Department of Energy
Washington, DC 20585

Order No. 202-25-12

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).[3] Unit 17 and Unit 18 began operations in 1983 and 1986 respectively. Unit 17 and Unit 18 are both slated to cease operations in December 2025.[4]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[5] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[6] MISO noted that over 60% of all

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[5] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[6] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

"MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[7]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[8] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[9]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[10] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[11]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[12]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[13]

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[7] *Id.* at 3-4.

[8] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[9] *Id.* at 11.

[10] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[11] *Id.* at 12.

[12] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[13] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[14] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[15] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[16] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[17]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[18] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[19]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[20] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[21] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[22] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

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[14] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[15] *Id.* at 2.

[16] *Id.* at 7.

[17] *Id.* at 9.

[18] *Id.* at 7, 9.

[19] *Id*.

[20] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[21] *Id.* P 84.

[22] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[23] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[24] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[25]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[26]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[27] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to

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[23] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.
[24] *Id*.
[25] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[26] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025 07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[27] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

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

A. From December 23, 2025, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of the Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 has operated in compliance with the allowances contained in this Order.

C. All operation of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

THE VALUE OF ECONOMIC DISPATCH

A REPORT TO CONGRESS
PURSUANT TO SECTION 1234
OF THE
ENERGY POLICY ACT OF 2005

Prepared by
United States Department of Energy

November 7, 2005

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LIST OF ACRONYMS

AGC	automatic generation control
ATC	available transmission capability
Btu	British Thermal Unit
CAISO	California Independent System Operator
Department	United States Department of Energy
EPAct	Energy Policy Act of 2005
EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FTR	financial transmission right
IPP	independent power producer
ISO	independent system operator
ISO-NE	New England Independent System Operator
kWh	kilowatt-hour
LMP	locational marginal price
MCP	market-clearing price
MISO	Midwest Independent System Operator
MW	megawatt(s)
MWh	megawatt-hour
NERC	North American Electric Reliability Council
NUG	non-utility generator
NYISO	New York independent system operator
PJM	PJM Interconnection
OOM	out of merit order
QF	qualifying facility
QSE	qualifying scheduling entity
RMR	reliability must run
RTO	Regional Transmission Organization
SCED	security-constrained economic dispatch
SCUC	security-constrained unit commitment
SPP	Southwest Power Pool
TTC	total transmission capability
U.S.	United States
WECC	Western Electricity Coordinating Council

SECTION 1

INTRODUCTION AND SUMMARY

Section 1234[1] of the Energy Policy Act of 2005 (EPAct) directs the U.S. Department of Energy (the Department) to:

1) study the procedures currently used by electric utilities to perform economic dispatch;

2) identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch; and

3) analyze the potential benefits to state and national residential, commercial, and industrial electricity consumers of revising economic dispatch procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

EPAct defines "economic dispatch" to mean "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities" [EPAct 2005, Sec.1234 (b)].

EPAct requires the Secretary of Energy to submit a report on economic dispatch to Congress and the states no later than 90 days following enactment of the act and annually thereafter. The study is to include any recommendations that the Secretary chooses to make to Congress and the states concerning legislative or regulatory changes related to economic dispatch [EPAct 2005 at Sec. 1234 (c)]. This report fulfills that statutory requirement. As explained below, the remaining sections of this document present information gathered for this report through a survey of stakeholders and a literature review, including how economic dispatch is practiced in the U.S., its benefits, practices and rules that are identified as obstacles to optimal participation of non-utility generators (NUGs) in economic dispatch, and suggestions for modifications and future research on economic dispatch.

Industry Changes

Electric utility investment practices and operation have been designed to ensure affordable, reliable electricity service to consumers. Affordability and reliability require thoughtful, long-term investments in generation and transmission as well as sophisticated operation of these assets. Economic dispatch focuses on short-term operational

[1] Section 1832 of EPAct, in identical language, also directs the Department to study the benefits of economic dispatch. This report responds to both sections.

decisions, specifically how to best use available resources to meet customers' electricity needs reliably and at lowest cost.

Ensuring the best use of available resources is much more than a mechanical process of minimizing the total variable cost of electricity production. In seeking lowest-cost production, economic dispatch practices must take into account several factors, including: the continuous variation in loads and generators' inability to respond instantaneously; the need to maintain reserves and plan for contingencies in order to maintain reliability; and the scheduling requirements imposed by environmental laws, hydrological conditions, and fuel limitations.

The nature of utilities has changed as some areas of the country have structurally unbundled and reorganized aspects of their generation and transmission systems. Utility generators have been supplemented by NUGs, built without a guaranteed franchise of customers to buy their output. In 2003, NUGs (including generation that was once utility owned but sold to independent power producers as well as generation owned by unregulated utility affiliates) accounted for 38 percent of total U.S. generation capacity and 27% of actual electricity production (Energy Information Administration, December 2004).

Oversight of utilities' performance in achieving affordable and reliable electricity has been a primary responsibility of state and federal regulatory agencies as well as local authorities and boards, depending on the form of ownership and organization of each utility. Thus, regulatory and ownership policies have an important effect on how economic dispatch is practiced by each utility or other dispatching entity. These policies affect whether the utilities that manage transmission systems own generation, the degree to which utility-owned generation competes with non-utility generation, and whether regional transmission organizations and independent system operators have been developed to manage the transmission system and generation dispatch across a wide geographic area.

Study Method and Overview

For this study, the Department used a survey to solicit state and stakeholder input about economic dispatch. The survey was distributed to stakeholders in late August 2005 with the assistance of seven associations: the American Public Power Association, the Edison Electric Institute, the Electric Power Supply Association, the Electric Consumers Resource Council, the National Rural Electric Cooperatives Association, the North American Electric Reliability Council, and the National Association of Regulatory Utility Commissioners. Appendix A contains the survey questions and the letters sent to these seven organizations. The Department appreciates the cooperation and assistance of these groups in completing this study.

The Department asked for survey responses to be submitted by e-mail by September 21, 2005. Ninety-two responses were submitted, from every sector of the industry and stakeholder community. The respondents and other study participants are listed in

Appendix B, and the detailed responses are posted on the DOE website at **http://www.electricity.doe.gov**. Information quoted in this report is identified as coming from survey respondents or participants. The survey responses greatly aided preparation of this study, and the Department is grateful to the organizations and individuals who took the time to share their views on economic dispatch.

Economic dispatch is a straightforward concept: costs to serve a given level of electricity demand are minimized by dispatching lower-cost generation before dispatching higher-cost generation. A number of considerations must be addressed to ensure that the resulting system operation is secure and reliable as well as lowest cost. **Section 2** explains how economic dispatch is practiced across the U.S., as reported by the survey respondents, and reviews security-constrained economic dispatch (SCED) and security-constrained unit commitment (SCUC). Section 2 also addresses factors that constrain and complicate economic dispatch.

The EPAct directs the Department to study the benefits of economic dispatch for electricity consumers and NUGs. Given the short time available for this study, it was not possible to conduct a new quantitative analysis, so this report reviews studies of economic dispatch performed to date. Most of these studies fall into two categories – those that simulate economic dispatch over a broad region to study the impact and cost-effectiveness of a new Regional Transmission Organization (RTO), and those that look at a defined geographic region and estimate the impact of substituting non-utility generation for less efficient utility-owned production. **Section 3** summarizes the findings regarding the benefits and impacts of economic dispatch in the studies reviewed for this report.

EPAct directs the Department to identify possible revisions to economic dispatch procedures that would improve the ability of NUGs to offer their output for sale under economic dispatch. This study concludes that because economic dispatch (or its more specific forms, SCED and SCUC) is a relatively mechanical optimization exercise, the real issue is not whether economic dispatch procedures are faulty, but rather what rules and practices might be preventing non-utility generation from participating appropriately in the economic dispatch process. **Section 4** reviews practices and rules that have been cited as obstacles to optimal participation of these entities in economic dispatch.

Section 5 lists suggestions for modifying economic dispatch as well as suggestions about how the Department might frame its future work in this area.

Summary of Findings

The Benefits of Economic Dispatch

Economic dispatch benefits electricity users in a number of ways. By systematically seeking the lowest cost of energy production consistent with electricity demand, economic dispatch reduces total electricity costs. To minimize costs, economic dispatch typically increases the use of the more efficient generation units, which can lead to better fuel utilization, lower fuel usage, and reduced air emissions than would result from using less-efficient generation. As the geographic and electrical scope integrated under unified economic dispatch increases, additional cost savings result from pooled operating reserves, which allow an area to meet loads reliably using less total generation capacity than would be needed otherwise. Economic dispatch requires operators to pay close attention to system conditions and to maintain secure grid operation, thus increasing operational reliability without increasing costs. Economic dispatch methods are also flexible enough to incorporate policy goals such as promoting fuel diversity or respecting demand as well as supply resources. Over the long term, economic dispatch can encourage new investment in generation as well as in transmission expansion and upgrades that enhance both reliability and cost savings.

In principle, all generation and transmission dispatchers practice economic dispatch to reduce the cost of serving loads. Economic dispatch reduces total variable production costs by serving load using lower-variable-cost generation before using higher-variable-cost generation (i.e., by dispatching generation in "merit order" from lowest to highest variable cost). Retail customers will benefit if the savings are passed through in retail rates. Economic dispatch can reduce fuel use when it results in greater use of lower variable cost, higher-efficiency generation units than of lower-efficiency units consuming the same fuel.

Understanding Economic Dispatch

Economic dispatch principles and operation are the same in both regulated utility operations and centralized wholesale markets. In centralized markets, the merit order of available resources is determined using offer schedules for each resource rather than the variable production costs that are used to dispatch a set of utility-owned resources.

Many factors influence economic dispatch in practice. These include contractual, regulatory, environmental, scheduling, unit commitment, and reliability practices and procedures. Because economic dispatch requires a balance among economic efficiency, reliability, and other factors, it is best thought of as a constrained cost-minimization process.

It is useful to divide economic dispatch practices in two separate stages: unit commitment and unit dispatch. Unit commitment takes place before real-time operation and determines the set of generating units that will be available for dispatch. Unit dispatch occurs in real time and determines the amount of generation needed from each available unit. Most utilities, regional transmission operators (RTOs), and independent system operators (ISOs) that perform economic dispatch modify least-cost dispatch to account for grid conditions and operational reliability needs; this is called security-constrained economic dispatch (SCED). In real time, many of the adjustments to least-cost dispatch are to prepare for or respond to contingencies that affect grid reliability.

State and federal regulation affects economic dispatch either explicitly through formal rules or implicitly through prudence reviews aimed at ensuring that dispatch minimizes the cost of serving load. State public utilities commissions have principal responsibility for oversight of economic dispatch by investor-owned utilities. The Federal Energy Regulatory Commission (FERC) has primary responsibility for oversight of economic dispatch by ISOs and RTOs. Oversight of economic dispatch by public power and cooperatives is the responsibility of their respective governing boards.

<u>Economic Dispatch Studies</u>

After reviewing recently published studies and responses to the survey, the Department finds that:

1) Studies evaluating the potential for benefits from changes to current economic dispatch practices can be grouped into two categories: studies of the impact of FERC policies encouraging formation of Regional Transmission Organizations ("RTO studies") and studies of the dispatch of IPPs ("IPP studies"). These two types of studies were not designed to present comprehensive information on economic dispatch benefits disaggregated by geographic region and customer class, as envisioned by Section 1234.

2) RTO studies compare centralized dispatch of a large portfolio of generating units (both utility owned and non-utility owned) aggregated over multiple control areas to the current practice of simultaneous, independent dispatch of subsets of this portfolio by individual control areas. RTO studies have found economic dispatch benefits ranging from $80 million to over $40 billion, depending on the region and length of time studied. Normalized, these benefits range from one to five percent of total wholesale electricity costs.

3) IPP studies compare dispatch of a combined fleet of new (typically non-utility owned) and existing (typically primarily utility-owned) generating units within a single control area to the current practice of dispatching existing generating units. IPP studies have found economic dispatch benefits ranging from $30 million to over $900 million, depending on the region and length of time studied. Normalized, these benefits range from eight to more than thirty percent of total variable production cost.

4) Both RTO and IPP studies rely, for the most part, on production cost simulation methods, which seek to replicate least-cost dispatch of a specified fleet of generation. However, modeling practices vary, and the modeling methods are sometimes limited in their ability to evaluate all aspects of actual dispatch procedures.

5) Several important dispatch procedures and practices will require more detailed treatment if they are to be studied adequately using production cost simulation methods.

Economic Dispatch Problems

NUG complaints about economic dispatch revolve around allegations that vertically integrated utilities use their dispatch processes to favor utility-owned generation over non-utility-owned generation. However, because economic dispatch is a relatively mechanical process, it appears that many of the concerns that NUGS see as ineffective economic dispatch are more accurately viewed as rules and practices that exclude NUGs (and other resources) from the economic dispatch stack. These practices include determinations of whether NUGs receive long-term contracts to sell their production to load-serving entities, whether they can secure sufficient transmission capacity to deliver their production to host utility loads or more distant purchasers, and whether NUGs provide sufficient operational flexibility to provide maximum operational value to the grid.

Potential Modifications to Economic Dispatch

There is room to improve economic dispatch practices to reduce the total cost of electricity and increase grid reliability. The FERC-State Joint Boards on Economic Dispatch (created pursuant to Sec. 1298 of EPAct) may wish to study these, starting with a more detailed examination of economic dispatch practices and administration than was possible in this limited study. Similarly, FERC may choose to address some of the obstacles that keep NUGs out of the dispatch stack in the context of its plan to review Order 888. In addition, DOE urges the NUG and power purchaser communities to work together to clarify and revise contract and operational considerations so that contract terms recognize and compensate NUGs for providing greater operational flexibility. The quality and accuracy of economic dispatch tools and load forecasting need further improvement. Last, further quantitative analysis and modeling of the benefits of economic dispatch should address a number of important details and considerations.

"Economic" Dispatch vs. "Efficient" Dispatch

In recent weeks there has been intense interest in the Congress in whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch" is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will usually run higher efficiency gas-fired units before lower efficiency units, that is not always the result, for a number of possible reasons. (See pp.13-20 below for more detail.) "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.

Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons. First, the fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers' electricity costs – for benefits that may not be large enough to offset these additional costs. Second, economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort. Third, a better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.

SECTION 2

ECONOMIC DISPATCH

For much of the past century, vertically integrated utilities conducted economic dispatch within their individual control areas, meaning that each utility coordinated the operation of its own generators to deliver electricity efficiently across its own transmission lines to serve its own customers. The utility's dispatchers knew the capabilities and costs of the firm's resources and the strengths and weaknesses of its transmission system. Sometimes they purchased energy from outside the firm's own system and deliberately shipped ("wheeled") electricity across other utilities' transmission lines.

Those practices began to change several decades ago with the growth in inter-regional bulk energy sales (as with hydropower sales from Quebec into New York and seasonal exchanges between California and the Pacific Northwest) and the proliferation of "qualifying facilities" (QFs) under the Public Utilities Regulatory Policy Act of 1978. QFs' energy production had to be integrated in real time with a utility's own power production and transmission flows. It also became apparent that significant economies could be achieved if several utilities within a region operated their plants in a single power pool for integrated dispatch; pooling took place primarily in the northeastern U.S. with the formation of the Pennsylvania-New Jersey-Maryland, New England, and New York power pools. Because each of these areas had a highly networked transmission system, the member utilities could reduce the both energy and capacity costs for their customers through pooled dispatch and reserve-sharing.

What is Economic Dispatch?

"Economic dispatch" has a common, general meaning – the practice of operating a coordinated system so that the lowest-cost generators are used as much as possible to meet demand, with more expensive generators brought into production as loads increase (and conversely, more expensive generation eliminated from production as load falls). Most people agree with EPAct's definition of economic dispatch – "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities" – but the details of how this definition is put into practice can vary significantly.

Electricity loads vary over time, rising and falling in daily and weekly patterns. Because electricity travels at the speed of light and cannot be stored inexpensively, generation must be available that can follow changes in load almost instantaneously. However, generators vary widely in their costs and capabilities; fossil-fired units with low marginal costs tend to be relatively inflexible, and generators that can follow load tend to be more expensive. Generators are also subject to fuel limitations and environmental regulations that restrict their availability. Finally, reliability considerations demand that excess generation be available in reserve, along with transmission capacity, to respond to sudden, unplanned contingencies.

These characteristics of the power system lead to a natural sequencing in system operations -- first, determine which units should be turned on and made available to serve loads (called unit commitment), and, second, determine how much production to call from each resource (economic dispatch). To better define the terms:

- Economic dispatch is the economic optimization process that determines a combination of generators and levels of electricity output to meet demand[2] at the lowest cost, given the operational constraints of the generation fleet and the transmission system.

- Security-constrained[3] economic dispatch (SCED) is an economic optimization process that searches for the set of resources and production levels available at a specific point in real time that minimizes the cost of electricity production, subject to a variety of operational constraints to assure reliable grid operations. Adequate reliability practices comply with the reliability practices and standards of NERC, or those that will be adopted by FERC under the recently enacted EPAct. Organizations that practice SCED check system conditions and re-optimize dispatch instructions frequently (usually every five minutes). Economic dispatch uses the resources available on the system for the time frame under analysis.

- Security-constrained unit commitment (SCUC) searches for a least-cost reliability solution by identifying the appropriate mix of units (capacity) to meet projected loads. SCUC is an optimization process that is typically run one day ahead of actual dispatch. This process looks at expected demands, resource availability, and system conditions and finds the combination of resources that should be committed to operate the next day to produce the least-cost mix of energy and reserves subject to expected operational considerations (such as start-up costs and times, minimum run levels, and ramp rates) and grid constraints. Entities that practice SCUC perform the analysis one or more times during the day preceding the dispatch day and issue commitment orders around 5 or 6 p.m. for the units needed the next day. Dispatchers who perform SCUC then conduct SCED for daily operations, but not every dispatching entity that performs SCED first conducts SCUC.

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[2] The electricity industry refers to the system's ability to meet peak load as system "adequacy."

[3] The electricity industry uses "security" to mean the ability of the transmission system to withstand changes or contingencies on a daily and hourly basis. NERC rules followed by all industry members require that each grid manager operate its system at all times so that it can withstand the loss of the specific grid facility that would cause most harm to system conditions (called the "N-1 contingency") and be able to restore stability and be prepared for the loss of the next-worst contingency within 30 minutes.

As indicated above, economic dispatch works to manage resources across time. Different resources have differing production capabilities and characteristics. A generator's production level this afternoon will be affected by its on-line status and production levels this morning and yesterday (e.g., a baseload coal plant or a hydroelectric pumped storage plant) as well as whether maintenance was performed on it last quarter or last year (e.g., nuclear refueling or a load-following plant that undergoes maintenance in non-peak months). This means that although the primary focus of economic dispatch is daily and minute-to-minute operations, the process must look beyond a single day to optimize the operation and cost of resources across a season.

Economic Dispatch vs. Efficient Dispatch

In a recent hearing of the Senate Energy and Natural Resources Committee*, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will *usually* run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. (See pp. 13-20 below for more detail.) "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.

Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

- The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers electricity costs – for benefits that may not be large enough to offset these additional costs.
- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.
- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.

*Senate Committee on Energy and Natural Resources, Full Committee Hearing – Hurricane Recovery Efforts, October 27, 2005

Security-Constrained Unit Commitment

All North American electricity industry dispatchers use economic dispatch; many use SCED; and many also use some form of SCUC in addition to SCED. This study uses the term "economic dispatch" broadly, as in the statutory definition, to mean the generic task of least-cost optimization subject to operational constraints; the more specific terms SCED and SCUC are used in discussing certain applications and implications of economic dispatch.

SCED coordinates the production levels of available resources to meet loads in a grid-secure fashion in real time, and SCUC increases the likelihood that the most cost-effective and reliability-supportive resources will be available to be dispatched. However, not every organization that performs SCED performs SCUC in advance.

Shahidehpour, Yamin and Li (2002) describe the process:

> Three elements are included in the SCUC paradigm: supplying load, maximizing security, and minimizing cost. Satisfying the load is a hard constraint and an obligation for SCUC. Maximizing security is often satisfied by maintaining sufficient spinning reserve at less congested regions that could easily be accessed by loads. Cost minimization is realized by committing less expensive units while satisfying the corresponding constraints and dispatching the committed units economically.

To operate the grid reliably in real time, it is necessary to have capacity in excess of the day's anticipated demand. This capacity must be fully synchronized to the system, unloaded, and able to respond immediately to dispatch instructions and be fully available within 10 minutes to serve load. Some of this capacity must be available in specific locations to address anticipated voltage, thermal, or stability need or to serve load on the short side of a transmission bottleneck. Some can be baseload or block-loaded (i.e., scheduled at a fixed output level for one or more hours), but some must be load-following units able to respond to automated dispatch instructions in real time (called Automatic Generation Control (AGC)) in order to match moment-to-moment changes in load.

SCUC is the exercise of conducting a modified form of economic dispatch for grid, load, and resource conditions in the very near future, to assure that the appropriate resources will be operational when they are needed for economic dispatch. Where it is practiced, SCUC produces energy, regulation, and reserve schedules for generators and loads for each of the 24 hours in a dispatch day. Where SCUC is coordinated by a market and system operator such as the New York ISO (NYISO), New England ISO (ISO-NE), or PJM Interconnection (PJM), SCUC also calculates day-ahead prices for energy and ancillary services for each generation location; those prices reinforce the ISO/RTO's unit commitment orders by providing a binding financial incentive for the generator to operate reliably.

Generators that are not committed under SCUC can either sell their output elsewhere under short-term contracts or can remain off line on the dispatch day. As American Transmission Company points out, if the unit commitment process results in insufficient resources to meet the dispatch day's actual load, the universe of resources available for SCED could come up short, exacerbating reliability challenges or raising total production costs for the dispatch day.[4]

Grid Conditions that Constrain Economic Dispatch

Security constraints limit economic dispatch options because grid operational conditions affect which combinations of resources will be able to meet loads and maintain the grid in a secure state. Grid reliability rules require that system operations respect voltage, thermal, and stability limits for individual grid assets (such as transmission lines and generators). To preserve secure operations, operators must always work with a combination of assets and loading that allows the system to lose its most security-valuable asset (called the "N-1 contingency") and be restored to a secure condition within 30 minutes. Security constraints determine which flows from which generators will support or compromise reliable grid operations.

Factors that affect and dictate grid security constraints include:

- Generation and transmission facility conditions and availability (e.g., whether a unit or line is out of service for maintenance or must operate under reduced limits);

- Line capacities under different power flows and loadings;

- Ambient weather, particularly temperature and wind speeds, which affect a line's thermal performance;

- The availability and capabilities of other grid facilities, including circuit breakers, series or shunt reactive devices, transformers, and other equipment and protection schemes to buffer and manage line loadings and voltages.

Further, load forecasts affect the level of resources and the unit-specific production levels assumed to be required to reliably serve the forecasted load. The accuracy of the load forecasts affects the calculations of how large a reserve margin is needed to maintain short-term grid reliability for day-of and day-ahead purposes.

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[4] The citation above refers to American Transmission Company's response to the Department's August 2005 survey on economic dispatch. All subsequent comments or quotations are drawn from the indicated respondent's survey comments unless otherwise noted. Appendix B lists the survey respondents, and the full text of the survey responses are posted on a Department website at **http://www.electricity.doe.gov**.

Resource Considerations Affecting Economic Dispatch

A variety of physical, environmental, and regulatory considerations affect how resources can be used and combined in the economic dispatch process, and a combination of attributes determines how each generation resource is identified and treated in the process. Depending on the dispatch regime, those factors may include:

- Real and reactive energy-production capacity;
- Whether a unit is on a cost-based, reliability-must-run (RMR) contract or its production cost curve is based on fuel costs and efficiency rates (or, in centralized wholesale markets, bids for production at differing levels on its output curve);
- Variable operations and maintenance costs;
- Start-up costs;
- A unit's mechanical or economical upper and lower production levels;
- Unit ramp rates within the range of production levels (e.g., the time it takes to move from one production level to another while respecting the turbine's safe thermal gradients);
- Minimum sustained production levels (to keep the unit available for the next hour or next day);
- Emissions limits and costs of emission allowances (because units that use up their emissions allowances prematurely may not be available to operate during peak periods);
- A unit's availability on the date and time in question (which might be affected by factors such as inclement weather, prior performance problems, or fuel availability);
- For a hydro, wind, or other intermittent units, a forecast of expected unit production levels at different points in the dispatch period;
- Contracts or other requirements that assign a unit must-run or must-take status so that is not fully dispatchable;
- A unit's prior commitments to make off-system sales; and
- A unit's ability and contractual requirement to deliver ancillary services, such as reactive power or quick-start capability.

Some of these factors, such as minimum production levels, will dictate whether a unit will be in the base level or the competitive region of the economic dispatch stack.

A number of respondents to the Department's survey pointed out that requirements of state public utility commissions and environmental regulations affect utility resource procurement and dispatch, and that these state- or utility-specific operating requirements must be taken into account in an individual utility's dispatch practices. Technically speaking, these requirements are treated as "constraints" in the cost-minimization procedures used by the utilities for economic dispatch. These concerns can be reflected in the dispatch process, whether as formal limitations on the selection of resources or as qualifiers on the utilization of specific resources:

- The financial condition or credit quality of the generator, on the principle that if the generator is not financially sound it should not be viewed as a reliable source to meet the utility's obligation to serve retail customers;

- State or corporate requirements for renewable production, use of in-state coal-fired generation, or fuel diversity;

- Whether the generator has both a firm fuel supply and firm fuel transportation, so it can perform reliably when dispatched;

- Whether the unit's fuel source has take-or-pay provisions that would make it more expensive to idle than to run;

- Whether the dispatching entity or its regulators explicitly attempt to minimize environmental impacts such as air emissions from generation;

- Whether the area needs to maximize its efficiency of natural gas use because of high natural gas prices or limited deliverability.

Security-Constrained Economic Dispatch

SCUC sets up the collection of resources that will be needed to operate the grid reliably in real time. Once SCUC establishes the mix of resources available for dispatch in real time, SCED is the iterative process in which the available units are dispatched to ensure both reliability and cost minimization. The SCED process first looks for the least-cost, merit order dispatch solution. Next, all significant, credible contingencies are considered, such as the unplanned loss of a generating or transmission facility. Usually, the contingencies are considered individually, one at a time; in some cases, double contingencies are considered. If a contingency would result in a violation of a thermal, voltage, or stability limit, the system is redispatched using the next-best available generation pattern and restudied to ensure that the contingency would not lead to a violation. Redispatch to assure system reliability typically causes some units to be dispatched out of merit order (OOM).

In regions managed by ISOs and RTOs and where transmission bottlenecks limit the amount of low-cost energy that can flow through to load, the dispatcher will redispatch out-of-merit (more expensive) energy from a local source to manage around the congestion. In these cases, the cost of redispatch (which is revealed through differences among locational marginal prices (LMPs)) can be mitigated by allocation of congestion hedging rights. Redispatch to manage around transmission bottlenecks and congestion also takes place outside ISO/RTO markets, but when it happens within integrated utilities, the costs are absorbed and allocated to all customers without explicit accounting.

Current Practices in Building the Economic Dispatch Resource Stack

In economic dispatch theory, every resource has a schedule of production levels and costs that reflects its start-up time, ramp rates, and the like. All available units for a specific point in time are "stacked" in order from lowest to highest cost per megawatt hour (MWh), and the least expensive units are dispatched in increasing cost order until customer demands (plus line losses and operating reserves) have been met. The dispatch process is repeated over and over. When resources are dispatched from least to most expensive, this is termed "merit order dispatch."

In practice, it is far more complicated to build the economic dispatch resource stack. For a variety of reasons, some of which are explained below, a number of resources are not required to compete for a slot in the dispatch order on the basis of cost alone but are "forced" into the stack at certain places and become part of the set of constraints that limit the dispatch opportunities for the remaining resources. The elements of the economic dispatch stack are illustrated in Figure 1.

<u>Minimum-Run Production</u>

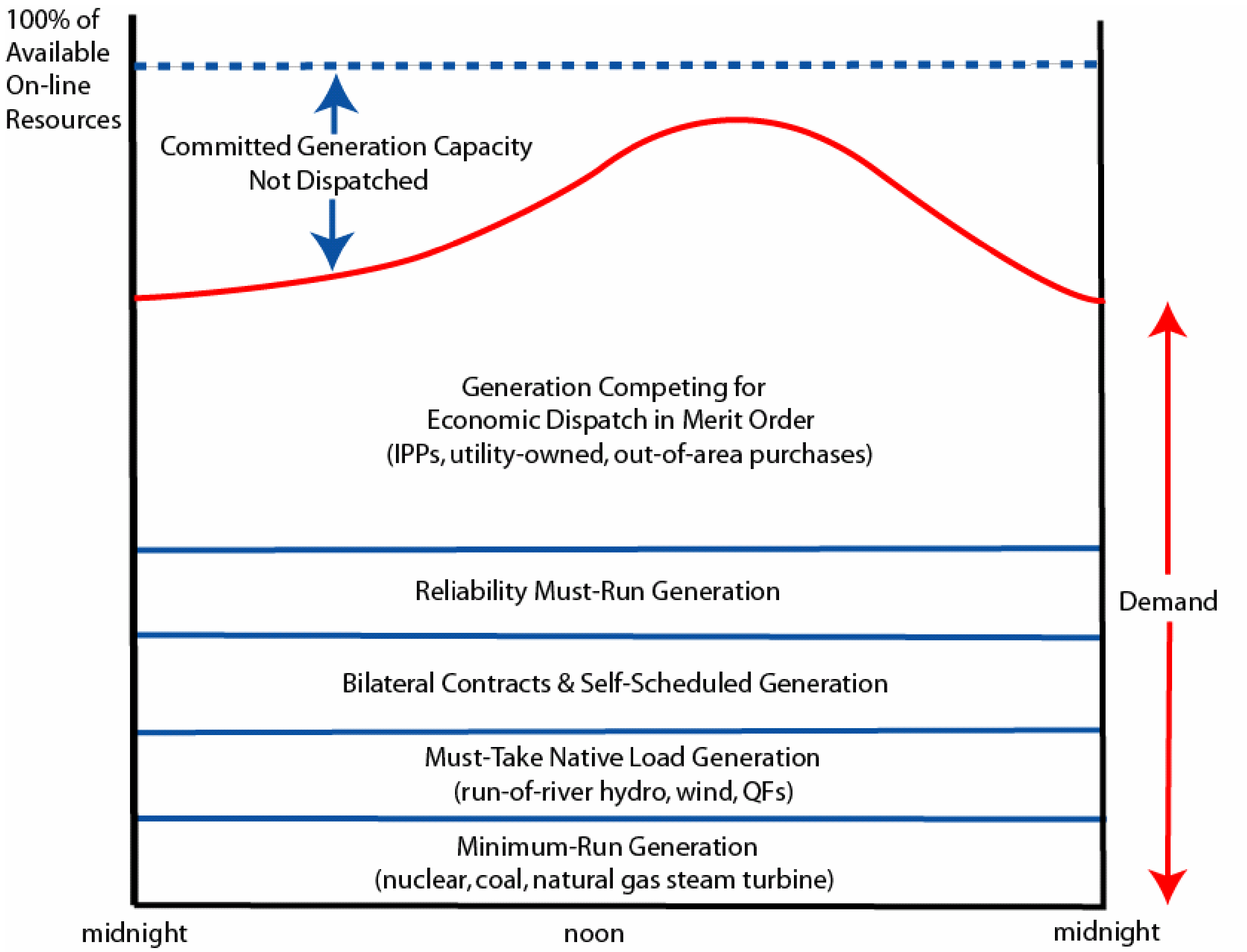
Large baseload units, such as coal, nuclear, and gas combustion, typically have low per-MWh marginal operating costs but require a lengthy start-up period during which their production is not very fuel-efficient. To have such units available to meet baseload demand or as load-followers, dispatchers frequently operate them at or above their minimum-run levels (i.e., above the point where production becomes efficient). These minimum-run levels are forced into the dispatch stack regardless of the units' production costs within the minimum-run range; their production above the minimum-run levels competes for merit-order dispatch.

<u>Self-Scheduled Generation and Bilateral Contracts</u>

Within an area that is under economic dispatch, load-serving entities and generators always have the option of securing energy supplies or sales through self-generation or bilateral contracts, subject to grid reliability. Within any dispatch area, production that is pre-committed and not available for dispatch must be carefully coordinated with and integrated into the dispatch algorithm because the flows from those resources affect transmission flows and grid conditions and thereby constrain the dispatch options.

Figure 1

Building the Economic Dispatch Stack



Economic dispatch accommodates self-dispatch (when a utility commits its owned generators exclusively to serve a portion of its native load) and bilateral contracts by fixing the volumes committed from specified plants into the non-discretionary portion of the stack.

Within the economic dispatch stack, self-dispatch and bilaterals are block-loaded and scheduled at the production levels and times nominated, rather than scheduled based on economic optimization. In market dispatch, they are not recognized as having an operational cost that must be integrated into the optimization but are treated as price takers; in reality, regardless of the market-clearing price, those transactions are settled outside the market at the predetermined price set in the contract between the buyer and seller. Only amounts actually purchased from the market are priced at the market-clearing price.

NUG contracts that are negotiated as non-dispatchable are treated as bilaterals or must-run production. The Electric Power Supply Association (EPSA) observes that some utilities are reluctant to enter into forward bilateral contracts with independent power producers (IPPs), so they first exhaust all utility-owned generation options before turning to NUGs for spot-market (daily or hourly) purchases. Mid-American indicates that "it is typically the terms and conditions of the NUG power purchase agreements, other than price, that determine how NUG is dispatched."

Economic dispatch treatment of bilateral contracts must recognize the nature of the underlying transmission and energy product being offered because that affects performance certainty. Under the Western Systems Power Pool agreement, three types of products are traded in the Western Interconnection:

- Schedule A is Economy Energy service, which can be interrupted anytime with notice;
- Schedule B is Unit Commitment Service, which is linked to the performance of a specific generating unit;
- Schedule C is firm sales or exchanges.

Calpine notes that economic dispatch does not limit load-serving entities' procurement decisions because most procurement and contracting decisions take place within a long-term state or regional planning and procurement process while economic dispatch focuses on how to manage procured resources in real time for maximum value. Economic dispatch does not change the utility's responsibility to determine an appropriate, balanced portfolio of self-generation and long-term and spot-market purchases, nor does it change the state commission's jurisdiction over regulated utility energy procurement.

<u>Reliability Must-Run (RMR) Production</u>

Some units are recognized as critical for maintaining grid security, to ensure that their production is available to protect against potential N-1 voltage, thermal, or stability problems. However, these units may not be economically competitive compared with other generation and so would not be dispatched under a pure least-cost optimization scheme. These units are included within the dispatch stack as price-takers to be sure that their production is scheduled as needed to meet reliability needs, and they are paid as a function of their costs rather than at the market-clearing price. Such units are often referred to as "reliability must-run," and their schedules are OOM. When RMR resources are dispatched in a centralized market, their actual operational costs often exceed the market-clearing price.

Intermittent, Must-Take Resources

Wind, run-of-river hydro, and QFs are the predominant types of intermittent and must-take resources. Their output levels cannot be controlled by the dispatcher, and there are contractual, regulatory, or cost factors that require these resources to be accepted in full whenever they are available. Forecast schedules for these resources are placed into the dispatch stack and modified in real time to reflect actual production; load-following resources are dispatched to compensate for the relative availability or absence of intermittent, must-take resources.

What's Left for Economic Merit Order Dispatch?

Whether in a stand-alone utility dispatch or a centralized energy market dispatch, the amount of generation that is forced into the stack varies widely. For example, within the PJM area, between 30 and 50 percent of the resources in the dispatch stack can be must-run and baseload units and treated as price-takers; the remainder are under bilateral contracts or are dispatchable resources that receive the market-clearing price.

Within the Electric Reliability Council of Texas (ERCOT), bilateral contracts account for a wide majority of the energy consumed. Qualifying Scheduling Entities (QSEs) participate in the ERCOT market, performing economic dispatch for their own portfolios of resources and loads. They submit the resulting schedules – a combination of fixed resources and competitive resource bid schedules – to ERCOT for coordination and operation of the balancing energy market. After the QSEs' contractual obligations and the OOM units, perhaps only 10 percent of energy in the ERCOT market is actually in the portion of the stack that is optimized competitively by cost and priced at the market-clearing price.[5]

In the Pacific Northwest, the bulk electricity system relies to a large extent on hydroelectric generation, which has major implications for economic dispatch. The Washington Utilities and Transportation Commission explains that hydropower resource management must take into account the region's flood control, fish management, irrigation, recreation, and transportation needs as well as electricity requirements. Hydro

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[5] Both LG&E Energy and APPA comment that the organized markets operated by RTOs and ISOs with bid-based SCED use a single-clearing price convention under which "all generators bidding into the market for a particular time interval are paid the price necessary to clear the market in that time interval, even if the bid a chosen generator made was much lower than that clearing price." In practice, the amount of energy receiving the market-clearing price depends on the market, but may range from only five percent (as in the CAISO and ERCOT markets) to 70 percent of the energy consumed (as in PJM). APPA suggests that this practice has significantly raised costs to ratepayers compared to the prior system of cost-based dispatch, with baseload coal and nuclear plants receiving high market-clearing prices set by marginal gas units. This is an issue of market design rather than an issue of economic dispatch *per se* and will not be discussed further in this study.

managers across the region work to optimize streamflows on an annual basis under the Pacific Northwest Coordination agreement, and coordinate daily and hourly hydro facility management of the integrated, interdependent river system under the Mid-Columbia Hourly Coordination Agreement. Although hydropower is one of the lowest-cost resources available, most hydro is used to follow load (thus displacing more costly thermal generation) rather than as a baseload resource.

The Cowlitz, Grant, and Pend Oreille Public Utility Districts explain that:

> Utilities that are largely dependent on hydropower are constantly rebalancing their portfolios to make best economic use of their 'discretionary water': hydro energy that can either be stored for later use or sold into the market now…. Economic dispatch of hydroelectric generation must also take into account the forward opportunity cost of production: what potential future revenues are being foregone if scarce (energy-constrained) fuel is used today to generate power? Owners … maximize the value of their scarce [hydro] fuel in response to market price signals, for example by purchasing power during off-peak periods, holding water in reserve, and generating with hydropower during peak periods. This contributes to the overall value of economic dispatch because a scarce fuel is being used in its highest value period.

Dispatchability – the ability to follow load closely – is an important attribute for resources in the dispatch stack. The Ohio Public Utility Commission observes that "market dispatch focuses on marginal units, which are typically peaking units whose operating characteristics are different from baseload coal-fired units. The real-time five minute economic dispatch used by PJM and MISO to meet reliability requirements does not favor baseload generation but focuses attention on units with quick response times." Xcel comments that "[m]ore non-utility generation would be dispatched if there were requirements for IPPs to sign a contract allowing a control area operator to dispatch its unit on an economic basis at a price agreed to by the parties…." The most valuable load-following capability is operation under AGC, in which the dispatcher sends automatic signals to the generator to change production levels instantaneously as load levels change. To date, few NUGs and dispatching entities have reached agreements that allow full dispatchability with appropriate compensation.

Current Practices for Optimizing Dispatch

Given all the factors outlined above, the dispatching entity takes its stack of fixed and economically ordered resources and attempts to find a cost-minimizing solution that meets expected load plus reserves without violating any grid security constraints.

For example, PacifiCorp dispatches a portfolio of owned generation, generation under contract, and interchange (purchases across balancing area boundaries) transactions "at the lowest available cost for our customers subject to constraints…." The company describes how it treats these resources:

- Coal-fired generation resources are normally dispatched as simple options with the dispatch cost consisting of the fuel cost, environmental cost, and variable operating and maintenance costs. In addition, several of these resources are occasionally used to supply operating reserves (contingency and regulating) for the control areas.

- Natural-gas-fired generation without long-term fuel contracts is normally dispatched as a spark spread option including variable operating, maintenance, and start-up costs. The decision to purchase natural gas and electricity is made in the day-ahead market and again in the hour-ahead market. In addition, several of these resources are routinely used to supply operating reserves (contingency and regulating) for the control areas.

- Hydro generation resources with storage capability are normally dispatched as swing options based on the opportunity cost of dispatching in some other time period. In addition, several of these resources are routinely used to supply operating reserves (contingency and regulating) for the control areas.

- Contractual resources are dispatched either as simple, spark spread, wing, or compound options, depending on the terms of the agreements.

Cost-minimization goals and methods appear to vary across the industry. The National Rural Electric Cooperative Association comments that in areas without ISO/RTO markets, "individual utility control area operators typically utilize their own generators first in their economic dispatch operation, supplemented by any network resources needed to meet their Open Access Transmission Tariff (OATT) requirements and units used to honor sales and purchase commitments to others." Kansas City Power & Light writes, "KCPL has an obligation to utilize the capital assets of the corporation that are included in the rate base to the best advantage of the retail customers. This obligation could, on occasion, require a dispatch order that some may not consider 'economic' based on the short-term but that may prove economic to the retail customer in the long run."

Resources that are not dispatched may offer their generation for sale in real time. Parties that do bilateral trades can use the spot market to supplement or backstop their transactions, buying energy in the spot market when it is less expensive than it would be to self-generate. They can also use spot market energy to meet energy imbalances between their contractual commitments to buy and sell and their actual purchases or sales.

Variations in Economic Dispatch Practices

Economic dispatch can be practiced across a single utility control area, or across multiple control areas by a single utility or other balancing authority[6] on behalf of multiple load-serving entities, transmission operators, and generators. Economic dispatch practices vary by area size and dispatcher type.

Small-Area Dispatch by Single Utilities

A number of survey respondents perform economic dispatch across relatively small areas:

- MEAG Power is a non-profit corporation that serves 49 Georgia communities from its share of two coal and two nuclear units and one combined-cycle generator, for a total of 3,563 megawatts (MW). MEAG meets its customers' 2,050 MW peak load using these resources plus Southeastern Power Administration hydro resources, and commits and dispatches its resources under an operating agreement with Georgia Power.

- The Western Farmers Electric Cooperative (WFEC) is an electricity generation and transmission cooperative in Oklahoma serving about 250,000 meters. WFEC performs economic dispatch to coordinate production from seven member-owned and Southwest Power Administration power plants with a total of 1,633 MW of capacity, plus additional economy energy purchases as available, and modifies dispatch every 60 seconds.

- The Nebraska Public Power District (NPPD) serves 24 public power districts and rural cooperatives, 54 municipal customers, and 87,000 retail customers in Nebraska, with a total peak load of 2,554 MW and a balancing authority load of 3,229 MW. NPPD performs economic dispatch for 3,200 MW of owned generation with purchases and sales as appropriate for reliability and economic efficiency; some of the plants' municipal co-owners (through participation agreements) have the right to independently dispatch their participation amounts.

- Portland General Electric Company in Oregon meets a peak load of 3,800 MW with a combination of company-owned generation and purchased resources by comparing the economic value of the available resources.

[6] "Control area" is the old term describing the geographic area and set of resources under control by a single dispatching utility. Today that dispatching entity is called a "balancing authority," defined by NERC as the "responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time." (NERC 2005)

- Avista reports that, like other generation owners in the Pacific Northwest, it dispatches its own power generation units "based upon supply obligations, the lowest variable economics of the generation units as compared to the market, and various non-power factors" (particularly hydro-generation considerations). Avista owns approximately 1,400 MW of generation capacity and serves a peak load of about 1,500 MW.

- The Hawaiian Electric Company serves five of the six principal Hawaiian islands. It dispatches utility and non-utility generators on an incremental cost curve basis, within the constraints of system operations limits and power purchase agreement requirements.

Mid-American Energy, which manages 4,800 MW of utility-owned owned generation for itself and its joint dispatch customers, describes how its economic dispatch process respects operational constraints:

1) Develop a day-ahead forecast for hourly load to be dispatched;

2) Arrange day-ahead purchases, sales, and/or demand response participation to maximize economy;

3) Commit adequate generating capacity to serve the resulting generation requirements;

4) In real time, dispatch MidAmerican generation and purchases to economically balance the requirements of MidAmerican and its joint dispatch customers; and

5) Maximize system economics by arranging next-hour purchases and sales.

<u>Large-Area Dispatch by Single Utilities</u>

Single utilities can perform dispatch control over large areas:

- Southern Companies perform economic dispatch for about 43,000 MW of nuclear, coal, hydro, pumped-storage hydro, natural gas, oil, and purchased power resources across a 120,000 square mile region. Southern conducts SCUC and SCED, coordinating term and hourly purchase and sale opportunities into the economic dispatch. "If a non-utility generator or other market participant is offering energy at a price that will reduce Southern Companies' production costs, then Southern Companies' traders will attempt to negotiate a purchase. If successful, such a purchase will be scheduled and subsequently incorporated into Southern Companies' unit commitment and real-time economic dispatch processes." Southern reports that during 2004, it purchased more than 2,760 gigawatt hours (GWh) from NUGs; total Southern sales (retail and wholesale) equaled 192,382 GWh, of which 7.2 percent is identified as purchased power (Southern Company 2004 Annual Report).

- Entergy Services, Inc., performs SCUC and dispatch across a three-state region, serving approximately 23,500 MW of load and integrating about 26,500 MW of generation. Entergy reports that purchased power now accounts for 30 percent of its total energy needs, but does not further identify its suppliers.

- PacifiCorp manages two control areas, one in Utah, Wyoming, and Idaho with a summer peak of 6,792 MW, and one in western Oregon, Washington, and California with a winter peak of 6,018 MW. Pacificorp only performs economic dispatch for resources in its system portfolio (although it purchases resources that it does not dispatch).

Southern Companies uses SCUC, selecting appropriate generation resources for the next day (including power purchased from NUGs over hourly, daily, or yearly terms) to minimize the expected costs of serving forecast load:

> Once the unit commitment and power purchase decisions are made, then the real-time economic dispatch process determines the optimal output levels of each dispatchable resource in real-time, based on marginal costs of each resource…. Marginal cost components include the generating resource heat rates (efficiency), commodity cost of fuel, fuel transportation costs, fuel-handling expenses, variable operations and maintenance expenses, emission allowance costs, and transmission losses. In real-time, Southern Companies' Energy Management System utilizes a resource balancing algorithm that measures generation and load balance of Southern Companies' electric system to meet their customers' real-time needs. This automated process captures system load demand, downward-and-upward regulating margin requirements, lower and upper economic and operational limits of each generating unit, maximum ramping rate of each generating unit, each unit's incremental heat rate, and system imbalance energy needs. It also automatically adjusts the output of the generating units that are operating on the margin to meet the instantaneous changes of load on the system…. Unit commitment and economic dispatch processes are subject to redispatch orders from the transmission provider to address transmission reliability constraints. Such orders include the dispatch of must-run generation for reliability purposes and, thus, not committed based on economics.

However, EPSA claims that:

> … In some utility systems – unless the utility has pre-purchased non-utility generation through a bilateral arrangement that includes the right to dispatch that generation – the utility-owned generation is economically dispatched first, and then the non-utility generation is economically dispatched on an as-needed basis…. For non-utility generation, the absence of bilateral contracts results in a sequential approach to dispatch,

> which means that more costly, less-efficient utility-owned generation can be operated ahead of less costly, more efficient non-utility generation.

Large-Area Dispatch by RTOs and ISOs

There are seven RTOs and ISOs in the U.S. (Figure 2) that manage grid operations. Three of the seven conduct some form of SCED within one state (NYISO, California ISO (CAISO), and ERCOT), while three perform SCED across many states (PJM, ISO-NE, and MISO). SPP has not yet begun performing SCED.

To envision the breadth of dispatch areas served by the ISOs and RTOs, consider that:

- NYISO coordinates the activities of over 335 generating stations representing 37,500 MW of capacity, plus demand resources.

- ISO-NE runs a dispatch area that coordinates 350 generators to serves 6.5 million meters, with more than 31,000 MW of installed capacity across six states.

- PJM performs economic dispatch over a 14-state, 164,260-square-mile region with a population of 51 million people, coordinating 163,800 MW of resources.

