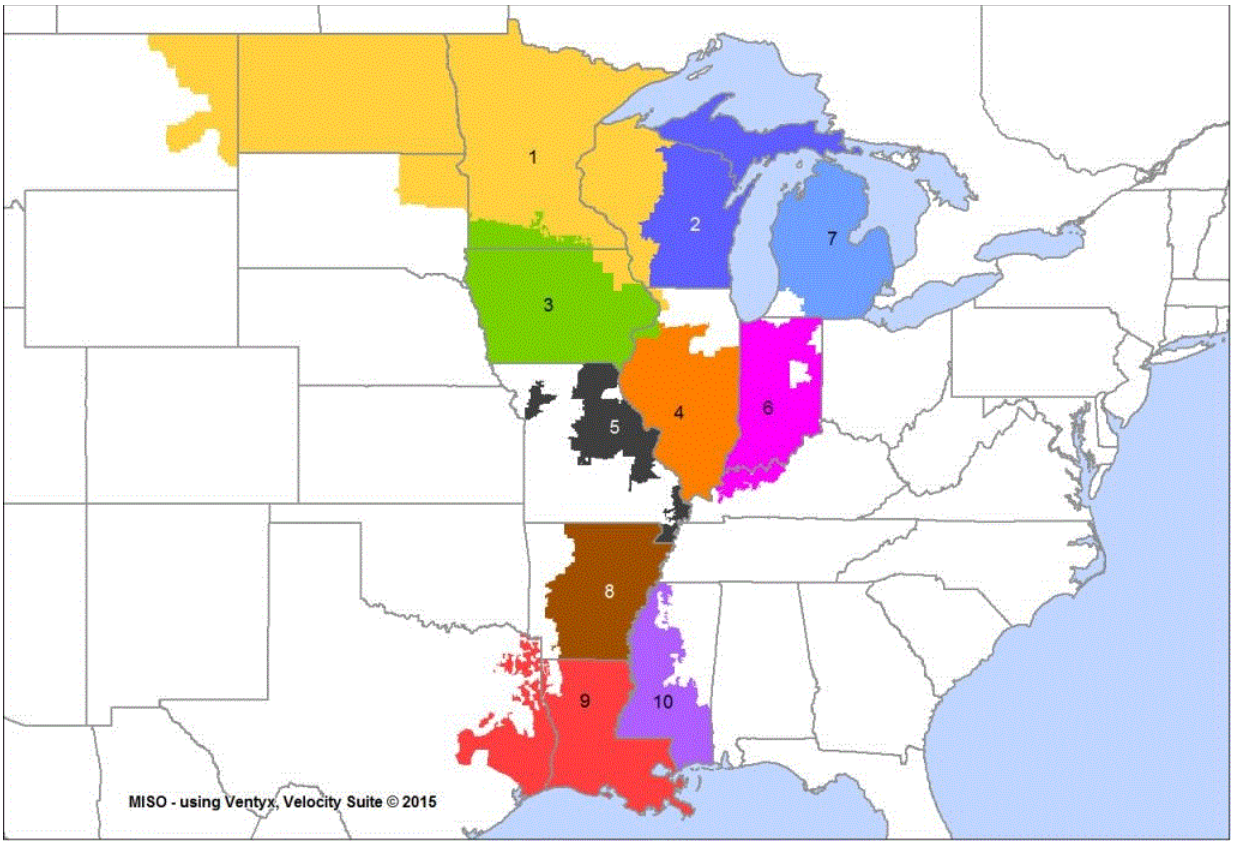
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 75
MISO Tariff Zonal Map

Midcontinent Independent System Operator, Inc.,FERC Electric Tariff

Filing Category:	Normal	Filing Date:	02/28/2020
FERC Docket:	ER20-01119-000	FERC Action:	Accept
FERC Order:	Delegated Letter Order	Order Date:	04/27/2020
Effective Date:	03/01/2020	Status:	Effective

ATTACHMENT VV, MAP of Local Resource Zone Boundaries (39.0.0)



Local Resource Zone	Local Balancing Authority
1	DPC, GRE MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWPLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO

8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EES, SME

Local Balancing Authorities:

ALTE - Alliant East

ALTW - Alliant West

AMIL - Ameren Illinois

AMMO - Ameren Missouri

BREC - Big Rivers Electric Corporation

CIN - Cinergy

CLEC - Central Louisiana Electric Company

CONS - Consumers

CWLD - Columbia Water and Light Department

CWLP - City Water Light and Power

DECO - Detroit Edison

DPC - Dairyland Power Cooperative

EAI - Entergy Arkansas

EES - Entergy Electric System

GLH - GridLiance Heartland, LLC

GRE - Great River Energy

HE - Hoosier Energy

HMPL – City of Henderson, Kentucky (d/b/a Henderson Municipal Power & Light)

IPL - Indianapolis Power and Light

LAFA - Lafayette Utilities

LAGN - Louisiana Generating Company

LEPA - Louisiana Energy and Power Authority

MDU - Montana Dakota Utilities

MEC - MidAmerican Energy Company

MGE - Madison Gas and Electric

MIUP – Michigan Upper Peninsula

MP - Minnesota Power

MPW - Muscatine Power and Water

NIPS - Northern Indiana Public Service Company LLC

NSP - Northern States Power

OTP - Otter Tail Power

SIGE - Southern Indiana Gas and Electric

SIPC - Southern Illinois Power Cooperative

SME - South Mississippi Electric Power Association

SMP - Southern Minnesota Municipal Power Agency

UPPC - Upper Peninsula Power Company

WEC - Wisconsin Electric Power Company

WPS - Wisconsin Public Service Company