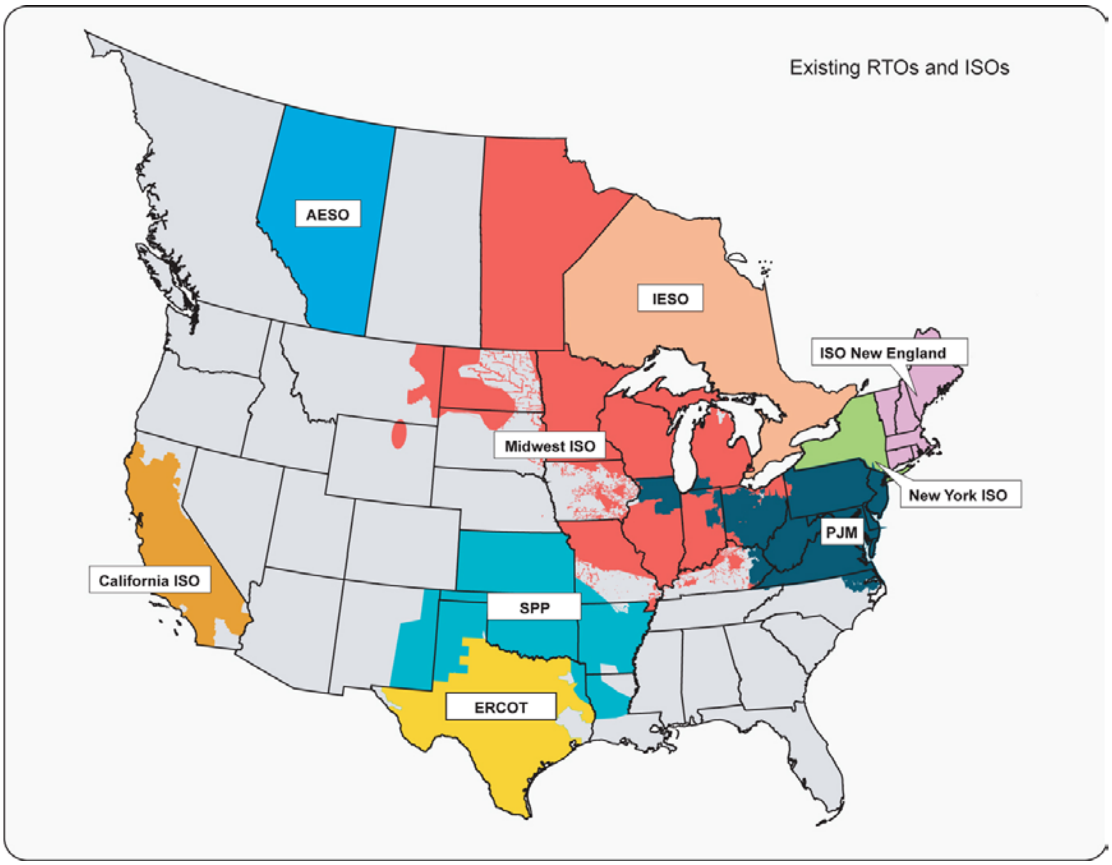
- MISO manages a dispatch area serving 16.5 million customers with a peak load of 112,000 MW, using 132,000 MW of generation resources.

Six of the seven ISOs and RTOs operate centralized wholesale electric markets in conjunction with SCED. In these regions, the key distinction between ISO/RTO economic dispatch and utility dispatch is that in the centralized market, every resource is priced at a bid schedule (prices at different output levels) submitted by its owner or scheduler, rather than from a database of unit-specific variable production costs.

Under fully regulated utility dispatch, utility-owned generators are entered into the bid stack and dispatched according to the marginal production cost of each unit. The capital costs for these power plants are placed in the utility's rate base and recovered – with an opportunity for a return on the investment as well – from native load customers through a wholly separate rate mechanism apart from production costs. Utility-owned generation often bears limited fuel-price risks because fuel costs are reviewed by the state regulator and passed on (in large part) to ratepayers through fuel adjustment cases that are exogenous to the economic dispatch process.

In contrast, NUGs are not rate-based and do not have a wholly separate revenue stream for capital cost recovery. Although economic theory says that in a perfectly competitive wholesale electric market, competing generators will bid their production at its marginal costs, this does not always happen. When a NUG's' bid exceeds its marginal production costs, the excess goes to cover some portion of its capital costs, other fixed costs, and profit. The NUG also bears all risks of fuel price volatility and associated hedging. This means that even though a NUG may be a more efficient power producer than a utility-owned plant on a pure “Btu-in, kWh-out” basis, the NUG’s bid may be expensive than the utility plant’s production cost.

Figure 2
Map of ISOs and RTOs



Because economic dispatch is designed to minimize the total cost of meeting demand reliably, it will use the lowest-cost resources first. Thus, utility-owned generation, priced at its marginal cost, may be dispatched more often than NUG production. If a NUG wishes to increase its dispatch rate and production, it must lower its bids; the Idaho Public Utility Commission notes that utility purchases of NUG energy through spot-market bids may allow NUGs to recover little of their capital costs.

Within these markets, ISO and RTO conduct SCED, but here too, the details vary. For instance, CAISO (as described by Southern California Edison):

> … operates a limited number of markets including day-ahead and hour-ahead ancillary services and real-time imbalance energy. The ancillary service markets are designed to provide operating reserves to the CAISO and the real-time imbalance energy market is designed … to enable the CAISO to balance energy supply and demand after the hour-ahead market.

> In both cases, the CAISO will dispatch from these markets based upon economic dispatch subject to system constraints. In the Day-Ahead and Hour-Ahead time frame, the CAISO relies on scheduling coordinators to submit a balanced schedule of loads and resources. Thus, scheduling coordinators (of which SCE is one) perform economic dispatch to optimize their own portfolios. These schedules are then subject to redispatch by CAISO due to system limitations or needs (e.g., transmission congestion), changing system conditions (e.g., loss of a generating unit), or economics (e.g., cost savings are achieved by accepting various bids from generators to increase or decrease their output).

The eastern RTOs and ISOs work more with individual resource schedules and have less bulk pre-scheduling than in CAISO and ERCOT. NYISO comments that the "most significant difference distinguishing the NYISO's system from the others is that it fully 'co-optimizes' bids and offers for energy and ancillary services, i.e., regulation and various reserves products, so that the total cost of all these products is as low as possible (consistent with reliability)."

How Large Should a Dispatch Area Be?

The size of a dispatch area matters for two reasons. First, the size of the area managed reflects both history and the scale of the tools and task appropriate to the individual grid manager. Second, the magnitude of the reliability and economic benefits realized from economic dispatch depends upon the size of the area that the integrated dispatch covers.

Survey respondents indicated that the area covered by economic dispatch should:

1) cover a utility's footprint (including the generation dedicated to serving that utility's load),

2) span a combination of loads and transmission and generation resources adequate to meet those loads, or

3) respect natural electricity trading patterns.

South Carolina Electric & Gas represents the small dispatcher's viewpoint, saying, "the fact that an economic dispatch area is small in scale presents no obstacle to effective economic dispatch. The benefits derived from economic dispatch are not determined by geographic area; rather, they are determined by the ability to select among different resources on the basis of cost without compromising system reliability or violating other requirements."

Southern Companies asserts that "areas smaller than approximately ten times the largest generating unit in the dispatch area would be exposed to unacceptable risk from unit trips and failures of other equipment that could impose dispatch step changes greater than can be accommodated by available ramp capacity."

In contrast, PacifiCorp "understands that economic dispatch is optimized when it is coordinated over as large an area as possible, with the participation of as many resource options as possible given transmission constraints."

Several participants expressed caution about the trade-off between the size of the coordination area to gain operational efficiencies and the complexity of the task. One representative caution comes from ISO-NE:

> In general, a larger geographic scale or area (from power system point of view) would produce a bigger benefit due to the savings in market efficiency and economies of scale, but these benefits would have to be weighed against the associated costs…. The complexity, technical challenges and risks will also grow exponentially with the scale of the power system. At a certain level, the operator comprehension during times of emergency, modeling complexity, regulatory complexity, state estimation, and even the supporting computer applications may reach their limits.

All participants agree that SCED captures efficiencies in production, reducing costs to customers. But economic theory suggests that the sum of separate cost-minimizing dispatch solutions for several independent but adjacent dispatch regions is likely to be larger than the cost-minimizing solution that would result if the entire area were combined and dispatched as one integrated system. This is the question of local versus global optimization or minimization. The experience of the northeastern RTOs and ISOs and myriad cost-benefit analyses (discussed in Section 3) show that cost optimization integrated across a larger pool of utilities produces lower total energy costs and greater economic savings from efficiency improvements than parallel dispatch operations. As an operational matter, the larger RTOs report that the bigger the area that SCED covers, the more likely that operational limits can be respected with a solution that melds economics and reliability quickly and effectively. A larger economic dispatch area also allows the dispatcher to take advantage of the load diversity across the area, to better allocate resources to load needs. The "GridWest Rewards and Risks" study, for example, projected $178 million per year in reduced generation production costs from the greater efficiencies that would result from RTO-wide economic dispatch.

The North Carolina Electric Membership Corporation says that in the southeast where dispatch is practiced on an entity-by-entity basis:

> ... the only attempt to optimize the dispatch regionally is through short term sales and purchases. This results in a sub-optimal dispatch on a regional basis. Attempts to optimize dispatch on a daily and hourly basis are further impeded by market rules that impede such short term transactions. The list of rules includes items such as:

- Timing of OASIS [Open Access Same Time Information System] reservations
- Tagging timelines
- Cost of energy imbalance impedes participation
- Energy imbalance versus inadvertent energy
- Lack of firm hourly transmission.

Although there is communication between dispatching entities, reliability can be challenged due to somewhat uncoordinated dispatching decisions.

It should be noted that wholesale electricity cost efficiencies and savings may or may not be passed through to retail customers, depending on whether the state has retail competition and, if traditional regulation is employed, how state regulators handle the utility's rate recovery.

Economic Dispatch and Reliability

Because economic dispatch incorporates security and reliability considerations and constraints, it promotes and improves grid reliability. NYISO observes that using economic dispatch allows the operator to deploy resources more efficiently and thus handle higher peak loads more reliably than would be possible without economic dispatch. PJM comments that economic dispatch, combined with LMPs, makes reliability needs clear and transparent to everyone in the region and the market. Because LMPs are highest where the need for power is greatest, they immediately reflect the impact of grid conditions such as transmission bottlenecks, peak loads, or generating units losses, and create an incentive for every market participant to respond by supplying power (or reducing load) where most needed. No participant suggests that economic dispatch, as currently practiced, might compromise grid reliability.

Nonetheless, several participants express concern that if the definition or practice of economic dispatch were changed to increase use of NUGs, "an overly simplified economic dispatch could put grid reliability in danger." This highlights the importance of assuring that economic dispatch definitions and rules continue to protect and do not inadvertently compromise reliability (although reliability should not be used as a pretext for discrimination). However, several participants believe that greater reliance on non-utility generation can improve reliability. More than one-third of the nation's capacity today is composed of these newer, advanced-technology, high-efficiency plants. Increasing their use could lead to higher unit availability rates, increased capacity to maintain grid reliability, possible improvements in transmission flows, and more low-cost energy and capacity.

SECTION 3

THE BENEFITS OF ECONOMIC DISPATCH

This section looks at the "potential benefits to residential, commercial, and industrial electricity consumers nationally and in each state if economic dispatch procedures were revised to improve the ability of NUGs to offer their output for inclusion in economic dispatch," as directed in EPAct Section 1234.

The assessment is based on a review of recently published studies and responses to the Department's brief questionnaire. The limited time available for this study did not allow the Department to perform new modeling and quantitative analysis specifically of economic dispatch impacts. It is important to bear in mind that most of the materials used for this assessment are not focused solely or even directly on the question of economic dispatch as posed by the Act. This review is not intended to evaluate the methods and assumptions of the studies examined, so the Department's findings are bounded by the studies' methods and assumptions. This review does, however, point out issues that merit attention in future studies.

Congressional Intent and Study Definitions

In assessing the benefits of economic dispatch, the term "benefits" is interpreted narrowly, as defined in EPAct Section 1234, by equating benefits with the direct, net economic savings that result from decreases in the price or cost of electricity to residential, commercial, and industrial customers (both nationally and in each state). Important but less direct or hard-to-measure impacts, e.g., on reliability or the environment, are not included. The studies estimate benefits from increased lower-cost generation and presume that those savings are passed through in retail rates to end-use customers (even though that is not always the case). When it is available, information on the economic costs associated with securing increased dispatch benefits (e.g., the cost of establishing and running an RTO) is noted because the benefits to electricity consumers would be net of these costs.

It is not possible to estimate the benefits of economic dispatch to different customer classes and states based solely on the studies of economic dispatch to date, because few of these studies disaggregated benefits to the level of individual customer classes or individual states. The lack of information reflects the aggregated nature of the regions studied. Equally important, assessing the impacts of dispatch changes on retail customers would require consideration of federal and state ratemaking policies, such as allocation of FTRs and the effects of retail rate freezes. The studies reviewed do not treat these issues consistently.

It is not always clear how the different studies classify non-utility generation. Every study appears to use a common meaning for "utility-owned generation" -- that which has been placed in the rate base for capital-cost recovery within the service area of the dispatching party. However, an off-system (export) sale from one utility-owned power plant into another utility's service area would be considered non-utility generation in the latter's economic dispatch stack. In regions where dispatch is performed by vertically integrated -- yet functionally unbundled -- utilities, this study uses the term "non-utility generator" to include any generation not owned by the party conducting the dispatch; other studies may use NUG to mean merchant generators or IPPs. This lack of consistent definition and focus makes it impossible to tally the impacts of economic dispatch upon NUGs.

Overview of Prior Studies and Other Materials Reviewed

This report examined twenty-five studies and documents, which can be found either in the public domain or among the additional materials submitted to the Department. Full citations of the sources reviewed are listed in Table 3.1. The studies were grouped into three categories:

1) **RTO studies**: Benefit-cost studies of the impacts of recent FERC electricity restructuring policies, notably policies encouraging formation of RTOs in various parts of the country;

2) **IPP studies**: economic dispatch studies prepared by or in response to IPPs seeking to increase production within an existing dispatch footprint (these generally focus on the southeastern U.S.); and

3) **Retail rate studies**: Empirical assessments of retail rates in restructured electricity markets.

This report focuses on the first two types of studies (RTO and IPP studies) because they formulate their study problems explicitly in terms of changes in generation dispatch.[7] Both compare two scenarios of generation dispatch: a base-case scenario that represents the status quo and a change-case scenario that alters assumptions about available generation or the manner in which generation is dispatched. The difference between the two scenarios measures the benefit or impact of the change in generation dispatch.

As noted earlier, the studies do not uniformly report findings either by customer class (i.e., residential, commercial, or industrial) or by state. Thus, to address Congress'

[7] The third type of study, retail rate studies, is not given further consideration in this assessment because the formulation of these studies prevents separation of the impact of changes in generation dispatch from the impact of other changes affecting retail rates. Two studies that fall into this category were identified (Sutherland 2003 and Biewald et al. 2004). These studies examine historic retail rate trends. Because retail rates are affected by many factors in addition to economic dispatch, such as state retail rate policies, it is not possible to isolate the impacts of economic dispatch in these studies.

direction in Section 1234, study findings are summarized with qualifications indicating the extent to which the studies address impacts on customer classes or states.

Review of RTO Studies

The largest body of recent, published work on economic dispatch consists of studies of the prospective benefits and costs of industry restructuring. We reviewed sixteen of these studies. Thirteen of these studies focused on FERC policies encouraging RTO formation. The remaining three studies focused on market redesign within an existing RTO (TCA/KEMA 2004), transmission construction to relieve bottlenecks (CERA 2004, 2004, and 2005), and an assessment of the overall impacts of restructuring (GED 2005).

The principal benefit quantified in these studies is improvement in generation dispatch. For example, the studies on RTO formation focus on the changes that might result from centrally dispatching a large fleet of generation over a broad geographic footprint, compared to the current practice of simultaneous economic dispatch of subsets of this fleet by the entities representing the individual geographic areas within this footprint. Total generation capacity (and its composition) and total demand are held fixed. The main cost that is quantified is that of setting up and operating either an ISO or RTO.

Table 3.2 summarizes the quantitative findings from RTO studies. RTO studies have found economic dispatch benefits ranging from $80 million to over $40 billion, depending on the region and length of time studied. Normalized, these benefits range from one to five percent of total wholesale electricity costs.

Improvements in generation dispatch tend to be driven by three factors. First, some savings result from substitution of lower-cost fuel (e.g., coal) for higher-cost (e.g., natural gas) fuel. This result is prominent in studies of areas in the Midwest. Second, some savings result from substitution of more-efficient generation (low heat rate) for less-efficient generation (high heat rate), both relying on the same fuel (typically natural gas). This result is prominent in studies of the Northeast. Third, some savings result from reductions in or even elimination of trading costs (called “hurdle” rates) between existing sub-regions. This effect is considered by all of the studies reviewed.

Production cost simulation methods are used to analyze the economic dispatch benefits treated in RTO studies. Production cost simulation is a mature technology that has long been used by utilities for assessing generation and transmission expansion plans. These tools seek to replicate generation dispatch procedures by determining the total variable cost of serving a fixed set of loads with a fleet of generating units. Advanced uses of these tools can take into account many important aspects of generation dispatch, including scheduled and unscheduled forced outages by generators, ramping constraints and unit commitment, hydro generation scheduling, and reliability issues in the form of transmission constraints. However, because production cost simulation models were developed originally to support planning studies, they often necessarily simplify or suppress aspects of actual dispatch procedures.

Eto, Lesieutre, and Hale (2005) reviewed many of the earlier RTO studies examined in this assessment. Several findings from that review are relevant here:

- Improvements in economic dispatch may not be most important impact of FERC's restructuring policies. The effects of FERC's policies on reliability management, generation and transmission investment, and wholesale market operations have not been treated systematically or comprehensively in the recent studies, and therefore may have been underestimated.

- Presentation of results in prior studies may be piecemeal or highly aggregated. This sometimes precludes assessments of the impacts on consumers versus producers or among all sub-regions affected by changes in dispatch. In addition, important regulatory policy considerations, such as assignment of FTRs, are sometimes not within the scope of the studies, which prevents them from assessing the final impact of changes in dispatch on retail rates.

- Because the principal economic benefit under analysis is improved dispatch over a larger geographic footprint, the results are affected by: specification of hurdle rates in the base case (and the rationale for changes to these rates in the change case), model calibration for the base case, treatment of bidding behavior by market participants, and the representation of the area's transmission capability.

Review of IPP studies

EPAct Section 1234 directs DOE to examine the "potential benefits … if economic dispatch procedures were revised to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch." Because economic dispatch is currently practiced in some form throughout North America's bulk power industry, this directive is interpreted as referring to the impact of potential increases in NUG electricity production as a result of either changes in current generation dispatch practices or changes in the rules by which NUGs can participate in the dispatch stack.

To suggest that additional benefits might accrue from changing current practices presumes both that lower-cost (e.g., non-utility) generation is available and that this generation is currently being under-dispatched. The assumption is that if lower-cost generation were both available and dispatched more frequently than is currently the case, total dispatch costs would be lower, which would lead to lower electricity costs. IPP studies start with this assumption and ask how much more NUG generation could be dispatched and what production cost savings would result.

Seven studies examine replacement of some amount of generation from an existing fleet with increased generation from IPPs. In each of these studies, the geographic footprint of the area dispatched and the demand served are held fixed. In the change-case scenario, the total generation capacity available to serve demand is increased by the additional generation capacity from the IPPs.[8] Thus, IPP studies increase the total amount of generation capacity available for dispatch to a fixed set of loads; in contrast, RTO studies hold both generation capacity and loads fixed.

The basic formulation of the IPP study problem is as follows:

> The economic impact of increased generation by IPPs
> *equals*
> [The amount of existing generation displaced or replaced by new generation
> *multiplied by*
> The cost of fuel (assumed to be roughly the same for existing and new generation)
> *multiplied by*
> The heat rate differential, which equals (the higher heat rate of less efficient, displaced existing generation *minus* the lower heat rate of the more efficient, replacement new generation)].

Table 3.3 summarizes the quantitative findings from the IPP studies. IPP studies have found economic dispatch benefits ranging from $30 million to over $900 million, depending on the region and length of time studied. Normalized, these benefits range from eight to more than thirty percent of total variable production costs.

Because the marginal fuel used in both dispatch scenarios is generally assumed to be the same (i.e., natural gas), changes in dispatch are driven primarily by differences in generation efficiency between the two fleets. Table 3.3 summarizes these differences in terms of the heat rates assumed for the two fleets of generation (for the studies that provided this supporting information).

The methods used to calculate these impacts range from simple spreadsheet-type examples to production cost simulations. As noted above, production cost simulations can in principle account for many of the factors influencing the generation dispatch by system operators. Spreadsheet approaches are more limited than production cost simulations in their ability to account for these factors.

The realism of IPP studies depends on how several elements are handled, including calibration of the base case and representation of the physical, market, and regulatory factors that may constrain dispatch of lower variable cost generation. In addition to the considerations discussed in reviewing the RTO studies, these factors also include treatment of bilateral contracts (including QF contracts), calculation and posting of available transmission capability (ATC), implementation of reliability requirements, handling and allocation of financial transmission rights (FTRs) and congestion costs, and whether and how potential production cost savings are passed through in retail rates.

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[8] One study (Entergy 2004a) examines transmission expansion in order to enable greater dispatch of merchant generation.

Findings from Review of Prior Studies and Submitted Materials

Studies that evaluate the potential for benefits from changes to current economic dispatch practices fall into two categories -- studies of the impact of FERC policies and studies of the impact of increased dispatch of IPPs. These two types of studies were not designed to present comprehensive information on economic dispatch benefits disaggregated by geographic region and customer class, as envisioned by Section 1234.

Only two of the studies reviewed were national in scope. One focused on the impacts of FERC Order 888, and the other focused on the impacts of SMD; neither was focused primarily on the issue of economic dispatch. The remaining studies focused on specific regions or dispatch areas. The time frames and study problems of each varied, sometimes considerably, depending on the study objective. Thus, it is impossible to extrapolate from these documents a consistently defined nationwide or regional estimate of the impacts of economic dispatch.

Most of these studies focused on changes in wholesale electricity costs. Assessing the impacts of changes in economic dispatch procedures on retail customers requires consideration of federal and state ratemaking policies, such as allocation of FTRs and the effects of rate freezes. As a group, the studies reviewed did not treat these issues consistently.

RTO studies compare centralized dispatch of a large portfolio of generating units (both utility-owned and non-utility owned) aggregated over multiple control areas to the current practice of simultaneous, independent dispatch of subsets of this portfolio by individual control areas. RTO studies have found economic dispatch benefits ranging from $80 million to over $40 billion, depending on the region and length of time studied. Normalized, these benefits range from one to five percent of total wholesale electricity costs.

The somewhat modest dispatch savings found by RTO studies (compared to the savings found by IPP studies) is consistent with the formulation of the study problem. That is, in the base case, individual control areas are assumed to dispatch the generation they control in order to minimize the total variable cost of production. Aggregating these control areas and redispatching the same fleet of generation to meet the same loads can reduce cost only if there are opportunities for additional cost-reducing, inter-control-area trade. Thus, the specification of hurdle rates, which are used to represent trading "friction" among control areas in the base case and which are lowered or eliminated in the change case, is extremely important.

IPP studies compare dispatch of a combined fleet of new (typically non-utility-owned) and existing (typically primarily utility-owned) generating units within a single control area to the current practice of dispatching existing generating units. IPP studies have found economic dispatch benefits ranging from $30 million to over $900 million, depending on the region and length of time studied. Normalized, these benefits range from eight to more than thirty percent of total variable production cost.

The percentage cost reductions found by IPP studies is consistent with the formulation of the study problem. The change case includes additional, highly efficient generation capacity from IPPs, and the redispatch in the change case results in increased generation by these units to displace generation by older, less efficient units in the base case.

Both types of studies rely, for the most part, on production cost simulation methods, which seek to replicate least-cost dispatch of a specified fleet of generation. However, modeling practices vary, and the methods used are sometimes limited in their ability to evaluate all aspects of actual dispatch procedures.

If production cost simulation models are used in the future to study the impacts and benefits of changes in dispatch procedures, the analysts will have to pay particular attention to handling the following issues:

- Representation of bilateral contracts (including QF contracts)
- Calculation and posting of ATC
- Bidding behavior by participants in wholesale markets
- Reliability requirements
- Fuel diversity requirements
- Hydrological and environmental constraints
- Handling and allocation of FTRs and congestion costs
- Whether and how potential production cost savings are passed through in retail rates.

Table 1 – Studies and Documents Reviewed to Assess Benefits of Economic Dispatch

Study Author ***Study Title***	**Date**	**Study Type**
Pennsylvania, New Jersey, Maryland Interconnection (PJM). *Northeast Regional RTO Proposal Analysis of Impact on Spot Energy Prices*.	2002	RTO
ICF Consulting. *Economic Assessment of RTO Policy*.	2002	RTO
Tabors, Caramanis, and Associates (TCA). *RTO West Benefit/Cost Study*.	2002	RTO
Energy Security Analysis, Inc (ESAI). *Impact of the Creation of a Single MISO-PJM-SPP Power Market*.	2002	RTO
Independent System Operator-New England (ISO-NE), New York Independent System Operator (NYISO). *Economic and Reliability Assessment of a Northeastern RTO*.	2002	RTO
Charles Rivers Associates (CRA). *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*.	2002	RTO
U.S. Department of Energy (DOE). *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*.	2003	RTO
Cambridge Energy Research Associates (CERA). *Economic Assessment of American Electric Power's Participation in PJM*.	2003	RTO
Science Applications International Corporation (SAIC). *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets.*	2004	RTO
CRA. *The Benefits and Costs of Dominion Virginia Power Joining PJM*.	2004	RTO
Henwood Energy Services, Inc. *Study of Costs, Benefits and Alternatives to Grid West*.	2004	RTO
TCA/KEMA. *Electric Reliability Council Of Texas, Market Restructuring Cost-Benefit Analysis*.	2004	RTO
CERA. *Grounded in Reality: Bottlenecks and Investment Needs of the North American Electric Transmission System.*	2004 2004 2005	RTO
CRA. *Southwest Power Pool, Cost-Benefit Analysis*.	2005	RTO
Global Energy Decisions (GED). *Putting Competitive Power Markets to the Test.*	2005	RTO
GridWest Risk/Reward Workgroup. *The Estimated Benefits of Grid West*.	2005	RTO
Dismukes, D., D. Mesyanzhinov, J. Burke, E. Downer	2003	IPP

The Power of Generation: Continued Economic Benefits from Independent Power Development in Louisiana.		
TECO Power Services. *Study on Benefits of IPP Generation to Entergy Consumers*.	2003	IPP
Tractabel North America. *Electric Competition in the States of Arkansas, Louisiana, and Mississippi – Is there an Opportunity?*	2004	IPP
Entergy. *Phase II. Transmission Study Report.*	2004	IPP
Entergy. *Transmission Pricing and ICT Benefits.*	2004	IPP
J. Kennedy Associates and Exeter Associates. *The LPSC Staff Retirement Study, Updated Draft Report for Comment.*	2005	IPP
Brubaker and Associates. *Entergy Oil/Gas Generation vs. Market Purchases.*	2005	IPP
Sutherland, R. *Estimating the Benefits of Restructuring Electricity Markets, An Application to the PJM Region*.	2003	Retail Rate
Biewald, B., W. Steinhurst, D. White, A. Roschel. *Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs*.	2004	Retail Rate

Table 2 - Summary of Economic Dispatch Benefits from RTO Studies

Study	Geographic Scope	Aggregate Benefits	Benefit Type (% of base case, if available)	Additional, Disaggregated Perspectives Also Presented
PJM 2002	PJM, NYISO, and ISO-NE	$300M/yr	Reduction in load payments (2%)	PJM, NYISO, ISO-NE Production cost and revenue changes
ICF 2002	National	$41B	20 year net present value in reduced wholesale generation costs (4%)	12 regions
TCA 2002	WECC	$300M/yr	Difference between load payment reductions and generator net revenue reductions	Subregions, WECC Consumer and producer impacts
ESAI 2002	MISO, PJM, SPP	$7.0B	Price of energy over 10 years (~3%)	None
ISO-NE/ NYISO 2002	ISO-NE and NYISO	$220M/yr in 2005 and $150M/yr in 2010	Wholesale power costs (3% declining to 2%)	ISO-NE and NYISO
CRA 2002	Eastern Interconnection	$2.1B	Present value of reduced generator payments + merchant generator net benefits 2004-2013 (<1%)	GridSouth, SeTrans, GridFlorida, Eastern Interconnection Consumer and producer impacts
DOE 2003	National	$1.8B/yr to $1.5B/yr	Wholesale electricity costs (both <1%)	12 regions
CERA 2003	PJM combined with AEP	$245M in 2004 declining to $188M in 2008	Wholesale energy costs	PJM and DVP, individually
SAIC 2004	MISO	$105M/yr	Reduced generation costs plus off-system sales and FTR revenue (~8%)	Wisconsin utilities Consumer and producer impacts
CRA 2004	PJM combined with DVP	$800M	Total energy plus capacity and ancillary services savings over 10 yrs	None
Henwood 2004	RTO West	$78M/yr	Pancaked wheeling rates, operating reserve cost savings, and transmission asset utilization	None
TCA/ KEMA 2004	ERCOT	$586M	NPV of generation cost reductions from 2005-2014 (-0.2% to +1.2%/yr)	Impacts on TX subregions
CERA 2004	Eastern, Western Interconnection	East $28-136M/yr West $18-64M/yr	Net generation cost savings in 2010 or 2015 under low and high gas price assumptions	Generator margin and load savings by sub-region, assuming LMP pricing

2005	and ERCOT	ERCOT $6M/yr	(Eastern and Western Interconnection); 2010 (ERCOT)	
CRA 2005	SPP	$614M	Production cost savings 2006-2015 (2.5%)	Impacts on firms, and states
GED 2005	Eastern Interconnection	$15.1B	Reductions in total operating expenses from 1999-2003 (7%)	PJM, individually
GridWest2005	GridWest	$144 to $458M/yr	Cost savings in contingency and regulating reserves, redispatch efficiencies, rate pancaking, and reconfiguration- transmission utilization	4 control areas vs. 10 control areas

Table 3 - Summary of Economic Dispatch Benefits from IPP Studies

	Economic Dispatch Benefits (% of base case)	**Study Type**	**Displaced Generation Heat Rate**	**Replacement Generation Heat Rate**	**Nat. Gas Cost**	**Notes**
Dismukes, et al. 2003.	Regional prod. cost savings 2000: $411M (15%) 2003: $825M (~30%); 2005: $926M (~33%)	Spreadsheet	Varies by unit	Varies by unit	N/A	Savings are the difference between two supply curves
TECO. 2003.	Production cost savings 2003-2007: $923M (8-9%)	Production cost simulation	Varies by unit	Varies by unit	N/A	
Tractabel. 2004.	Fuel savings: $610M/yr Fixed O&M savings: $280M/yr	Spreadsheet	11375 Btu/kWh	7000 Btu/kWh	$6/MBtu	Separate results for AR, LA, MS
Entergy. 2004a	$128-311M in net savings over 2004-2026	Production cost simulation	Varies by unit	Varies by unit	N/A	Net savings from seven transmission projects
Entergy. 2004b.	$30M/yr for every 1% reduction in oil/gas generation	Unknown	N/A	N/A	N/A	From Entergy presentation
Kennedy and Exeter. 2005.	$-54M-32M/yr average (2006-2012) considering retirement of Entergy units and replacement with both new Entergy units and merchant generation	Production cost simulation	Varies by unit	Varies by unit: 7700-8500 Btu/kWh	$6.4 –5.1 /MBtu	Savings are net of fixed cost of new utility-owned units
Brubaker. 2005.	Cost savings from market purchase 2004: $214M 2005: $146M (first 7 mo)	Spreadsheet	2004: 73.6 mills 2005: 85.9 mills	2004: 42.0 mills 2005: 45.7 mills	N/A	Comparison of actual gen. and market purchases

SECTION 4

WHICH RESOURCES GET INTO THE DISPATCH STACK?

Economic dispatch (including both SCED and SCUC) is a complex but relatively mechanical process that should identify a set of resources to be dispatched to meet electricity loads and should meet demand at the lowest cost given the available resources and prevailing grid conditions at the time. Section 2 above addresses two issues that could reduce a NUG's chances of being dispatched -- if the NUG's bid price exceeds the utility-owned generator's marginal production cost, or if the dispatching entity needs certain reliability-related services or has certain reliability or operational requirements that the NUG is not contractually or physically able to provide or meet.

The Electric Power Supply Association (EPSA) notes that across the U.S. there are 55,920 MW of non-utility generation that are listed as uncommitted resources, i.e., are available but have no bilateral forward contracts with utilities or firm transmission service.[9] EPSA asserts that, particularly within the Southeast Electric Reliability Council and the Southwest Power Pool (both regions where integrated utilities manage economic dispatch), new, highly fuel-efficient NUGs are under-utilized and sit idle while older, less efficient utility-owned plants run. EPSA contends that in the absence of a formal contract with a NUG, the utility dispatcher will dispatch its own generation first and then fill in with the non-utility generation "on an as-needed basis."

NUG complaints about economic dispatch revolve around allegations that vertically integrated utilities use their dispatch processes to favor utility-owned generation over non-utility-owned generation. NUGs point to several practices by vertically integrated utilities as indicating this bias:

1) Practices that limit the consideration of NUG resources within the economic dispatch stack,

2) Practices that limit NUGs' ability to sell their power to the dispatching utility or to off-system buyers,

3) Utilities' unwillingness to consider electricity offered by NUGs, and

4) Inadequate information on and transparency of the details of utility dispatch procedures and whether these procedures are being fairly administered.

Utilities respond that:

[9] This designation of uncommitted resources is found in NERC's 2005 Long-Term Reliability Assessment.

1) They are using appropriate economic dispatch procedures mandated and overseen by their state regulators or governing boards/authorities.

2) Under these procedures, total production costs are minimized, subject to the aforementioned constraints, such that cost-minimizing economic dispatch will not always call on NUG units even when the short-run variable costs of NUG units may be low.

3) NUGs don't offer all of the services provided by utility-owned generation (such as regulation, load following, operating reserves, and voltage support) and thus cannot be incorporated into dispatch processes as equals to utility-owned generation.

Section 1234 of EPAct[10] directs the Department to identify changes in economic dispatch procedure that would improve the ability of NUGs to participate in economic dispatch.[11] As Section 3 illustrates, economic dispatch procedures are neutral and will dispatch whatever available resources satisfy specific requirements and constraints in the most economic way. Virtually every survey respondent to the Department's survey offers the view that economic dispatch should not distinguish between utility and non-utility generation. Therefore, the challenge is not to modify economic dispatch procedures *per se* but to look at two related issues – whether constraints that frame the economic dispatch system inappropriately favor or harm NUGs, and whether NUGs (and other resources) are recognized as available for dispatch consideration.

If a resource is considered to be available, it will be included in the economic dispatch resource stack and will be dispatched if its cost is competitive with other resources or if its output is needed to satisfy reliability concerns. But if it is not in the stack, it cannot be dispatched.

The alleged rationale for an integrated utility to discriminate against a NUG in the dispatch process is as follows: because the utility owns generation (for which it receives return of and on its investment, plus a fuel cost pass-through), it wants to run its own generation rather than lose sales to another supplier (whether an NUG from within the system or an import from outside the system). The dispatching utility can use its control over transmission service availability and economic dispatch processes to protect its own generation and hinder competing resources. Although several complaints have been filed alleging such conduct by various dispatching utilities, few have been conclusively proven.

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[10] The same mandate also appears in Sec. 1832.

[11] The language of the statute ("improve the ability of non-utility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch") can be interpreted in two ways: either it refers broadly to increased sales by NUGs or narrowly to increased dispatch of NUGs. This section uses the latter interpretation; however, in many cases this can only be achieved by making the NUG fully dispatchable under the direct control of the dispatcher.

This section briefly reviews various conditions under which a resource might be affected by the specification of economic dispatch constraints or might not be included in the economic dispatch resource stack. In listing these conditions, this report takes no position on whether such events are occurring in specific areas or result from the practices of any particular dispatching entity. Some of these conditions or practices have been alleged to be violations of the prohibition against "undue prejudice or disadvantage" within interstate power markets [16 USC 824(d)] and may be under past or current non-public investigation at FERC.

Conditions that Could Exclude a Resource from the Dispatch Stack

<u>Qualifications for transmission service</u>, such as firm contracts to serve network loads. A generator that has a firm contract with a buyer will be dispatched (if it has a transmission contract and does not require a reliability redispatch). Utility-owned, rate-based generation generally has an explicit arrangement to serve network (native) loads. If a dispatcher excludes from the dispatch stack any generator that does not have such a contract, a NUG would not be allowed to compete within the resource stack.

<u>Calculation of Available Transmission Capability (ATC)</u> <u>or Total Transmission Capability (TTC)</u> in ways that reduce the amount of transmission available to competing resources. TTC is the amount of electric power that can be transferred reliably over the interconnected transmission network. ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses; it is calculated as TTC minus existing transmission commitments (such as those to retail customers), less a margin to protect load-serving entities' ability to import power in the emergency event that they lose local generation needed to serve retail customers, less an additional margin to provide flexibility in the event of changes in transmission system conditions (NERC 2005).

TTC and ATC are calculated by the dispatcher using information about grid flow capabilities and loadings that may be proprietary (and thus not transparent to outside parties). Some dispatchers use calculation methods and assumptions that are not shared with all of the resources using the transmission system; this lack of transparency invites questions about the accuracy and objectivity of the calculations. Beyond the issue of whether the calculations are correct and unbiased, there have been situations where utilities have posted inaccurate ATCs.[12]

<u>Reserving transmission capacity (ATC) for native load and network customers</u>. The economic dispatch process seeks to match production from generation to the loads within the dispatch service area. Some integrated utility dispatchers will allocate transmission

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[12] For instance, a 2004 FERC audit found significant errors in Entergy's use of the methodology, including erroneous calculations and inadequately documented Transmission Service Requests that led to inaccurate estimates of ATC (now called Available Flowgate Capacity within Entergy).

capacity first to deliveries to native load or network customers and make the residual capacity available for other transmission flows. If there is no remaining ATC available for a NUG to use to deliver to native load customers, then the NUG is eliminated before it ever gets into the dispatch process. This can be a circular problem; the NUG may not be able to get contracts without transmission access and may not be able to get transmission access without contracts.

Suez Energy North America reports that a dispatching utility may lock up and hold onto transmission capacity for its own generation to preclude merchant generation from selling to other buyers, but later modifies the dispatch order to reduce its own generation and pick up the merchant generator's production at a lower cost.

A related problem may be whether the NUG can get transmission service to sell its output to a neighboring area if it is not selling in the host dispatch region. Without transmission access, the NUG may not be able to deliver power to another region, either for contracted off-system sales or to compete in its economic dispatch stack.

Special requirements for provision of ancillary services. If the dispatcher requires that dispatchable units have must have regulation capability, automatic voltage control capability, or must meet particular standards for unit excitation systems, a NUG unit that does not offer these features might be excluded from the dispatch stack even if the generator's contract does not call for these capabilities.

Persistent displacement by OOM[13] resources. If the dispatching entity repeatedly determines that a reliability problem requires that an OOM resource be employed, and the OOM resource blocks sustained deliverability from the interrupted generator to that generator's load, the blocked generator may lose its sales opportunities and its customers will lose access to lower-cost energy.

The configuration of the existing transmission system. The existing transmission system's configuration limits the ability of dispatchers to accommodate additional generation from units located in certain transmission-constrained locations within the system. In many cases, expanded transmission capacity will increase the deliverability of output from efficient generators to loads. But in many areas there are delays in building new transmission capacity that would reduce congestion and enable greater transmission flows.

Requirement to share proprietary generator data. These data are needed for accurate, effective dispatch modeling. Although NUGs are willing to share these data with an

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[13] Out of merit order dispatch refers to changes in the dispatch that occur in real-time after the dispatch stack has been selected. In real-time, unplanned contingencies or the cumulative effect of schedules implemented by neighboring systems may necessitate re-dispatch of existing resources "out of merit" order, such that higher cost resources are sometimes dispatched in place of lower cost resources."

independent market operator (such as an ISO or RTO) that has an obligation and protocols to keep the data confidential, many NUGs feel differently about sharing with a dispatcher that owns competing generation. NUGs claim that if they disclose proprietary business data about the costs and operational capabilities of their units, the utility can use this information to disadvantage the NUG units and favor its own generation by changing the cost curves of utility-affiliated generation to undercut NUG capacity in the dispatch stack or by using its control of transmission service to allocate available capacity to utility-affiliated flows rather than NUG transactions. This is a code of conduct issue that can have a negative impact on economic dispatch.

Although the above issues are relevant to NUGs, similar concerns have been voiced by other non-utility resources, including renewable-energy producers and demand response.

SECTION 5

PROPOSED MODIFICATIONS TO ECONOMIC DISPATCH AND SUGGESTIONS FOR FUTURE WORK

Section 1234 of EPAct directs the Department to recommend legislative or regulatory changes that may be needed to improve economic dispatch and the use of NUGs as part of economic dispatch. This section lists a number of suggestions offered in responses to the Department's economic dispatch survey, along with suggestions for future work. Some of these suggestions are for FERC, which is working with state regulators in FERC-State Joint Boards considering economic dispatch, and reexamining Order 888 on open transmission access. Other recommendations are for the Department or other analysts doing future work on economic dispatch.

Proposals for Modifying Economic Dispatch

Respondents to the survey for this study offered a number of comments and suggestions for modifying economic dispatch to increase cost minimization. This section reviews several of those suggestions. Common themes are ways to improve the transparency of economic dispatch – both the process and outcome – and increase ways for NUGs to be included in that dispatch.

Addressing the definition of economic dispatch given in Section 1234, a majority of survey respondents caution that economic dispatch should not just seek economic optimization, but should try to ensure reliable system operations at the lowest cost possible. Several respondents suggest that reliability will be better served by referring to "security constraints" rather than "operating limits," because the latter is a narrower concept.

All the ISO/RTOs comment that their dispatch is owner-neutral and does not distinguish between NUGs and other resources (several try to be even-handed between generation and demand resources as well). Therefore, they contend that no economic dispatch changes are needed to increase NUG participation. Many of the dispatching utilities express a similar view.

Calpine recommends that all utilities be required to establish an all-inclusive daily dispatch order that incorporates every resource interconnected to their systems, and then dispatches the lower-cost units first (subject to explicit reliability and security requirements). Similarly, EPSA proposes that in non-RTO/ISO regions there should be a mandate that all available and eligible generation will be considered for merit-order dispatch, and that regulators should demand explanations when a utility dispatches the generation it owns in lieu of less expensive resources.

EPSA suggests that utilities should be encouraged to purchase from IPPs using forward bilateral contracts as part of the procurement process rather than looking to NUGs largely for spot-market purchases. This would lead to increased use of NUGs and greater inclusion of NUGs in the bilateral rather than competitive segment of the economic dispatch curve.

Several participants emphasize the importance of having an independent entity with no generation interests – or even an entity separated from all other vertically integrated utility functions, to eliminate all potential conflicts of interest – perform economic dispatch, to assure an objective outcome that does not favor any particular group of resources. Among other things, this entity should have strict requirements for the confidentiality of the proprietary production information used in the economic dispatch process.

If a generator is included in the dispatch stack, the presumption is that the generator can deliver its production to loads; otherwise, the unit cannot be dispatched. Transmission adequacy affects how much generation can flow and how much grid reliability concerns will constrain different generation production and deliverability patterns. Easing key transmission constraints improves access to load for almost every generator as well as improving grid reliability. Therefore, many respondents reiterate the importance of enhanced transmission planning processes that address long-term economics as well as reliability, and of building a more robust transmission network that will enable customers to save money by reliably accessing more efficient generation than is possible with today's transmission system. One NUG recommends that every transmission upgrade that enables access to low-cost generation resources should be built if the upgrade's cost is less than the savings achievable by the dispatch of the lower-cost supply.

Whatever the state of the transmission grid, generators' production and contracting options are limited unless they can get transmission service for their products. Therefore, a number of participants assert that federal and state regulators must reinforce open access transmission rules and outcomes. Where there is no independent entity administering open transmission access, regulators should prevent practices such as "transmission delisting," in which a utility reserves transmission capacity for self-generation until the last minute but then "delists" the self-generation block in order to purchase less-expensive NUG power under a short-term contract.

The Arkansas Public Service Commission notes that there is a need for more transparent determinations of Available Flowgate Capacity (or ATC) than are currently offered. This information would allow market participants and regulators to understand and trust a dispatching utility's statements about whether particular transactions can safely flow across the grid.

A few respondents recommend that the resources considered under economic dispatch should include demand-side resources (such as emergency and market-oriented demand response), and that the Section 1234 definition of economic dispatch should be changed accordingly.

Many respondents caution that it would be a mistake to mandate the use of a specific economic dispatch definition or method throughout the U.S. electricity industry. Some respondents recommend that economic dispatch should be used to employ energy-efficient generation more extensively, and one suggests modifying economic dispatch specifically to maximize the use of cogeneration. However, others fear that this would "create a new class of out-of-economic-merit-order dispatch," leading to energy cost increases. Although many participants note that customers would benefit if increased NUG generation results from increased dispatch of least-cost resources, others warn that a formal mandate could have unintended consequences by compromising reliable operations in favor of pursuing cost savings.

The Edison Electric Institute and several utilities recommend that if a NUG wants to be included in a utility's economic dispatch queue, that generator must commit to provide its energy (and in some instances supporting ancillary services or other desirable unit commitment properties) at the specified price for a specified period of time, to meet the unit commitment schedule. Furthermore, they recommend that all suppliers in the queue should face contractual performance standards with penalties for failure to deliver. Presumably, these suggested requirements (and others such as the ability to follow AGC and provide other ancillary services such as voltage control) can be handled through contract revisions with appropriate compensation. On the same point, EPSA proposes that the industry develop technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms to support these routine transactions.

Several participants recommend greater sharing of reliability and operations information among dispatching entities. A complementary suggestion is to enhance economic dispatch by coordinating and optimizing economic dispatch decisions between adjacent control areas. The National Rural Electric Cooperative Association adds that, "greater planning and coordination across control areas is a concern to cooperatives that have load and/or resources embedded in multiple control areas."

Although meeting load reliably is the fundamental goal of economic dispatch, load forecasting is an unappreciated element of the dispatch challenge. Improving the quality of load forecasting will lead to improvements in both the reliability and cost-minimization impacts of economic dispatch.

Recommendations for Future Work

DOE and FERC should explore the EPSA and Edison Electric Institute proposals for more standard contract terms and conditions for NUG-to-buyer contracting and should encourage stakeholders to undertake these efforts, which should benefit the entire wholesale electric industry and its customers.

This study asked briefly about the economic dispatch methods in use, but did not receive detailed, easily comparable information about SCED, SCUC, and their implementation by different entities and areas. As discussed in Section 2, economic dispatch outcomes are affected by which entities administer the dispatch and how each interprets and executes its responsibilities. These questions deserve further study, which could be performed by the FERC-State Joint Boards established under new Section 223(b) and 209(a) of the Federal Power Act. The FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some investor-owned utilities, federal power agencies, ISOs, and RTOs, to determine how they conduct economic dispatch. These reviews could document the rationale for all deviations from pure least-cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. Entity-specific and regional business practices should be distinguished from regulatory, environmental, and reliability-driven constraints. These reviews, and FERC's ongoing reexamination of Order 888, should be alert for potential discrimination within economic dispatch or exclusion of qualified resources from dispatch opportunities (as discussed in Section 4). Although it is not clear that uniform economic dispatch rules and practices are needed across all dispatching entities, FERC and the states may need to rethink existing rules or craft new rules and procedures to allow NUGs and other resources to compete effectively and contribute to meeting customers' loads economically and reliably.

Several utilities indicated that they do not dispatch NUGs often because the utilities need instantaneous load-following regulation service under AGC, and the NUGs are incapable of providing such service or are unwilling to give up unit control to automatic dispatch. Entergy comments that "IPPs must be required to follow operating instructions with the same level of precision as Entergy's generating units (e.g., respond to AGC signals and comply with voltage schedules) if they are [to be] dispatched in lieu of Entergy's own units with AGC." The NUGs, in contrast, say they provide exactly the services that their contracts call for, and that few contract negotiations have requested or been willing to pay for AGC or other ancillary services features. The issue of NUG capabilities and willingness to provide such features with proper assurances and reliability – and the degree to which the dispatching entity needs them from every NUG – deserves further study.

NUGs suggest that a study is needed to look at non-ISO/RTO areas and examine real-time historical data about actual unit cost and schedule offers in comparison with actual dispatch patterns to determine whether NUG and utility-owned generation were truly dispatched in an unbiased fashion or whether more NUG production could have been dispatched (within the prevailing system conditions), producing greater savings for customers. The required data sets would have to be obtained from control areas under federal promise of confidentiality and data protection.

One industry observer proposes a study of areas that perform bid-based economic dispatch within real-time markets, to compare the market-clearing price outcomes and total costs against the true production costs of the actual units dispatched. This study would presumably examine two questions: how NUG bids in regulated utility dispatch (and utility-owned generator bids in centralized markets) compare to actual production costs, and how total electricity costs in centralized markets compare to total costs in the of the same production priced at its actual production cost. Such a study would require significant data or assumptions, incorporating energy costs and line losses within economic dispatch. It would have to recognize that a significant amount of the total energy consumed within a region comes from utility-owned generation and bilateral contracts that are not priced at the MCP. In addition, the study would need to incorporate ratepayer charges for capacity for utility rate-based plants and stranded cost recovery, any payments made under a market-capacity-revenue scheme, and acknowledge any savings that might accrue to ratepayers for NUG capital costs left unrecovered from an energy-only revenue stream.

Given the diversity of size and scope of the dispatch areas now operating across the nation and the need for economic dispatch to continue to produce affordable, reliable outcomes, the technical quality of current economic dispatch technology tools – software, data, algorithms, and assumptions – deserves scrutiny. Any enhancements to these tools, including identification and elimination of any resource biases in the calculation methods, will improve the reliability and affordability of the nation's electricity supplies.

As Section 3 discusses, the analyses of economic dispatch impacts that have been conducted to date do not fully address Congress' charge in Section 1234. These studies ask questions that are different from those itemized in the legislation and use analytical models and assumptions that are not wholly appropriate to answer Congress' questions. It would be useful to improve both the modeling and availability of data before attempting a new study to answer the questions specified in EPAct about the impacts of economic dispatch on different regions and customer classes across the U.S. DOE plans to address these matters in next year's report to Congress on economic dispatch.

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APPENDIX A

U.S. DEPARTMENT OF ENERGY SURVEY AND SAMPLE LETTER

Energy Policy Act of 2005, Section 1234
Economic Dispatch Study
Questions for Stakeholders

Section 1234 of the Energy Policy Act defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities." With that definition in mind, please answer as many of the following questions as you wish, attaching supporting materials such as studies or testimony that was filed in state or federal regulatory proceedings to support your answer.

Please send your response by e-mail to Economic.Dispatch@hq.doe.gov **no later than September 21, 2005**. Be sure to include the name and phone number of an individual who can answer any questions that may arise about your comments. Thanks in advance for your assistance with this study.

Alison Silverstein alisonsilverstein@mac.com
Joe Eto jheto@lbl.gov

Questions

1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

2) Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by nonutility generators, please explain the changes you recommend.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

U.S. Department of Energy
Washington DC 20585

Thursday, September 1, 2005

Mr. David Mohre
Executive Director
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, VA 22203

Dear Mr. Mohre:

Section 1234 of the Energy Policy Act of 2005 requires the Department of Energy to conduct a study on the benefits of economic dispatch in the electricity industry. In particular, the law directs the Department to study:

> (1) the procedures currently used by electric utilities to perform economic dispatch;
> (2) possible revisions to those procedures to improve the ability of nonutility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch; and
> (3) the potential benefits to residential, commercial and industrial electricity consumers nationally and in each state if economic dispatch procedures were revised to improve the ability of nonutility generation resources to offer their output for inclusion in economic dispatch.

The Act provides a definition of economic dispatch, and directs the Department to offer recommendations to Congress and the States for legislative or regulatory changes. This study must be completed in time for the Department to submit its report, with appropriate recommendations, to Congress and the states by November 7, 2005. DOE's Office of Electricity Delivery and Energy Reliability has tasked Joe Eto (at the Lawrence Berkeley National Laboratory) and Alison Silverstein to perform this study.

Because the tight schedule will not permit us to conduct fresh analysis of the topic, I have directed them to collect existing information and analysis about economic dispatch, and to draft a report drawing on that material. To that end, I understand that Alison Silverstein has spoken with you and that you have agreed to support this research by sharing this request with the members of your stakeholder organization and inviting them to share their views and information directly with us. The Department appreciates your support of this effort very much.

Attached is a short list of questions on how economic dispatch is now practiced, and how it might be changed in the future. We invite interested parties to prepare answers to these questions and send them **no later than September 21 to** Economic.Dispatch@hq.doe.gov, including such studies, testimony from regulatory proceedings, or other materials that can help Joe and Alison understand the issues and the submitter's views and concerns.

We realize that this schedule allows little time for gathering and submitting this material, so we thank you and your members in advance for your understanding and timely assistance. The statute requires DOE to update this study every year, so it is likely that issues not fully addressed in this initial study will get more attention in the future.

If you have any questions about the study, please contact me at David.Meyer@hq.doe.gov or Alison Silverstein at alisonsilverstein@mac.com.

Sincerely,

David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy

This same letter was sent to:

Ms. Sue Kelly at American Public Power Association
Mr. David Owen at Edison Electric Institute
Ms. Nancy Bagot at Electric Power Supply Association
Mr. John Anderson at Electricity Consumers Resource Council
Mr. James Torgerson at Midwest ISO for the ISO-RTO Council
Commissioner Jimmy Ervin, North Carolina Utilities Commission, for the National Association of Regulatory Utility Commissioners, Electricity Committee
Commissioner Phyllis Reha, Minnesota Public Utilities Commission, for the NARUC Energy Resources and the Environment Committee
Mr. David Cook at North American Electric Reliability Council

APPENDIX B

LIST OF SURVEY RESPONDENTS

Alabama Public Service Commission
Alberta Electric System Operator
Allegheny Power and Allegheny Energy Supply
Alliant Energy
Ameren Corporation

American Electric Power
American Public Power Association
American Transmission Company
Arizona Public Service/ Pinnacle West Corp.
Arizona Electric Power Cooperative, Inc

Arkansas Public Service Commission
Avista Utilities
Bonneville Power Administration
California ISO
California Public Utilities Commission

Calpine Corporation
Casazza, Jack
CenterPoint Energy
Cogeneration Association of California
Con Edison Energy

Constellation Energy Commodities Group
Consumers Energy
Dayton Power and Light
Detroit Edison
District of Columbia Public Service Commission

Dominion Resources Services
Duke Power
ECAR
Edison Electric Institute
Electric Power Supply Association

Entergy Services, Inc.
ERCOT
Florida Public Service Commission
Florida Reliability Coordinating Council
Hawaiian Electric Company

Idaho Power Company
Idaho Public Utilities Commission
INGAA Foundation
International Transmission Company
Iowa Utilities Board

ISO New England
ISO/RTO Council
Kansas City Power & Light
Kansas Corporation Commission
Kentucky Public Service Commission

Large Public Power Council
LG & E Energy Services Corp.
Lively, Mark B.
Maryland Public Service Commission
MEAG Power

MidAmerican Energy Company
Midwest ISO
Missouri Public Service Commission
National Rural Electric Cooperatives Association
NC Municipal Power Agency #1

Nebraska Public Power District
New Jersey Board of Public Utilities
New York Department of Public Service
New York Independent System Operator
New York Transmission Owners

NiSource
North Carolina Electric Membership Corp.
North Carolina Municipal Power Agency 1
North Carolina Utilities Commission
North Dakota Public Service Commission

Ohio Public Utilities Commission
Oklahoma Corporation Commission
Oklahoma Gas and Electric Company
Omaha Public Power District
Otter Tail Power Company

PacifiCorp
PJM Interconnection
Portland General Electric
PPL Corporation
Progress Energy (Carolina Power & Light)

Public Utility District 1 of Cowlitz County; PUD 2 of Grant County; PUD 1 of Pend
Oreille County (joint filing)
Santee Cooper
Sierra Pacific
South Carolina Electric and Gas
South Carolina Public Service Commission

Southern California Edison
Southern Companies
Southwest Power Pool, Inc.
SUEZ Energy North America
Tennessee Valley Authority

TXU Wholesale
Utah Public Service Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission
Western Farmers Electric Cooperative

Wisconsin Public Service Corporation
Xcel Energy

Department of Energy
Washington, DC 20585

Order No. 202-25-13

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.[3]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[4] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[5] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[6]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[4] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[5] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[6] *Id.* at 3-4.

transforming energy landscape."[7] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[8]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[9] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[10]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[11]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[12]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

[7] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[8] *Id.* at 11.
[9] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[10] *Id.* at 12.
[11] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[12] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.[13] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[14] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[15] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[16]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[17] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[18]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[19] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[20] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[21] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

[13] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[14] *Id.* at 2.
[15] *Id.* at 7.
[16] *Id.* at 9.
[17] *Id.* at 7, 9.
[18] *Id.*
[19] *Midcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).
[20] *Id.* P 84.
[21] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[22] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[23] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[24]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[25]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[26] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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[22] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.
[23] *Id*.
[24] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[25] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[26] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

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

A. From December 23, 2025, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

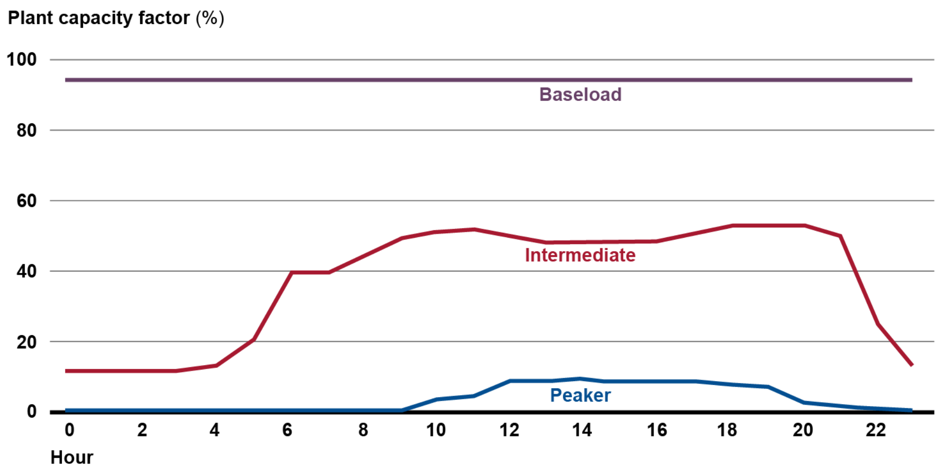
Electricity: Information on Peak Demand Power Plants

GAO-24-106145
Q&A Report to Congressional Requesters
May 21, 2024

Why This Matters

Peaker power plants are part of the U.S. energy infrastructure and help meet peak electricity demand. Peak demand generally occurs at times during the day when cooling and heating needs are generally the highest among households. Peakers are used to supplement other types of power plants, such as baseload plants, which run consistently throughout the day and night, and intermediate plants, which run mostly during the day and less at night (see fig. 1).

Figure 1: Illustrative Example of Annual Average Hourly Capacity Factors, by Plant Type



Source: GAO Analysis of Environmental Protection Agency data. | GAO-24-106145

Note: A plant's capacity factor is the percent of energy it produced of the total energy it could have produced during a certain time frame if it operated continuously at full power.

Peakers may be less efficient than other types of plants—such as intermediate and baseload plants—because they undergo frequent startups using comparatively large amounts of fuel. Further, environmental advocates and some congressional leaders have expressed concerns that peakers may also negatively affect the air quality in communities—which may be historically disadvantaged or disproportionately low income—around the plants.

We were asked to examine pollution from peakers across the nation. We are providing information on the number and locations of peakers in the U.S.; the proximity of peakers to disproportionately low-income, and historically disadvantaged racial or ethnic populations; the extent to which they emit pollutants and how these pollutants affect the health of people exposed; alternatives for replacing them; and potential challenges of replacing them.

Key Takeaways

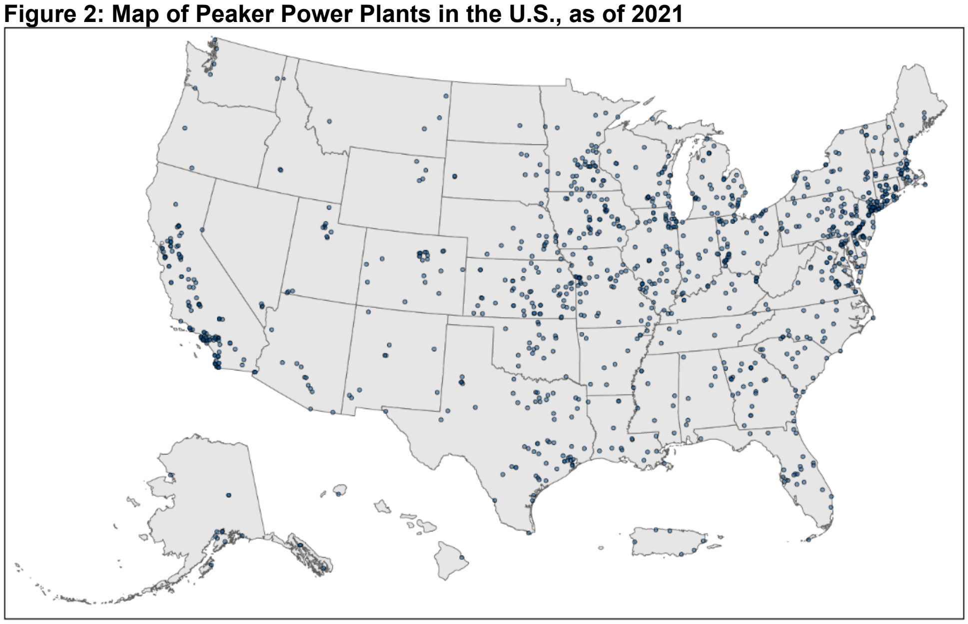
- Historically disadvantaged racial or ethnic communities tend to be closer to peakers.

- Fossil-fueled peakers are primarily fueled by natural gas and emit air pollutants associated with various negative health effects, including on respiratory, cardiovascular, and nervous systems.
- Alternatives are available that could potentially replace or provide similar services as peakers, but we identified challenges for their use related to costs, reliability, space, and location.

How many peakers are there in the U.S., and where are they located?

We identified 999 peakers in the U.S. in 2021, based on our analysis of Environmental Protection Agency (EPA) data (see fig. 2).[1] For the purpose of our report, we generally define peakers as plants that use fossil fuels, including natural gas, coal, and oil; have a capacity factor (the percent of energy produced over a certain time frame, out of what could have been produced at continuous full power operation) of 15 percent or less; and have a nameplate capacity (the designed full-load sustained output of a facility) of greater than 10 megawatts (MW) of electricity.[2] Most of these peakers are fueled by natural gas (see table 1). In 2021, these peakers accounted for 3.1 percent of annual net generation and 19 percent of total nameplate capacity for all power plants.

Figure 2: Map of Peaker Power Plants in the U.S., as of 2021



Source: GAO analysis of Environmental Protection Agency Emissions & Generation Resource Integrated Database (eGRID). | GAO-24-106145

Note: Alaska, Hawaii, and Puerto Rico are shifted for display purposes. We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity. Areas with multiple peakers appear darker than those with only one. This map does not identify whether there is any statistically significant spatial association or differentiate whether peakers are more concentrated in certain geographies relative to underlying population size.

Table 1: Total Net Electricity Generation and Total Nameplate Capacity of Peaker Power Plants, by Primary Fuel Type, 2021

Plant primary fossil fuel type	Number (%)	Total net generation (MWh)[a] (%)	Total nameplate capacity[b] (MW)
Natural gas	698 (69.87)	106,791,342 (82.75)	190,373
Oil	267 (26.73)	2,646,700 (2.05)	23,991
Coal	33 (3.30)	19,617,924 (15.20)	22,904
Other[c]	1 (0.10)	-9,824 (0.00)[d]	99
Total	**999 (100)**	**129,046,142 (100)**	**237,367**

Source: GAO analysis of Environmental Protection Agency data. I GAO-24-106145

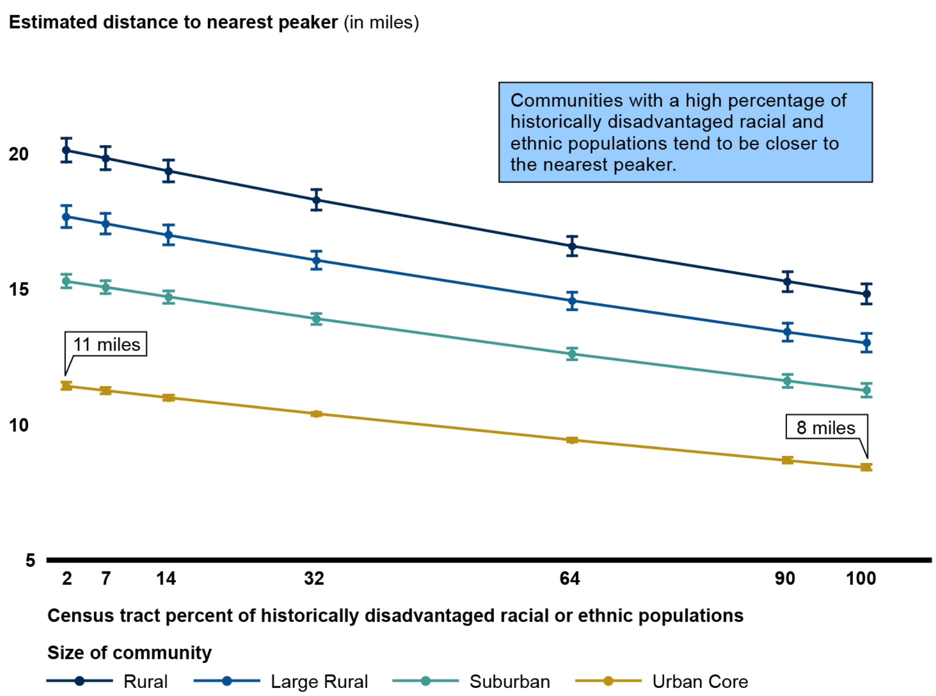
Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity.

[a]MWh = megawatt hour
[b]Nameplate capacity is the maximum output of electricity a power plant can produce without exceeding design thermal limits.
[c]This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[d]This plant has a negative net generation because electricity consumed by the plant exceeds the gross generation of the plant.

How closely are peakers located to historically disadvantaged and low-income communities?

We found that historically disadvantaged racial or ethnic communities (i.e., census tracts with higher percentages of historically disadvantaged racial or ethnic populations) are associated with being closer to peakers (see fig. 3).[3] To perform this analysis, we developed a statistical model to assess how community demographics are associated with proximity to peakers.[4] We tested this model with four alternative definitions of peakers and found that historically disadvantaged racial or ethnic communities are associated with being closer to peakers for all four definitions.[5] For example, based on our model and main definition of a peaker, a community that is 71 percent historically disadvantaged is expected to be 9 percent closer to the nearest peaker than the average community, which is 40 percent historically disadvantaged.[6] In addition, we found that the estimated distance to the nearest peaker varies according to population density, where urban communities have smaller estimated distances to the nearest peaker when compared to otherwise similar rural or suburban communities.

Figure 3: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Historically Disadvantaged, by Population Density

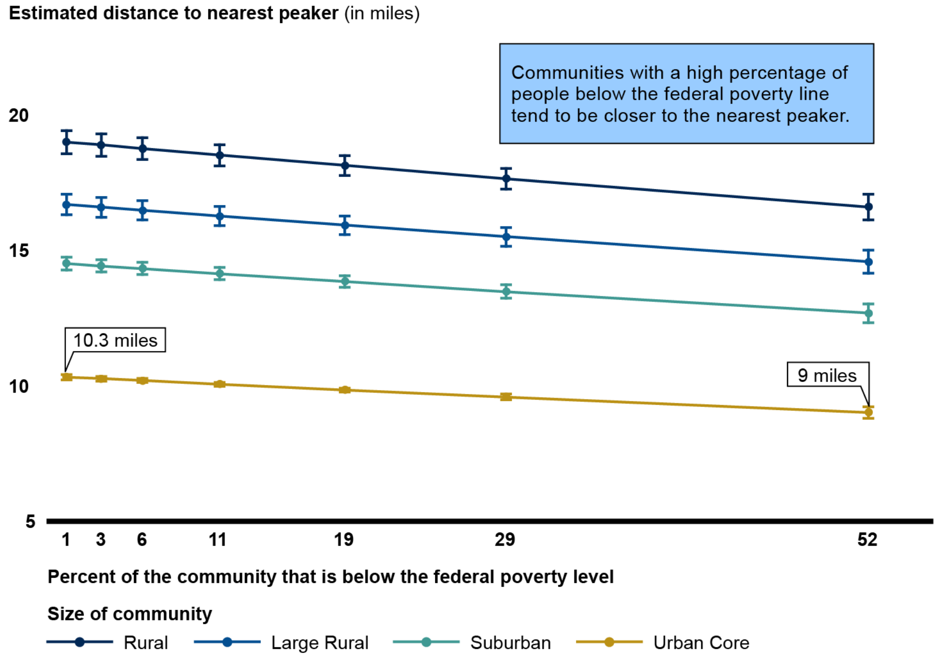


Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

We found mixed results for income. Specifically, for three of our four definitions of a peaker, we found that communities with higher percentages of people below the federal poverty level were statistically significantly closer to the nearest peaker (see fig. 4).[7] Income was not statistically significant for our fourth definition.[8]

Figure 4: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Below the Federal Poverty Level, by Population Density



Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results for three definitions, but insignificant results for one definition. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

To what extent do peakers emit pollutants, and how can these pollutants affect the health of people exposed?

When operating, peakers emit similar types of pollutants to other power plants that also use fossil fuels, and these pollutants are associated with various negative health effects, according to existing literature.

Pollutants

Compared to non-peakers, peakers emitted more pollutants—such as nitrogen oxides and sulfur dioxide—per unit of electricity generated, but fewer total annual pollutants in 2021, according to our analysis of EPA data (see table 2).[9] In other words, peakers emit less in total because there are fewer peakers and they operate less frequently overall than non-peakers. However, when they do operate, they emit more pollution per unit of electricity produced. For example, the median sulfur dioxide emission rate for natural gas fueled peakers was 1.6 times more per unit of electricity generated than the median emission rate for non-peakers. Conversely, total annual sulfur dioxide emissions from peakers were 96.8 percent lower than total non-peaker annual sulfur dioxide emissions. Overall, peakers contributed 3 percent of the total annual sulfur dioxide emissions and 9 percent of total annual nitrogen oxide emissions.

Table 2: Sulfur Dioxide and Nitrogen Oxide Emissions from Fossil-fueled Peaker and Non-peaker Power Plants with Nameplate Capacity Greater than 25 MW, 2021

	Fuel Type	Peaker	Non-peaker
Median sulfur dioxide emission rate (pounds per megawatt hour)	Natural Gas	0.008[b]	0.005
	Coal	2.487	1.308
	Oil	4.218	2.174
	Other[a]	—	0.027
	All fuel types	**0.009**	**0.008**
Median nitrogen oxides emission rate (pounds per megawatt hour)	Natural Gas	0.949[b]	0.156
	Coal	1.554	1.330
	Oil	15.014[b]	3.152
	Other	—	0.670
	All fuel types	**1.272[b]**	**0.468**
Total annual sulfur dioxide emissions (tons)	—	32,111	1,014,787
Total annual nitrogen oxides emissions (tons)	—	83,874	885,345

Source: GAO analysis of Environmental Protection Agency data. | GAO-24-106145

Note: This analysis is limited to fossil-fueled plants with a nameplate capacity greater than 25 megawatts of electricity (1,605 plants) because plants of this size are required to report certain emissions, including sulfur dioxide and nitrogen oxides. Peakers in this analysis include plants with a capacity factor of 15 percent or less, and non-peakers include baseload and intermediate plants that supply more consistent power throughout the day. This analysis excludes plants that had incomplete emissions or generation data (57 plants).

[a]This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[b]Statistically, the median for peakers is significantly different from the median for non-peakers at the 0.05 level.

In addition to sulfur dioxide and nitrogen oxides, ground-level ozone and particulate matter are pollutants related to the operation of peaker plants. Ground-level ozone is formed through chemical reactions between nitrogen oxides—emitted by peakers—and volatile organic compounds. Particulate matter is a mixture of solid particles and liquid droplets found in the ambient air and can be directly emitted from power plants or formed by chemical reactions involving pollutants such as sulfur dioxide that are emitted by peakers.

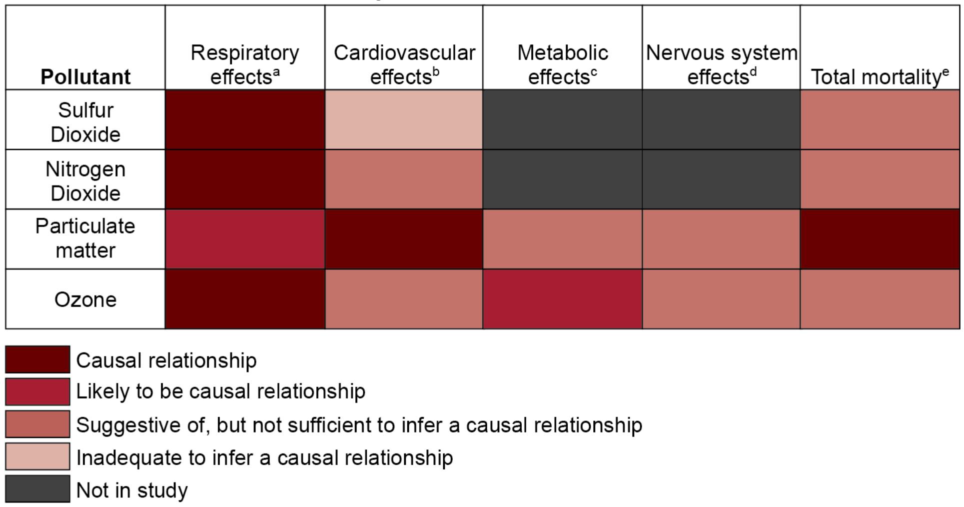
Peakers may have higher median emission rates per unit of electricity generated because of the nature of their operations. According to EPA, emissions generally increase under partial load conditions, which is how peakers operate.[10] Further, peakers typically do not have emissions control technologies, according to EPA officials.

Health effects

Multiple pollutants that are emitted from peakers and other plants are associated with various negative health effects for the people exposed, according to federal agency reports we reviewed.[11] In particular, EPA's Integrated Science Assessments identified causal relationships between short-term exposures to four key pollutants (nitrogen dioxide, sulfur dioxide, particulate matter, and ozone) and health effects that vary in degree of severity and duration (see fig. 5).[12] For instance, short-term exposure to sulfur dioxide—the indicator for sulfur oxides used in EPA's assessments—can lead to negative respiratory effects, such as decreased lung function, cough, chest tightness, and throat irritation.

Figure 5: EPA's Assessment of Causal Determinations for Relationships between Short-Term Exposure to Certain Air Pollutants and Health Effects

Health effects from short-term exposure



Source: Environmental Protection Agency (EPA) Integrated Science Assessments. | GAO-24-106145

Notes: Short-term exposure refers to time periods from minutes to 1 month.

We used sulfur dioxide and nitrogen dioxide in the figure because they are the indicators for sulfur oxides and nitrogen oxides, respectively, and sources of health effects studies for causal determinations in EPA's integrated science assessments.

The causal determinations related to particulate matter in the figure are associated with exposure to particles that are 2.5 microns or less in diameter. Causal determinations are also made for exposure to particles of other sizes (e.g., 10 microns or less).

We selected four of the six criteria air pollutants because we deemed them the most relevant pollutants to our analysis. This figure focuses on health effects of short-term exposures to these four pollutants. EPA's Integrated Science Assessments also include causal determinations for long-term exposures and for health effects that are not specific to short-term or long-term exposures (e.g., cancer and pregnancy and birth outcomes for particulate matter exposure).

[a]Respiratory effects include decreased lung function, cough, chest tightness, and throat irritation.
[b]Cardiovascular effects include heart attack, stroke, and changes in blood pressure.
[c]Metabolic effects include changes in blood glucose level and inflammation.
[d]Nervous system effects include brain inflammation and oxidative stress.
[e]Total mortality includes all nonaccidental causes of mortality and is informed by findings for the spectrum of morbidity effects (e.g., respiratory, cardiovascular) that can lead to mortality.

Additionally, mercury emitted from peakers, and other sources, is associated with neurological health effects, including tremors and disturbances of vision and cognitive performance, according to federal agency reports we reviewed.[13]

According to EPA, elevated temperatures can directly increase the rate of ground-level ozone formation, worsening air quality effects on human health. Elevated temperatures can also drive increased electricity demand, which is associated with the operation of peakers. As previously noted, the operation of peakers further increases ozone—and other pollutant—levels, exacerbating air quality issues and poor public health days.

What are some available alternatives that can potentially replace fossil-fueled peakers?

Available alternatives such as battery storage systems could potentially replace fossil-fueled peakers, according to studies we reviewed and stakeholders we interviewed (see table 3).[14] These alternatives could decrease emissions associated with peakers.

Table 3: Examples of Alternatives That Could Potentially Replace Fossil-fueled Peakers

Alternative type	Potential examples
Electricity generation and storage: Alternatives able to store or generate electricity to directly replace the output of peakers.	• Battery storage, which consists of rechargeable batteries charged during off-peak times, and discharged during times of peak demand. • Pumped hydroelectric storage is an energy storage system that pumps water to higher

	levels during off-peak times and releases said water to turn turbines and generate electricity during peak times. • Thermal energy storage is an energy storage system that stores thermal energy, which is released to power turbines during times of peak demand. • Renewable energy systems (e.g., wind and solar) may be paired with energy storage. For example, adding roof-top solar and battery storage to houses could reduce the demand for peakers in adjacent areas.
Transmission and distribution infrastructure improvements: Upgrades or expansions to increase the capacity of current infrastructure that transmits and distributes electricity. These upgrades or expansions may help enable existing underutilized plants to meet peak demand.	• Upgrading transmission lines by expanding the capacity of current lines or adding additional lines to solve bottlenecks in the grid and allow electricity to be moved to other locations. • Upgrading distribution systems by expanding or adding infrastructure to deliver electricity more efficiently.
Efforts to decrease consumers' use of power during peak times: Efforts to incentivize consumers to reduce or shift electricity use during times of peak use to off-peak times.	• Consumer based demand initiatives that provide lower prices for energy consumption during off peak hours, such as overnight electric vehicle charging. • Various energy efficiency programs.

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Note: These alternatives are not comprehensive. For example, there are other alternatives that are not ready for grid-scale deployment and are in early development stages, such as other types of energy storage technologies.

What are the potential challenges of replacing peakers?

Potential challenges to replacing peakers with non-emitting or non-combustion alternatives include challenges related to cost, reliability, and location, according to studies we reviewed and stakeholders we interviewed (see table 4).

Table 4: Potential Challenges Associated with Alternatives for Replacing Fossil-fueled Peakers

	Alternatives		
	Electricity generation and storage	**Transmission and distribution improvements**	**Efforts to decrease consumers' use of power during peak times**
Cost: some alternatives may have higher capital and operating costs compared to current fossil-fueled peakers	✓	✓	✓
Reliability: current alternatives may not be able to provide the same reliability of current fossil-fueled peakers	✓	—	✓
Location: alternatives may not be able to be installed because of space and location concerns	✓	✓	—

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Replacing peakers, some of which have already paid off their capital costs, will likely lead to additional up-front or operating costs compared to keeping the existing peakers. Further, the U.S. Energy Information Administration (EIA) reported that solar and wind plants had higher average construction costs compared to natural gas-fired plants in 2023.[15]

Similarly, some alternatives may create reliability challenges. For the grid to be reliable, the energy resources in an area need to be able to supply power to meet peak demand for as long as it lasts, according to U.S. Department of Energy (DOE) officials. Some battery storage systems provide up to 4 hours of output, but peak demand may be longer in some areas. In contrast, a fossil-fueled peaker is only limited by fuel availability—a natural gas-fueled peaker could keep operating so long as natural gas is available.

Some alternatives may also run into space constraints or location concerns. For example, a densely populated urban community likely would not have sufficient space for a large renewable energy system paired with battery storage to help meet peak electricity demand.

In general, recognizing these challenges, some officials with whom we spoke identified trends that may lead to the continued use of fossil-fueled peakers. According to DOE officials, some U.S. peakers may not be able to be replaced with existing alternatives within cost, reliability, and location constraints. Combinations of electricity generation and storage technologies, transmission and distribution improvements, and efforts to decrease consumer's use of power during peak times may be too costly for consumers in some areas to provide an adequate level of grid reliability. Further, officials at two utilities noted that due to increased use of intermittent renewable resources on the grid (e.g., wind and solar power), the continued use of peakers to meet electricity demand may be necessary to maintain grid reliability. For example, the availability of sunlight for a solar installation may not match with peak demand in the evening when the sun goes down. Therefore, additional supplemental energy resources would be needed to fill the gaps and meet demand.

Agency Comments

We provided a draft of this report to DOE, EPA, and the Federal Energy Regulatory Commission (FERC) for review and comment. DOE and EPA provided technical comments, which we incorporated, as appropriate. FERC did not have any comments on the report.

How GAO Did This Study

To identify the number and location of peakers, we analyzed data from EPA's Emissions and Generation Resource Integrated Database and EIA power plant data. We generally define peakers as plants that use fossil fuels, have a capacity factor of 15 percent or less, and have a nameplate capacity of greater than 10 megawatts of electricity. In addition to the primary definition of peakers used in this report, we also considered several other definitions including plants with a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers).

To describe the relationship between community demographic characteristics (e.g., race, ethnicity, and income)[16] and distance to a peaker, we developed a statistical model that includes controls for population density (e.g., rural or urban), climate, and other factors. (See app. I for more detail.)

To identify air quality effects associated with peakers, we analyzed data from EPA's Emissions and Generation Resource Integrated Database to describe emissions and emission rates from peakers versus non-peakers. Our emission rate analysis focused on plants with a nameplate capacity greater than 25 MW because EPA regulations define that as the threshold for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program.[17] We reported median emission rates because the median is robust to outliers. For example, the top three emitting plants for sulfur dioxide had emission rates in the hundreds of pounds per megawatt, and two of the three had nitrogen oxide emission rates in the thousands of pounds per megawatt. Officials from EPA and EIA told us these plants were likely used infrequently as peakers, or they generated electricity for on-site consumption.

To identify health effects, we reviewed reports from EPA, the Agency for Toxic Substances and Disease Registry, and the Centers for Disease Control and Prevention that assess the health effects of exposure to selected pollutants that are emitted from, or related to, emissions from power plants. We also conducted a systematic literature search of peer reviewed journals and grey literature published from 2013–2023 in databases such as ProQuest Research Library and Natural Science Collection, and Dialog Energy & Environment collection. We conducted an additional search to identify studies on the health effects of peakers in the same databases, and additionally PubMed, published from 2018–2023. Based on these searches, conducted from November 2022 to March 2023, we did not identify studies that looked specifically at health effects of peaker plants.

To identify available alternatives for and challenges to replacing peakers, and to inform our other reporting questions, we conducted a systematic literature search. We conducted searches of databases such as ProQuest Research Library, Harvard Kennedy School Think Tank Search, SCOPUS, and Dialog Energy and Environment collection to identify studies and grey literature published between 2013 and 2023 that were relevant to our research objectives. We performed these searches from November 2022 to March 2023. Additionally, we reviewed studies recommended to us by stakeholders.

To inform all our questions, we also interviewed federal officials from DOE, EPA, and FERC, and state officials from California, Georgia, Indiana, New York, and Texas. We selected these states based on their geographic diversity and electricity market structure (e.g., traditionally regulated or deregulated). We also interviewed stakeholders representing 13 industry and nongovernmental organizations with a diversity of perspectives about peakers. The sample of officials and stakeholders we interviewed is non-generalizable.

We used data from EPA, EIA, and the U.S. Census Bureau. We reviewed information about the data and the systems that produced them, and interviewed agency officials knowledgeable about the data. We requested and received written responses about data reliability from EPA and EIA. We determined that the data were sufficiently reliable for the purposes of our reporting objectives.

We conducted this performance audit from July 2022 through May 2024 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

List of Addressees

The Honorable Jamie Raskin
Ranking Member
Committee on Oversight and Accountability
House of Representatives

The Honorable Alexandria Ocasio-Cortez
House of Representatives

The Honorable Yvette D. Clarke
House of Representatives

We are sending copies of this report to the appropriate congressional committees, the Secretary of Energy, the Administrator of EPA, and the Chairman of FERC. In addition, the report is available at no charge on the GAO website at https://www.gao.gov.

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Appendix I: Technical Appendix

To assess the relationship between the distance to the nearest peaker and the demographic characteristics of a community (i.e., census tract), we developed an ordinary least squares regression model where the outcome is distance and the covariates are the demographic characteristics of a community. These characteristics are the percent of a community that are from historically disadvantaged racial or ethnic populations and percent of a community at or below the federal poverty level. We also controlled for the community's climate, population density, and distance to the nearest power plant.

The resulting coefficients from our model allowed us to

- describe whether there was a statistically significant relationship, and if so, the direction of the relationship. For an otherwise similar community and for significant coefficients, a negative coefficient means communities with higher values of the covariate are associated with being closer to a peaker, whereas a positive coefficient means they are further.
- quantify the estimated distance in miles to the nearest peaker for communities with higher rates of disadvantaged populations and for those with lower rates of this demographic, but that are otherwise similar.
- estimate the percentage decrease in distance to the nearest peaker for a community that is "above average" on a demographic, compared to an otherwise similar, but average community. Note we define "above average" as one standard deviation above the sample value of that demographic.

Model Variables/Data Sources

- Distance. We assigned to each community the distance between its central point and the central point of the nearest peaker's property, and this formed the outcome of our model. Similarly, we assigned to each community the distance between its central point and the nearest power plant, which was included as a control in our model. We used great circle distances.
- Demographics. We used American Community Survey (ACS) 2021 5-year estimates for the percent of people in a community who are below the federal poverty level and the percent of people in the community who are from historically disadvantaged racial or ethnic populations. Specifically, individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races.
- Climate. We included the county level heating and cooling degree days from 2017–2019 as indicators of electricity demand for heating and cooling. These indicators are intended to control for climate variations within states in our model. These data are not available for Alaska or Hawaii; therefore, any models with climate data excluded these states. We assessed models that were otherwise similar, but that excluded climate data (hence included Alaska and Hawaii), and the results were consistent. We calculated county level averages using data accessed from Columbia University on daily minimum and maximum temperatures on a 2.5x2.5-mile grid for the contiguous United States.
- Population density. We used U.S. Department of Agriculture (USDA) Economic Research Service (ERS) 2010 rural/urban commuting area codes (RUCAs), the most recently available data, with a four-category classification scheme based on Secondary RUCA Codes to classify each tract's population density.

- We associated the 2019 USDA ERS tract codes with 2020 U.S. Census tracts using the U.S Census tract relationship files between the 2020 census tract entities and the 2010 tract entities.
- In cases where there is more than one record for a 2020 tract, we select the tract that has the largest area of intersection.

- Definition of peakers. We identified plants as peakers using each of the four definitions described and ran separate models for each definition. To capture potential variation within a plant in recent years, the peaker status in our regression is based on 2018–2021 Environmental Protection Agency (EPA) data.

Model Specifications. We took several steps to assess the validity and sensitivity of our models.

- Statistical significance was determined at the 0.05 level of significance.
- Our distance and climate measures were on the logarithm scale to satisfy model assumptions, such as normality of errors, and to scale the effect of these factors and account for non-linearity.
- We used robust standard error estimation.
- We included fixed-effects for states to account for state-to-state variation.
- We assessed models that were otherwise similar to our primary model, but that excluded climate, and results were consistent. This allowed us to assess the sensitivity of our results when including Alaska and Hawaii, states that did not have weather data.
- We examined the four different definitions of peaker described in this report, and conclusions regarding race or ethnicity and population density were consistent across peaker definitions, but conclusions regarding poverty were inconsistent. In particular, models that did not factor in the plant startup time when defining a plant as a peaker resulted in a significant association with poverty, whereas only one definition of peaker that incorporated plant startup time was significant for the primary definition of poverty.
- We examined an alternative specification of race and ethnicity that separately accounted for race and ethnicity within the model. The results were consistent with our primary model and models that used alternative definitions of peaker.
- We examined an alternative specification of poverty that examined the percent of a community that was at twice the federal poverty level, and results were again inconsistent for different definitions of peakers.
- While we chose to examine race, ethnicity, and poverty, other measures of vulnerability exist, and are often correlated. Therefore, similar results might be discovered when examining other measures of vulnerability. Some of these measures—such as the ACS 5-year estimates for percent of a tract that speaks English less than “very well,” or the Council on Environmental Quality (CEQ) Climate and Economic Justice (CEJ) Screening Tool—have large margins of error, do not assess margins of error, or have higher rates of missingness when compared to our selected demographics. Additionally, the CEQ Screening Tool uses the census tract boundaries from 2010 because many of the data sources in that tool use the 2010 census boundaries, but those boundaries are not consistent with most recently available 2020 U.S. Census and ACS demographics. Further, the CEQ Screening Tool uses a binary classification of

communities as "disadvantaged" or "not" based on indicators of burdens, but other classifications exist. We chose to use continuous measures of the proportion of population in different race, ethnicity, and poverty groups to assess the association between communities with a range of percentages, from low or high, of their populations with these demographics, rather than using a definitive, yet subjective, classification of a community as "disadvantaged" or "not."

Limitations. We took several steps to assess the validity and sensitivity of our models, but certain limitations remain. Importantly, our measure of distance does not include other aspects—such as stack height, wind speed, or wind direction—that play important roles in the dispersion of pollutants and potential populations exposure. In addition, although we include some variables to control for factors that could influence the findings, it is possible that other controls might be important and were not accounted for in our model. Inclusion of a state fixed-effect partially addresses this by controlling for factors that vary by state. Still, our findings of associations between distance to peakers and historically disadvantaged racial and ethnic communities does not imply any causal relationships.

Endnotes

[1]2021 data was the most recent year of data available from EPA.

[2]There is no standard definition of a peaker plant. We considered several other definitions for peakers in our analysis. These included plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers).

[3]We use the terms "historically disadvantaged racial or ethnic populations" and "historically disadvantaged communities" to include individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races. Census tracts are small, relatively permanent statistical subdivisions of a county.

[4]Executive Order 13985 of Jan. 20, 2021, "Advancing Racial Equity and Support for Underserved Communities Through the Federal Government," 86 Fed. Reg. 7009 (Jan. 25, 2021), charged the federal government with advancing equity for all, including communities that have long been underserved, and identifying and overcoming systemic barriers to opportunity for such communities in federal policies and programs. We chose race and ethnicity, and poverty as two dimensions of disadvantage. Both measures are components of the EPA's Environmental Justice Screening and Mapping Tool. See appendix I for additional details.

[5]In our model, we primarily focus on peakers with a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts, as previously noted. We also ran results with other definitions including plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers). We found consistent results in the relationship between race/ethnicity and distance to the nearest peaker regardless of definition.

[6]The value of 40 percent corresponds to our sample average for this demographic, whereas 71 percent corresponds to one standard deviation above the sample average.

[7]References to the "federal poverty level" in this document are based on the Census Bureau's poverty threshold, which follows the Office of Management and Budget's Directive 14. According to the Census Bureau, it uses a set of money income thresholds that vary by family size and composition to detect who is in poverty. If a family's total income is less than that family's threshold, then that family, and every individual in it, is considered to be in poverty. In our model, we look at the percent of families in a Census tract whose income in the past 12 months is below the federal poverty level.

[8]In the case of poverty, for peakers defined as plants with a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes, the association (regression coefficient) between a tract's poverty rate and distance to peakers is insignificant at the 0.05 level.

[9]Our emission rate analysis focuses on fossil-fueled peakers and non-peakers with a nameplate capacity greater than 25 megawatts because that is a threshold defined in EPA regulations for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program. *See* 40 C.F.R. Part 75.

[10]Environmental Protection Agency, Combined Heat and Power Partnership, *Catalog of CHP Technologies*, September 2017.

[11]We conducted a literature search to identify health effects related to peakers specifically, but our literature search did not identify any such studies (e.g., studies that compare health effects based on proximity to peakers or attribution of ambient air pollution attributed to peakers). Our search strategy included conducting a systematic literature search of peer-reviewed journals as described in the section "How GAO Did This Study." We also inquired about published studies on the health effects of peakers during our interviews with agency officials and stakeholders. Our search identified some studies of the health effects related to retirements of coal fired power plants (for example, see Joan A. Casey, Deborah Karasek, Elizabeth L. Ogburn, Dana E. Goin, Kristina Dang, Paula A. Braveman, and Rachel Morello-Frosch, "Retirements of Coal and Oil Power Plants in California: Association with Reduced Preterm Birth Among Populations Nearby," *American Journal of Epidemiology*, vol. 187, no. 8 (2018), 1586-1594, DOI 10.1093/aje/kwy110). We did not conduct a systematic review of such articles because they are not peaker-specific, and because a low percentage of peakers are coal-fired.

[12]EPA's Integrated Science Assessments integrate information on criteria pollutant exposures and health effects from controlled human exposure, epidemiologic, and toxicological studies to form conclusions about the causal nature of relationships between exposure and health effects. For more information, see the EPA Preamble for Integrated Science Assessments at Preamble To The Integrated Science Assessments (ISA) | ISA: Integrated Science Assessments | Environmental Assessment | US EPA (accessed 8/30/2023).

[13]Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Mercury: Draft for Public Comment,* CS274127-A (April 2022). Environmental Protection Agency, National Center for Environmental Assessment, *Mercury, Elemental*, Integrated Risk Information System (IRIS) CASRN 7439-97-6.

[14]The discussion in this section applies to fossil-fueled peakers as defined above–those with a capacity factor less than 15 percent and a nameplate capacity greater than 10 megawatts—as well as to fossil-fueled peakers more broadly.

[15]U.S. Energy Information Administration, US Construction Costs Dropped for Solar, Wind, and Natural Gas-fired Generators in 2021 (October 3, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60562.

[16]See appendix I for additional details.

[17]*See* 40 C.F.R. Part 75.

Integrated Resource Plan

NIPSCO 2024 SUMMARY

NIPSCO
A NiSource Company

NIPSCO.com/IRP

BACKGROUND

For a balanced, sustainable energy future, NIPSCO is committed to transitioning to diverse, cleaner energy solutions in a manner that is driven by real-world data and economics and that ensures continued protections and benefits to the customers and communities we serve across Northern Indiana. NIPSCO presents this Integrated Resource Plan, or IRP, to the Indiana Utility Regulatory Commission (IURC) every three years.

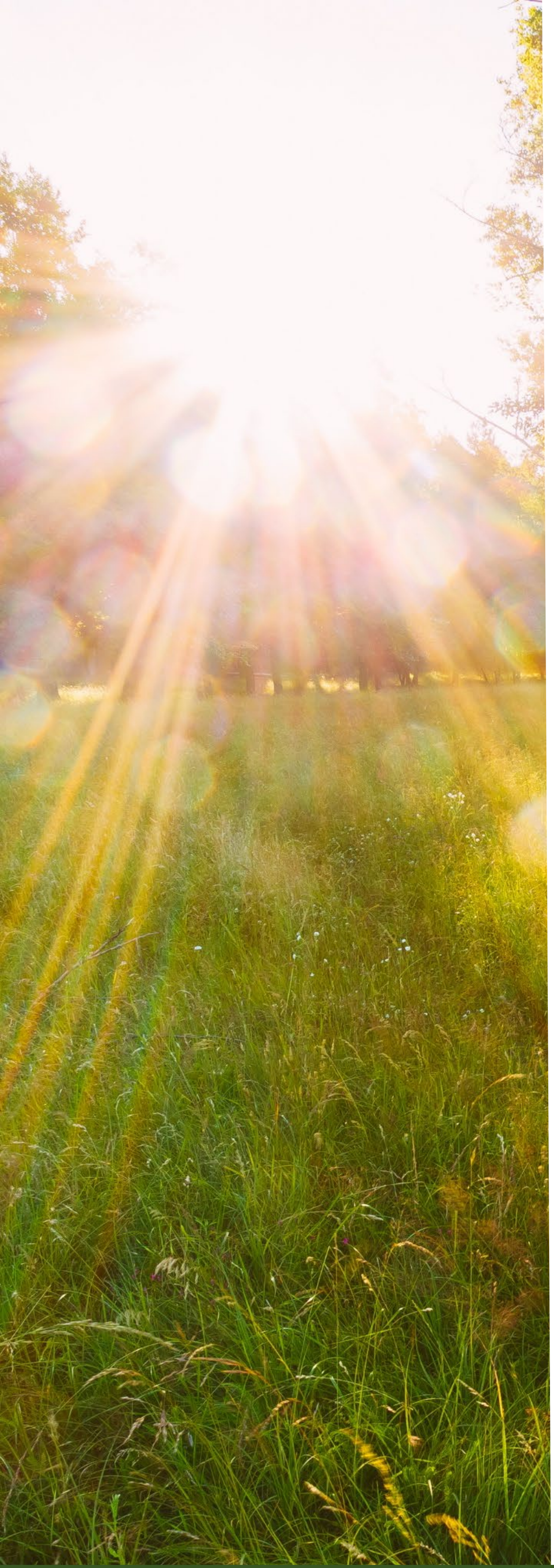
Since NIPSCO introduced our last plan in 2021, we've continued to build out our electric generation portfolio with the completion of wind, solar, and storage projects and gained regulatory approval for our natural gas peaking resource that will be located at the R.M. Schahfer Generating Station property. We look forward to soon adding more renewable energy resources to our portfolio, including battery storage technology that will support the safety and reliability of the energy we provide.

As we evolve alongside our communities and the rapidly changing energy landscape, we use a forward-looking analysis framework to create our updated IRP, which establishes a roadmap 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 IRP outlines a path that keeps our customers' best interests at the forefront and allows NIPSCO to be flexible as we move forward. As new load comes on to NIPSCO's system and as regulations continue to evolve, we will ensure we have the appropriate generation resources to meet the reliability and energy needs of all of our customers.

EVOLVING ALONGSIDE OUR COMMUNITIES

The modeled portfolios throughout the IRP are regulatory requirements made in connection with integrated resource planning that contain the Company's forward-looking assumptions. These modeled portfolios are not an indication of actual future events and should not be relied upon as such.



ABOUT THE 2024 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 2024 plan reflects the dynamic changes taking place in the electric industry, the changing needs and behaviors of our customers, and evolving policy and market rules.

Our 2024 IRP captures this evolving environment and creates a highly flexible plan that achieves the following:

- Maintains the window to retire all remaining coal-fired generation by 2028, with our largest remaining plant retiring by 2025
- Retires aging gas peaking units by 2027
- Continues replacement of retiring 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 storage, and new natural gas peaking resources
- Prepares for potential hyperscaler data center load with a combination of baseload and peaking natural gas generation, battery storage, and renewable capacity
- Explores potential alternatives on the path toward further decarbonization of the generation portfolio, including hydrogen generation, carbon capture, and emerging energy storage technologies
- Positions the portfolio to meet reserve margin obligations associated with Midcontinent Independent System Operator Inc.'s (MISO) new Direct Loss of Load (D-LOL)[1] market construct, which will materially impact resource accreditation and NIPSCO's seasonal load obligation
- Prepares for compliance with the Environmental Protection Agency's (EPA) Greenhouse Gas (GHG) rule and provides NIPSCO flexibility for several potential pathways toward its Net Zero emissions target based on potential future technological developments

[1] On October 28th, 2024, the Federal Energy Regulatory Commission (FERC) approved MISO's D-LOL methodology for calculating and awarding capacity value to generating facilities. This new method of capacity accreditation will impact intermittent resources most significantly.

ABOUT NIPSCO

Approximately 500,000 Northern Indiana homes and businesses in 32 counties depend on NIPSCO each day for safe, reliable and affordable energy.

NIPSCO IS INTEGRATED INTO THE BROADER ENERGY MARKETPLACE

NIPSCO's service territory and resources are part of the 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; and
- 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 MISO capacity and energy markets, 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 the 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:
    - Development of new methods of calculating capacity credit for resources
    - Establishment of participation models for distributed energy resources (DER) and long-duration storage energy resources (LDES)

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.

NIPSCO'S 2024 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 2024 IRP, several key 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 intermittent resources under MISO's D-LOL capacity accreditation methodology
- **Carbon Emissions and Environmental Policy Trends**, including assessment of diverse portfolio options under the EPA GHG rule for fossil-fueled resources and NIPSCO's goal to achieve Net Zero carbon emissions by 2040
- **Flexibility & Adaptability of the Portfolio** to meet potential new sources of load growth in the NIPSCO territory while still planning to meet the needs of all NIPSCO customers

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.

NIPSCO's 2024 IRP is based on the best available information at the time this IRP is submitted. 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, carbon capture, utilization, and sequestration (CCUS), and hydrogen-based technology - and demand side resources, as well as changing local and federal laws and environmental regulations.

ENGAGE CUSTOMER AND PUBLIC STAKEHOLDERS

Indiana's energy future is everyone's concern. That's why any discussion of resource planning for the future must invite 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 2024 IRP in April when we hosted a public meeting at Fair Oaks Farm in Fair Oaks, Indiana. Four additional public meetings followed in June, August, and October (2), each one hosted in-person with a virtual participation option as well. NIPSCO also hosted additional virtual technical webinar workshops to discuss IRP topics in greater detail with interested stakeholders. Each of the public stakeholder meetings had over 100 registered participants and garnered a high level of stakeholder participation. Members of NIPSCO's 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 data centers.

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 2024 IRP. The 2024 IRP undertook more rigorous analysis of Electric Vehicle (EV) and industrial loads, including potential new data center loads. A more robust analysis of demand-side management potential and programs was incorporated in the 2024 IRP as well. Grid-edge technologies such as electric vehicle charging, DER, and advanced metering infrastructure (AMI) were assessed to evaluate more responsive customer loads in the future.

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 along with detailed analysis of the impact of changes in customer behavior on load requirements.

NIPSCO then forecasted the impact of customer-owned DER and 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.

The anticipated growth in demand related to hyperscaler data centers is a new and rapidly changing opportunity in the NIPSCO service territory and across the broader utility industry. NIPSCO's analysis in the 2024 IRP was intended to provide initial guidance with the facts available at the time the core analysis was conducted. NIPSCO, however, will continue to monitor and evaluate the development of data center projects in the coming years. Further, NIPSCO will continue to refine its analysis of potential hyperscaler data center additions in future IRPs and other long-term portfolio planning analyses.

The Reference Case load forecast includes 600 MW of new demand attributable to hyperscaler data center projects beginning in 2028. To account for further data center and large industrial load growth over the IRP horizon, new demand attributable to large economic development projects rises to approximately 2,600 MW by 2035, approximately doubling NIPSCO's projected demand.

NIPSCO also included an Emerging Load sensitivity to account for increased data center demand beyond the Reference Case. This Emerging Load sensitivity projects an initial 3,200 MW of new demand attributable to data centers by 2028 and rising to 8,600 MW of new demand by 2035.

CURRENT SUPPLY

NIPSCO's resource portfolio is in the midst of a transition. NIPSCO continues with retirement activities at the R.M. Schahfer Generating Station. Schahfer Units 14 and 15 were retired in 2021, while Schahfer Coal Units 17 and 18 remain on track to retire by the end of 2025. 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. An additional wind project was placed into service in 2021. A fourth wind project as well as NIPSCO's first set of solar projects, were placed into service in 2023.

Due to supply chain constraints and price increases, several projects included in the 2021 IRP were either delayed or replaced with projects that were executable and more affordable for NIPSCO customers. NIPSCO's first solar plus battery storage project came online in 2024. The remaining seven projects, representing a mix of wind, solar, and storage, are expected to be completed throughout 2025. NIPSCO also expects a new Gas Peaking resource to come online by the end of 2027 to provide flexibility and reliability to customers and the system.

Additionally, NIPSCO's existing resource portfolio is composed of its last remaining coal-fired plant (Michigan City Unit 12),[2] two hydroelectric plants (Norway and Oakdale), a natural gas-fired combined cycle (Sugar Creek),[3] two older vintage natural gas-fired peaking units at Schahfer (Units 16A and 16B),[4] and demand-side management (DSM) resources.

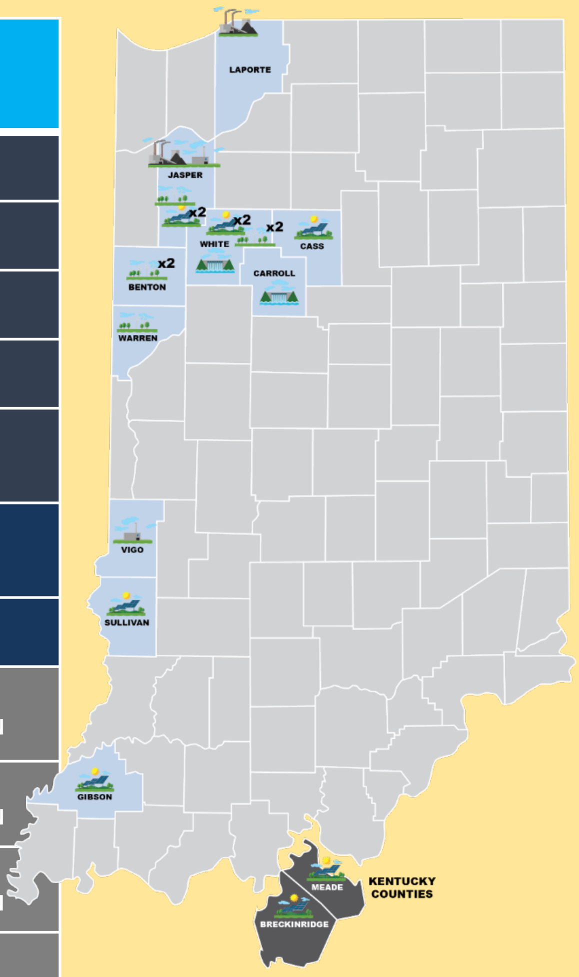
As NIPSCO looks beyond the implementation of its short-term action plan from the 2021 IRP, it is clear that evolving market rules, environmental policies, and potential hyperscaler data center loads will require attention not only on annual supply and demand of capacity and energy, but also on energy adequacy on an hourly basis. Thus, the 2024 IRP was structured to ensure a robust assessment of the type of resources needed to respond to emerging market conditions and future portfolio retirements.

[2] Michigan City's Unit 12 is planned to retire by the end of 2028.
[3] Sugar Creek was recently uprated to capacity of 565 MW at the end of 2024.
[4] Expected to retire by the end of 2027.

CURRENT & FUTURE NIPSCO GENERATION PORTFOLIO

Robust Renewable Investments in Indiana

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
CAVALRY SOLAR	200 MW + 60 MW BATTERY	WHITE	2024 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE (KY)	2025 CONSTRUCTION
DUNNS BRIDGE SOLAR II	435 MW + 75 MW BATTERY	JASPER	2025 CONSTRUCTION
GIBSON SOLAR	200 MW	GIBSON	2025 CONSTRUCTION
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025 CONSTRUCTION
TEMPLETON WIND	200 MW	BENTON	2025 PRE-CONSTRUCTION
CARPENTER WIND	200 MW	JASPER	2025 PRE-CONSTRUCTION
APPLESEED SOLAR	200 MW	CASS	2025 PRE-CONSTRUCTION
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PRE-CONSTRUCTION



GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER RETIRING 2025 (COAL) – 2028 (NG)	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	563 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL

ANALYZING FUTURE SUPPLY OPTIONS – REQUESTS FOR PROPOSALS

NIPSCO conducted four separate Request for Proposals (RFP) events covering all sources to help inform the 2024 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 2024 RFP, NIPSCO received 116 proposals — representing 58 individual projects with more than 9.6 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. NIPSCO is likely to conduct additional RFPs should hyperscaler data center opportunities materialize, to supplement the capacity sourced in the 2024 RFP. NIPSCO will also ensure full evaluation of a wide range of new technologies either via the RFP process or through other means such as pilots at existing facilities (i.e., Carbon Capture, Utilization, and Sequestration (CCUS) and hydrogen at Sugar Creek), LDES, and Small Modular Reactors (SMR), among other potential future technologies.

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 also 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 conserve energy and save money. The programs are tailored to customers and designed to help ensure energy savings. From 2010 through June 2024, NIPSCO customers have saved more than 1.7 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 2024 IRP included a robust assessment of future DSM programs through a Market Potential Study and rigorous portfolio analysis of the various options.

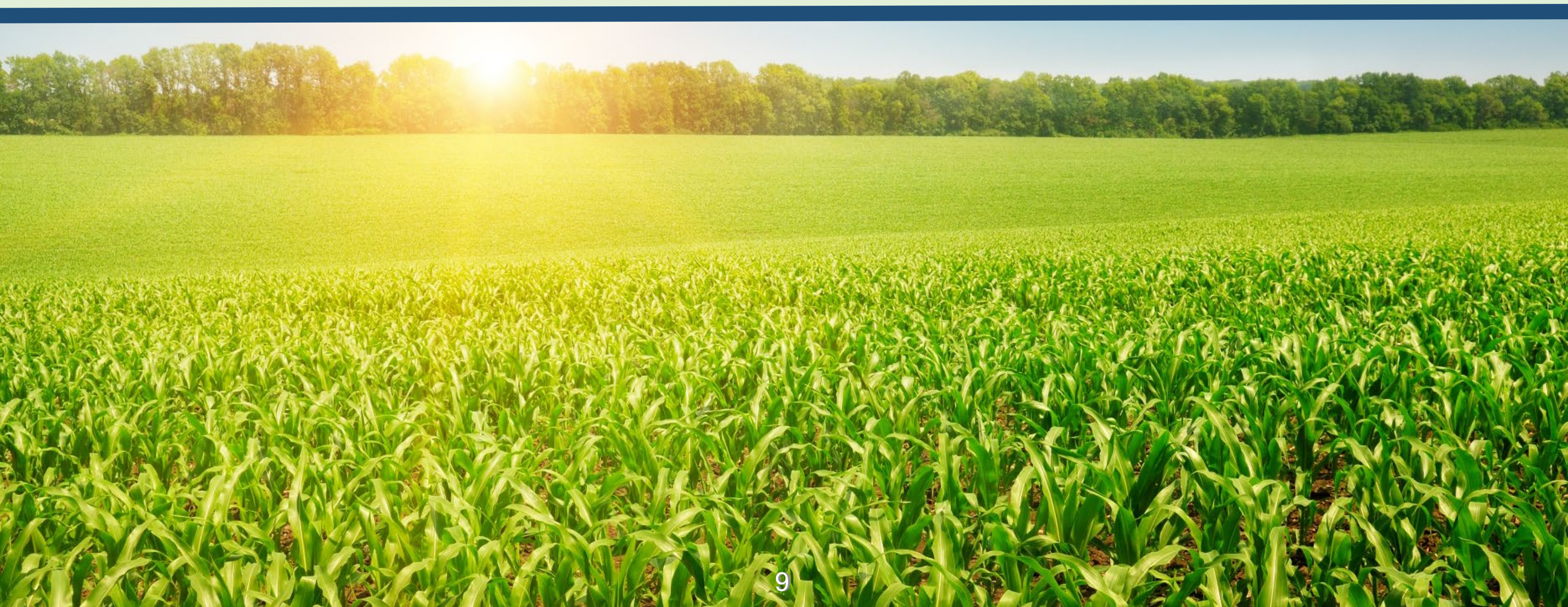
PREFERRED PORTFOLIO AND NEXT STEPS

NIPSCO has developed a short-term action plan in this 2024 IRP that ensures NIPSCO can confidently provide the least cost portfolio available while complying with significant regulatory changes from MISO in 2024. The short-term action plan ensures NIPSCO can maintain reliability, diversity, and flexibility regardless of whether or not new large loads come onto our system. Therefore, the action plan will cover needed actions and investments regardless of the level of load growth, and separately, other investments that will be contingent on large load growth (particularly from data center customers).

As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2025 and continue activities associated with the implementation of transmission system reliability upgrades. NIPSCO will also continue in its plan to retire Michigan City Unit 12 by 2028. 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 2025 retirement of all coal units at Schahfer, and the scheduled 2028 retirement of Michigan City. A total of ~2,100 MW have been approved by the Commission and will be placed in-service between now and 2028: ~1,700 of renewable projects and the 400 MW gas peaker. Additionally, NIPSCO's two vintage gas peaking units (Schahfer 16A/B) will also retire in 2027, with the addition of the previously planned gas peaker at the Schahfer site.

Given the uncertainty around the timing and amount of hyperscaler data center load that may come onto NIPSCO's system, NIPSCO has a preferred plan that lays out two sets of new resource additions: The first set of resource additions will be added to the portfolio regardless of the size and timing of new hyperscaler data load on the system, and the second set of resource additions will only be added after hyperscaler data center load is contracted.

The first set of resource additions include short-term purchase power agreements (PPA) in the near term through 2029, along with significant amounts of new storage resources primarily over the next five years to provide needed accredited capacity under MISO's new D-LOL market design rule. To ensure compliance with MISO's D-LOL capacity accreditation rule that was approved by FERC in October 2024, NIPSCO will plan to add between 900 and 1,150 MW of new storage capacity and 350 MW of short-term thermal PPAs by 2028-2029. This will ensure we meet the peak load capacity requirements needed as the capacity accreditation of our existing and planned renewable assets decline under the D-LOL rule. NIPSCO will continue to track accreditation trends as the rule is implemented and adjust its storage procurement plan accordingly.



NIPSCO’s plan also calls for 440 MW of combined Demand-Side Management resources to be implemented beginning in 2027 (both energy efficiency and demand response resources). In the mid-term and long-term, the preferred plan then includes additional storage resources and new wind resources to provide needed energy in the latter part of the IRP horizon. To continue progress towards NIPSCO’s goal to achieve Net Zero for Scope 1 and Scope 2 CO2 emissions by 2040, the plan also projects a retrofit for Sugar Creek Generation Station to be powered by hydrogen after 2035.

The second set of resource additions will be contingent on contracting hyperscaler data center load. These include new combined cycle gas turbine (CCGT) resources that match the load needs of hyperscaler customers. These resources may be sourced from PPAs, build transfer agreements (BTAs), self-build projects, or some combination of those types. The preferred plan also includes flexible plans for additional capacity to be met by natural gas peaking resources if needed in preparation for the EPA’s GHG rule, which will limit CCGT capacity factors to 40% in 2032 and beyond. Over the longer term, additional solar and wind capacity may be added if environmental policy continues to restrict gas-fired generation output and provide the needed tax credits for renewables to be economic. All new combined cycle gas resources will then plan for decarbonization retrofits in the latter half of the IRP to continue our pathway to Net Zero by 2040. The plan allows for flexibility in determining how these assets are decarbonized, and NIPSCO will continue to evaluate the most cost-effective methodology for decarbonizing the new facilities as technologies mature and costs change. Additional storage capacity may be added as further technology, policy, and reliability diligence is performed.

NIPSCO’s 2024 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. More information about NIPSCO’s electric supply strategies and the IRP process can be found at **NIPSCO.com/IRP**.

ACTION PLANS

NEAR-TERM ACTIONS (2025-2029)	

ACTION OVERVIEW	• Complete and place previously planned resource additions:
	    • 1,700 MW renewables
	    • 400 MW gas peaker
	• Complete retirement and shutdown of remaining Schahfer coal units (17, 18) by 2025 and Schahfer gas units (16A, 16B) by 2027
	• Complete retirement of Michigan City Unit 12 by 2028
	• Implement two sets of new resource resources additions:
	    • To meet the existing portfolio capacity needs by 2029 with short-term thermal contracts and battery storage
	    • To meet hyperscaler data center load with new gas CCGT and peaking resources
	• Implement new demand-side management programs in 2027 for energy efficiency and demand response
	• Actively monitor changing federal/state policy, MISO market rules, and technology advancements
	• Optimize exact quantities and resource types of portfolio additions

RETIREMENTS	• Schahfer Units 17, 18 (by 2025) • Schahfer Units 16A/B (by 2027) • Michigan City Unit 12 (by 2028)

NEW RESOURCE ADDITIONS – ABOVE IURC APPROVED PROJECTS	1. Resources planned for legacy portfolio load and any new hyperscaler data load:
	    • Storage (900+MW)*
	    • Thermal Contracts (150-350 MW)*
	    • DSM Resources (Energy Efficiency + Demand Response) (440 MW)*
	    • NIPSCO-owned DER (up to 20MW)*
	2. Resources planned only if new hyperscaler data center load is contracted (IRP assumes 2,600 MW of new load in total, with 600 MW of that total by 2028, and 1,600 by 2030):
	    • Gas CCGT (1,285 MW)
	    • Gas Peaking (420 MW)

MID-TERM ACTIONS (2030-2034)	

ACTION OVERVIEW	• Continue with two sets of new resource resources additions:
	    • To meet the existing portfolio energy and capacity needs with any additional wind and storage resources
	    • To meet hyperscaler data center load with new gas CCGT and peaking resources, supplemented with solar and wind resources if energy needs arise
	• Reevaluate decarbonization options including CCUS, H2, and other emerging technologies for best fit to decarbonize Sugar Creek and any additional gas resources brought online for hyperscaler data center load
	• Actively monitor changing federal/state policy, MISO market rules, and technology advancements
	• Optimize exact quantities and resource types of portfolio additions

RETIREMENTS	N/A

NEW RESOURCE ADDITIONS – ABOVE IURC APPROVED PROJECTS	1. Resources planned for legacy portfolio load and any new hyperscaler data load:
	    • Storage (125 MW)*
	    • Wind (150-650 MW)*
	2. 2Resources planned only if new hyperscaler data center load is contracted (IRP assumes 2,600 MW of new load in total by 2035):
	    • Gas CCGT (1,950 MW)
	    • Gas Peaking (200 MW)

* These resources are required for the portfolio even when evaluated without new data center load

ACTION PLANS

LONG-TERM ACTIONS (2035-2043)	

ACTION OVERVIEW	• Continue with two sets of new resource resources additions:
	  • To meet the existing portfolio energy and capacity needs with any additional wind and storage resources
	  • To meet hyperscaler data center load energy needs add additional solar capacity
	• Implement most cost-effective decarbonization retrofits to all gas CCGT units
	• Determine additional steps to achieve net zero
	• Optimize exact quantities and resource types of portfolio additions

RETIREMENTS	N/A

NEW RESOURCE ADDITIONS – ABOVE IURC APPROVED PROJECTS	1. Resources planned for legacy portfolio load and any new hyperscaler data load:
	  • Storage (25 MW)*
	  • Wind (200-900 MW)*
	  • Hydrogen retrofit at Sugar Creek Generating Station*
	2. Resources planned only if new hyperscaler data center load is contracted (IRP assumes 2,600 MW of new load in total):
	  • Solar (525 MW)
	  • Carbon capture retrofits on any new CCGT units

TIMING	NEAR TERM ACTIONS (2025-2029)	MID-TERM ACTION (2030-2034)	LONG TERM ACTIONS (BEYOND 2035)
RETIREMENTS	• Schahfer Units 17,18 (by 2025) • Schahfer Units 16A,16B (by 2027) • Michigan City Unit 12 (by 2028)	• N/A	• N/A
PREFERRED PLAN – CAPACITY ADDITIONS	• Storage (900+MW)* • Thermal Contracts (150-350MW)* • DSM Resources (Up to 440MW over 20 Year Period)* 2600MW DATA CENTER LOAD • Gas CCGT (1,285MW) • Gas Peaking (420MW)	• Storage (125MW)* • Wind (150-650MW)* 2600MW DATA CENTER LOAD • Solar (750MW) • Gas CCGT (1,950MW) • Gas Peaking (200MW)	• Storage (25MW)* • Wind (250-900MW)* • Sugar Creek Retrofit – Hydrogen* 2600MW DATA CENTER LOAD • Solar (525MW) • CCGT Retrofits - CCUS

OTHER ACTIVITIES	• Monitor changing regulatory policy (MISO, EPA, local) and technology advancements
	• Previously planned additions:
	  • 1,700MW Renewables
	  • 400MW Gas Peaker
		• Reevaluate decarbonization options including CCUS, H2 and other emerging technologies for best fit
		• Add additional renewables as needed to support higher energy needs
			• Implement most cost-effectives retrofits
			• Determine final steps to achieve Net Zero

STORAGE INVESTMENT	CCGT/GAS PEAKING INVESTMENT	MONITOR/RESPOND TO CHANGES	EXECUTE PREVIOUSLY PLANNED ACTIVITIES
~900MW of storage dependent on file MISO capacity accreditation	CCGT additions to support data center load and gas peaking investment as needed for additional capacity	MISO rules; EPA rules; Long-duration energy storage; Hydrogen; Carbon capture; Nuclear	Schahfer & Michigan City retirements; Renewable Projects ~1,700MW, ~400MW Gas Peaker

* These resources are required for the portfolio even when evaluated without new data center load

Northern Indiana Public Service Company LLC

2024
Integrated Resource Plan

December 9, 2024

Table of Contents

ACRONYMS AND ABBREVIATIONS

A

AC	Air Conditioning
ACS	American Community Survey 2022
AEO	Annual Energy Outlook (from EIA)
AER	Aggressive Environmental Regulation scenario
AGP	Advanced Gas Path
AI	Accelerated Innovation scenario
ASHP	Air Source Heat Pumps
AMI	Advanced Metering Infrastructure
ATC	Around-the-Clock

B

BECCS	Biomass Energy Carbon Capture and Storage
BEV	Battery Electric Vehicles
BIL	Bipartisan Infrastructure Law
BTAs	Build transfer agreements
BTM	Behind-the-meter
BMV	Bureau of Motor Vehicles
BWR	Boiling Water Reactors

C

C&I	Commercial and Industrial
CAES	Compressed air energy storage
CAGR	Compound Annual Growth Rate
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 Storage
CCUS	Carbon Capture, Utilization, and Sequestration
CDD	Cooling Degree Days
CES	Chemical energy storage
CF	Capacity Factor
CO	Carbon Monixide
CO2	Carbon Dioxide
CO/UT	Colorado/Utah Basin

Company	Northern Indiana Public Service Company LLC
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
D-LOL	Direct Loss of Load
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
DR	Demand Response
DRR1	Demand Resource Type 1
DRS	Domestic Resiliency Scenario
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
EES	Electrochemical energy storage
EGU	Electric Generating Unit
EIA	Energy Information Administration of the U.S. Department of Energy
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
ESR	Electric Storage Resources
EUE	Expected Unserved Energy
EV	Electric Vehicles

F

FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

FOB	Free Over Board

G

GDS	GDS Associates, Inc.
GDS Team	GDS and Demand Side Analytics
GHG	Green House Gas
GHG Rules	GHG Standards and Guidelines
GPCM	Gas Pipeline Competition Model
GPR	Green Power Rider
GW	Gigawatt
GWh	Gigawatt-hour

H

H2	Hydrogen
HALEU	High-Assay, Low-Enriched Uranium
HDD	Heating Degree Days
HDV	Heavy-Duty Vehicle
Hg	Mercury
HPMS	Highway Performance Monitoring System
HRSG	Heat Recovery Steam Generator
HSPF	Heating Seasonal Performance Factor
HTGCR	High-Temperature Gas-Cooled Reactor
HVAC	Heating, Ventilation, and Air Conditioning

I

ICAP	Installed Capacity
ICE	Internal Combustion Engine
IDEM	Indiana Department of Environmental Management
IEDC	Indiana Economic Development Corporation
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IFSA	Indiana Solar For All coalition
IGCC	Integrated Gas Combined Cycle
ILB	Illinois Basin
IMEP	Interregional Market Efficiency Project
INDOT	Indiana Department of Transportation
IRA	Inflation Reduction Act
IRP	Integrated Resource Planning
IRP Rule	170 IAC 4-7 Guidelines for Electric Utility Integrated Resource Plans
ISO	Independent System Operator

ISP	Investment Tax Credit
ITC	Integrated System Planning
IURC/Commission	Indiana Utility Regulatory Commission

J

JA	Junior Achievement
JOA	Joint Operating Agreement

K

kWh	Kilowatt hour

L

LAES	Liquid Air Energy Storage
LDES	Long-Duration Energy Storage
LDV	Light-Duty Passenger Vehicle
LED	Light Emitting Diode
LEU	Low-Enriched Uranium
LHS	Latent Heat Storage
LLF	Line Loss Factors
LMR	Load Modifying Resource
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
MES	Mechanical Energy Storage
Michigan City	Michigan City Generating Station
Michigan City 12	Michigan City Unit 12
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Metric Million British Thermal Unit
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Planning
MT	Million Tons
MTEP	MISO Transmission Expansion Plan
MTPA	Million Tons Per Annum
MW	Megawatt

MWh	Megawatt-hour

N

NAPP	Northern Appalachian
NDC	Net Demonstrated Capacity
NERC	North American Electric Reliability Corporation (formerly Council)
NETL	National Energy Technology Laboratory
NEVI	National Electric Vehicle Infrastructure
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
NPP	Nuclear Power Plant
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NSRDB	National Solar Radiation Database
NREL	National Renewable Energy Laboratory
NTD	National Transportation Database
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

PEC	Polyethylene Carbonates
PenDER	CRA's DER Penetration Model
PEV	Plug-In Electric Vehicle
PGC	Potential Gas Committee
PHEV	Plug-In Hybrid Electric Vehicle
PHS	Pumped Hydro Storage
PJM	PJM LLC (Regional Transmission Organization)
PPA	Purchase Power Agreement
PPC	Polypropylene Carbonate
PRB	Powder River Basin
PRMR	MISO's Planning Reserve Margin Requirement

PTC	Production Tax Credit
PV	Photovoltaic
OWR	Pressurized Water Reactor

R

RAP	Realistic Achievable Potential
RBDC	Reliability Based Demand Curve
RCRA	Resource Conservation and Recovery Act
RCx	Retro-Commissioning
REC	Renewable Energy Credit
REF	Reference Case Scenario
RFP/2024 RFP	Request for Proposals/2024RFP Events
RIIA	Renewable Integration Impact Assessment
RIM	Rate Payer Impact Measure
RNG	Renewable natural gas
RPPA	Renewable Purchase Power Agreement
RTE	Round-trip efficiencies
RTO	Regional Transmission Organization (Independent System Operator)

S

SAIFI	System Average Interruption Frequency Index (Reliability-SAIDI and CAIDI)
SAM	System Advisor Model
SCADA	Supervisory Control and Data Acquisition
Schahfer	R.M. Schahfer Generating Station
SEER	Seasonal Energy Efficiency Ratio
SHS	Sensible Heat Storage
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
SOC	State of Charge
SO2	Sulfur Dioxide
ST	Slower Transition scenario
STEM	Science, Technology, Engineering, and Math
Sugar Creek	Sugar Creek Generating Station

T

T&D	Transmission and Distribution
Tcf	Trillion cubic feet
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
TES	Thermal Energy Storage
THS	Thermochemical Heat Storage

TRC	TRC Companies, Inc.
TRL	Technology Readiness Level
TRM	Technical Resource Manual
TW	Terawatt
TWh	Terawatt-hours

U

UCAP	Unforced Capacity (the amount of Installed Capacity actually available)
UCCI	Upstream Cost of Capital Index
UCT	Utility Cost Test

V

VOM	Variable Operations and Maintenance Costs

W

WACC	Weighted Average Cost of Capital

Z

ZRCs	Zonal Resource Credits

Section 1. Integrated Resource Plan Summary

1.1 Short-Term Action Plan

NIPSCO has developed a short-term action plan in this 2024 IRP that ensures NIPSCO can confidently provide a portfolio that best balances cost to customers while complying with significant regulatory changes from MISO in 2024. The short-term action plan ensures NIPSCO can maintain reliability, diversity, and flexibility regardless of whether or not new large loads come onto our system from data centers. Therefore, the action plan will cover needed actions and investments regardless of the level of load growth, and separately, other investments that will be contingent on large load growth (particularly from data center customers).

As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2025 and continue activities associated with the implementation of transmission system reliability upgrades. NIPSCO will also continue in its plan to retire Michigan City Unit 12 by 2028. 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 2025 retirement of all coal units at Schahfer, and the scheduled 2028 retirement of Michigan City. A total of ~2,100 MW have been approved by the Commission and will be placed in-service between now and 2028: ~1,700 of renewable projects and the 400 MW gas peaker. Additionally, NIPSCO's two vintage gas peaking units (Schahfer 16A/B) will also retire in 2027, with the addition of the previously planned gas peaker at the Schahfer site.

In order to ensure compliance with MISO's D-LOL capacity accreditation rule that was approved by FERC in October 2024, NIPSCO will plan to add between 900 and 1,150 MW of new storage capacity and 350 MW of short-term thermal PPAs by 2028-2029. This will ensure we meet the peak load capacity requirements needed as the capacity accreditation of our existing and planned renewable assets decline under the D-LOL rule. NIPSCO will monitor accreditation metrics under the D-LOL rule and adjust its storage procurement plan as needed over time.

In addition, if new large load data centers are contracted, NIPSCO currently is prepared to meet these capacity and energy needs with an equivalent amount of installed capacity from CCGTs. These resources may be sourced from PPAs, BTAs, self-build projects, or some combination of those types. NIPSCO will also prepare plans for additional gas peaking resources if data center load is contracted, in order to supplement the previously mentioned CCGT resources, should the EPA's GHG rule limit CCGT capacity factors to 40% in 2032 and beyond.

The robust response to the 2024 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, particularly with storage. NIPSCO will select projects/bids through the 2024 RFP's evaluation process, prioritizing cost-effective dispatchable resources that can be implemented before the D-LOL rule goes into effect in 2028, including storage and thermal contracts. 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 implement NIPSCO-owned DER opportunities over the next five years to support the energy needs of local communities, as well as look to partner with recipients of federal solar grants in implementing their programs in our service territory.

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 additional resources to support large load growth and decarbonization.

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: 2024 IRP Short-Term Action Plan

Complete and place in service the remaining renewable facilities and gas peaker project approved by the IURC but not yet operational
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by the end of 2025
Complete the retirement of Michigan City 12 by the end of 2028
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Continue implementation of filed DSM Plan for 2025 through 2026
Select the best storage projects from the 2024 RFP, optimizing existing interconnection rights and federal tax credit opportunities
Procure short-term capacity as needed from the 2024 RFP, the MISO market, or through short-term bilateral capacity transactions
Continue discussions with new data center customers and refine the near- to mid-term load outlook as contracts are signed and expected loads are firmed
Perform additional diligence on the costs, feasible locations, and operational characteristics of new natural gas combined cycle and peaking additions necessary to meet any new data center load
Study potential future decarbonization pathways for gas-fired generation further, particularly CCUS and hydrogen blending
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 energy storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
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 potential 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 utilized the 2024 RFP solicitations to identify the best combination of supply- and demand-side resources to meet its capacity needs.

The 2024 RFPs provided NIPSCO insight into the most relevant types of resources available to meet customer needs and their prices (*see* Section 4). NIPSCO performed its analysis using robust scenario and risk-based (stochastic) approaches that capture the flexibility and adaptability of the portfolio among changing market rules; environmental policy and regulations/incentives in an uncertain policy future; and system reliability implications of a portfolio with significant intermittent resources. NIPSCO also performed a probabilistic reliability assessment to understand the 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 2024 IRP.

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

- Phase out 100% of its coal generation by the end of 2028;
- Replace retired generation resources with a diverse, flexible, and scalable mix of planned resources, including short-term capacity contracts, large energy storage additions, and incremental long-term wind resources;
- Plan for new natural gas-fired generation, both CCGT and gas peaking resources, supplemented by solar and wind resources if new hyperscaler data centers are contracted;
- Seek to advance NIPSCO's knowledge and understanding of carbon capture and sequestration, hydrogen, and other emerging storage technologies identified as potential pathways toward further decarbonization of the generation portfolio in the long term;

- Remain on a pathway to achieve NiSource's Net Zero Goal for Scope 1 and Scope 2 greenhouse gas emissions by 2040; 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 supply strategy focused on compliance and reliability, with a mix of storage and new gas resources to support large load growth, as well as incremental renewable resources and market purchases in the mid-term. This provides the mobalanced plan that mitigates risk associated with changing capacity rules, policy, and technology uncertainty.

1.3.1 Market Rules Uncertainty

At the outset of its 2024 IRP process, NIPSCO identified several regulatory developments at the MISO level that could impact portfolio capacity accreditation. In 2023, MISO implemented a four-season capacity construct with obligations and resource accreditations varying by the four seasons across the MISO Planning Year. Previously capacity credit had focused on the summer peak. In 2025, MISO plans to implement a "downward sloping" reliability-based demand curve to value capacity across a range of reserve margin levels. And, during our IRP process, MISO filed for another capacity credit change for the 2028 planning year, the D-LOL market design which drives toward marginal capacity accreditation, with obligations and resource accreditations focused on performance during tight margin hours. This D-LOL market design was then approved by FERC in October 2024. This D-LOL market design is expected to have the following characteristics and impacts:

- Strong incentive to perform during hours when net load and outages are high;

- Resource accreditation based on LOLE assumptions based on historical class-level and unit-specific data;

- Capacity accreditations are expected to change, with MISO's indicative forward modeling currently projecting that:

    - The capacity credit of wind and solar resources will be significantly reduced across all four seasons;

    - The capacity credit of lithium ion battery storage will be reduced primarily in winter;

    - There will likely be a reduction in natural gas resource accreditation across all four seasons.

- Seasonal planning reserve margins are expected to decline, but NIPSCO's resource obligation during the summer is expected to grow by as much as ~500 MW due to the reduction in capacity credit given to its current and planned renewable resources.

1.3.2 Policy Uncertainty

During the development of NIPSCO's 2024 IRP, the EPA finalized its Greenhouse Gas Rule in April 2024. This led to a preferred portfolio focused on compliance with the rule, and as a result included additional projected gas peaking and renewable resources to prepare for the rule's impacts in 2032 (additional information on all environmental issues can be found in Section 7). After the preferred plan was announced, the federal election results indicated a change to Republican control of the presidency and both houses of Congress. Given the policy leanings of the new administration and Congress, this may lead to further uncertainty for implementation of the EPA GHG rule, along with uncertainty in various provisions of the Inflation Reduction Act:

- The magnitude and eligibility period of the PTC and ITC for clean energy resources
- The potential development of the hydrogen economy, incentivized by the IRA's regional Hydrogen Hubs grants
- The enhancements to the 45Q tax credit which incentivized the use of CCUS

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;
- Long-duration storage technologies, including redox flow, metal air, compressed air, and other mechanical storage and their associated costs, efficiencies, and other value drivers;
- Hydrogen production developments 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 any new CCGT generation built for load growth;
- Other technologies that may emerge over the long term, including small modular reactors and other nuclear technology; and

- 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.

Section 2. Planning for the Future

2.1 IRP Public Advisory Process

NIPSCO's 2024 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. In addition, for the 2024 IRP, NIPSCO acquired Aurora model licenses for interested stakeholders and provided three separate model data releases to stakeholders as it performed and completed modeling analysis. The model releases were delivered after Stakeholder Meetings 3, 4, and 5, and included Aurora project and database files and accompanying data inputs and notes in Excel format. 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 a RFP solicitation to identify the most viable resources currently available in the market 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.

NIPSCO hosted five public advisory meetings with in-person and virtual attendance options as part of the 2024 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 additional technical workshop sessions with smaller groups of 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. 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.

2.1.1 Stakeholder Meeting 1

NIPSCO's first stakeholder meeting was held at Fair Oaks Farm located in Fair Oaks, Indiana[1] (and virtually) on April 23, 2024. In this first meeting, NIPSCO set the stage for the 2024 IRP and outlined the fundamental pillars of NIPSCO's long-term resource planning strategy and how they align with the Five Pillars of long-term planning established by the Indiana 21st Century Energy Task Force. NIPSCO then provided an update on recent state, ISO, and federal policy developments, including capacity accreditation reforms at MISO and power sector GHG rules from the EPA. An update on the progress of the 2021 Short-Term Action Plan and the ongoing generation transition plan was also discussed.

1 The in-person portion of all five stakeholder meetings was hosted at Fair Oaks Farm in Fair Oaks, IN.

Process improvements from the 2021 IRP were then discussed in detail, including improvements associated with the load forecast, demand-side management analysis, portfolio evaluation, and stakeholder collaboration. NIPSCO then provided an overview of its overall resource planning process, introduced its 2024 IRP scenarios, discussed its evolving stochastic analysis approach, and introduced its 2024 IRP scorecard. NIPSCO then provided an overview of its load forecast, including detailed projections for customer-owned distributed energy resource and electric vehicle growth.

NIPSCO then introduced its 2024 RFP, outlining the process, structure of RFP events, preliminary evaluation criteria, and timeline. Finally, NIPSCO concluded with the stakeholder advisory meeting road map for the remainder of the year. 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 on June 24, 2024. 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. Based on information that emerged between the first and second stakeholder meetings, NIPSCO then provided an update to its load forecast, with special attention given to significant new load growth now anticipated from large economic development loads, particularly data centers. The update included a new reference case load forecast and a high emerging load sensitivity. NIPSCO then provided an overview of all of its IRP load scenarios associated with uncertainty in economic growth, electric vehicle and distributed energy resource penetration, and long-term electrification. The electric vehicle review included forecasts of charging load on highway corridors. NIPSCO then provided a detailed review of its starting supply-demand position, particularly in light of MISO's D-LOL filing.

NIPSCO then introduced its fundamental market modeling structure and reviewed the Reference Case projections for fuel prices (natural gas and coal), environmental policy drivers, and MISO market dynamics, including MISO price forecasts. Each of the key variable drivers across each of NIPSCO's five planning scenarios was then reviewed. NIPSCO then provided a summary of the major stochastic variable inputs (renewable generator output, NIPSCO load, thermal resource outages, natural gas prices, and power prices) and summarized the stochastic analysis approach to measure reliability and cost risk.

Finally, NIPSCO provided a preliminary summary of the results of its RFP, including the number of proposals received, the types of projects offered, the location of the projects, and initial summaries of average pricing. 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 on August 21, 2024. In this third meeting, NIPSCO provided a recap of its revised Reference Case load forecast and its starting supply-demand balance. NIPSCO then shared an in-depth overview of DSM modeling, methodology, and how these resources are considered in the IRP. This included an overview of the market potential for energy efficiency, the various energy efficiency bundles, and the range of demand response program options to be evaluated in the 2024 IRP.

NIPSCO then reviewed the full set of resource options available for portfolio selection, including the details of the DSM bundles, detailed RFP tranche data, and the cost and operational assumptions for other generic new resource options, including eligible tax credits. NIPSCO closed the session with an overview of the portfolio construction framework and plan for full portfolio optimization and evaluation. 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 on October 8, 2024. In this fourth meeting, NIPSCO reviewed the overall IRP process and summarized responses to feedback and questions provided since the third stakeholder meeting. NIPSCO then reviewed its available new resource options and presented an overview of the portfolio construction framework, which developed six portfolio themes based on different constraints associated with MISO capacity accreditation rules and the emissions intensity of its portfolio.

NIPSCO then reviewed the results of its portfolio optimization analysis for each of the six portfolio themes. This included a review of the annual and total resource additions by type, seasonal supply-demand balances for all four MISO planning seasons, and projected energy positions. NIPSCO also presented the energy efficiency and demand response selections for all six portfolio themes and introduced two additional portfolio variants that contemplated retrofitting combined cycle capacity with carbon capture, utilization, and storage capability or the ability to blend hydrogen fuel. NIPSCO closed the presentation with a summary comparison of all eight portfolios and offered an overview of the remaining analysis components to be presented at the final stakeholder meeting. The presentation (including the agenda), notes (including questions / responses), and registered participants for Meeting 4 are included in Appendix A.

2.1.5 Stakeholder Meeting 5

NIPSCO's fifth stakeholder meeting was held on October 28, 2024. In this fifth meeting, NIPSCO reviewed the overall IRP process and summarized responses to feedback and questions provided since the fourth stakeholder meeting. NIPSCO then reviewed the composition of the eight portfolio concepts that were presented in Stakeholder Meeting 4 and, in direct response to feedback from stakeholders, introduced two new portfolios based on a flat load forecast (without data center growth) in response to stakeholder feedback.

NIPSCO then provided the details of its full portfolio analysis for all portfolios across all of its planning scenarios. This included a review of the net present value of revenue requirements for each portfolio and observations on the key relationships between portfolio concepts and across the range of market conditions embedded in the five IRP scenarios. NIPSCO then provided a summary of its stochastic analysis, summarizing key findings for the portfolios associated with forced market exposure risk and cost risk. Next, NIPSCO summarized sensitivity analysis that was performed for a high emerging load sensitivity and an alternate DSM sensitivity. Within the high emerging load sensitivity, NIPSCO summarized expected resource additions over time under very high load growth conditions, while the DSM sensitivity evaluated the implications on portfolio composition and costs of implementing more aggressive DSM programs.

NIPSCO then presented its proposed scorecard, which included metrics associated with affordability, rate stability, environmental sustainability, reliability, and positive social and economic impacts. 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.

NIPSCO's 2024 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 Other Stakeholder Input Since NIPSCO's Last IRP

2.2.1 IURC Contemporary Issues

NIPSCO participated in the Commission's IRP Contemporary Issues Technical Conferences that occurred since NIPSCO completed its last IRP and incorporated learnings and key topical areas in its 2024 IRP activities. Meeting dates and topics discussed are summarized in Table 2-1.

Table 2-1: IURC Contemporary Issues Meeting Dates and Topics

Date	Topics
September 22, 2022	• MISO seasonal resource adequacy construct • Resource adequacy in PJM • Interaction between energy efficiency and demand response
October 20, 2023	• ISP • Building on TDSIC to support ISP
June 6, 2024	• Resource adequacy • Capacity accreditation and reforms • Load forecast development and use in PJM and MISO

2.2.2 2021 IRP Feedback and 2024 Process Improvement Efforts

NIPSCO strives to continuously improve all aspects of its resource planning process, and, for the 2024 IRP, NIPSCO reviewed the major feedback it received throughout the 2021 IRP process and implemented key improvements. The process improvements in the 2024 IRP were designed to enhance the robustness of the load forecast, perform a more detailed demand response assessment, improve upon NIPSCO's portfolio modeling approach, and improve stakeholder collaboration with earlier sharing of modeling files and analysis inputs and outputs. Table 2-2 summarizes the major areas of feedback received on NIPSCO's 2021 IRP and the improvements that were included in the 2024 IRP process.

Table 2-2: 2024 IRP Process Improvements

Category	2021 IRP Feedback	2024 Improvement Plan
1 Load Forecast	• More detail on Electric Vehicle (EV) forecast; for example, penetration has not been able to separate non-NIPSCO-serviced light-duty vehicles (LDVs) from total counts in counties served by more than one utility • Clearer analytic methods regarding forecasting demand from large industrial customers	• More rigorous EV modeling with focus on vehicle counts within service territory and by class and separate truck corridor analysis • Additional econometric analysis of industrial loads, as well as review of potential additional emerging industrial load types (i.e., data centers)
2 Demand-Side Resources	• Interaction between energy efficiency (EE) and demand response (DR) resources require further consideration; more attention to meter-based pay-for-performance program designs	• Additional DSM evaluation, including integration with AMI and EV charging management • Continued assessment of distributed energy resources (DERs)
3 Portfolio Analysis	• Positive feedback on reliability assessment: • "Based on this initial effort, [NIPSCO] is well positioned to provide future analytical improvements" • Other stakeholders remain interested in various alternative technologies (RICE, storage, grid-forming inverter-based technology SMR)	• Advance continuous improvement around reliability analysis and quantification of risk • Ensure full evaluation of a wide range of new technologies either via the RFP or other means (CCS at Sugar Creek, hydrogen, SMR, LDES)
4 Stakeholder Collaboration	• Joint Commenters requested increased collaboration in the IRP process and the RFP process • "…comments emphasized the need for continued collaboration and improvement between stakeholders and NIPSCO for the next IRP filing"	• Facilitate the procurement of Aurora Energy Forecast Software licenses to interested stakeholders to enable visibility into certain modeling files • Provide opportunity for feedback on upcoming RFP for interested stakeholders under a Non-Disclosure Agreement

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 an important issue to address. NIPSCO's 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. As part of the 2024 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. NIPSCO also issued an RFP event for NIPSCO-owned DER opportunities over the next five years to support the energy needs of local communities.

In the 2024 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 looks forward to engaging in a statewide dialogue with the Commission, other utilities, and interested stakeholders on the topic of equity in future IRP Contemporary Issues Technical Conferences and other forums. Although equity was not adopted as a formal part of NIPSCO's scorecard, 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 Overall IRP Approach

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 IRP Rule.

NIPSCO's IRP team included experts from key areas of NIPSCO and its affiliate NiSource Corporate Services Company. In addition, the energy consultants identified in Table 2-3 also provided input.

Table 2-3: 2024 IRP Consultants

Charles River Associates (CRA) 200 Clarendon Street Boston, MA 02116	Provided fundamental long-term scenario forecasts, performed the NIPSCO load forecast, and performed all portfolio modeling and analysis. A separate division of CRA provided assistance in administering the All-Source RFP and evaluating the responses.
ElectroTempo 4201 Wilson Blvd, Suite 700 Arlington, VA 22203	Performed analysis associated with highway corridor heavy-duty vehicle charging.
GDS 1850 Parkway Place, Suite800 Marietta, GA 30067	Developed DSM measures inputs for a long-term DSM forecast.
Demand Side Analytics 691 John Wesley Dobbs Ave NE Suite V3 Atlanta, GA 30312	Provided assistance with analyzing demand response measures and opportunities.

NIPSCO's long-term resource planning process includes five major steps, as summarized in Figure 2-1 and further discussed in separate sub-sections below.

1. The first step in this process is to identify objectives and metrics.

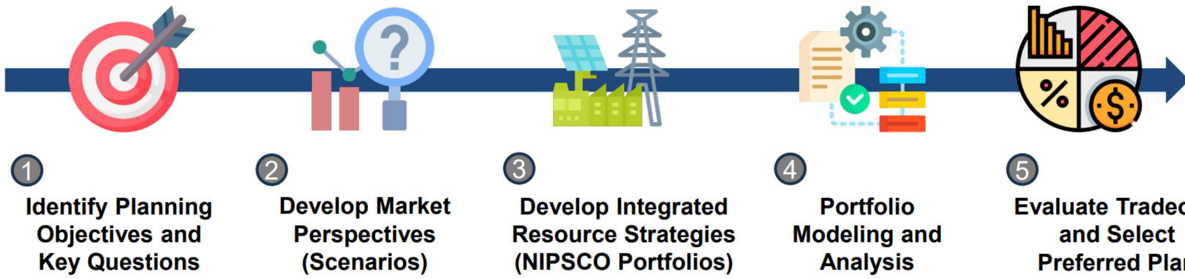
2. Next, NIPSCO develops market perspectives for key variables such as customer demand, environmental policy, and commodity price outlooks. This involves the creation of distinct thematic "states-of-the-world" that represent potential future operating environments for NIPSCO.

3. Then NIPSCO develops integrated resource strategies or portfolios of options.

4. NIPSCO then performs detailed modeling and analysis to evaluate the performance of these various resource portfolios across a range of potential futures as well as a distribution of key stochastic variables.

5. Finally, NIPSCO evaluates tradeoffs and selects a preferred portfolio. 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.

Figure 2-1: NIPSCO's IRP Process Steps



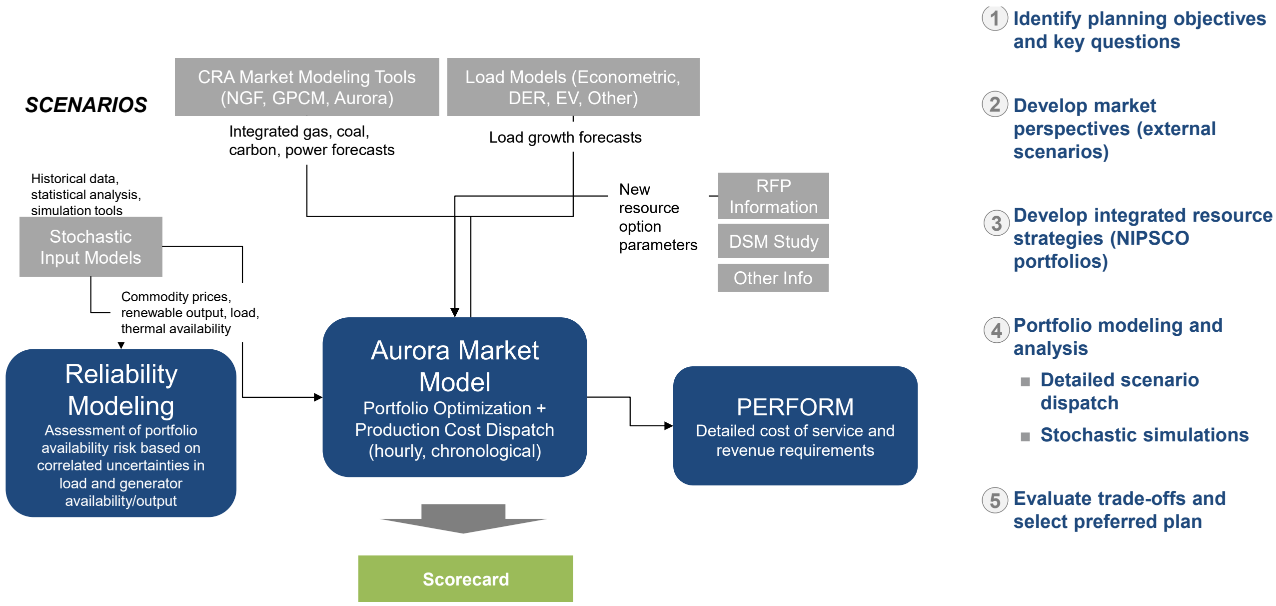
The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs. The short-term action plan identifies the steps NIPSCO will take over the next three to five years to implement the long-term strategic plan.

NIPSCO recognizes future economic, policy, market design, and technology changes are difficult to accurately predict. While the 2024 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.

Consistent with the principles set out above, the 2024 IRP identifies a preferred portfolio plan for NIPSCO over a 20- to 30-year[2] planning horizon that seeks to deliver reliable, compliant, flexible, diverse, and affordable electric service to its customers. NIPSCO's 2024 IRP was performed according to the detailed planning approach process that is outlined in Figure 2-2 and described in more detail below.

[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.

Figure 2-2: Overall Integrated Resource Planning Approach



2.3.1 Step 1: Identify Planning Objectives and Key Questions

The first step in NIPSCO's planning approach was to identify planning objectives and key questions to guide the overall analysis framework. These key questions and objectives 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 2024 IRP are described in more detail below.

2.3.1.1 Meeting New Load Growth

As introduced during the second stakeholder advisory meeting, NIPSCO has seen a significant increase in the potential for new large loads, primarily hyperscaler data centers, to enter its service territory. NIPSCO believes that Northern Indiana is a favorable location for data centers to locate because of the low risk for natural disasters; a robust transmission network; available land, strong connectivity and fiber; access to water; proximity to customers, a major metropolitan area, and construction labor; and favorable state policy. As a result of these emerging trends, NIPSCO developed a Reference Case load forecast that assumes two to three potential data center projects come to fruition, driving up to 2,600 MW of new load for the system. In addition, an emerging high load sensitivity was developed to incorporate up to six potential data center projects entering the system at a level of up to 8,600 MW.[3]

[3] Such load additions are not attributable to a specific customer(s) but represent NIPSCO's attempt to reasonable estimate total load additions that may come to fruition under various future states of the world.

NIPSCO's 2024 IRP seeks to evaluate the implications associated with a range of new data center load growth trajectories to assess the type and timing of new resource additions to its existing portfolio. NIPSCO acknowledges that final data center growth trajectories remain uncertain, and thus, NIPSCO will need to be flexible in its resource procurement activities based on the range of outcomes studied in the 2024 IRP.

2.3.1.2 Ensuring Reliability in the Context of Changing Market Rules

Over the last several years, MISO has been actively evaluating emerging reliability issues within its footprint, particularly through its Reliability Imperative framework, which was initiated in 2020,[4] and which has identified the following key initiatives: ensure resources are accurately accredited; identify critical system reliability attributes; and ensure accurate pricing of energy & reserves. One pillar in the Reliability Imperative is "Market Redefinition," and as part of its effort to redesign key elements of the market, MISO has implemented or proposed to implement several key reforms in recent years:

- In 2023, MISO implemented a four-season capacity construct with obligations and resource accreditations varying by the four seasons across the MISO Planning Year.[5]

- By 2025, MISO plans to implement a "downward sloping" reliability-based demand curve to value capacity across a range of reserve margin levels.

- On March 28, 2024, MISO filed its D-LOL market design proposal with the FERC,[6] driving toward marginal capacity accreditation, with obligations and resource accreditations focused on performance during tight margin hours. On October 25, 2024, FERC approved this filing, and NIPSCO expects it to enter into force for the 2028/29 planning year.

The D-LOL methodology, in particular, will have significant impacts for how NIPSCO's resources are accredited. Accreditation for wind, solar, and storage resources will be evaluated based on a combination of forward-looking loss of load analysis performed by MISO and actual three-year historical availability during MISO's risky hours (Tier 1 and Tier 2 resource adequacy hours).

Although future accreditations are highly uncertain, NIPSCO's 2024 IRP has evaluated portfolios under the D-LOL framework in order to assess the potential implications of different accreditation outlooks, including under the current market rules and the best information available to NIPSCO on potential changes under D-LOL. These are summarized in Figure 2-3, Figure 2-4,

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4 See: https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

5 Note that the four-season capacity construct was anticipated in NIPSCO's 2021 IRP, with the preferred portfolio developed under the expected construct.

6 See: https://cdn.misoenergy.org/2024-03-28%20Docket%20No.%20ER24-1638-000632361.pdf

Figure 2-5, and Figure 2-6 for solar, wind, gas peaking, and four-hour storage capacity, respectively.[7] Given ongoing market design uncertainty and evolving accreditation forecasts associated with D-LOL implementation, NIPSCO will need to ensure near-term capacity addition decisions are flexible enough to adapt to changing market rules.

Figure 2-3: Accreditation Expectations under Different Constructs – Solar

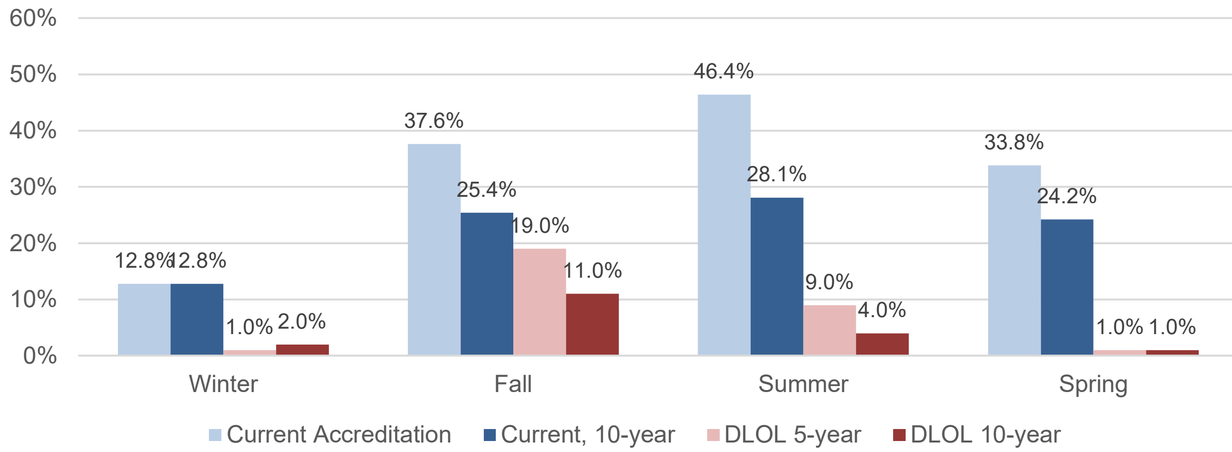
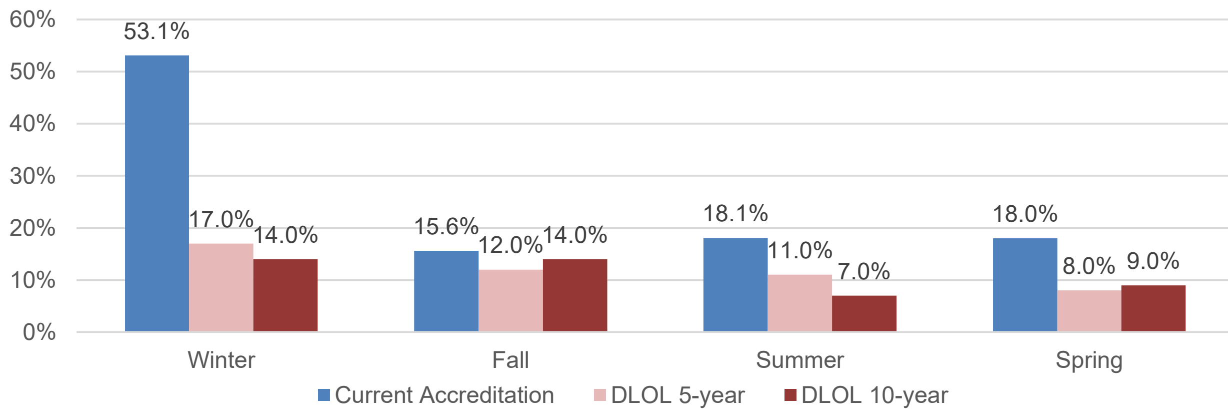


Figure 2-4: Accreditation Expectations under Different Constructs – Wind



[7] D-LOL accreditation expectations adopted from MISO RASC meeting in January 2024: https://cdn.misoenergy.org/20240117%20RASC%20Item%2007a%20Accreditation%20Presentation%20(RASC-2020-4%20and%202019-2631379.pdf

Figure 2-5: Accreditation Expectations under Different Constructs – Gas Peaking

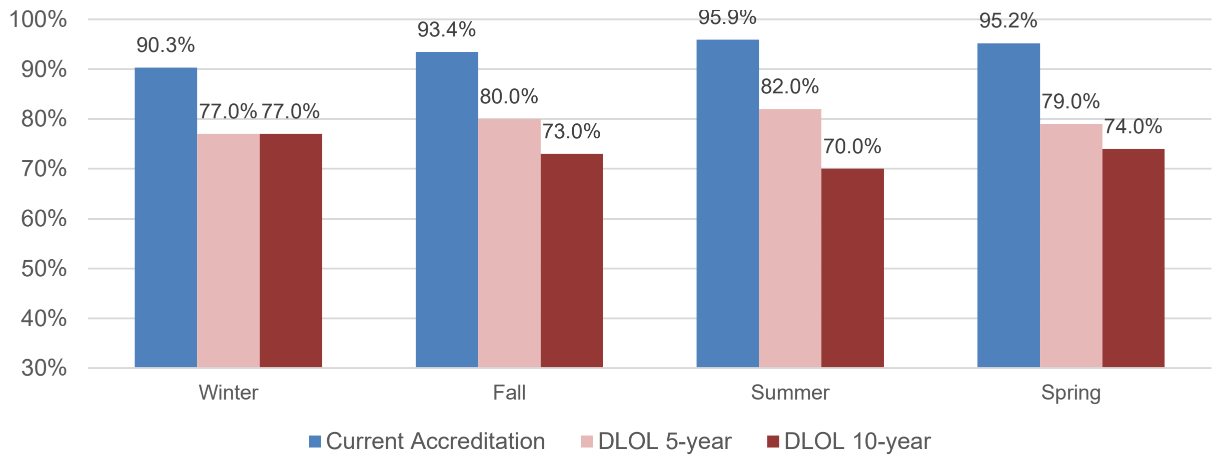
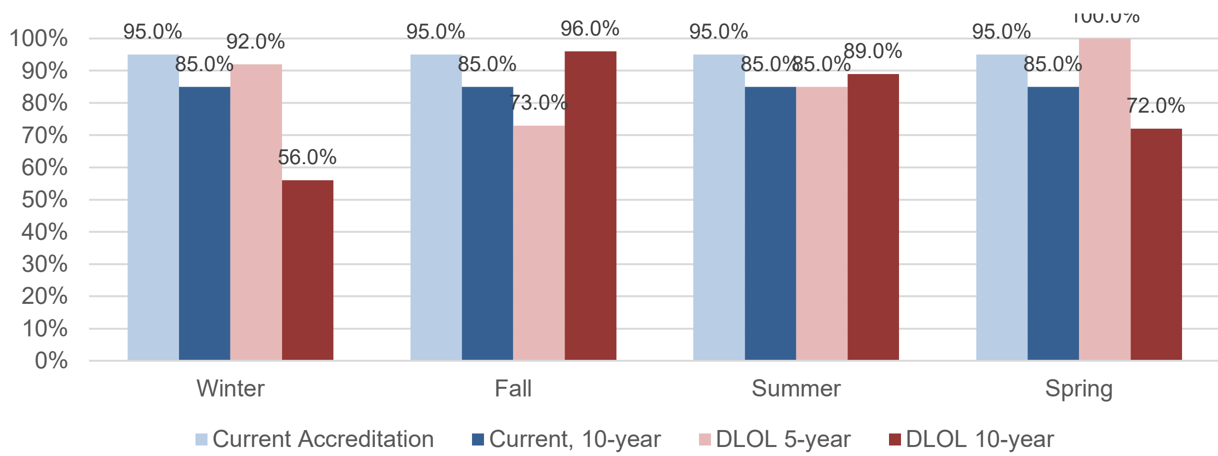


Figure 2-6: Accreditation Expectations under Different Constructs – 4-Hour Storage



2.3.1.3 Navigating Dynamic Environmental Policy Drivers and NIPSCO's Sustainability Objectives

On April 25, 2024, the EPA finalized greenhouse gas emissions rules for the power sector. These rules limit the future operation of coal-fired power plants and govern the emissions and operational profiles of new natural gas-fired units. Most importantly, capacity factor limitations are included for new combined cycle plants. In addition, federal tax credit policy associated with clean energy resources, energy storage, CCUS, and hydrogen may change in the future.

Meanwhile, NIPSCO remains committed to supporting NiSource's Net Zero Goal and will assess the best pathways for achieving it based on developments in federal policy, market rules, and technology advancement. Given legal challenges to the EPA GHG Rules and potential changes to EPA regulations and federal legislation under a new President and Congress, NIPSCO must be flexible in adapting its portfolio to future policy change. To reflect uncertainty, as part of the 2024 IRP, NIPSCO:

- Evaluated portfolio constructs with and without the GHG Rules in place; and
- Evaluated scenarios with different long-term assumptions associated with the availability of federal production tax credits and investment tax credits.

2.3.1.4 Preserving the Flexibility and Adaptability of the Portfolio

A key element of NIPSCO's 2018 and 2021 IRPs was *flexibility*. The preferred plans from both of these prior IRPs 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 energy transition has done exactly that by; (i) conducting additional sets of RFPs to secure projects as needed; (ii) adjusting NIPSCO's procurement strategy to integrate storage and shift the amount of solar and wind in the portfolio; (iii) adjusting resource retirement dates and online dates in response to external market factors like supply chain constraints and tariff pressures; and (iv) evolving the analytical tools used in IRP studies to incorporate broader risks and considerations.

In the 2024 IRP, NIPSCO identified key market, policy, and regulatory developments early in the planning process to ensure market scenarios and portfolios were constructed to be flexible to a dynamic market. These included:

- Significant demand growth across the power sector as a result of data center loads;
- The documentation of the Five Pillars of long-term planning identified by the Indiana 21st Century Energy Task Force;
- MISO's D-LOL filing associated with capacity accreditation;
- EPA's GHG rules;
- NIPSCO conducted RFP events to solicit actionable resource offers of all types and duration;
- NIPSCO deployed a portfolio construction process that did not rely solely on least cost optimization, but also assessed a wide range of strategies to understand the implications of different capacity accreditation and emissions constraints.

2.3.1.5 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 <u>not</u> produce a single score or ranking of portfolios, but serves as a tool to facilitate decision-making.

For its 2024 IRP scorecard, NIPSCO identified five major planning objectives and multiple metrics within seven key indicator categories, as summarized in Figure 2-7. 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 2021 IRP and track closely and are consistent with the Five Pillars of long-term planning identified by the Indiana 21st Century Energy Task Force.[8]

Figure 2-7: Key Scorecard Objectives and Indicators

Objectives	Indicators
Affordability	Cost to Customer
Rate Stability	Cost Certainty
	Cost Risk
	Lower Cost Opportunity
Environmental Sustainability	Carbon Emissions
Reliable, Flexible, and Resilient Supply	Reliability, Flexibility
Positive Social, & Economic Impacts	Local Investment in Economy

2.3.2 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 to arrive at a Reference Case set of inputs and four alternative scenarios against which to evaluate resource options. The elements involved in this step are described in more detail below.

2.3.2.1 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, environmental policy and emission allowance prices, and power prices (energy and capacity) for the Reference Case and four 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

8 The Five Pillars include Reliability, Resilience, Affordability, Stability, and Environmental Sustainability IRP.

fleet. For example, for coal pricing, delivered coal contract details and expected coal transportation rates were provided by NIPSCO's Fuel Supply group to conform to near-term price expectations for the existing fleet of plants. Long-term fundamental forecasts were blended in over time. Figure 2-8: presents a summary of the source and reference information for each of the major market inputs.

Figure 2-8: 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 (fundamental forecast) 4 (coal procurement and current contracts/ transportation arrangements)
Emission Prices and Environmental Regulation	CRA forecasts and NIPSCO environmental group	7 and 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.

- Natural gas and power price stochastic inputs were developed with CRA's MOSEP model. The tool's Monte Carlo engine simulates price deviations around expected paths based on historical volatility and natural gas-power correlation to yield hundreds of iterations of daily and hourly price paths. CRA also generated correlated synthetic wind output, solar output, and NIPSCO load iterations using *CRA AdequacyX* – Charles River Associates' proprietary probabilistic reliability analysis tool. The details of the stochastic development process are discussed in more detail in Section 8.

2.3.2.2 Environmental Planning Inputs

For the 2024 IRP, the joint NIPSCO-CRA team developed a range of potential environmental policy input assumptions across market scenarios, given uncertainty regarding federal legislative policy and regulation at the U.S. EPA. These environmental planning inputs included scenarios with and without the recently issued EPA GHG Rules for the power sector, with and without the long-term continuation of federal tax credits for clean energy that were extended and or/expanded through the Inflation Reduction Act of 2022, and with and without CO2 pricing. 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.

2.3.2.3 Energy and Demand Forecast

For the 2024 IRP, CRA developed an independent load forecast for NIPSCO's energy sales and expected future summer and winter peaks. The 2024 IRP included a robust accounting of the impacts of historical DSM, as well as quantitative scenario-based projections of electric vehicle and customer-owned distributed energy resource penetration and their impacts on NIPSCO's load growth outlook. Scenario variables also included economic growth, industrial load uncertainty, broader market-wide electrification, and large economic development (data center) load growth. All methods, assumptions, and detailed forecast results are provided in Section 3.

2.3.2.4 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.

2.3.2.5 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 and Demand Side Analytics, as described in Section 5. Supply-side resource options were developed largely from the 2024 RFPs. The 2024 RFPs provided real-world cost information and resource operational characteristics, including capacities, heat rates, and expected capacity factors for renewable resources. NIPSCO supplemented the RFP data with third-party research and internal cost estimates from its Major Projects group for additional generic technology types. Section 4 describes the overall new supply-side resource 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.

2.3.2.6 Planning Reserve Margin Target

NIPSCO operates in the MISO market and must demonstrate a sufficient planning reserve margin to ensure reliability and resource adequacy. MISO's most recent seasonal reserve margin targets were used under current market rules: 9% in Summer, 27% in Winter, 14% in Fall, 27% in Spring. For the reserve margin used under the D-LOL analysis, NIPSCO used a coincidence factor based on information provided to NIPSCO by MISO in Spring 2024 that developed an expected planning reserve margin requirement obligation under D-LOL rules for the 2028/29 planning year based on backcasting analysis of the 2023/24 planning year. This coincidence factor aims to approximate NIPSCO obligation for the season based on its expected load during all MISO risk hours and not just during the single peak hour. On a peak load basis, the implied seasonal reserve margins were: 4.2% in Summer, 2.8% in Winter, 9.2% in Fall, 1.2% in Spring. The implied reserve margins under D-LOL are lower because the system risk hours are not necessarily coincident with times of NIPSCO's internal peak.

2.3.2.7 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 2-9.

Figure 2-9: Major Financial Assumptions

Financial Assumption	Value
Cost of Equity	9.80%
Cost of Debt	4.76%
Equity %	58.60%
Debt %	41.40%
After-Tax Weighted Average Cost of Capital	7.22%
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	7.22%
Allowance for Funds Used During Construction%	7.44%
Blended Depreciation Rate for Existing Assets	3.88%

2.3.3 Step 3: Develop Integrated Resource Strategies

The third major step in the 2024 IRP process was to develop resource strategies or portfolios for further evaluation. Foundational to this step was establishing NIPSCO's starting supply-demand position. On the supply-side, NIPSCO is currently in the midst of retiring its coal-fired Schahfer and Michigan City units and replacing them primarily with wind, solar, storage, and natural gas peaking resources. Meanwhile, capacity accreditation for all resource types is uncertain as MISO rules evolve. On the demand side, NIPSCO currently expects significant load growth associated with new large data center loads entering its system.

As shown in Figure 2-10 and Figure 2-11 for the summer and winter seasons, respectively, NIPSCO faces an uncertain future capacity gap as a result of potential load growth and potential capacity accreditation changes. The gap is expected to materialize in 2028 after the retirement of NIPSCO's final coal-fired unit at Michigan City and grow over time. As shown, both the capacity accreditation and NIPSCO obligation are expected to change in 2028 after the implementation of the D-LOL rules.

Figure 2-10: Starting Supply-Demand Balance – Summer with and without D-LOL

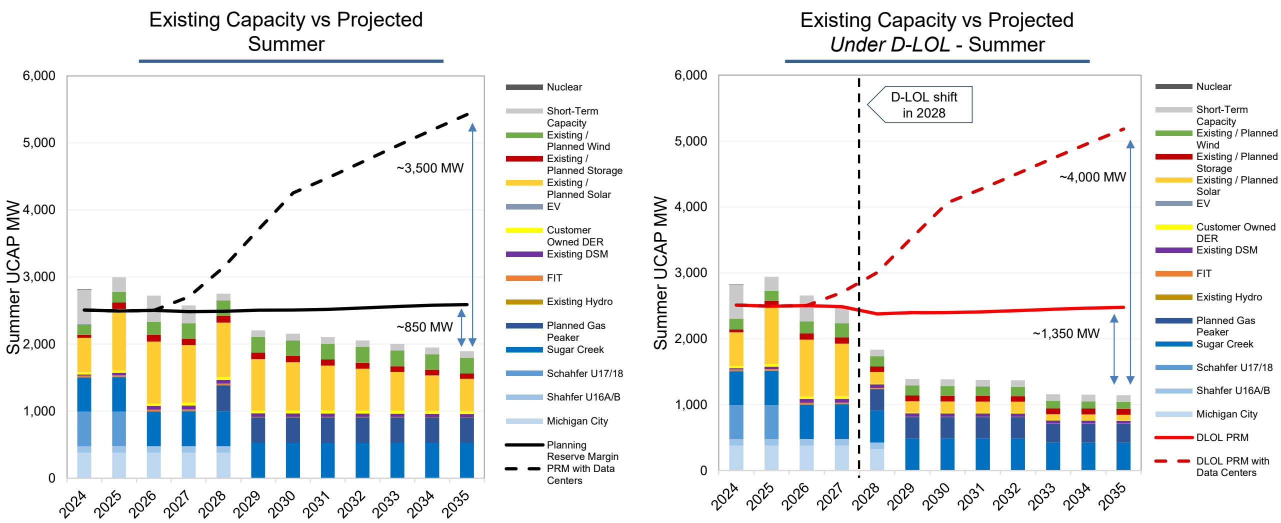
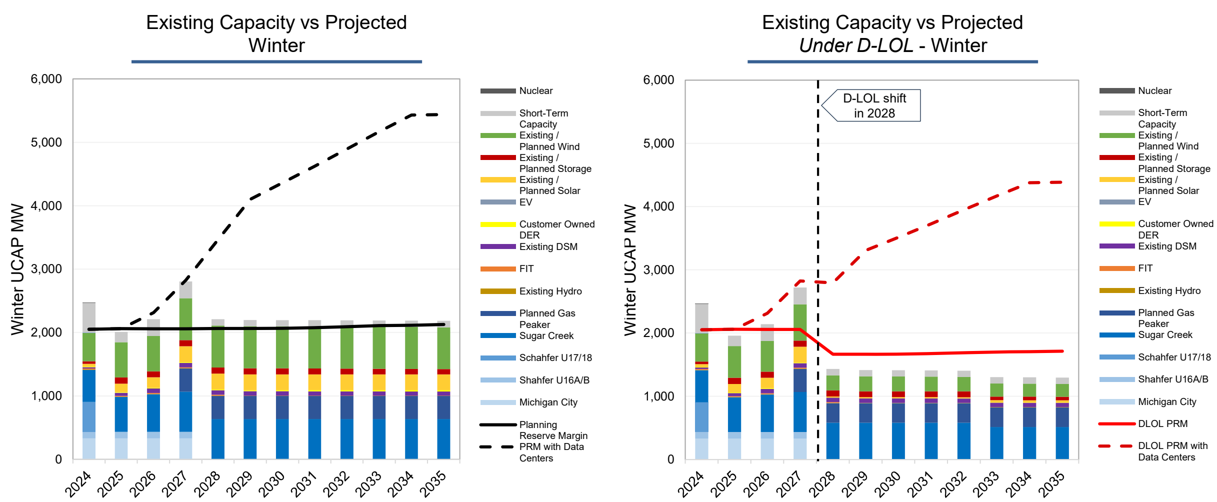


Figure 2-11: Starting Supply-Demand Balance – Winter with and without D-LOL



With this foundational starting point, the 2024 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 developed six different portfolio concepts around accreditation and emission intensity through least cost portfolio optimization analysis. Variants were also developed based on load growth sensitivities and future decarbonization pathways. The analysis is described in more detail in Section 9.

2.3.4 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 power purchase agreements, 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.

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 (including detailed accounting associated with federal tax credits) 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 and each individual integrated market scenario.

2.3.5 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 2024 IRP, NIPSCO worked with CRA to produce a comprehensive load forecast by customer class and load category. This entailed an econometric core load forecast for residential, commercial, small industrial, and large industrial customers,[9] plus projections for EV demand and BTM DER f

penetration throughout the service territory. NIPSCO also developed a view on the potential for large economic development projects, particularly data centers, to drive additional demand growth. Major highlights of the forecast include:

- As part of its 2024 load forecasting efforts, NIPSCO has identified several large economic development projects that could contribute significant load growth to the system. To capture this new source of demand, NIPSCO developed two large load sensitivities to supplement the base econometric forecast. Data center growth has the potential to add 21,810 to 72,140 GWh to the annual sales forecast by 2035 and between 2,600 and 8,600 MW to peak load.

- In the Reference Case, NIPSCO's energy sales are projected to grow at a CAGR of approximately 11.3% over the next 20 years, *including the impact of new large economic development loads*. The summer and winter peaks are projected to increase by 8.9% and 10.6%, respectively. Prior to the inclusion of such loads, NIPSCO's energy sales were projected to growth at a CAGR of approximately 1.1% over the next 20 years.

- Residential and commercial customer counts are projected to grow at CAGRs of 0.87% and 1.02%, respectively, with the industrial customer count projected to decline at a rate of 0.26% per year. Overall sales to residential customers are projected to increase by 0.37%, despite sales per customer declining. The overall sales to commercial customers are similarly projected to increase by 0.36%, driven by growing customer count but modestly declining sales per customer. The sales to small industrial customers are projected to decline by 0.15%, driven by modestly declining customer count and flat sales per customer.[10]

- EV growth has the potential to add between approximately 700 to 1,800 GWh to the annual sales forecast by 2043 and between 140 and 360 MW of summer peak impact.

[9] 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.

[10] The projections in this paragraph exclude the new large economic development loads referenced in the immediately preceding paragraphs.

EVs also have the potential to substantially shift the time of peak load, depending on consumer behavior and potential future time of use rate design incentives.

- Customer-owned DERs in the form of residential and commercial solar resources have the potential to reduce the sales forecast by approximately 150 to 400 GWh. However, this resource is unlikely to materially reduce peak demands, given expectations for overall hourly load profiles to shift to times before or after the sun has risen or set.

- NIPSCO's scenario and sensitivity analysis provides a broad range of potential load growth outcomes based on uncertainty regarding future economic growth, EV and DER penetration, other electrification, potential industrial load migration, and large economic development growth.

3.2 Forecasting Methodology Overview

For the 2024 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 six 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), weather variables (heating and cooling degree days based on historical temperature and humidity), and historical data associated with EV and DER penetration.

- **Weather Normalization:** Development of weather-normalized energy sales by class (kWh/customer) for the historical period, *excluding* historical DSM program impacts.

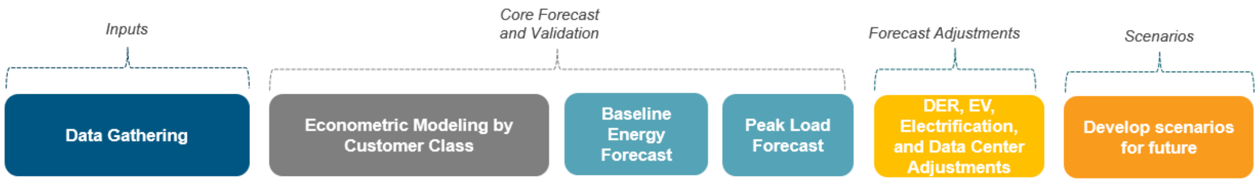
- **Econometric Modeling by Customer Class:** Testing of all economic and demographic "driver" variables in a dynamic regression system and performance of post-estimation tests on econometric models' specification and forecasting performance (for example, Systemic Mean Absolute Percentage Errors).

- **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.

- **Forecast Adjustments**, including:
  - Adjustments to the load forecast to incorporate existing and planned *known* DSM programs.
  - Synthesis of forecasts for elements of the future load associated with emerging market trends, including EVs, DERs, other sources of electrification, and new large economic development loads like data centers, inclusive of transmission and distribution losses and accounting for changing load shapes.

- **Scenario Development:** Evaluation of alternative economic growth in econometric models and development of ranges for EVs, DERs, other electrification, industrial load, and new large economic development loads like data centers based on fundamental analysis and other inputs.

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 2013 through 2023,[11] macroeconomic and demographic indicators for the region from Moody's Analytics,[12] weather data (heating and cooling degree days based on historical temperature) from the National Oceanic and Atmospheric Administration, and information regarding NIPSCO's historical DSM and EE program savings. After estimating regression equations for each customer class, a number of statistical tests were performed to validate the regression equations specifications and forecast errors. NIPSCO selected the presented model based on R-squared, adjusted R-squared, Root Mean Squared Error and Mean Absolute Percentage Error for out-of-sample data. Stata and Python software packages were used to perform the load forecasting analysis.

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 were 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, household income was the key variable used to forecast residential, commercial customer count,

[11] It is important to note that NIPSCO's baseline load forecast takes out all historical DSM and energy efficiency (EE) savings from historical electric energy consumption prior to the econometric analysis.

[12] Note that the final IRP load forecast was based on economic data from Moody's as of Q4 2023.

and total industrial customers,[13] while the commercial customer count was also based on a measure of employment.[14]

Note that after predicting the total number of industrial customers, these were divided into categories for small industrial customers, large industrial non-531 customers, large industrial 531 Tier 1 customers, and large industrial 531 Tier 2/3 customers. The number of large industrial customers in each class was assumed to remain constant at the current number, while smaller industrial customers were evaluated through NIPSCO's econometric analysis.[15]

A representation of the estimated regression model for the customer count forecast is presented in Equation 3-1.

Equation 3-1: Regression Equation for Number of Customers

$C_{\mathrm{it}} = \mathrm{b_o} + \mathrm{b_1 X_{it}} + \mathrm{b_{jt}} \theta_{\mathrm{t}} + \pi_{\mathrm{it}}$

Where

i=customer class (residential, commercial, total 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)

$b_1, b_2, .. b_j$ = Estimated coefficients (slopes) for each variable included in the regression model.

π_{it} = random error term

Similarly, NIPSCO developed econometric regression models for predicting energy sales per customer[16] 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 and commercial regression equations included the average class-specific monthly retail rate, heating and cooling degree days, household income (for residential), employment in the manufacturing sector (for commercial), and monthly dummy variables that control for seasonal impacts on energy consumption. A dummy variable was also used to account for changing

13 The coefficient on the household income variable is positive for residential, commercial, and small industrial customer counts, suggesting that an increase in the household income is associated with an increase in the number of these customers in the NIPSCO service territory.

14 The coefficient on the employment variable is positive, which indicates that the number of commercial customers in the NIPSCO service territory will increase with increasing levels of employment.

15 The present number of large industrial customers is 9 large Industrial non-531 customers, 7 large Industrial 531 Tier 1 customers, and 7 large 531 Tier 2/3 customers. These are assumed to continue at constant levels in the Reference Case forecast.

16 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).

customer behavior following the COVID-19 pandemic. The following variables were used in the development of the electric energy sales per customer model:

- Heating (residential only) and cooling degree day variables control for the impact of weather on electricity consumption. Particularly, the 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 the residential and commercial customer classes.[17]

- Demographic variables (i.e., household income, employment in manufacturing, and overall employment) control for the impact of regional economic factors on electricity consumption.

- 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.

- Dummy variables were used to control for sharp changes in customer behavior following the COVID-19 pandemic.[18]

A representation of the estimated regression model for the usage per customer forecast is presented in Equation 3-2.

[17] 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.

[18] This COVID-19 dummy variable was positive for residential use per customer and negative for commercial use per customer. This indicates changing customer behavior, which increases typical residential use and reduces commercial use.

Equation 3-2: Regression Equation for Usage per Customer Forecast

$$D_{it} = a_o + a_2 X_{it} + a_3 Weather_{it} + a_{jt}\theta_t + a_4 I_t + \varepsilon_{it}$$

Where

i=customer class (residential and commercial)

t= month

a_o= constant term

D_{it}= electric energy usage per customer 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

I_t= Indicator function for post-2020 years to account for impacts of changing behavior during and following the COVID-19 pandemic

ε_{it}= random error term

$a_1, a_2, a_3, \, ..a_j$ = Estimated coefficients (slopes) for each variable included in the regression model.

Regression models on Moody's variables were not found to provide good predictive power for the sales per customer in the industrial classes, and the industrial classes (small industrial, large industrial non-531, large industrial 531 Tier 1, large industrial 531 Tier 2, and large industrial 531 Tier 3) were found to be highly correlated with relatively stable portions of overall sales (25.45%, 5.38%, 16.06%, 17.46%, and 34.2%, respectively). This indicates that the industrial load is a single overall ecosystem that is driven by underlying long-term, techno-economic trends. The sales for the overall industrial class have historically seen modest declines, but they have stabilized following the COVID-19 pandemic. The industrial sales also showed significant monthly variations, indicating predictable yearly cycles in the industries represented in NIPSCO's footprint. Given these trends, the overall industrial sales were predicted as the post-2020 monthly average. Then, the overall sales were decomposed to the respective classes, based on the historical trends.

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	Industrial
Customer Count Forecast	Household Income	Household Income, Employment	Manufacturing employment, Metals employment
Baseline Sales per Customer Forecast	Household income, HDD, CDD, seasonal monthly dummies, 2020 and after indicator function	Employment, Manufacturing, CDD, seasonal monthly dummies, 2020 and after indicator function	Seasonal average → decomposed by rate class

3.3.2 Industrial Service Structure

The 2024 IRP incorporated NIPSCO's industrial service tariff, known as Rate 531. This industrial service tariff, originally named Rate 831, was included in the settlement agreement in Cause No. 45159 approved by the Commission in 2019, and it gave certain large industrial customers the option to secure their energy and capacity needs, although NIPSCO at all times is the Market Participant in the MISO market. Since then, these rates classes have been renamed as Rate 531. For IRP planning purposes, NIPSCO's load forecast for the large industrial customer class includes Rate 532, Rate 533, and Rate 531 (Tier 1 energy only) customers.[19]

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 0.54% between 2013 and 2024. The commercial class makes up about 12% of NIPSCO customers, and the industrial class makes up about 0.45% of NIPSCO customers. The CAGR between 2013 and 2024 for commercial and industrial classes is 0.76% and *minus* 0.98%, respectively.

Figure 3-3 presents NIPSCO's projected customer count for the Residential class, Figure 3-4 presents NIPSCO's projected customer count for the Commercial class, and Figure 3-6 presents NIPSCO's projected customer count for Industrial customer classes.

The CAGR is also calculated for the number of customers for each customer class projection between 2024 and 2043 in order to provide an understanding on the future growth trends for NIPSCO's customer counts. NIPSCO's forecast projects residential and commercial CAGRs of 0.87% and 1.02%, respectively. The number of industrial customers is projected to decline modestly at a rate of minus 0.26%.

[19] 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 Tier 2 and Tier 3 on Rate 531 is excluded from the load forecast because this load is not served by NIPSCO.

Figure 3-3: NIPSCO Residential Customer Count Forecast

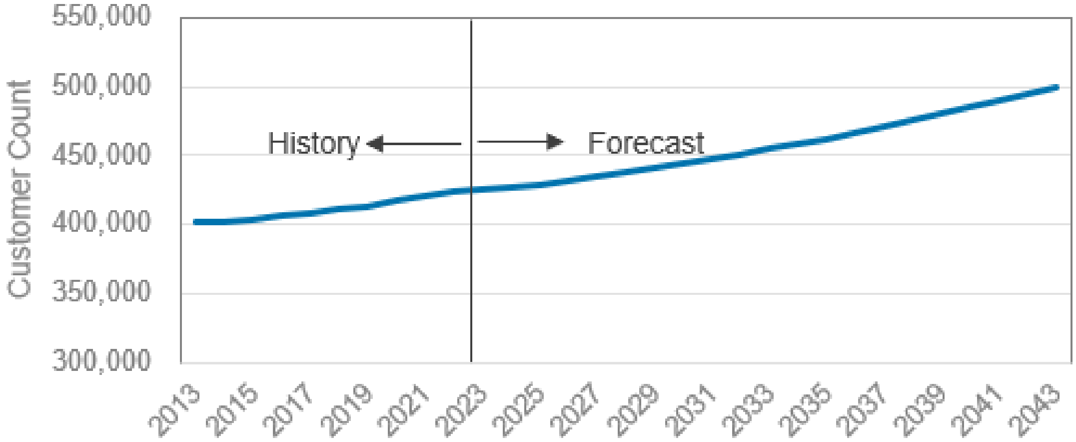


Figure 3-4: NIPSCO Commercial Customer Count Forecast

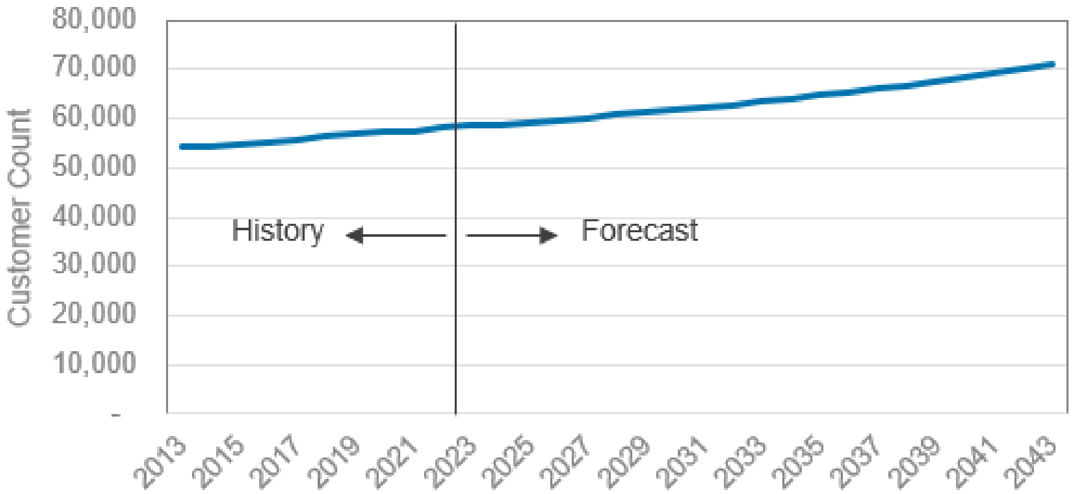
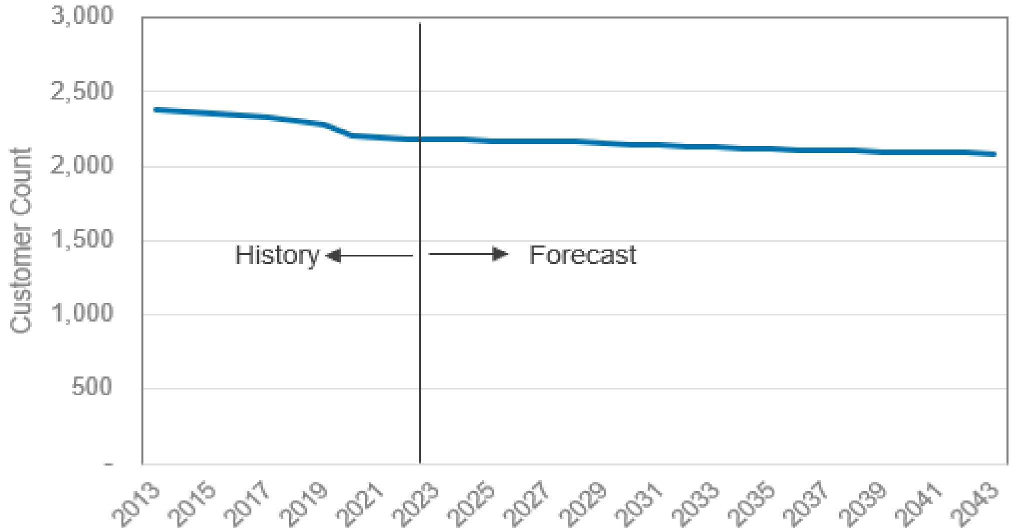


Figure 3-5: NIPSCO Industrial Customer Count Forecast



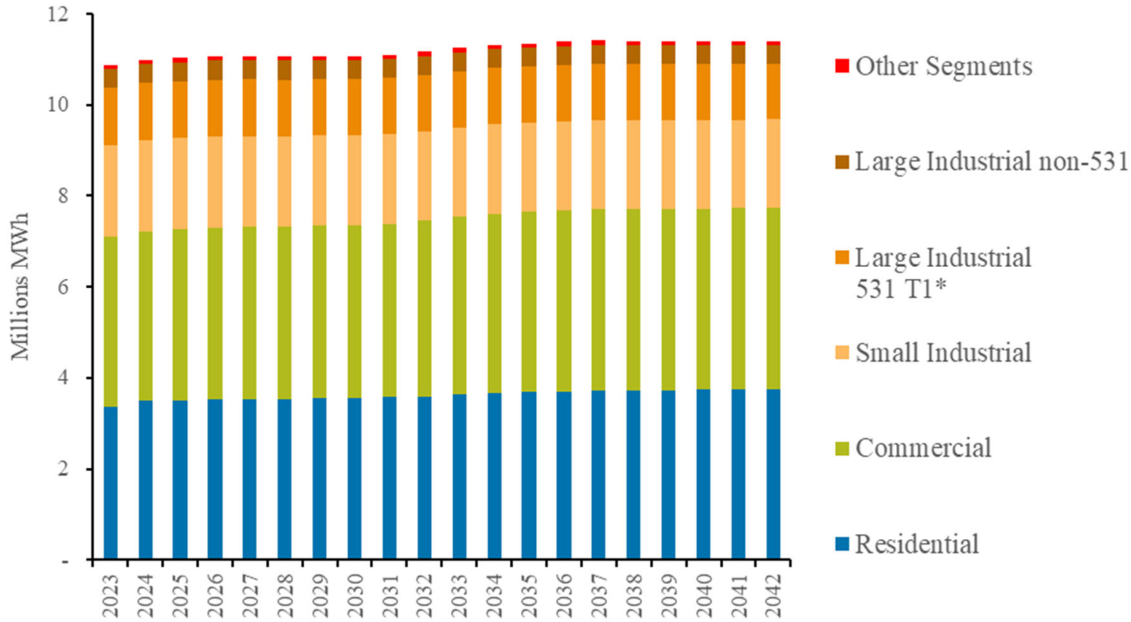
3.3.4 Sales per Customer and Total Electric Sales Forecast

To obtain the total monthly energy sales forecast for each class between 2024 and 2043, the energy sales per customer forecast is multiplied by the customer count forecast. Figure 3-6 presents NIPSCO's projected electric energy sales forecast by customer class and total NIPSCO energy sales through 2043,[20] *prior to any adjustments for EVs, DERs, and large economic development loads*, which are described later in this section.[21] The CAGR for residential customers is projected to be 0.37%, the CAGR for commercial energy sales is projected to be 0.36%, while the CAGR for the industrial class is projected to be -0.15% between 2024 and 2043.

[20] 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 4.62% on a monthly basis.

[21] Note that these summaries also do not include the impact of transmission and distribution system losses, which are included in the final forecasts presented later in this Section.

Figure 3-6: NIPSCO Electric Sales Forecast by Customer Class before Adjustments and Excluding Losses (MMWh)



3.3.5 Peak Load Forecast Development

After developing the baseline energy forecasts, NIPSCO developed peak load forecasts on a monthly basis. 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 3-7. Based on the sample data, peak load factors are lowest during summer months including June, July, 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, and the summer and winter peak load forecasts by customer class, *prior to any adjustments for EVs, DERs, and large economic development loads*, which are described later in this Section, are shown in Figure 3-8 .

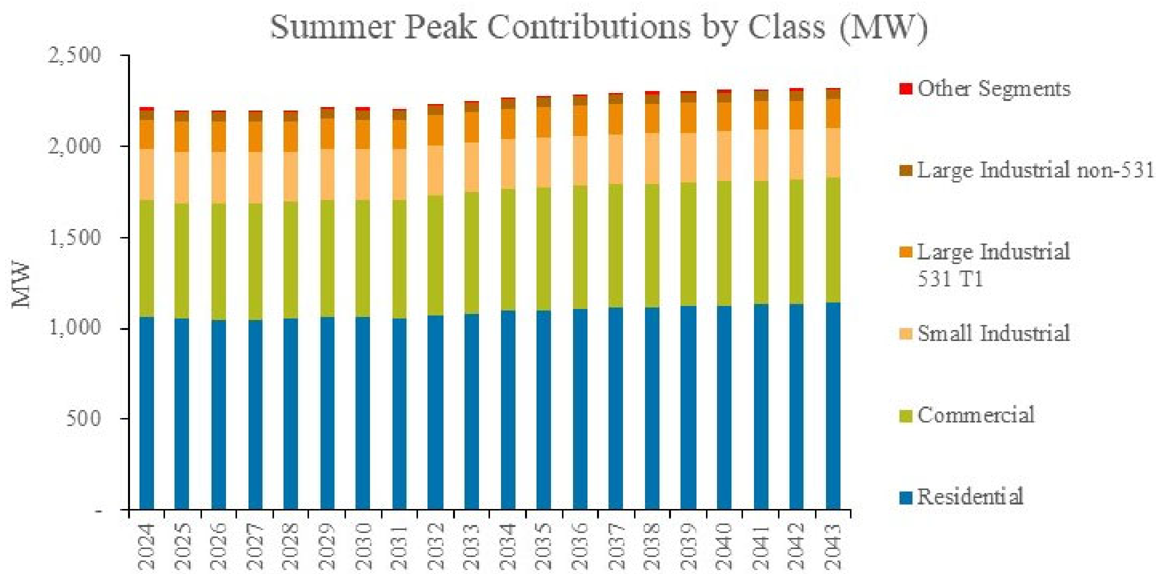
Equation 3-3: Load Factor Calculation

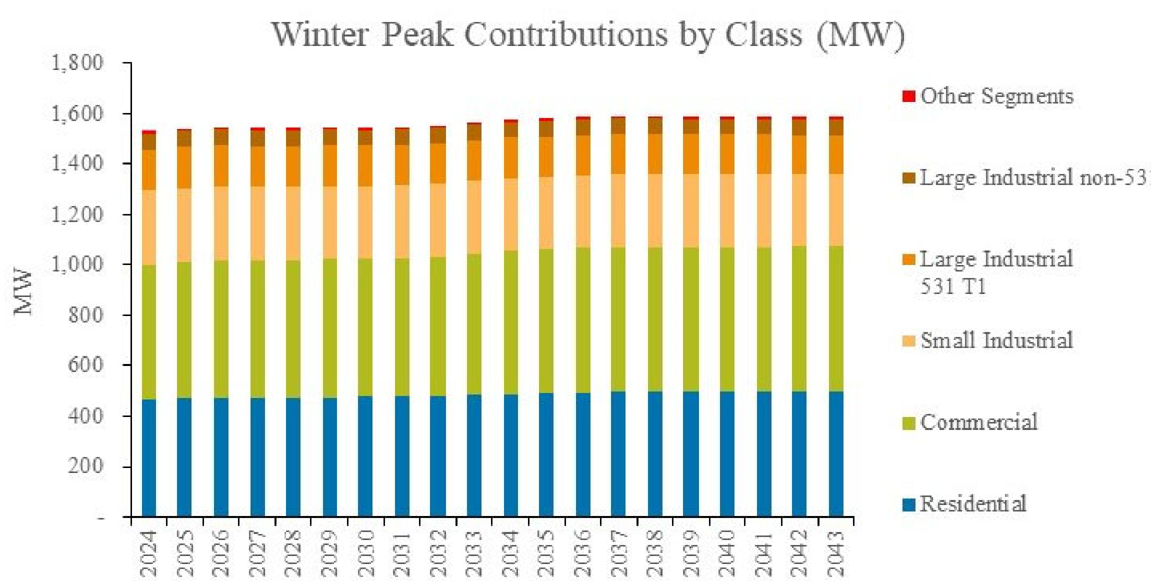
$$Load\ Factor = \left(\frac{Usage\ (kWh)}{\left(Demand\ kW\ *\ 24\frac{hr}{day} *\ X\frac{days}{mo}\right)} \right)$$

Figure 3-7: Calculated Peak Load Factors by Customer Class

Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential	88.88%	88.88%	88.88%	69.90%	69.90%	51.60%	51.60%	51.60%	51.60%	69.90%	88.88%	88.88%
Commercial	81.60%	81.60%	81.60%	75.30%	75.30%	75.40%	75.40%	75.40%	75.40%	75.30%	81.60%	81.60%
Industrial	83.60%	83.60%	83.60%	80.80%	80.80%	83.00%	83.00%	83.00%	83.00%	83.00%	83.60%	83.60%

Figure 3-8: Seasonal NIPSCO Peak Load Forecast by Customer Class before Adjustments and Excluding Losses





3.4 Electric Vehicles

3.4.1 Methodology Overview

NIPSCO developed a range of potential EV penetration rates based on existing data regarding ICE vehicle and EV counts in NIPSCO counties and a top-down forward-looking outlook based on analysis of third-party projections, policy goals, and current trends. 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 market scenarios.

The EV analysis was broken down different classes of vehicles and charging locations, which were independently forecasted:

- LDVs in service territory;
- MDVs, including transit vehicles, such as buses and shuttle vans, in service territory;
- Highway corridor charging for HDVs and MDVs

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 from the following major sources:

- LDVs and MDVs: Indiana Vehicle Fuel Dashboard data
- Transit vehicles: 2022 National Transportation Database
- Corridor charging data: DOT –HPMS

3.4.2.2 Vehicle Count Growth Rate Projections

NIPSCO developed an econometric forecast model to develop EV growth estimates based on adoption rates applied to a sigmoid growth curve. Historical EV registrations were analyzed to create a view of EV adoption in historical years and expected 2024 adoption. Historical ICE registration data was used to obtain a view of total vehicle registrations, and the total number of vehicles was kept constant over time. The inflection year, maximum EV adoption by 2045, and the k value (slope) of the sigmoid curve function were varied across scenario based on analysis of third-party projections, policy goals, and current trends. These assumptions are provided in Table 3-1 and Table 3-2.

Table 3-1: LDV EV Sales Assumptions by Scenario

	Inflection Year	Target EV Adoption as % of LDV Sales by 2045	K Value
Low	2035	50%	0.4
Med	2032	80%	0.45
High	2031	95%	0.5

Table 3-2: MDV and Transit EV Sales Assumptions by Scenario

	Inflection Year	Target EV Adoption as % of MDV Sales by 2045	K Value
Low	2032	30%	0.9
Med	2032	75%	0.9
High	2030	95%	0.9

3.4.3 Light Duty Vehicles

3.4.3.1 LDV EV Growth Forecast

NIPSCO utilized the Indiana Office of Energy Development Vehicle Fuel Dashboard to determine the existing number of electric vehicles registered in the state. The Indiana Vehicle Fuel Dashboard is designed to provide public information about the types of vehicle fuels in the state and trends over time. The dashboard allows users to explore Indiana BMV registration data from January 2018 to present. NIPSCO found that by Jan. 1, 2024, there were approximately 2,015 LDV electric vehicles registered in the service territory. Estimated LDV numbers by County are provided in Table 3-3 and Table 3-4:.

Using the 2023 count of vehicles as a starting number of EV registrations in NIPSCO service territory as of Jan. 1, 2024, the annual sales of light duty vehicles were forecasted to grow as detailed in Table 3-1. NIPSCO took an average of total LDV vehicle registrations between 2018 and 2023 to find a total of approximately 644 thousand LDVs, data detailed in Table 3-5:. This average number of LDVs was kept constant throughout the forecast period.

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: Electric and Hybrid Light Duty Vehicle Registrations in NIPSCO Counties[22]

County	Electric						Electric and Gas Hybrids					
	2018	2019	2020	2021	2022	2023	2018	2019	2020	2021	2022	2023
Benton	1	1	1	1	3	9	14	16	19	28	38	58
Carroll	-	-	-	-	3	11	51	54	56	78	106	129
DeKalb	2	2	3	9	11	25	105	99	110	158	188	237
Elkhart	17	22	33	66	105	183	720	747	815	1,057	1,283	1,570
Fulton	-	-	1	4	10	18	51	43	57	54	77	106
Jasper	-	-	2	9	14	25	67	76	82	126	138	199
Kosciusko	3	3	7	18	37	78	298	324	346	460	581	684
LaGrange	1	1	-	5	10	11	55	60	70	103	125	141
Lake	18	42	72	215	417	794	1,455	1,454	1,597	2,195	2,798	3,715
LaPorte	11	12	24	44	73	122	317	314	330	472	563	748
Marshall	1	1	1	6	20	31	134	149	152	217	269	327
Newton	-	-	-	1	2	5	34	29	30	45	58	71
Noble	1	1	-	8	18	21	90	83	93	127	170	208
Porter	23	26	48	103	214	385	784	803	866	1,156	1,145	1,918
Pulaski	1	-	1	2	5	1	24	21	18	28	35	40
St. Joseph	19	29	48	111	224	379	1,247	1,314	1,492	1,831	2,232	2,753
Starke	-	1	1	2	5	4	48	49	43	72	77	112
Steuben	3	4	4	10	19	23	108	117	121	172	219	284
White	1	1	1	9	16	27	65	58	60	86	115	154
Total	102	146	247	623	1,206	2,152	5,667	5,810	6,357	8,465	10,217	13,454

22 Indiana Office of Energy Development, Indiana Vehicle Fuel Dashboard, accessed Jan. 11, 2024. Electric and Gas Hybrid counts include non-plug-in hybrids. County vehicle counts are not representative of the NIPSCO service territory. https://www.in.gov/oed/resources-and-information-center/vehicle-fuel-dashboard/

Table 3-4: Estimated EVs in NIPSCO Service Territory[23]

County	% Households in NIPSCO Service Territory	2018	2019	2020	2021	2022	2023
Benton	100%	2	2	2	3	5	12
Carroll	77%	2	2	3	4	7	14
DeKalb	17%	1	1	2	3	4	7
Elkhart	57%	35	38	47	74	105	159
Fulton	55%	2	1	2	4	8	13
Jasper	82%	3	4	6	14	18	30
Kosciusko	58%	12	13	16	27	42	70
LaGrange	52%	2	2	2	6	9	10
Lake	100%	105	129	168	347	585	1,017
LaPorte	100%	30	31	44	72	107	167
Marshall	36%	3	4	4	7	13	18
Newton	65%	1	1	1	2	4	6
Noble	6%	0	0	0	1	2	2
Porter	91%	64	68	91	158	258	457
Pulaski	47%	1	1	1	2	3	2
St. Joseph	0%	0	0	0	0	1	1
Starke	3%	0	0	0	0	0	0
Steuben	67%	6	7	8	14	21	27
White	5%	0	0	0	1	1	2
Total	-	272	306	397	737	1,193	2,015

[23] Estimated count of electric vehicles in the NIPSCO service territory is determined by the approximate % of households within the country that fall into NIPSCO service territory. The Electric and Gas hybrid category is assumed to be predominantly non-plug-in hybrids based on analysis of hybrid vehicle types. NIPSCO assumes 6% of Electric and Gas hybrids are plug-in electric hybrids.

Table 3-5: Estimated Total LDVs in NIPSCO Service Territory[24]

County	2018	2019	2020	2021	2022	2023
Benton	6,659	6,710	6,583	6,662	6,658	6,614
Carroll	15,752	15,883	15,749	16,147	15,781	16,003
DeKalb	30,804	31,072	31,381	32,065	31,782	32,128
Elkhart	121,397	122,113	122,107	126,259	123,869	124,125
Fulton	15,068	15,065	14,969	15,216	15,185	15,031
Jasper	24,705	24,961	24,615	25,669	25,217	25,542
Kosciusko	53,812	54,281	53,587	55,122	54,495	54,503
LaGrange	20,567	20,488	20,252	21,192	20,648	20,474
Lake	261,456	262,859	258,449	267,672	262,950	264,550
LaPorte	73,125	72,880	72,329	73,906	72,083	72,614
Marshall	31,769	31,979	31,572	32,512	32,273	32,136
Newton	11,163	11,107	10,814	11,206	10,880	10,880
Noble	33,111	33,170	33,480	34,425	33,966	33,825
Porter	105,597	105,964	10,4951	108,077	107,414	108,048
Pulaski	10,065	10,087	9,891	10,307	10,050	10,181
St. Joseph	148,686	149,829	148,934	151,421	149,359	150,223
Starke	17,681	17,442	17,316	17,893	17,625	17,768
Steuben	25,323	26,115	25,917	26,586	25,977	26,175
White	18,829	19,305	19,048	19,487	19,126	19,145
Total	639,562	642,705	635,213	655,478	644,701	647,984

24 Indiana Office of Energy Development, Indiana Vehicle Fuel Dashboard accessed Jan. 11, 2024. https://www.in.gov/oed/resources-and-information-center/vehicle-fuel-dashboard/

Figure 3-9: LDV EV Adoption: EVs as a % of new LDV sales

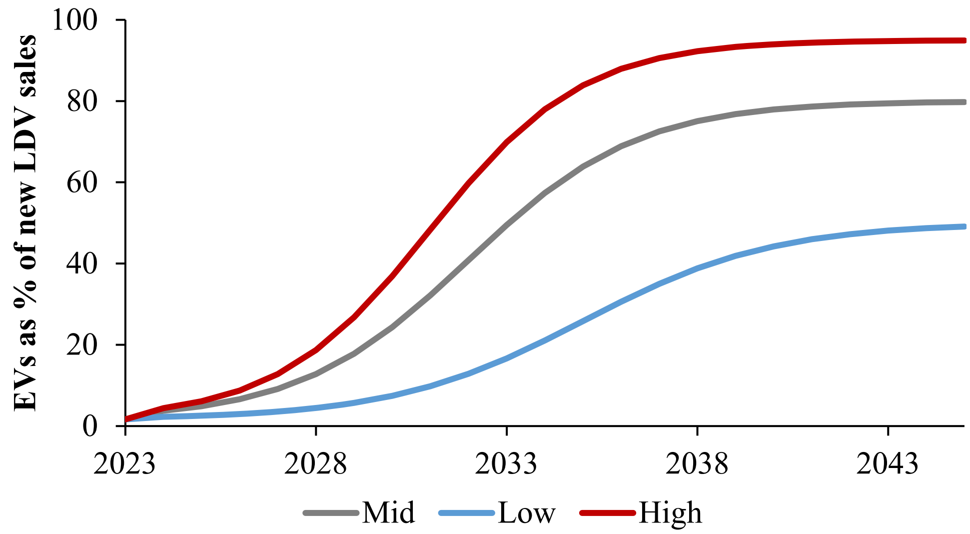
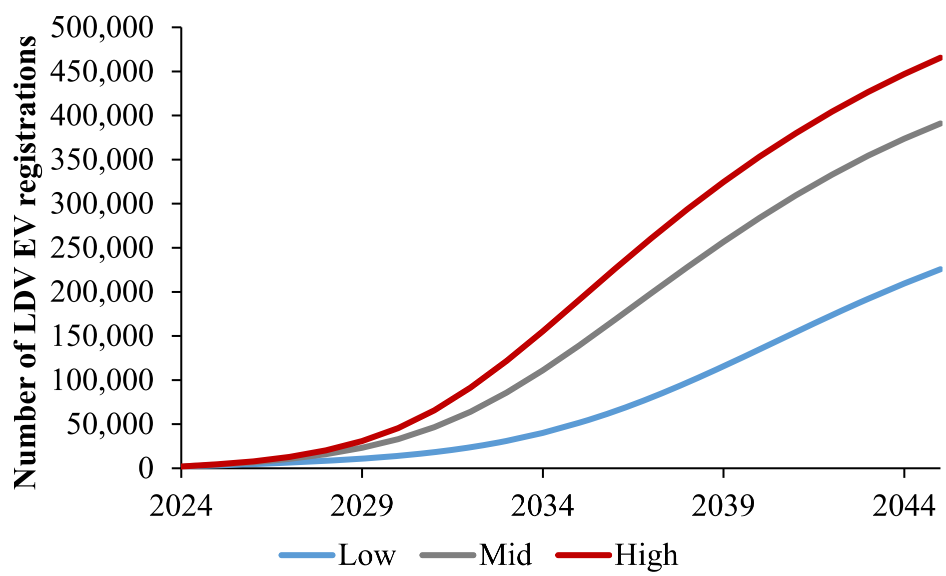


Figure 3-10: LDV EV Adoption: Number of EVs registered in NIPSCO service territory[25]



25 NIPSCO assumes an average LDV lifetime of 12 years based on Bureau of Transportation data. As the makeup of the existing fleet age is unknown, the historical registration data is evenly distributed over the 12-year assumed lifetime to factor in retirements for the fleet turnover analysis. https://www.bts.gov/content/average-age-automobiles-and-trucks-operation-united-states

3.4.3.2 LDV EV Energy Use

NIPSCO utilized the EVI-Pro-Lite[26] tool from the National Renewable Energy Lab to develop hourly vehicle charging shapes and resulting energy use from EV charging. NIPSCO developed three main charging shapes to represent an hourly weather-adjusted 2024 ("Today") charging profile, a 2030 charging profile, and a 2040 charging profile. The EVI-Pro-Lite tool allows the user to specify a number of inputs, including:

- **Fleet size:** This input is not utilized directly as results are normalized to inflate by the number of vehicles shown in Figure 3-10.
- **Average daily miles traveled per vehicle:** Detailed in Table 3-8.
- **Average ambient temperature:** NIPSCO uses an average daily temperature based on historical weather data.
- **Mix of vehicles that are fully electric:** NIPSCO assumes a plug-in electric vehicle focused distribution of vehicles, detailed in Table 3-7.
- **Share of electric vehicles that are sedans vs. SUVs:** NIPSCO assumes relatively even distribution of sedan and SUV vehicles, detailed in Table 3-7.
- **Share of Level 1 and Level 2 workplace charging:** Assumed to evolve over time.
- **Share of electric vehicles with access to home charging:** NIPSCO assumes that 100% of electric vehicles will have access to home charging as much of the service territory falls in residential areas. This could be Level 1 or Level 2 charging.
- **Vehicle preference for home charging:** NIPSCO assumes that 100% of electric vehicles will prefer home charging if they have access to a charger.
- **Home charging strategy** (immediate, delayed, etc.)
- **Workplace charging strategy** (immediate, delayed, etc.)

[26] NREL and DOE EVI-Pro-Lite https://afdc.energy.gov/evi-x-toolbox#/evi-pro-ports

Figure 3-11: LDV assumptions evolution over time

As EV adoption becomes more widespread, model forecasts charging behavior will align with changes in charger / vehicle efficiencies

2024 Load Profile
- Primary home and work charging strategy: *as fast as possible*
- Home charger composition: 20% L1, 80% L2
- Uses EVI-pro default values, assuming same EV efficiency

2030 Load Profile
- Home charger composition: 50% L1, 50% L2
- Efficiency factor applied to dampen the kW per EV required

2040 Load Profile
- Home charger composition: 50% L1, 50% L2
- Continued efficiency factor applied to dampen the kW per EV even more

Table 3-6: Assumed efficiency of LDV vehicle types (miles/kWh)[27]

EV Type	2024-2029	2030-2039	2040-2045
BEV Sedan	2.57	3.5	5.0
BEV SUV	2.3	3.0	4.5
PHEV Sedan	2.95	4.0	5.0
PHEV SUV	2.4	3.25	4.5

Table 3-7: Vehicle type market share assumptions (share of EVs adopted by year)

EV Type	2024-2029	2030-2039	2040-2045
BEV Sedan	44%	50%	52%
BEV SUV	36%	41%	43%
PHEV Sedan	14%	7%	4%
PHEV SUV	6%	3%	2%

Table 3-8: Vehicle miles traveled per day[28]

	2024-2029	2030-2039	2040-2045
VMT	27.5	33.75	40.0

Sample LDV weekday and weekend charging profiles are detailed in Figure 3-12 through Figure 3-17. EV charging profiles are blended over the forecast horizon to create hourly EV charging profiles that consider ambient temperature, day of week, number of vehicles, type of charger (level and location, and vehicle mix).

27 https://atb.nrel.gov/electricity/2022/index

28 https://www.sciencedirect.com/science/article/abs/pii/S254243512300404X

Figure 3-12: LDV EV 2024 Weekday Charging Profile (kW/vehicle)

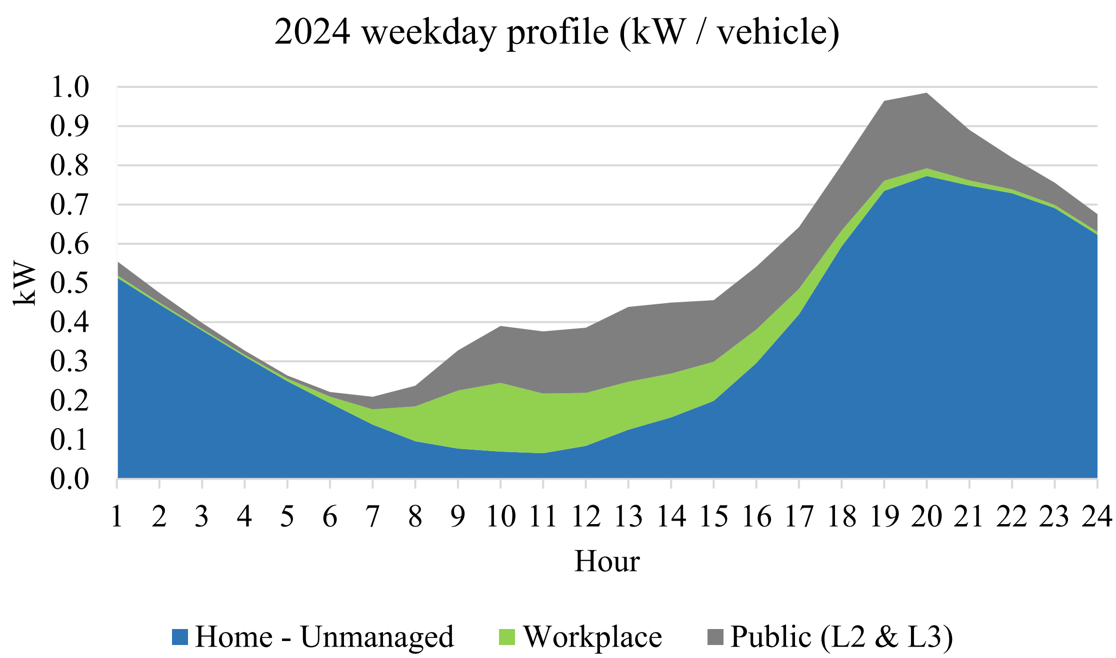


Figure 3-13: LDV EV 2024 Weekend Charging Profile (kW/vehicle)

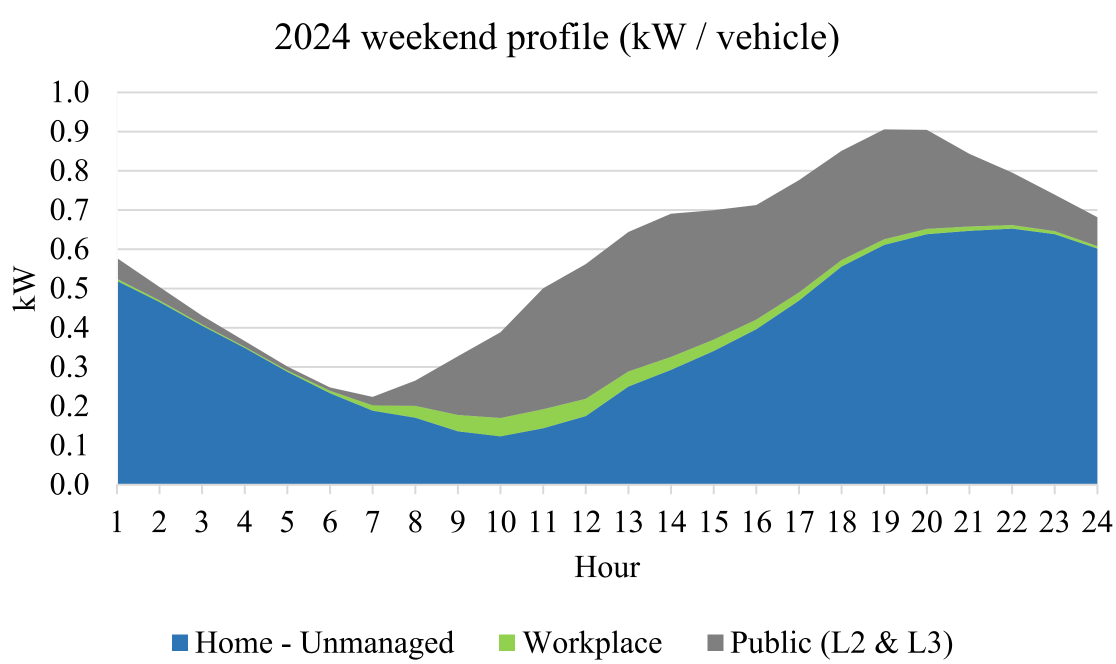


Figure 3-14: LDV EV 2030 Weekday Charging Profile (kW/vehicle)

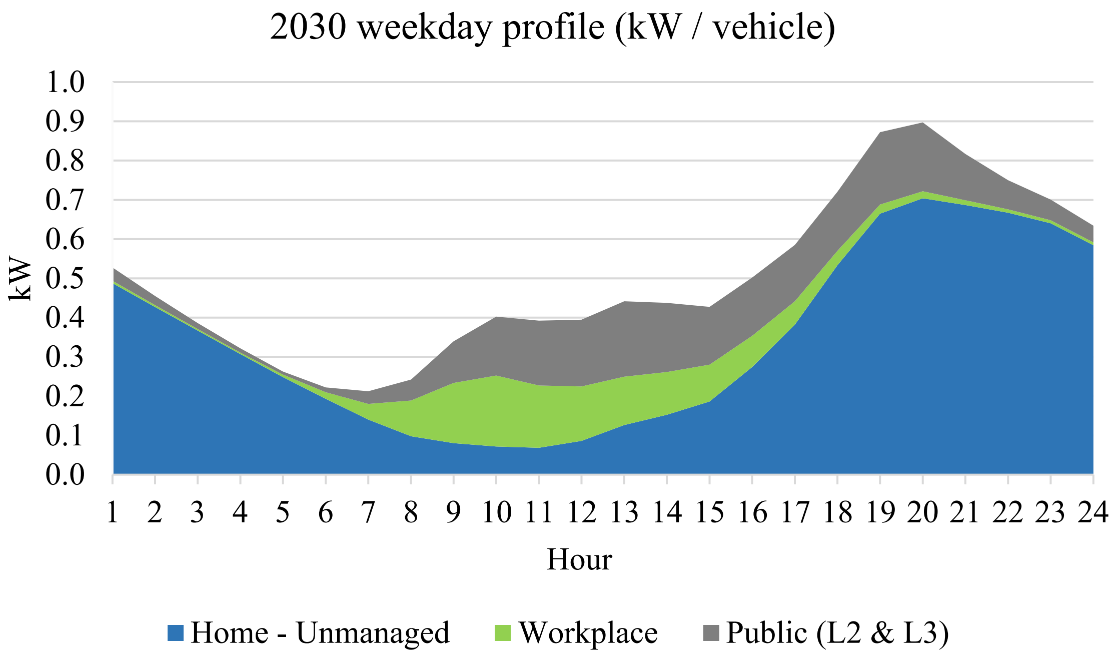


Figure 3-15: LDV EV 2030 Weekend Charging Profile (kW/vehicle)

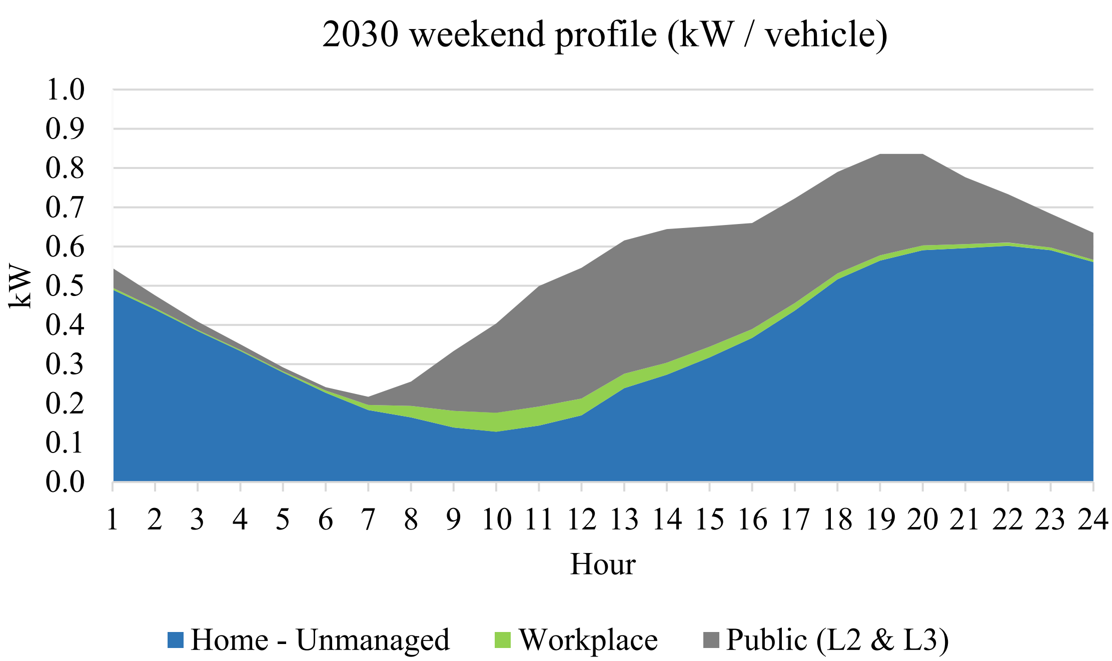


Figure 3-16: LDV EV 2040 Weekday Charging Profile (kW/vehicle)

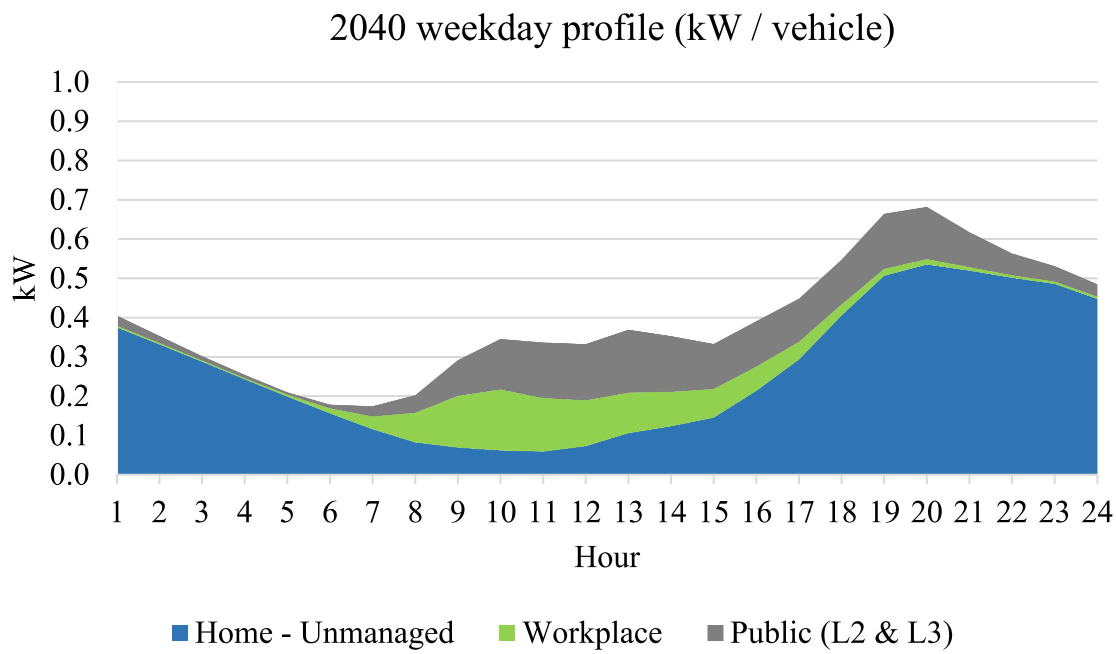
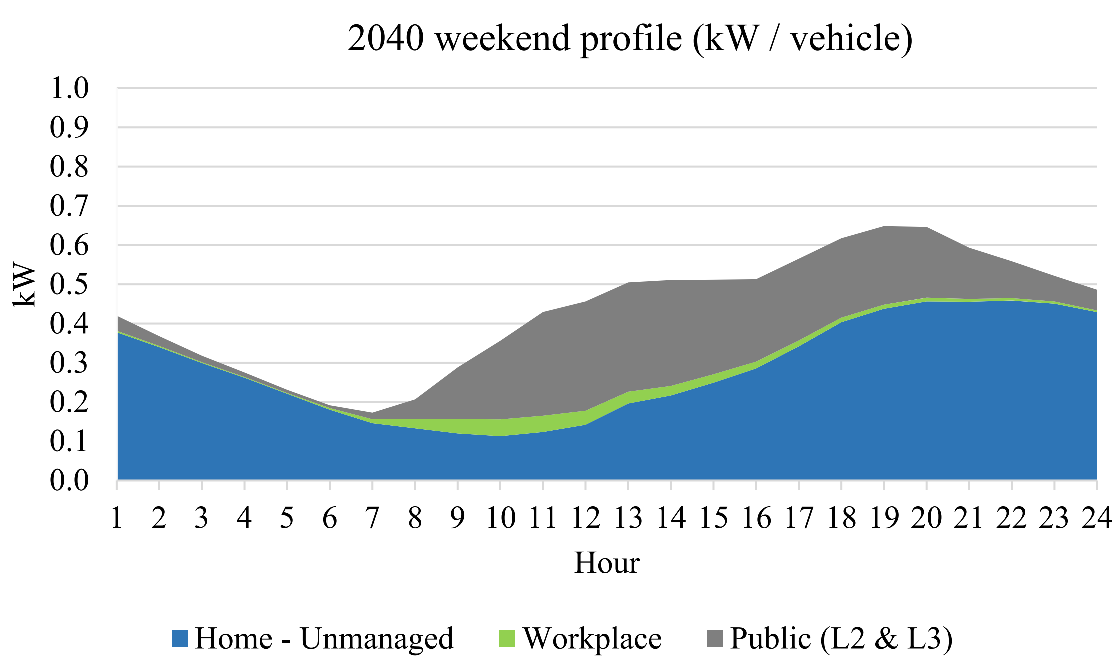


Figure 3-17: LDV EV 2040 Weekend Charging Profile (kW/vehicle)



3.4.4 MDV and Transit Vehicles

3.4.4.1 MDV and Transit EV Growth Forecast

A similar approach was used for estimating fleet wide vehicle numbers, which includes buses, cutaway vans, and shuttles. The MDV EV growth forecast used the same approach as was used for LDVs in Section 3.4.3.1. The historical MDV vehicle count by county and NIPSCO service territory are detailed in Table 3-9 and Table 3-10.

Table 3-9: All MDV Vehicles in NIPSCO Service Territory[29]

County	2018	2019	2020	2021	2022	2023
Benton	206	217	248	276	274	307
Carroll	495	530	536	602	629	686
DeKalb	812	852	892	1,043	1,033	1,123
Elkhart	3,409	3,415	3,624	3,900	3,843	4,228
Fulton	455	486	533	580	591	653
Jasper	755	752	816	916	957	1,109
Kosciusko	1,518	1,541	1,703	1,740	1,841	1,960
LaGrange	775	815	893	959	1,004	1,072
Lake	4,824	5,093	5,228	5,630	5,562	6,170
LaPorte	1,714	1,765	1,918	2,047	2,030	2,317
Marshall	994	1,032	1,140	1,333	1,276	1,306
Newton	279	308	334	377	410	454
Noble	961	1,030	1,077	1,205	1,228	1,333
Porter	1,938	2,087	2,175	2,406	2,420	2,673
Pulaski	323	325	341	377	391	416
St. Joseph	2,946	3,092	3,224	3,475	3,315	3,559
Starke	457	472	482	510	531	573
Steuben	750	744	782	860	917	966
White	533	558	640	676	678	835
Total	14,446	15,035	15,875	17,220	17,302	19,105

29 Indiana Office of Energy Development, Indiana Vehicle Fuel Dashboard accessed Jan. 11, 2024. County vehicle counts are not representative of the NIPSCO service territory. MDVs are distributed using determined by the approximate % of households within the country that fall into NIPSCO service territory. See Table 3-4:. https://www.in.gov/oed/resources-and-information-center/vehicle-fuel-dashboard/

Table 3-10: MDV EVs and Total MDVs in NIPSCO Service Territory

Year	Electric	E&G Hybrid	Total
2018	0	0	14,446
2019	0	0	15,035
2020	0	0	15,875
2021	0	0	17,220
2022	2	0	17,302
2023	8	0	19,105

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 2022 National Transit Database, the Federal Transit Administration's repository of data on financial, operating, and asset conditions of American transit systems. Filtering on NIPSCO counties, there were approximately 471 transit vehicles registered, with 267 estimated to be within the NIPSCO service territory, as summarized in Table 3-9 and Table 3-12. As there is no data for electric transit vehicles, NIPSCO starts with fully internal combustion engines for all transit.

From the National Transit Database, an average lifetime for each vehicle type was determined, detailed in Table 3-13. This data point is consistent with the idea that higher utilization leads to shorter lifetimes, when compared to the lifespan of LDV passenger light-duty vehicles. Forecasts of electric MDVs and transit vehicles were developed using the sigmoid growth curve described in Section 3.4.2.2. See Table 3-2 for assumptions. The EV MDV and transit adoption profiles by scenario are detailed in Figure 3-18. Final MDV and transit EV vehicle counts are shown in Figure 3-19 and Figure 3-20, respectively.

Table 3-11: All Transit Vehicles in NIPSCO Counties[30]

County	Bus	Cutaway	Minivan	Over-the-road Bus	Steel Wheel Vehicles	Trucks and other Rubber Tire Vehicles	Van
Benton	0	0	0	0	0	0	0
Carroll	0	0	0	0	0	0	0
DeKalb	0	3	8	0	0	0	0
Elkhart	0	0	0	0	0	0	0
Fulton	0	2	9	0	0	0	0
Jasper	0	0	0	0	0	0	0
Kosciusko	0	11	1	0	0	0	0
LaGrange	0	8	5	0	0	0	0
Lake	28	34	0	0	0	8	1
LaPorte	0	19	0	0	0	1	0
Marshall	0	2	8	0	0	0	0
Newton	0	0	0	0	0	0	0
Noble	0	2	9	0	0	0	6
Porter	0	33	1	5	18	93	1
Pulaski	0	0	0	0	0	0	0
St. Joseph	62	23	10	0	0	7	0
Starke	0	0	0	0	0	0	0
Steuben	0	9	6	0	0	0	0
White	0	15	23	0	0	0	0
Total	90	161	80	5	18	109	8

30 Federal Transit Administration, The 2022 National Transit Database. https://www.transit.dot.gov/ntd

Table 3-12: Estimated Transit Vehicles in NIPSCO Service Territory[31]

County	% Households in NIPSCO Service Territory	Bus	Cutaway	Minivan	Over-the-road Bus	Steel Wheel Vehicles	Trucks and other Rubber Tire Vehicles	Van
Benton	100%	0	0	0	0	0	0	0
Carroll	77%	0	0	0	0	0	0	0
DeKalb	17%	0	1	1	0	0	0	0
Elkhart	57%	0	0	0	0	0	0	0
Fulton	55%	0	1	5	0	0	0	0
Jasper	82%	0	0	0	0	0	0	0
Kosciusko	58%	0	6	1	0	0	0	0
LaGrange	52%	0	4	3	0	0	0	0
Lake	100%	28	34	0	0	0	8	1
LaPorte	100%	0	19	0	0	0	1	0
Marshall	36%	0	1	3	0	0	0	0
Newton	65%	0	0	0	0	0	0	0
Noble	6%	0	0	1	0	0	0	0
Porter	91%	0	30	1	5	16	85	1
Pulaski	47%	0	0	0	0	0	0	0
St. Joseph	0%	0	0	0	0	0	0	0
Starke	3%	0	0	0	0	0	0	0
Steuben	67%	0	6	4	0	0	0	0
White	5%	0	1	1	0	0	0	0
Total	-	28	103	19	5	16	94	2

Table 3-13: Estimated Transit Vehicle Age[32]

Transit Vehicle Type	Average Fleet Age (years)
Bus	7.0
Cutaway	5.0
3-13	5.7
Over-the-road Bus	11.4
Steel Wheel Vehicles (Service)	12.9
Trucks and other Rubber Tire Vehicles (Service)	5.7
Van (MDV)	10.8

31 Estimated count of transit vehicles in the NIPSCO service territory is determined by the approximate % of households within the country that fall into NIPSCO service territory.

Figure 3-18: MDV and Transit EV Adoption: EVs as a % of new sales

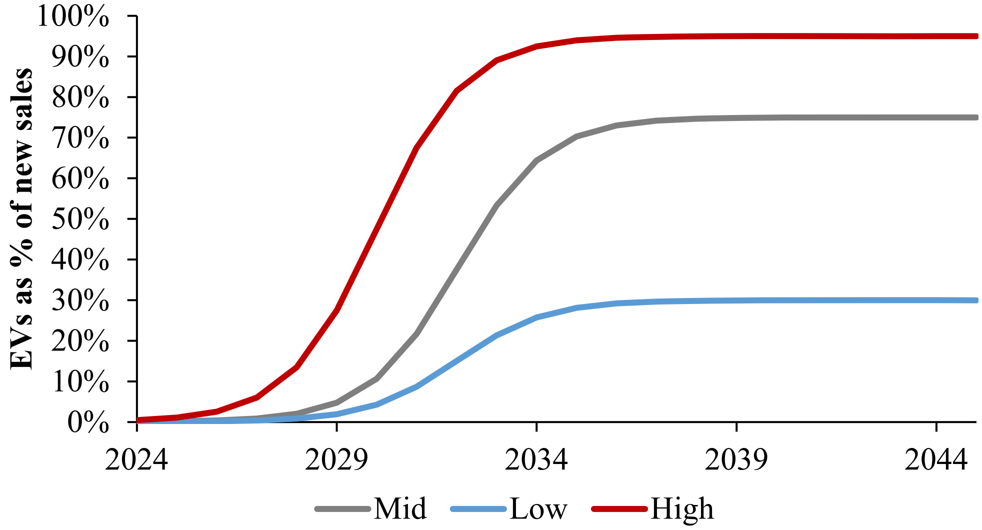
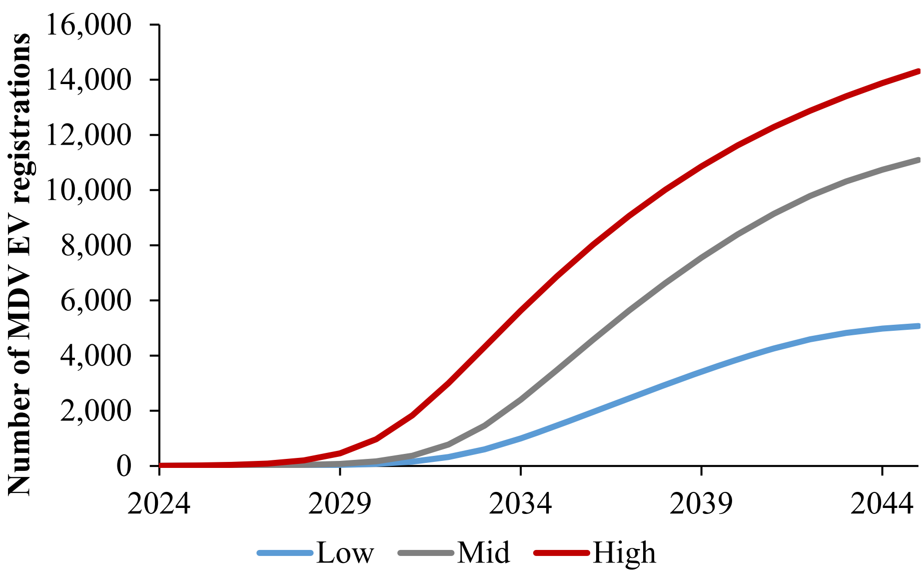
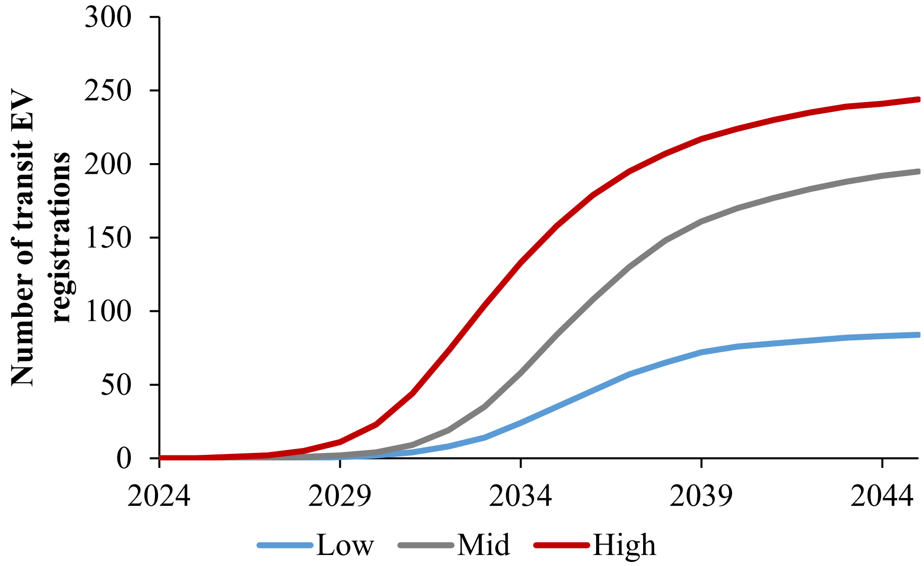


Figure 3-19: MDV EV Adoption: Number of EVs registered in NIPSCO service territory[33]



33 See Table 3-13 for fleet age assumptions. As the makeup of the existing fleet age is unknown, the historical registration data is evenly distributed over the fleet age assumed lifetime to factor in retirements for the turnover analysis.

Figure 3-20: Transit EV Adoption: Number of EVs registered in NIPSCO service territory[34]



3.4.4.2 MDV and Transit EV Energy Use

NIPSCO utilized MDV and transit charging shapes based on a 2016 NREL Study of MDV Electric Delivery Trucks[35] depicted as the "unmanaged" shape in Figure 3-21. This unmanaged shape is used from 2024 through 2030, when a blend of managed charging loads begins to emerge, based on the assumption that time-of-use rates and managed charging infrastructure will begin to displace unmanaged behavior in later years. The managed charging shape was adapted from recent data releases from California IRP proceedings, based on 2021 study from Berkeley Lab.[36] This approach assumes the adoption of TOU rates and managed charging approaches and is used as a baseline future projection for how MDV loads may balance from 2030 to 2045, although some degree of unmanaged charge remains for duration of forecast period. Vehicle efficiency and vehicle miles traveled assumptions are detailed in Table 3-14 and Table 3-15, respectively. Ambient temperature adjustments to the charging profiles are detailed in Table 3-16.

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34 See Table 3-13 for fleet age assumptions. As the makeup of the existing fleet age is unknown, the historical registration data is evenly distributed over the fleet age assumed lifetime to factor in retirements for the turnover analysis.

35 https://www.nrel.gov/docs/fy17osti/66382.pdf

36 https://www.energy.ca.gov/sites/default/files/2021-09/5%20LBNL-FTD-EAD-HEVI-LOAD%20Medium-%20and%20Heavy-Duty%20Load%20Shapes_ADA.pdf

Figure 3-21: MDV and Transit EV Charging Shapes

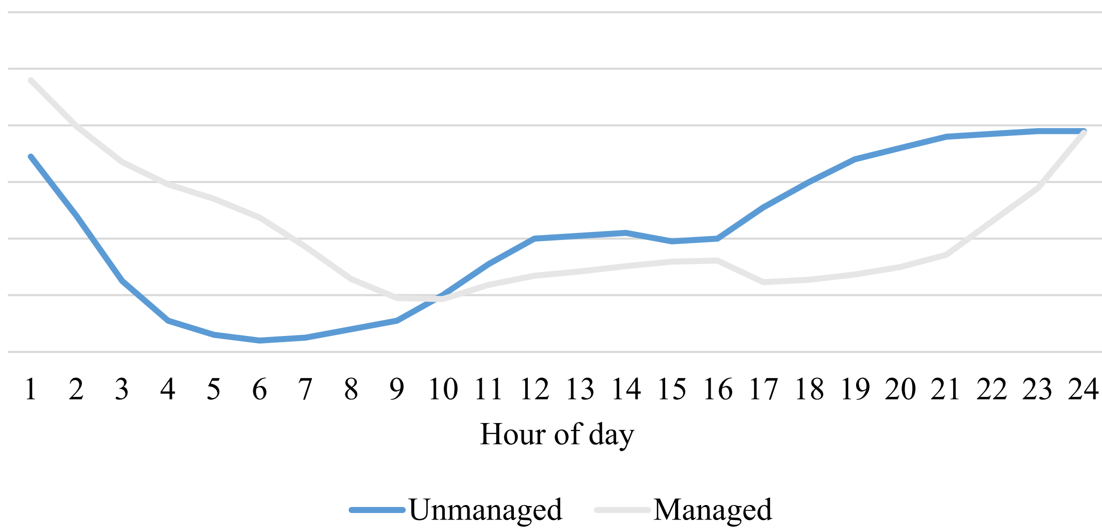


Table 3-14: Assumed Efficiency of MDV And Transit Vehicle Types (kWh/mile)[37]

EV Type	2020	2025	2030	2035	2040	2045	2050
Step Van (MDVs)	1.38	1.27	1.16	1.06	1.03	0.99	0.96
Box Truck	1.45	1.33	1.23	1.13	1.09	1.06	1.02
Bus	3.10	2.84	2.60	2.38	2.30	2.23	2.16
Cutaway	0.49	0.45	0.41	0.38	0.36	0.35	0.34
Minivan	0.49	0.45	0.41	0.38	0.36	0.35	0.34
Over-the-road Bus	3.10	2.84	2.60	2.38	2.30	2.23	2.16
Steel Wheel Vehicles	0.49	0.45	0.41	0.38	0.36	0.35	0.34
Trucks and other Rubber Tire Vehicles	1.12	1.02	0.94	0.86	0.83	0.80	0.78

37 Assumptions compiled from the following: (1) NREL (2022). 2022 Annual Technology Baseline Transportation Data. (2) MISO (2021) Exploring enhanced load flexibility from grid-connected electric vehicles on the Midcontinent Independent System Operator grid. (3) Characterization of battery electric transit bus energy consumption by temporal and speed variation, published in Energy (2023).

Table 3-15: Vehicle Miles Traveled Per Weekday, Weekend Operation Assumptions[38]

EV Type	Average miles / day	Weekend % of weekday
Step Van (MDVs)	31	75%
Box Truck	45	75%
Bus	119	75%
Cutaway	31	66%
Minivan	31	66%
Over-the-road Bus	119	75%
Steel Wheel Vehicles	31	66%
Trucks and other Rubber Tire Vehicles	75	66%

Table 3-16: Temperature Impact On MDV And Transit Vehicle Miles Traveled[39]

Degree Celsius	MDV % increase in VMT from baseline	Transit % increase in VMT from baseline
-20	30%	42%
-10	20%	38%
0	10%	33%
10	0%	10%
20	0%	0%
30	10%	10%

3.4.5 Heavy-Duty Vehicles

NIPSCO did not assume electrification of native HDVs within the service territory. However, NIPSCO did study truck corridor charging along major roadways within the service territory that included heavy-duty vehicles as a breakout class, as detailed in the next section.

3.4.6 Corridor Charging

In addition to predicting the adoption of EVs for vehicles based in the service territory, NIPSCO explored the potential impact of charging by vehicles that are not based in NIPSCO service territory but travel through the territory via highway corridors. To perform this analysis, NIPSCO contracted with ElectroTempo Inc., a software-based consultancy that specializes in projecting electrical vehicle charging demand and infrastructure. The types of vehicles captured in

[38] U.S. DOE, Average Annual Vehicle Miles Traveled by Major Vehicle Category https://afdc.energy.gov/data/widgets/10309

[39] Information gathered from the U.S. EPA (https://www.epa.gov/system/files/documents/2023-04/elec-schl-bus-cold-weather-consider-2023-04-19.pdf) and the following study: https://www.power.com/community/green-room/blog/impact-climate-range-electric-vehicles

the corridor analysis include delivery trucks and long-haul trucks that choose to exit the highway and recharge within the NIPSCO service territory. This additional charging is counted towards total sales regardless of whether the vehicle starting point or destination falls outside of the service territory.

3.4.6.1 Truck Charging Station Locations, Daily Traffic, and Growth

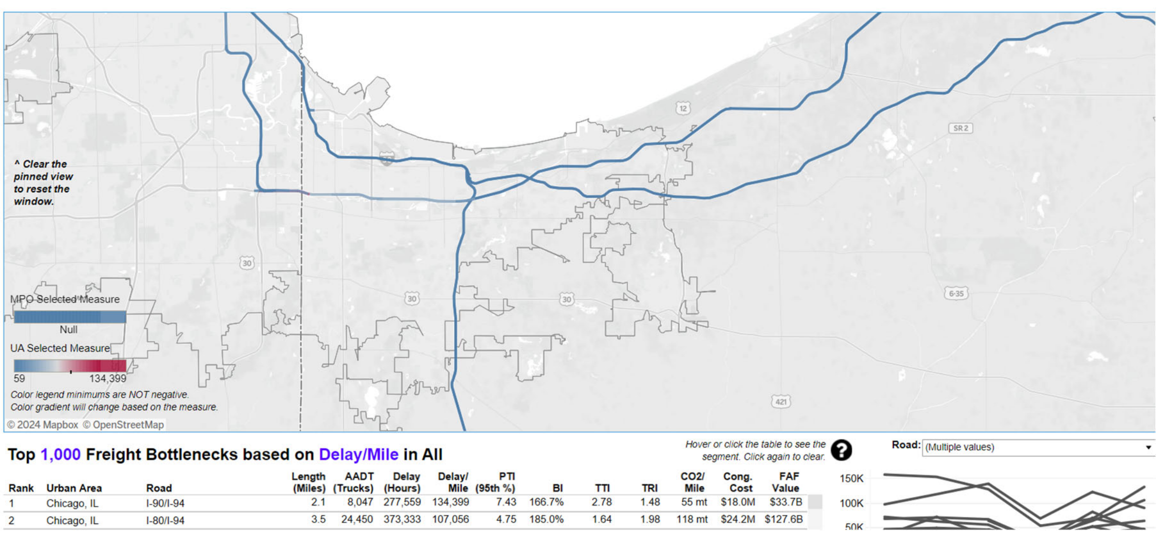
First, NIPSCO identified key traffic corridors within the service territory using Google Maps and satellite imagery. These included I-94, I-90, I-65, I-69, and other state roads (see Table 3-17). Next, NIPSCO located all highway and truck stops with current fueling stations to establish the universe of potential charging locations along the corridors. For this forecast, 43 sites were identified.

Table 3-17: Charging Locations on Each Corridor

Corridor	Sites
I-94	13
State Roads	11
I-90	6
I-65	8
I-69	5
Total	**43**

NIPSCO then estimated daily traffic along the six main corridors using national freight flow surveys and state highway traffic counts reported to the DOT HPMS. From the daily traffic figures, NIPSCO was then able to develop a view of the total daily estimated arrivals at each individual site. Total arrivals in future years were projected from the current estimate through 2035 by applying an annual growth factor based on historical traffic data.

Figure 3-22: DOT HPMS



3.4.6.2 Estimated Electric Vehicle Traffic as Share of Total Traffic

To estimate total relevant vehicle counts by class, NIPSCO applied EV penetration factors that represent the saturation of electric vehicles relative to the total number of vehicles on the road. Using ElectroTempo's EV Growth Simulator, three electric vehicle penetration scenarios were generated to map to NIPSCO's five planning scenarios used throughout this IRP.

The predicted EV saturation for these corridor-based vehicles by 2035 for each class and each scenario is shown in Table 3-18. More detailed saturation trajectories are shown in Figure 3-23 for MDVs and Figure 3-24 for HDVs. The scenarios aim to provide views on lower and higher rates of electrification of the Medium- and Heavy-Duty fleets moving through NIPSCO's service territory in line with NIPSCO's in-service territory analysis, described earlier in this Section. Given the lack of current HDV adoption and additional uncertainty around the future regulatory environment, NIPSCO employed a conservative HDV adoption rate in its reference and low scenarios.

Table 3-18: Predicted EV Saturation by Class and Scenario by 2035#

Scenario	MDV	HDV
Low	5%	0%
Ref	14%	2%
High	27%	10%

Figure 3-23: MDV EV Saturation Forecast by Scenario

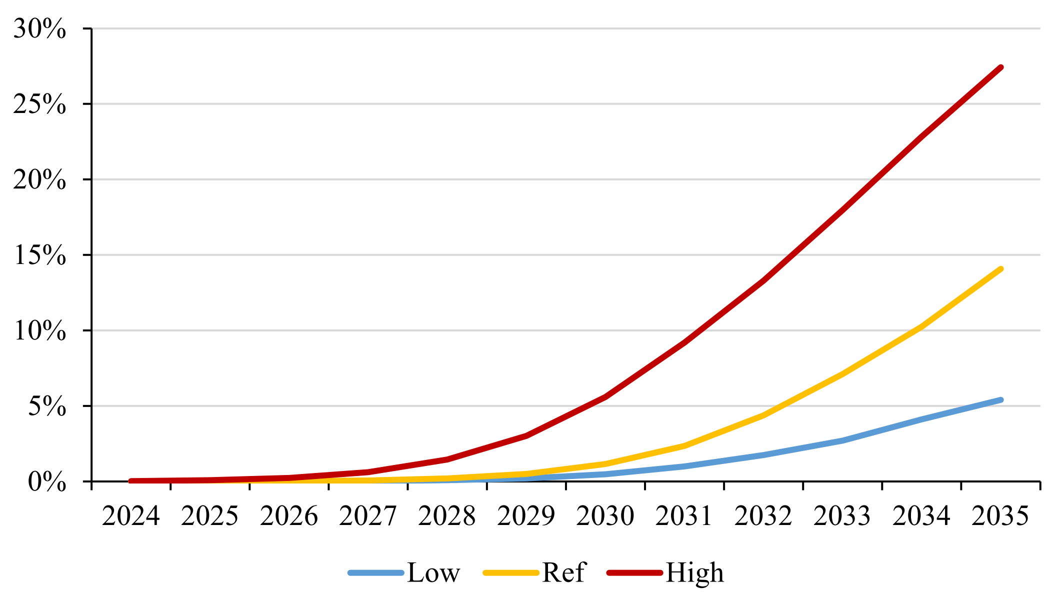
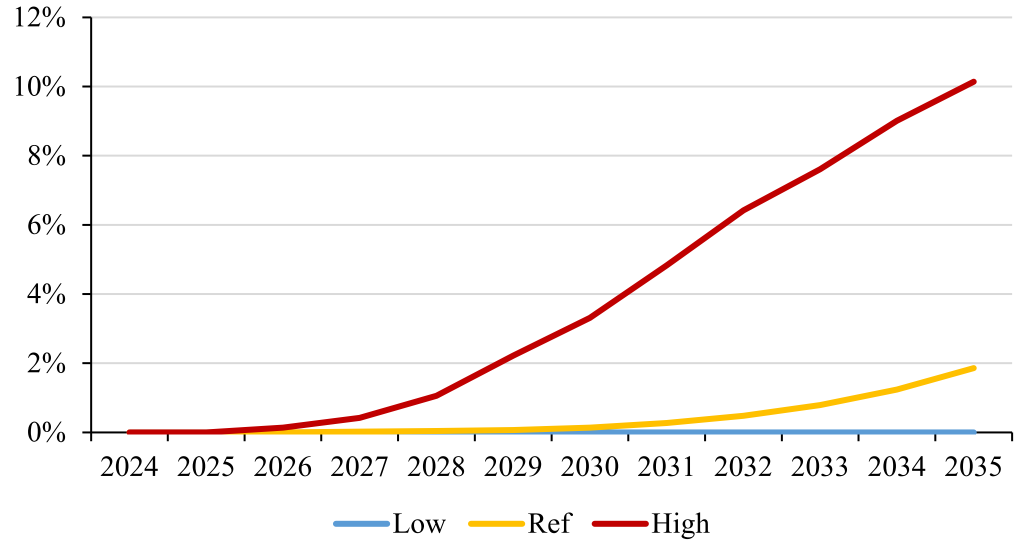


Figure 3-24: HDV EV Saturation Forecast by Scenario



3.4.6.3 Corridor Traffic Patterns and Charging Shape

The total number of EVs stopping at a specific site was calculated using a two-step process. First, the total number of EVs expected to travel by an exit is estimated. Assuming 10% of vehicles choose to stop at an exit,[40] the total daily number of EVs charging at a given exit can be found. Second, the total annual exit charges were divided evenly by the total number of charging sites associated with the given exit. This assumes that, for each exit, total demand is shared evenly between each charging location. The result is the year-by-year average daily count of electric trucks recharging at each of the 43 sites across NIPSCO's main transportation corridors.

Daily arrivals at each site were then distributed over a 24-hour period using the 24-hour arrival profile from the Institute of Transportation Engineers Trip Gen data tool for Truck Stops.[41] For annual aggregation, traffic is assumed to be 25% lower on weekends and federal holidays.

To translate total vehicle charges to energy, NIPSCO identified the class-specific SoC of each vehicle visiting a given fueling/charging point based on its relative positioning to its logical highway endpoints. The corridor endpoints identified in this forecast are included in Table 3-19.

40 The 10% assumption was based on historical data.

41 https://www.ite.org/technical-resources/topics/trip-and-parking-generation/other-resources/

Table 3-19: Defined Highway Segments (US DOT)

Interstate	NW endpoint	SE endpoint
I-65	Chicago	Indianapolis
I-69	Lansing	Fort Wayne
I-90	Chicago	Cleveland
I-94	Chicago	Detroit
US-30	Chicago	Fort Wayne

SoC values were assigned for each route based on one of four categories:

1. Category 1: Route originates at one highway endpoint and terminates at another endpoint. Assume 30% of the battery is charged en route.
2. Category 2: Route originates at a highway endpoint and terminates elsewhere. Assume 60% of the battery is charged en route.
3. Category 3: Route doesn't originate at a listed highway endpoint but terminates at a local endpoint. Assume 30% of the battery is charged en route.
4. Category 4: Route originates and terminates in places other than the highway endpoints. Assume 70% of the battery is charged en route.

Differentiating how SoC values were assigned across length of freight routes also allowed NIPSCO to avoid double counting with at-home charging and local vehicle traffic. This was achieved by assuming that charging needs of vehicles on the shortest routes or those based within the NIPSCO service territory would be lower than demand from vehicles on long-haul routes. For example, a trip that starts in Chicago and ends in Detroit will only charge 30% of its total battery while a vehicle that is charging en route for a trip that might extend across the entire country is assumed to charge 70%.[42]

NIPSCO used the following baseline assumptions for MDVs and HDVs charging along NIPSCO's primary corridors. Medium-duty vehicles, such as single-unit trucks, were assumed to have a 300 kWh battery; Heavy-Duty vehicles were assumed to have a battery size of 600 kWh.

3.4.6.4 Energy and Power Calculation

To return hourly energy consumption, NIPSCO applied the assigned SoC ratios and battery attributes to the 24-hour charging distribution curve for each vehicle class across each segment of the highway. Finally, the total energy consumption for each corridor segment was split between each identified truck charging site to get the hourly energy consumption per site.

42 Informed by the Freight Analysis Framework Version 5 Data Tabulation Tool." Oak Ridge National Laboratory

Each of the vehicle categories was assigned to a charger rating to calculate power requirements:

- MDV: 150kW
- HDV: 450kW

To calculate peak power demand, NIPSCO employed an hourly energy consumption approach, where hourly energy consumption was matched to the minimum number of required chargers based on vehicle class. This assumes that any required charge below the thresholds above will create a demand of the next highest charger threshold. For example, if two arriving trucks require 50 kWh each for a total of 100 kWh, there will be power demand of 150 kW (one 150 kW charger). This approach may require vehicles to wait for an available charger.

To account for changes in seasonal demand, NIPSCO applied seasonal shaping factors based on the temperature impacts defined in the EVI-Pro-Lite tool. This matches the seasonal variation seen in the native LDV and MDV vehicles and reflects the higher charging demand seen during extreme temperatures, particularly very cold temperatures.

3.4.6.5 Results of Northern Indiana Corridor EV Forecast

In total, power demand over an average 24-hour period across all charging sites is projected to peak at 67 MW. Given the current state of the market, NIPSCO assumes that site operators will be conservative in their investment in charging infrastructure, and vehicle operators will be willing to wait for access to chargers. Thus, the net demand has been modeled to be slightly lower. The average weekday corridor charging shape in 2030 across scenarios is shown in Figure 3-25. Average daily corridor energy consumption for each year of the study period is shown in Figure 3-26.

Figure 3-25: Average Weekday Corridor Charging Shape (2030)

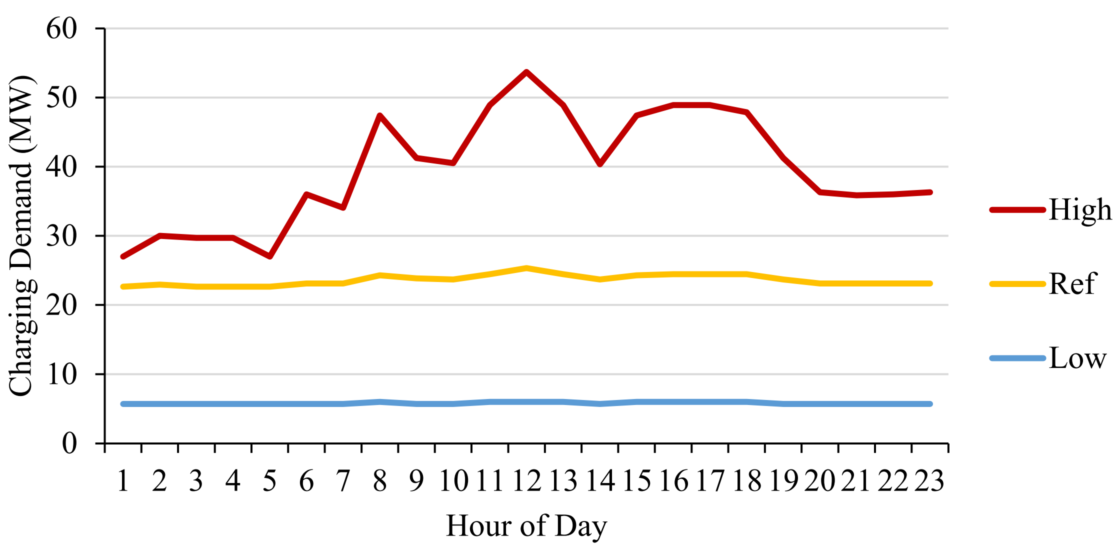
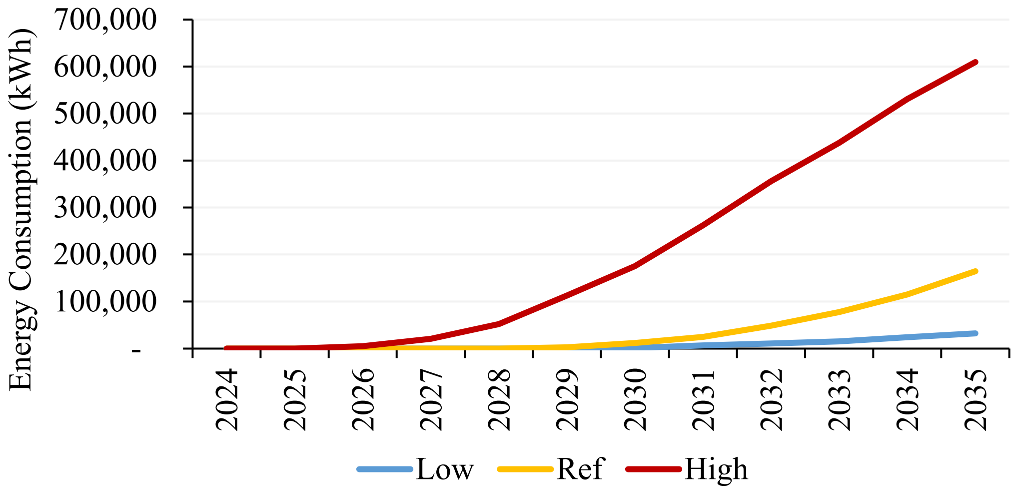


Figure 3-26: Average Daily Corridor Energy Consumption (kWh)



The results of the EV corridor charging forecast indicate that trucks charging en route within NIPSCO's service territory will make up 9.4% of total EV charging sales by 2035 in the reference case. This contribution increases to 21.1% in the high scenario and decreases to 5.1% in the low case, representing the varied states of heavy-duty freight adoption and related charging infrastructure. Total annual sales from corridor-based EV charging across the reference case, low case, and high case are shown in Figure 3-27, Figure 3-28, and Figure 3-29, respectively.

Figure 3-27: Annual Corridor EV Energy Demand – Reference Case (GWh)

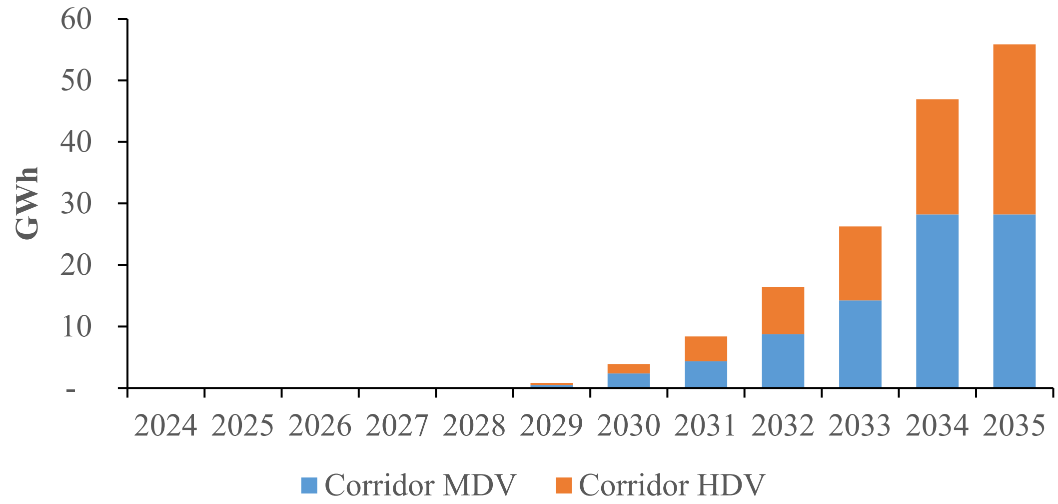


Figure 3-28: Annual Corridor EV Energy Demand – Low Case (GWh)

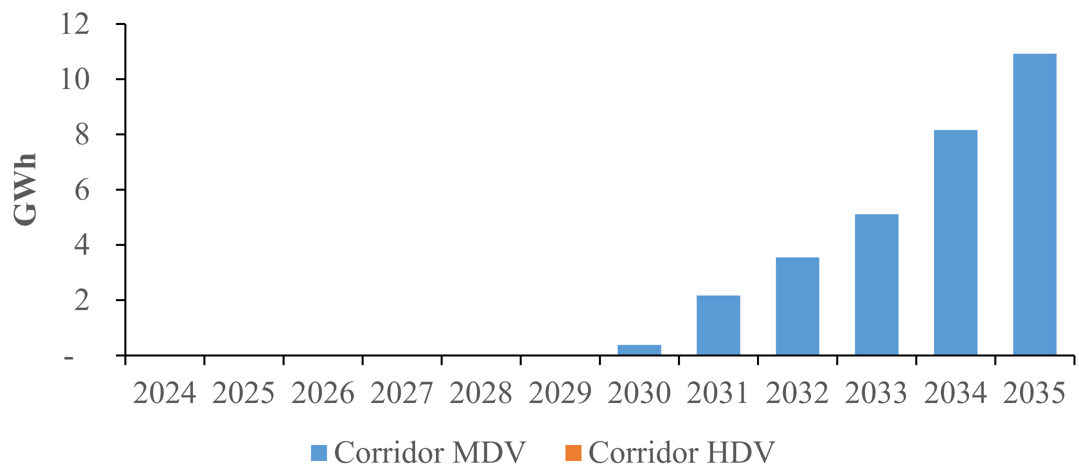
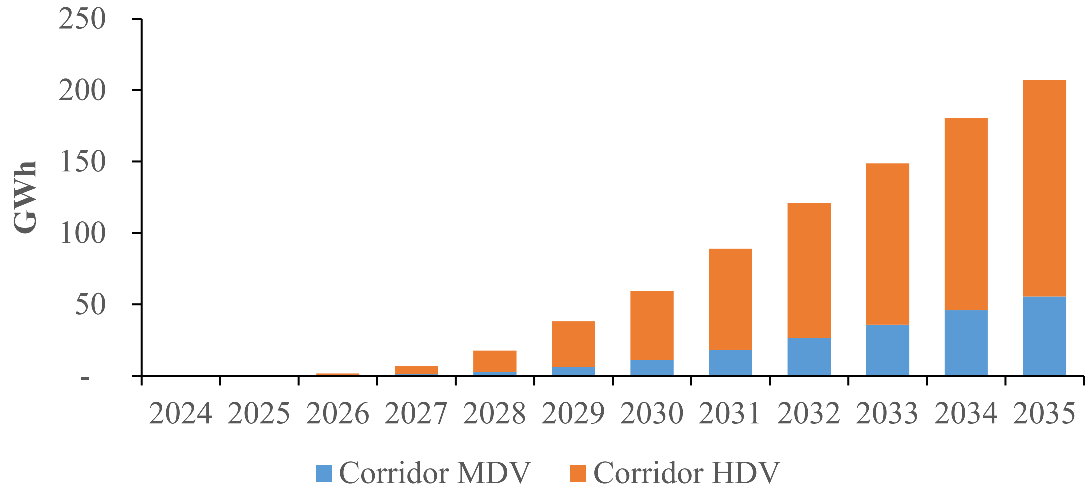


Figure 3-29: Annual Corridor EV Energy Demand – High Case (GWh)



3.4.7 Electric Vehicle Forecast Results

3.4.7.1 Annual EV Energy and Peak Load Forecasts

Annual electric vehicle energy demand for the reference, low, and high cases are shown in Figure 3-30, Figure 3-31, and Figure 3-32, respectively. As seen in these figures, light-duty vehicles are the major driver of EV load across all scenarios. For example, they comprise nearly 85% of total EV demand in 2045 in the reference case. After LDVs, native MDVs are the next greatest driver of increasing energy demand. Lastly, charging from medium- to heavy-duty-vehicles along Northern Indiana's six primary shipping corridors contribute to increasing growth, particularly in the high scenario. Although the low case assumes minimal adoption of heavy-duty electric vehicles, charging for HDVs contributes over a fifth of the total EV charging energy demand by 2035 under the high case.

Figure 3-30: Annual EV Energy Demand – Reference Case (GWh)

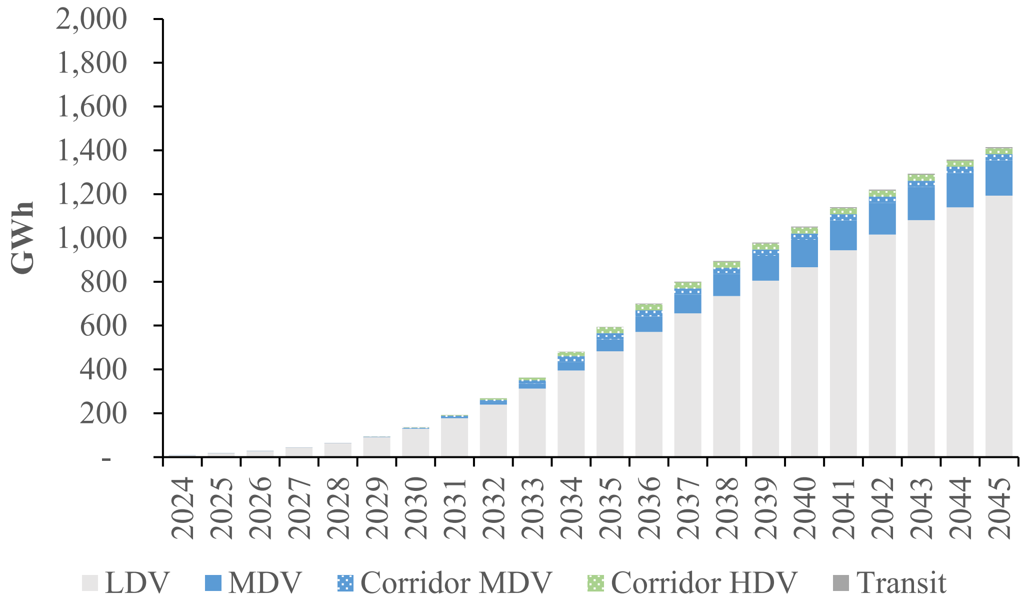


Figure 3-31: Annual EV Energy Demand – Low Case (GWh)

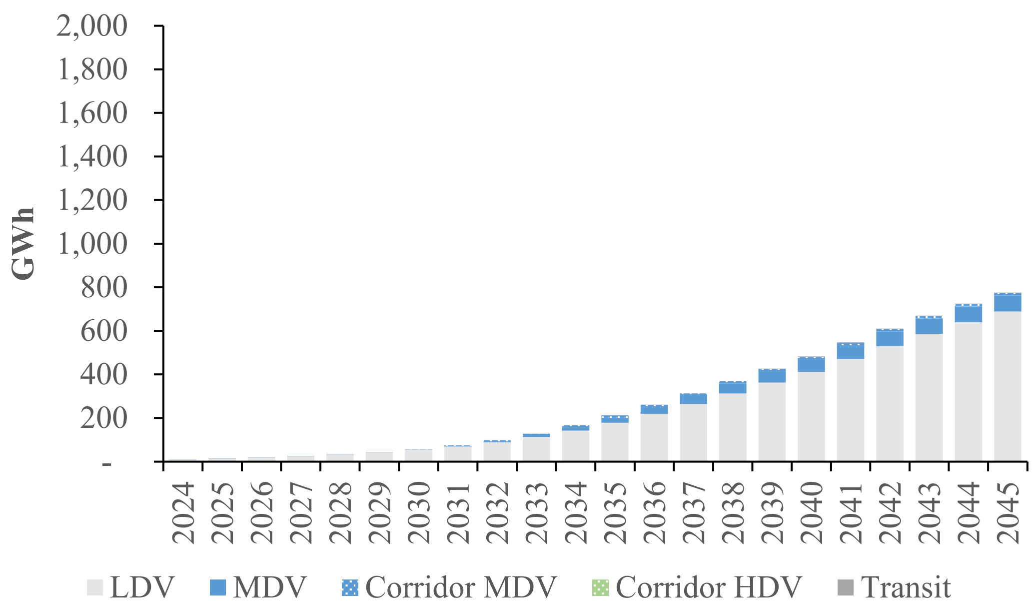
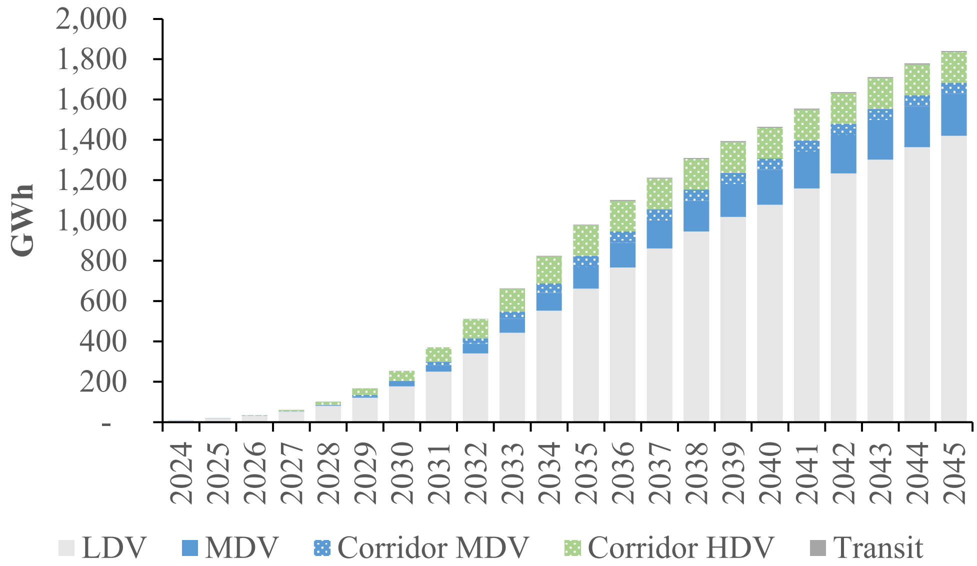


Figure 3-32: Annual EV Energy Demand – High Case (GWh)



3.5 Customer-Owned DERs

Customer-owned DERs are expected to grow throughout NIPSCO's territory, and this may materially impact NIPSCO's net sales and peak demand requirements. To estimate a range of impacts for DER penetration in the 2024 IRP, NIPSCO deployed CRA's agent-based PenDER model - customized and calibrated to NIPSCO's existing database of DER customers - to predict the customer adoption of DERs. NIPSCO's DER study focused exclusively on solar PV resource since this technology type (with or without storage) is expected to be the most widespread DER resource type at the residential and commercial levels.[43] In addition, the study focused on two main customer groups likely to adopt DER: residential and commercial.

3.5.1 Existing Solar Distributed Energy Resources

In its territory, NIPSCO has established DER programs for eligible electric customers (residential and commercial) with small-scale solar, wind, and hydro installations:

- Feed-in Tariff (FiT): Although now closed for intermediate solar systems (10kW – 200 kW), customers registered in this program, can sell power back to NIPSCO at a predetermined rate.[44]
- Net Metering (NM): Under this program, customers can generate their own electricity to offset their monthly usage, and any extra generation receives energy

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43 Note that distributed storage additions to pair with solar DERs were included as part of the Demand Side Management study.

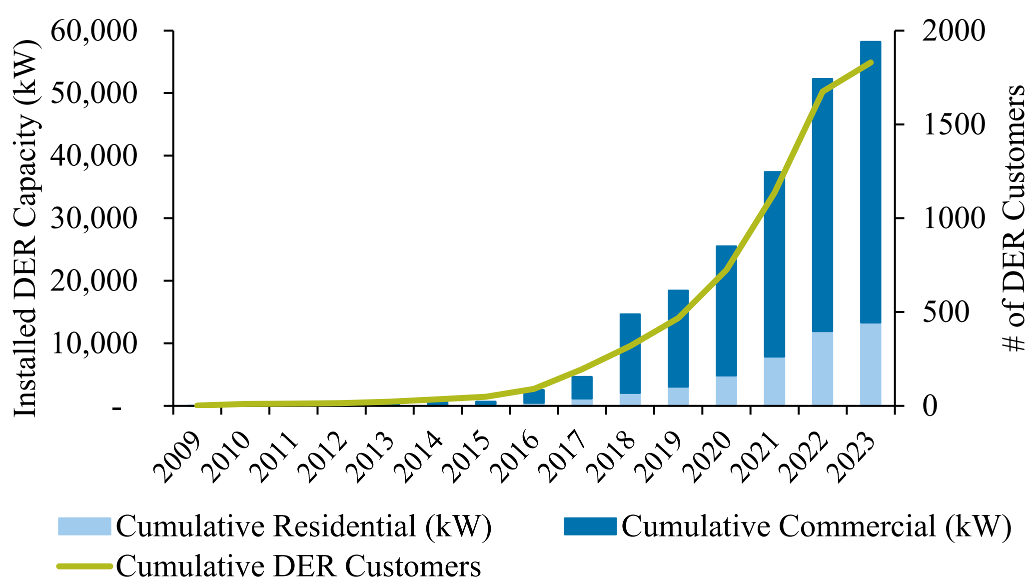
44 Please find more detailed information on the Feed-in Tariff program here.

credits that can be applied to future usage.[45] However, the program ended on October 1, 2021 for commercial customers and on June 30, 2022 for residential customers.

- EDG Tariff: Currently, the only DER program receiving new applications. Under this tariff, customers with excess generation will receive utility bill credits that can be applied to reduce their future bill by 125% of the wholesale price power for all excess DER generation.[46]

Based on customer adoption data, collected as of September 2023, 1,830 electric customers have installed small-scale solar systems throughout NIPSCO's service territory. Solar DER adoption has increased 32% annually, reaching a total deployment of 58 MW, with residential customers totaling 13 MW and commercial customers totaling 45 MW. Figure 3-33 illustrates the historical cumulative number of customers with DERs and the installed DER solar capacity by customer class, under the NM and EDG programs in the NIPSCO territory. Table 3-20 and Table 3-21 present the existing solar DER Adoption by County within the NIPSCO Territory for residential and commercial customers. Among residential customers, 80% of the solar DER adoption is concentrated in four counties: Elkhart, Lake, LaPorte, and Porter. On the commercial side, 78% is concentrated in five counties: Elkhart, Lake, LaPorte, LaGrange, and Kosciusko.

Figure 3-33: Cumulative Total DER Customers and Solar DER Adoption by Customer Class under NM and EDG Programs



Approximately 16 customers have adopted solar plus battery systems, totaling 98 kW, with an average two-hour battery duration. Most storage systems have been installed by residential customers, with an average solar to storage ratio of 1.5:1.

45 Please find more detailed information on the Net Metering program here.

46 Please find more detailed information on the Excess Distributed Generation Tariff here.

Table 3-20: Existing Residential (Res.) Solar DER Adoption, by County, within the NIPSCO Territory

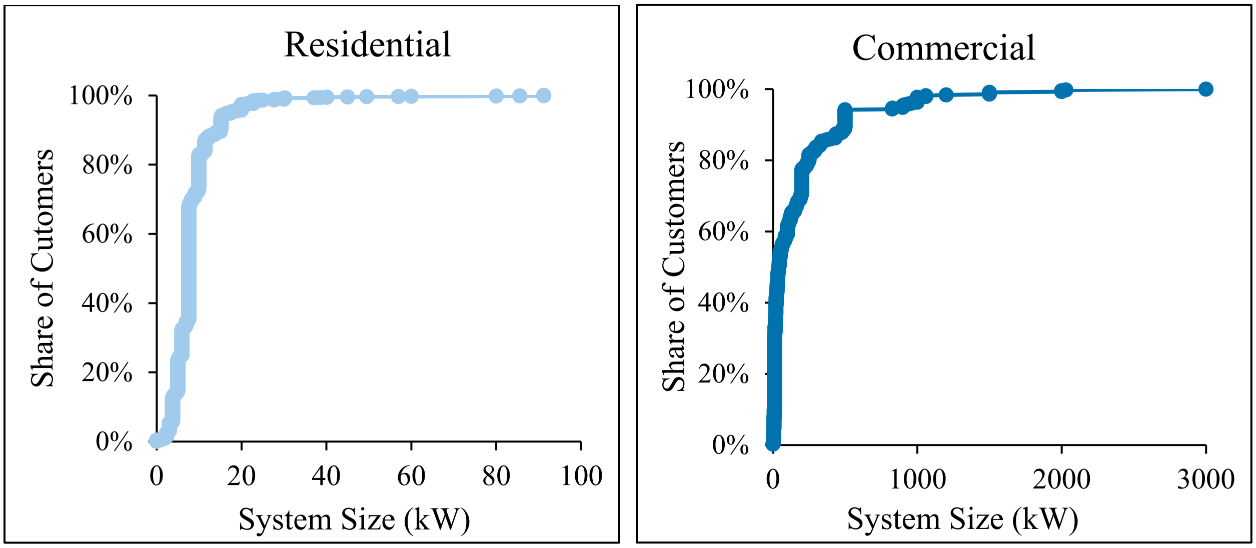
NIPSCO Counties	Total Res. Customers	Res. Solar DER Customers	% Res. Customers with Solar DER	Total Res. Solar DER (kW)
Benton	3,592	7	0.2%	60
Carroll	6,477	13	0.2%	113
DeKalb	3,035	23	0.8%	272
Elkhart	44,330	477	1.1%	4,830
Fulton	4,487	24	0.5%	248
Jasper	11,026	28	0.3%	277
Kosciusko	19,847	61	0.3%	587
LaGrange	6,841	31	0.5%	292
Lake	239,312	422	0.2%	3,181
LaPorte	54,911	192	0.3%	1,544
Marshall	7,026	15	0.2%	112
Newton	3,760	17	0.5%	141
Noble	1,126	4	0.4%	30
Porter	68,129	161	0.2%	1,264
Pulaski	2,368	8	0.3%	90
St. Joseph	171	3	1.8%	23
Starke	287	1	0.3%	8
Steuben	9,662	21	0.2%	153
White	532	4	0.8%	60
Total	486,919	1,512	0.3%	13,284

Table 3-21: Existing Commercial (Com.) Solar DER Adoption, by County, within the NIPSCO Territory

NIPSCO Counties	Total Com. Customers	Com. Solar DER Customers	% Com. Customers with Solar DER	Total Com. Solar DER (kW)
Benton	636	3	0.5%	230
Carroll	1,027	4	0.4%	536
DeKalb	415	14	3.4%	1,322
Elkhart	5,691	115	2.0%	19,222
Fulton	627	3	0.5%	360
Jasper	1,475	10	0.7%	1,500
Kosciusko	2,889	15	0.5%	3,219
LaGrange	1,337	20	1.5%	4,042
Lake	21,673	24	0.1%	2,810
LaPorte	6,097	51	0.8%	5,913
Marshall	1,060	10	0.9%	1,327
Newton	593	3	0.5%	311
Noble	178	4	2.2%	236
Porter	6,629	15	0.2%	1,682
Pulaski	328	1	0.3%	8
St. Joseph	31	0	0.0%	-
Starke	52	0	0.0%	-
Steuben	1,691	9	0.5%	1,942
White	136	7	5.1%	210
Total	52,565	308	0.6%	44,869

The average system size for residential customers is 8.6 kW, with a median of 7.6 kW, and approximately 80% of installed systems are below 10 kW. For commercial customers, the average system size is 178 kW, with a median of 40 kW, and around 60% of installed systems are below 100 kW, indicating higher system size diversity among commercial customers. For commercial customers, in recent years, following the EDG rate program implementation, system sizes have averaged 125 kW (median of 35 kW). Figure 3-34 illustrates the system size distribution of the historical adoption of solar DER systems for residential (left) and commercial (right) customers.

Figure 3-34: Solar DER System Size Distribution under Residential (left) and Commercial (right) Customers



3.5.2 Customer-Owned Distributed Energy Resource Projections

3.5.2.1 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, wholesale rates projections, the costs of installing DER, and potential financial incentives.

- The techno-economic variables deployed in the PenDER modeling for NIPSCO's 2024 IRP include:
    - The capital cost of a solar PV system, inclusive of expected ITC benefits
    - Solar capacity factor and solar system lifetime expectations
    - Average solar DER system size
    - Retail rates and wholesale rates projections (for EDG)
    - Assumptions for customer discount rate and for inflation rate
- The socio-economic and demographic data required to characterize customer groups (agents) in PenDER consist of:
    - Existing population with DER adoption
    - Household income
    - Total housing units and housing characteristics (detached, attached, apartments, etc.)
    - Business type

- Energy usage

The combination of the techno-economic variables and agent income levels are then used to develop a calculation of payback period and household budget to assess the probability of DER adoption through a calibrated logit probability function.

While economics play 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.[47] Therefore, the simulated agents are randomly assigned a "Bass innovation index," representing their personal propensity on a scale of early adopters to laggards of a 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, PenDER was set up for each county with the NIPSCO territory, where 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).

3.5.3 Key Input Assumptions

NIPSCO developed techno-economic assumptions for each of its five market scenarios[48] to develop a range of potential future customer-owned solar DER penetration levels. The techno-economic input assumptions for PenDER used in NIPSCO's 2024 IRP under each scenario are summarized in Table 3-22 and described in more detail in the remainder of this section.

Table 3-22: Solar DER Techno-economic Assumptions by Scenario

	Reference Case	Slow Transition	Domestic Resiliency	Aggressive Environmental Regulation	Accelerated Innovation
	Ref	**ST**	**DR**	**AER**	**AI**
Capital Cost	Med	High	High	Med	Low
ITC	Current Policy	Early IRA phase out	Current Policy	Current Policy	Current Policy
Wholesale Rates Growth	Base	Low	High	High	Base
DER Program	EDG continues through 2045	EDG continues through 2045	EDG continues through 2045	EDG transitions back to NM Program	EDG continues through 2045

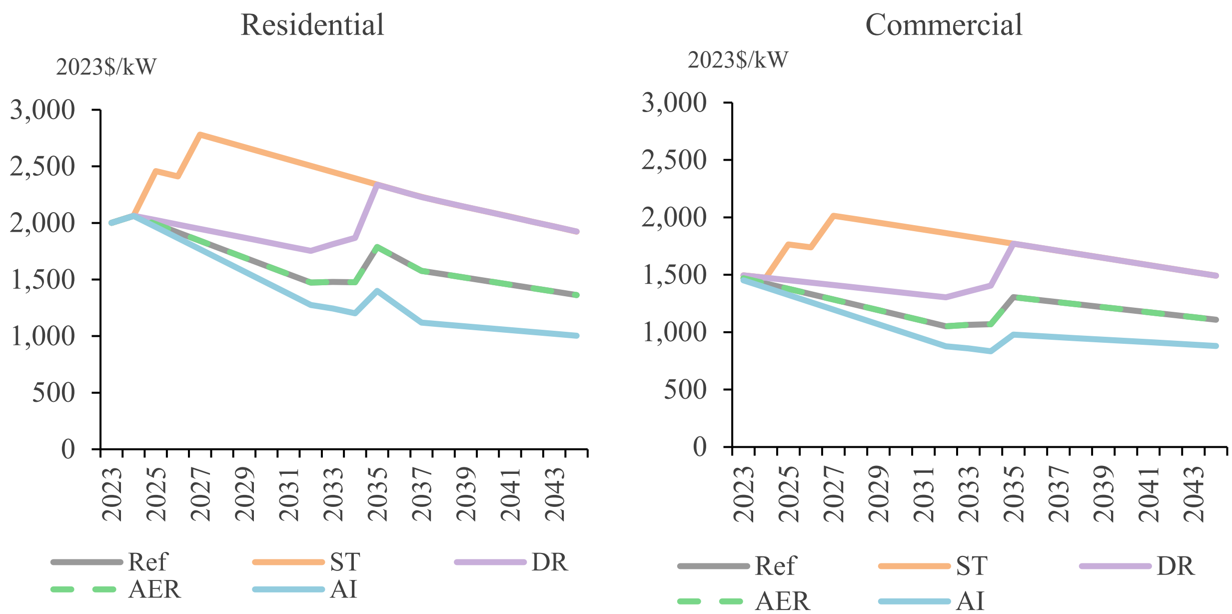
Capital Cost and Tax Credit Inputs: Assumptions regarding capital cost projections, capacity factor, and lifetime for solar PV were taken from NREL's 2023 Annual Technology Baseline for

47 See Bass, F. (1969). "A New Product Growth for Model Consumer Durables." *Management Science*. 15 (5): 215-227

48 Note that NIPSCO's five scenarios are described in more detail in Section 8.

the Advanced (Low cost), Moderate (Medium cost), and Conservative (High cost) cases for both residential and commercial solar PV technologies – Class 5 Rooftop PV.[49] Assumptions regarding the federal ITC were consistent with the provisions under the IRA and with those defined across NIPSCO's five core planning scenarios, where solar ITC benefits are available until 2035 in all but one scenario.[50] Figure 3-35 shows the solar DER system cost trajectories for residential (left) and commercial (right) customers by scenario, inclusive of the impact of the federal ITC.

Figure 3-35: Solar DER System Cost Trajectories by Case, including ITC, for Residential (left) and Commercial (right) Customers



Wholesale Rate Real Growth Rate: Wholesale rate growth is uncertain and dependent on NIPSCO's generation plan, commodity prices, the wider MISO market, regulatory policy, transmission and distribution system cost drivers, and several other factors. NIPSCO developed a range of wholesale rate real growth rates with broad alignment to NIPSCO's five core planning scenarios. The Reference and AI scenarios assume a base annual growth rate of 0.7%, the ST scenario has a lower rate growth of 0.2%, the DR scenario has a higher annual growth rate of 1.2%, and the AER has the highest wholesale growth rate of 3.6%.

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

49 NREL (National Renewable Energy Laboratory), 2023. 2023 Annual Technology Baseline. Golden, CO.
50 Note that under the Slower Transition scenario, the ITC is assumed to phase out by 2026.

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. Since the NIPSCO Excess Distributed Generation Rider was approved, PenDER simulated most future scenarios under the EDG program. In one scenario–AER–a transition back to a rate design similar to the prior NM rate is assumed. These policy scenarios were designed to assess a broad range of potential DER penetration outcomes.

Solar System Characteristics: Information regarding the average size of DER solar installations currently on NIPSCO's system was used to define future system sizes. Historical system size averages are approximately 8 kW for residential customers and 125 kW for commercial customers. NIPSCO estimated CF for the DER systems based on NREL's 2023 Annual Technology Baseline for both residential and commercial solar PV technologies – Class 5 Rooftop PV – 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 3-23: Residential and Commercial Project Parameter Assumptions

	Residential	Commercial
Average PV Size	8 kW	125 kW
Solar CF	15.5%	15.5%
Solar Lifetime	25 years	25 years
Inflation	2.1%	2.1%
Real After-Tax WACC	7.00%	6.00%

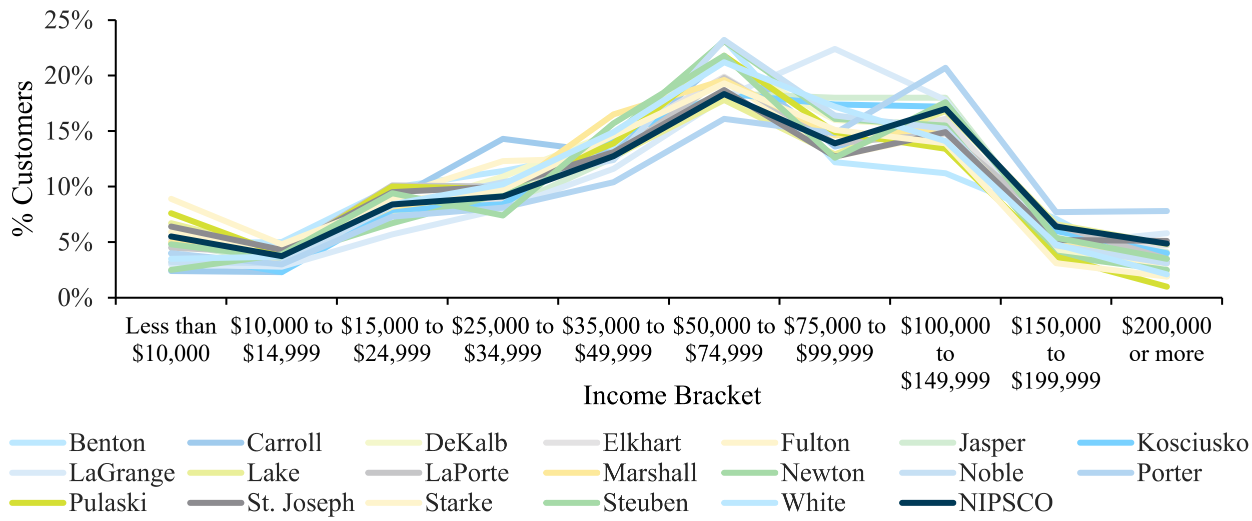
Household Income: Household income distributions by county within the NIPSCO territory were determined from the ACS. The ACS is a nationwide survey that collects and produces information on demographic, housing, economic, and social characteristics of the nation's population every year.[51] Household 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."[52] For each county, agents in the PenDER model were assigned a household income level to preserve consistency with the distribution of income levels, by county, in NIPSCO's service territory from

51 For more detailed information referred to ACS's website.

52 Guzman, G. (September 2020). "Household Income: 2019". *American Community Survey*. https://www.census.gov/content/dam/Census/library/publications/2020/acs/acsbr20-03.pdf

the ACS's five-year *Selected Economic Characteristics* Table.[53] Figure 3-36 shows the county-level household income distribution assumptions used in the model. On average, 42% of residential customers, across counties, report a medium income above $75,000/year (U.S. median household income, based on 2022 ACS data), with a distribution range between 32% and 51%.

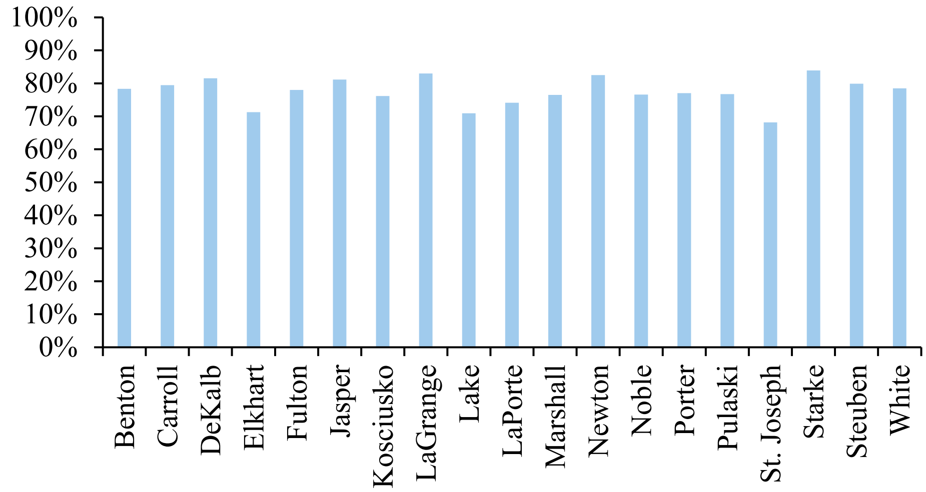
Figure 3-36: Household Income Distribution by County



Housing Units: The single-detached, owner-occupied housing units, by county, were also assessed from the ACS to determine the total population of agents with the potential to adopt solar DER. Figure 3-37 shows the estimated maximum percentage of customers with the potential to install solar DER systems.

[53] Retrieved from the ACS's 2022 Data Release.

Figure 3-37: Estimated Percentage Customers with Solar DER Potential



Solar DER-related Grants: On April 22, 2024, the city of Gary, located in Lake County, Indiana, was awarded a monetary grant from the U.S. Environmental Protection Agency for low-income solar projects, under the *Solar for All* program.[54] In PenDER, it is assumed that, approximately 3,000 low-income residential customers will install solar DER systems through this grant.

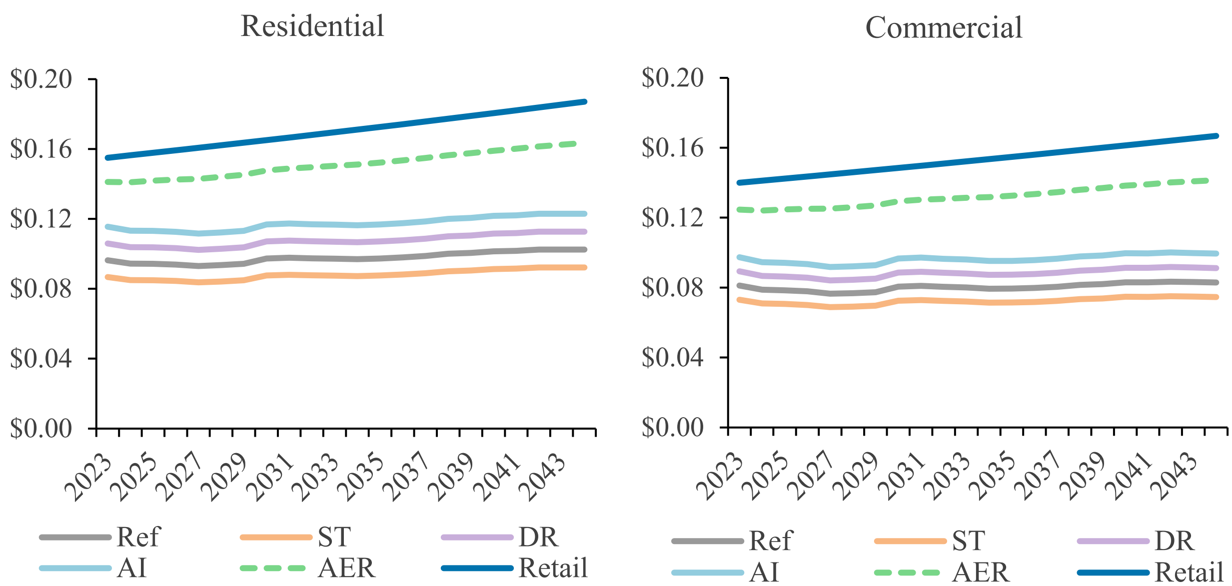
Bass Innovation Index Parameters: By using NIPSCO's customer adoption numbers from 2012 through 2023 from the Net Metering program, PenDER's bass innovation index parameters were calibrated to match historical adoption decisions (using historic retail rates and solar PV capital costs).

Based on the input assumptions described above, internally, for each simulation, PenDER calculates the following parameters assigned to each agent:

- **System Value**: For each agent, the expected cash inflow, resulting from installing a solar DER system, is estimated as annual production (based on expected solar capacity factor), in kWh, multiplied by the inferred retail rate savings as well as the monetization of excess generation at the wholesale rate in $/kWh. Figure 3-38 shows the estimated value streams for residential (left) and commercial agents (right) by scenario. The ST scenario exhibits lower value than the Reference scenario due to lower wholesale rates, while other scenarios assume higher retail and wholesale rates, which increase value for the DER. The AER scenario assumes excess generation can be valued at the retail rate. Note that for commercial customers, a greater percentage of value is assumed to be derived from the retail rate savings than for residential customers even though retail rates are lower.

54 For more information, refer to EPA's Solar For All Program.

Figure 3-38: Solar DER Value Streams, in 2023$/kWh, for Residential (Left) and Commercial (Right) Customers, by Scenario



- **Customer Budget**: A budget is assigned to each agent via probability distribution, informed by the 2022 ACS five-year census estimates. The customer budget parameter is omitted from the commercial customer forecast, as commercial agents are assumed to act economically and can utilize loans.

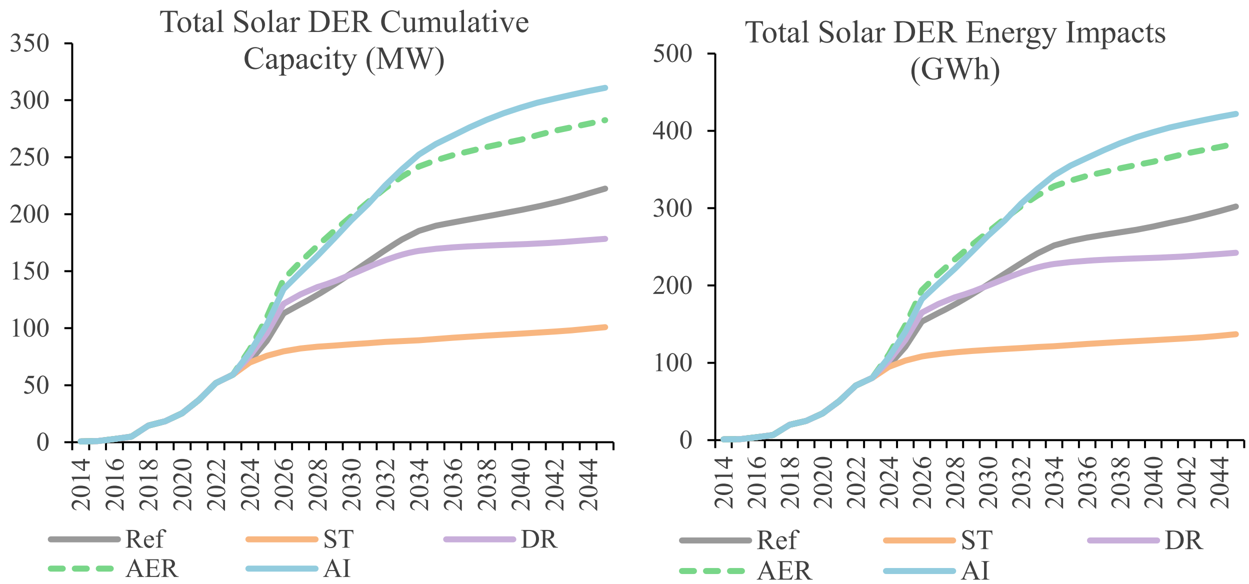
- **Payback Period**: Based on the upfront PV system capital cost, the cash flow from renewable energy incentives (i.e., EDG rates), discount rate, and solar PV lifetime, the payback period is determined by the number of years of discounted annual revenues that are required to cover the upfront PV system cost.

3.5.3.1 DER Forecast Results

Using all the input assumptions outlined above, NIPSCO deployed the PenDER model to estimate a range of DER penetration levels across the five major planning scenarios. Projections for total cumulative customer-owned solar DER installations and associated cumulative energy impacts, by scenario, are summarized in Figure 3-39,[55] while the disaggregated results for the residential customer class are shown in Figure 3-40, and the results for the commercial class are presented in Figure 3-41. In aggregate, a range of approximately 100 MW to 310 MW of DER capacity is projected across scenarios by 2045.

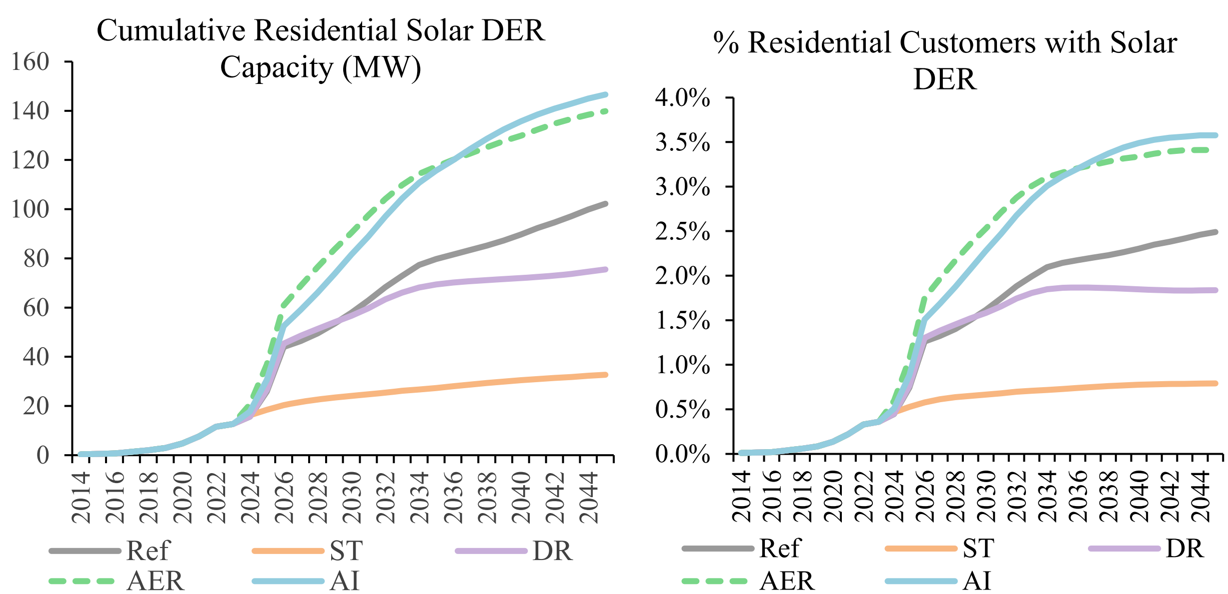
[55] Note that this graphic displays energy projections at the customer meter. For purposes of inclusion in the IRP load forecast modeling, NIPSCO grossed up the energy impact by 5% to incorporate line losses.

Figure 3-39: Projected Cumulative Customer-Owned DER Installations (MW) and Associated Energy (GWh) Impact, by Scenario



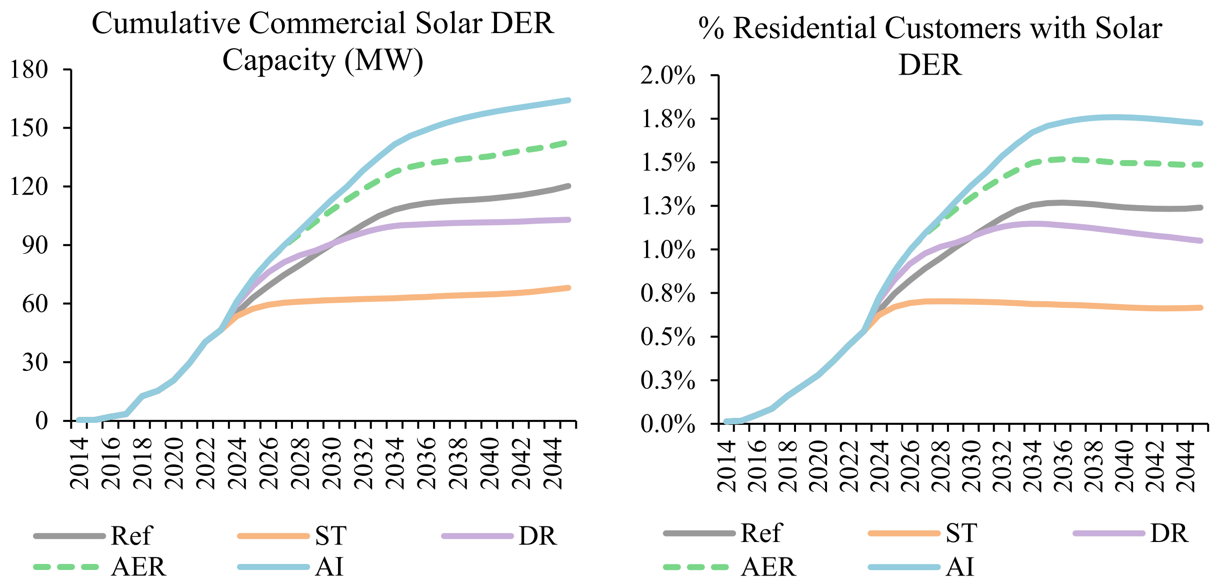
Across scenarios, it is estimated that between 0.8% and 3.6% of residential customers will install solar DER systems by 2045. There is a notable uptick in expected penetration in the early years, driven in part by the implementation of the Solar for All program among residential customers in selected counties. Over the long term, growth is impacted by scenario variables associated with system costs, system value, and social network effects. The solar DER penetration forecast for residential customers is summarized in Figure 3-40.

Figure 3-40: Projected Solar DER Penetration for the Residential Class, by Scenario



Across scenarios, it is estimated that between 0.7% and 1.7% of commercial customers will install solar DER systems by 2045. Despite an overall lower percentage of commercial customer adoption, commercial solar DER installations have far larger system sizes, pushing total installed capacity higher (depending on the scenario) than residential values. The solar DER penetration forecast for commercial customers is shown in Figure 3-41.

Figure 3-41: Projected Solar DER Penetration for the Commercial Class, by Scenario



3.6 Large Economic Development Loads

Following NIPSCO's first IRP Stakeholder Advisory meeting held on April 23, 2024, there was a significant increase in data center announcements in Indiana, including one public announcement in the NIPSCO service territory. In response to this development and its potential impact on future energy demand in the service territory, NIPSCO updated its Reference Case load forecast and developed an additional large load sensitivity load forecast.

NIPSCO and Indiana are both attractive to data center developers due to many favorable factors, such as a low risk for natural disasters; robust transmission network and reliability; available land at relatively reasonable prices; telecommunication connectivity and fiber optic cable; access to water; and proximity to customers, major metropolitan areas, and construction labor. Additionally, Indiana is a pro-business state with strong incentives for data center development. Indiana provides a sales and use tax exemption on purchases of qualifying data center equipment and energy to operators of a qualified data center for a period not to exceed 25 years for data center investments of less than $750 million.[56] Local governments have also provided local tax abatements and incentives on qualified enterprise information technology equipment to owners of a data center who invest at least $25 million in real and personal property in the facility, furthering incentives and likelihood of future data center load in Indiana and NIPSCO's service territory.[57]

At the time of the second NIPSCO IRP Stakeholder Advisory meeting held on June 24, 2024, there were six active data center projects in NIPSCO's service territory that had begun or taken steps to begin development activities and in were in discussions with NIPSCO. These six projects are initially expected to increase NIPSCO's anticipated annual total peak demand up to approximately 8,600 MW by 2035. As such, these new loads were an essential component in the 2024 IRP core analytical framework.

NIPSCO has an obligation to serve current and expected load from existing customers in its service territory and to reasonably plan for potential load growth. NIPSCO has developed perspectives on how much new large load may enter the system over time. NIPSCO estimated the potential energy demand from these projects in consultation with NIPSCO's Economic Development team and other internal subject matter experts. Projections were based on prospective and actual near-term customer prospects, as well as potential long-term industry-wide growth trends. These internal and industry projections were incorporated into the 2024 Load Forecast through the development of load projections for new projects that are expected to come online beginning in 2028 through 2035 ("Large Economic Development projects"). Figure 3-42 displays the anticipated incremental load attributable to Large Economic Development projects in the NIPSCO service territory. The Reference Case load forecast includes 600 MW of new demand attributable to Large Economic Development projects beginning in 2028. To account for further data center and large industrial load growth over the IRP horizon, new demand attributable to Large Economic Development projects rises to approximately 2,600 MW by 2035.

56 If the investment exceeds $750M, the Indiana Economic Development Corporation may award an exemption for up to 50 years. This program is established by Indiana Code § 6-2.5-15.

57 St. Joseph County and the City of LaPorte have both offered incentives to recently announced data center developments. *See* https://nwindianabusiness.com/community/economic-development/microsoft-chooses-la-porte-as-first-indiana-data-center-location/65133/ and https://www.wvpe.org/wvpe-news/2024-05-31/st-joseph-county-officials-eye-tax-breaks-for-massive-amazon-data-center

Figure 3-42: Projected New Large Load Additions

	2028	2030	2035
IRP Peak Load – Original Reference Case	2,300 MW	2,300 MW	2,500 MW
+New Load Added to All IRP Scenarios	*600 MW*	*1,600 MW*	*2,600 MW*
IRP Peak Load – New Reference Case	**2,900 MW**	**3,900 MW**	**5,100 MW**
+Emerging Load Sensitivity	*2,600 MW*	*4,500 MW*	*6,000 MW*
Total IRP Peak Load with Emerging Load Sensitivity	**5,500 MW**	**8,400 MW**	**11,100 MW**

The six aforementioned Large Economic Development projects are part of a potential wave of increased economic activity in the Northwest Indiana region, largely resulting from potential increased demand for data centers and related cloud storage/computing services. NIPSCO included the Emerging Load scenario to account for increased data center demand beyond the Reference Case. The Emerging Load projects 3,200 MW in new demand by 2028 and rising to 8,600 MW of new demand by 2035.

The anticipated growth in demand related to Large Economic Development project load is a new and rapidly changing phenomena in the NIPSCO service territory. NIPSCO's analysis in the 2024 IRP was intended to provide initial guidance with the facts available at the time the core analysis was conducted. NIPSCO, however, will continue to monitor and evaluate the development of Large Economic Development projects in the coming years. Further, NIPSCO will continue to refine its analysis of potential Large Economic Development load additions in future IRPs and other long-term portfolio planning analyses.

3.7 All-in Load Summary

Figure 3-43 depicts total net energy for load across customer classes in the Reference Case inclusive of adjustments from EVs, DERs, and new Economic Development loads, as well as losses associated with transmission and distribution.[58] Figure 3-43 below shows the contributions of all customer classes and load types to summer and winter peak load across all years in the reference case.

The largest diver of load growth in the Reference case is new loads associated with large Economic Development projects in the region. In the Reference case, these projects are projected to contribute 2,600 MW of peak load above the base forecast, making up nearly 50% of total summer peak demand and growing at a CAGR of 17.4% between 2027 and 2034.

58 Note that a loss factor of 4.62% was assumed to arrive at the "net energy for load" forecast that must be served by NIPSCO's generation resources. Transmission system losses are 1.62% and distribution system losses are 3%.

Figure 3-43: Total Net Energy for Load by Customer Class, with Adjustments (MW)

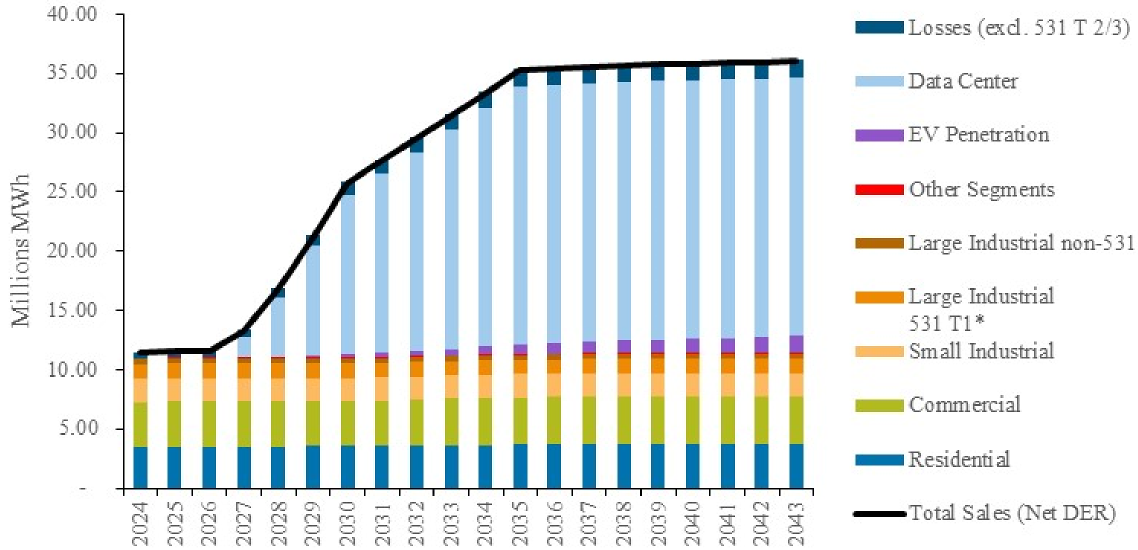
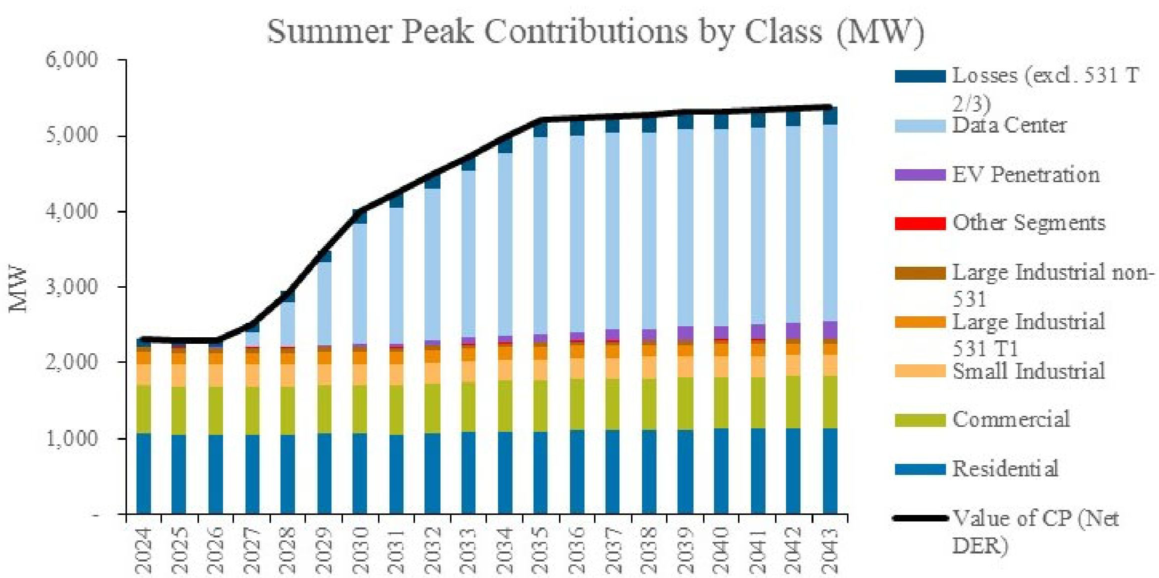
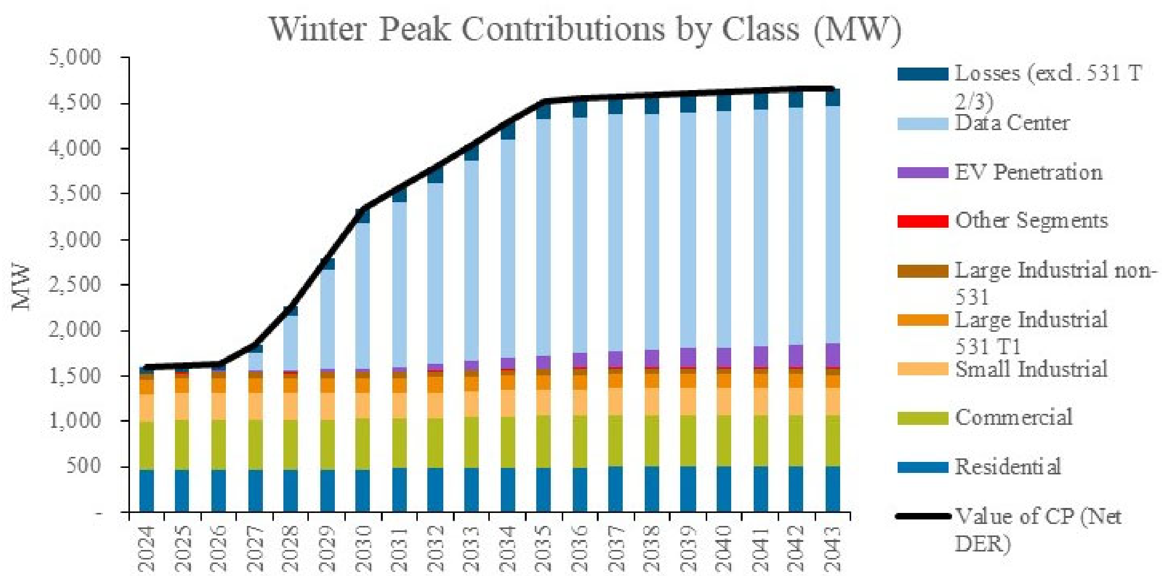


Figure 3-44: Summer and Winter Peak Contributions by Customer Class, with Adjustments (MW)





3.8 Scenario Analysis

NIPSCO combined the econometric modeling analysis with the EV, DER, and large economic development load analyses across all five planning scenarios to develop a range of future load growth outcomes, as outlined in Table 3-24. Each of these scenarios provides an internally consistent view of a possible future state of the world. The remainder of this section outlines the key drivers of scenario uncertainty and provides a summary of the forecasts.

Table 3-24: Scenario Drivers Summary

	Scenario Name	Description	Economic Growth (C&R, I Count)	EV Penetration	DER Penetration	Electrification (MISO Futures Report)	Large Econ. Development Load
	Reference Case	Reference Point	Base Moody's Baseline forecast	Base Rate of Adoption	Base Expected Rate of Adoption	Limited (Future 1)	*Separate sensitivity with significant additional economic development load potential, across all scenarios*
	Slower Transition	Environmental policy incentives reduce; economic slowdown in region	Low Moody's Low forecast	Low Rate of Adoption	Lowest High capital costs, low tax credits, low wholesale prices	Limited (Future 1)	
	Domestic Resiliency	Influx of new economic development load	Base Moody's Baseline forecast	Base Rate of Adoption	Lower High capital costs	Limited (Future 1)	
	Aggressive Environmental Regulation	Aggressive decarbonization policy, moderate electrification	Base Moody's Baseline forecast	High Rate of Adoption	High Net metering policy change	High (Future 2)	
	Accelerated Innovation	Faster energy transition, high electrification with additional econ. dev. load	Base Moody's High forecast	High Rate of Adoption	High Low capital costs, larger installation sizes	Highest (Future 3)	

3.8.1 Economic Variables

NIPSCO relied on Moody's macroeconomic data for forecasts of the econometric variables described in Section 1.3.1. NIPSCO used the Moody's Baseline forecast for the Reference Case as of October 2023 (also used for Domestic Resiliency, Aggressive Environmental Regulation, and Accelerated Innovation scenarios) and deployed the Alternative Scenario 3 - Downside - 90th Percentile for the low case (mapped to the Slower Transition scenario).

3.8.2 Electric Vehicles

NIPSCO developed a range of EV penetration scenarios and resulting charging demand, as described in Section 1.4. These low, base, and high scenarios are mapped to the scenarios, as summarized in Table 3-24.

3.8.3 Distributed Energy Resources

NIPSCO developed a range of DER penetration scenarios with resulting impacts on the load forecast, as described in Section 1.5 and mapped to the scenarios as summarized in Table 3-24.

3.8.4 Other Electrification

For the AER and AI scenarios, NIPSCO incorporated additional electrification impacts according to the electrification study developed by AEG for MISO's MTEP 2021 process.[59] This study incorporated potential electrification of residential and commercial/industrial heating, hot water, appliances, and commercial/industrial processes. NIPSCO adopted the projections for MISO LRZ 6 (scaled to account for only NIPSCO's portion of LRZ 6[60]) and added increasing energy demand due to electrification, as summarized in Figure 3-45 (AI Scenario) and Figure 3-46 (AER Scenario). The seasonal and annual peak demands are also impacted. As many of the electrification impacts have larger demand impacts in the winter than summer, this peak demand growth occurs asymmetrically in the winter.

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59 https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

60 Electrification was assumed to occur symmetrically across the LRZ6 footprint. As such, NIPSCO was assumed to account for 12% of the electrification, in line with its historical portion of LRZ6 sales.

Figure 3-45: Electrification Impact on NIPSCO Energy Sales (AI Scenario)

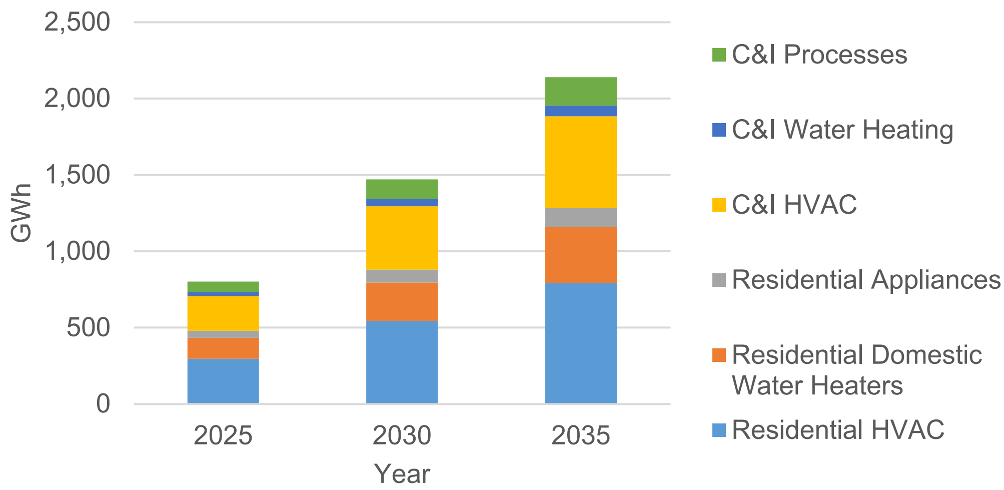
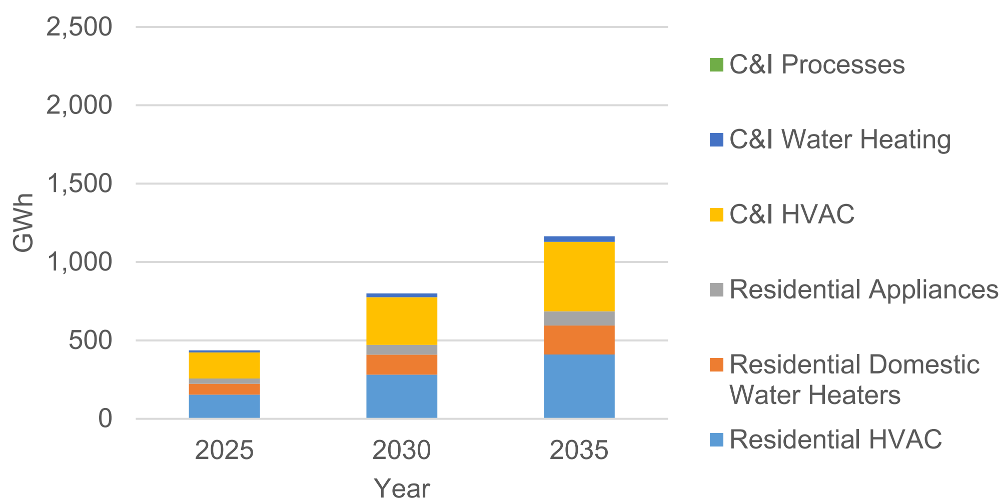


Figure 3-46: Electrification Impact on NIPSCO Energy Sales (AER Scenario)



3.8.5 Industrial Load Risk

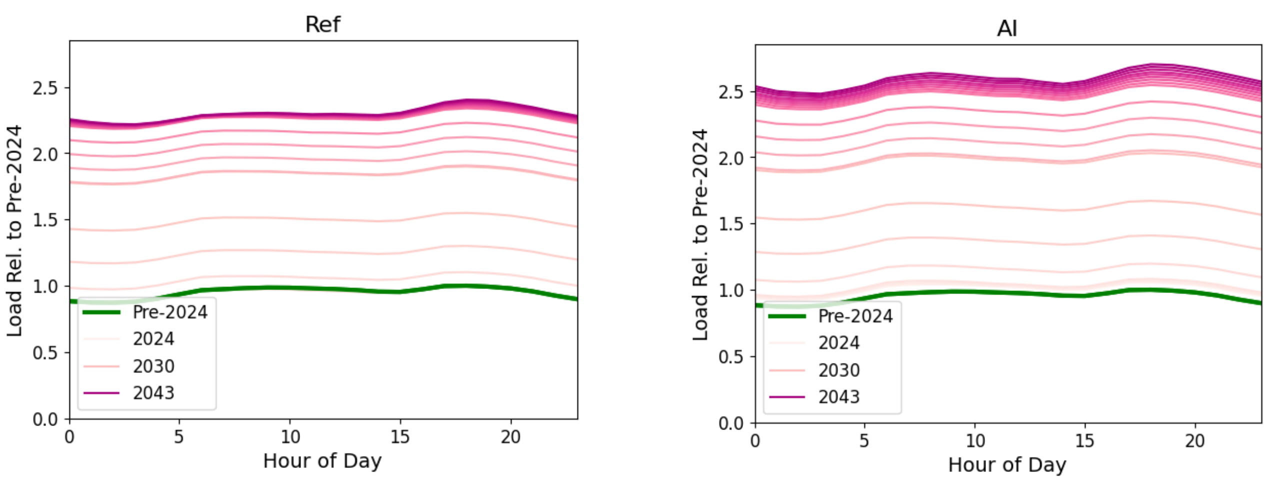
For the Slower Transition scenario, NIPSCO assumed that total industrial sales continue to decline at the pre-COVID rate (-0.12% CAGR). This scenario also incorporated the potential for additional industrial load migration, since NIPSCO recognizes that Tier 1 commitments may decline over time, particularly after the Rate 831/531 Modification Agreement approved in Cause No. 45772. Although no firm declarations of commitment reductions have been made by any Rate 531 customer, and it is not certain that all seven current Rate 531 customers would elect to reduce their demand to the tariff minimum, NIPSCO incorporated the migration of 100 MW of load from Rate 531 Tier 1 to Rate 531 Tier 2 by 2030 in the Slower Transition scenario. By migrating to

Tier 2, this load would no longer be served by NIPSCO but would instead be procured by the customer(s) through NIPSCO.

3.8.6 Conversion from Sales to Peak

The base sales forecast (without the addition of EVs, DERs, electrification, or large loads) was converted to a peak load forecast using the load factor approach described in Section 1.3.5. However, the addition of EVs, DERs, and other sources of electrification can have a substantial impact on the hourly load shape. Given a sufficient change in shape, the hour of the peak load will change. An example of this changing hourly load shape for the winter season is shown in Figure 3-47 for the Reference and AI cases. The darker shades of pink in this figure indicate future years that are further into the planning horizon. As seen in this figure, both scenarios will experience a flattening of the hourly shape due to the additional high load factor, data center load. However, in the AI case, further load growth would occur in the early morning and evening hours due to the increased electrification of heating.

Figure 3-47: Winter Hourly Shaping Impacts to Load (Base, Accelerated Innovation)



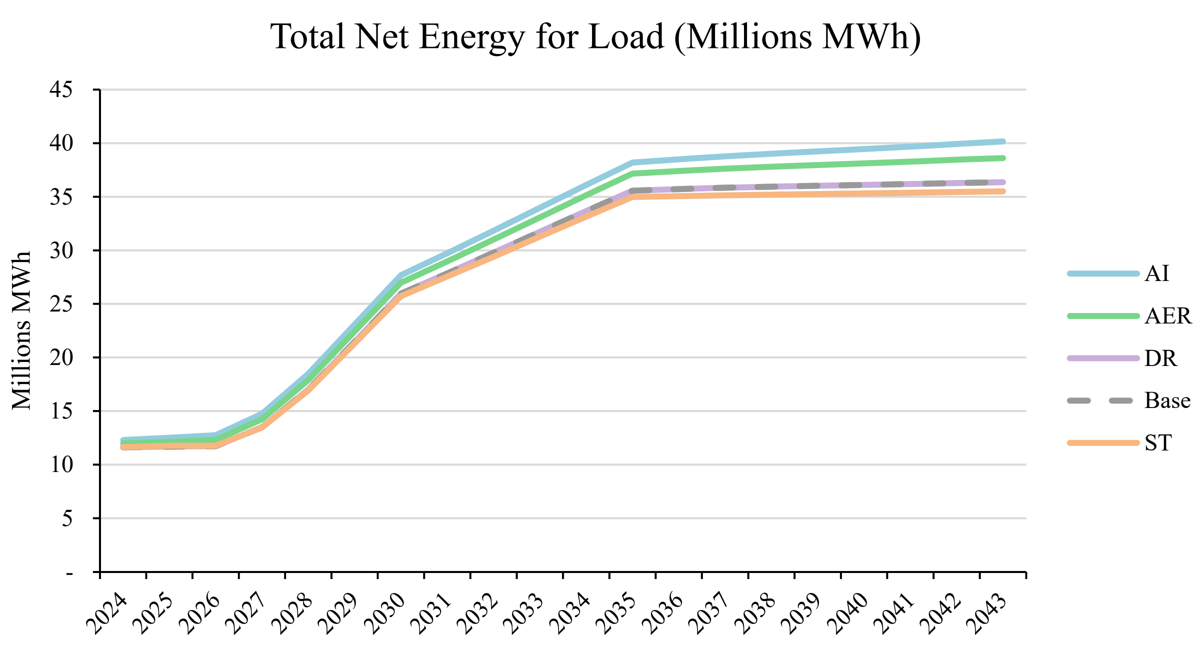
As electrification grows, a larger portion of demand will be shifted to hours before the sun rises or after the sun has set, due to the impact of EV charging, DER growth, and new electrification. This growth will also occur asymmetrically across seasons. With sufficient growth, the hour of the peak will change. As such, it is not appropriate to simply add the contribution of new sources of load growth in the historic peak hour. Rather, for each year in the forecast horizon, NIPSCO simulated the addition of the new sources of electrification to the historical load shape. Under this *future* looking load shape, the new hour of peak load for each season is found. If the hour of peak is changed, the econometric load (i.e., load forecast without electrification impacts) is scaled to capture the lower contribution to peak in this hour. This scaling factor is taken as the historic ratio of load between the future peak load hour and historic peak load hour. Then the expected contribution of DERs, EVs, other sources of electrification, and large loads is added, based on their expected performance in this new peak hour. For example, under current conditions, the peak may occur at 5 pm. However, with increasing DER and EV penetration, the new peak may be shifted back to 7 pm. To account for this change, the base load contribution to peak is scaled by current ratio of load demand at 7 pm versus 5 pm. Then the expected DER, EV, other electrification, and data center demand during this hour is added to synthesize the peak demand forecast.

3.8.7 Scenario Results

Figure 3-48 presents a summary of the total net energy for load forecast across the five planning scenarios and under the base outlook for large economic development loads.[61] In the short term, the varying techno-economic and policy assumptions driving differences in the econometric, EV, and DER forecasts are overshadowed by the magnitude of new large economic development loads (primarily data centers). Over the long run, other differences between scenarios begin to become more apparent. Higher demand in the AI and AER scenarios is driven primarily by increased charging demand from EVs in addition to increased assumptions around the electrification of traditional natural gas services, like space heating and cooking.

The Reference Case and DR scenarios forecast net sales to grow at a CAGR of 5.6%, while increased expectations around EV and electrification push up growth in the AER and AI scenarios to 5.9% and 6.1%, respectively.

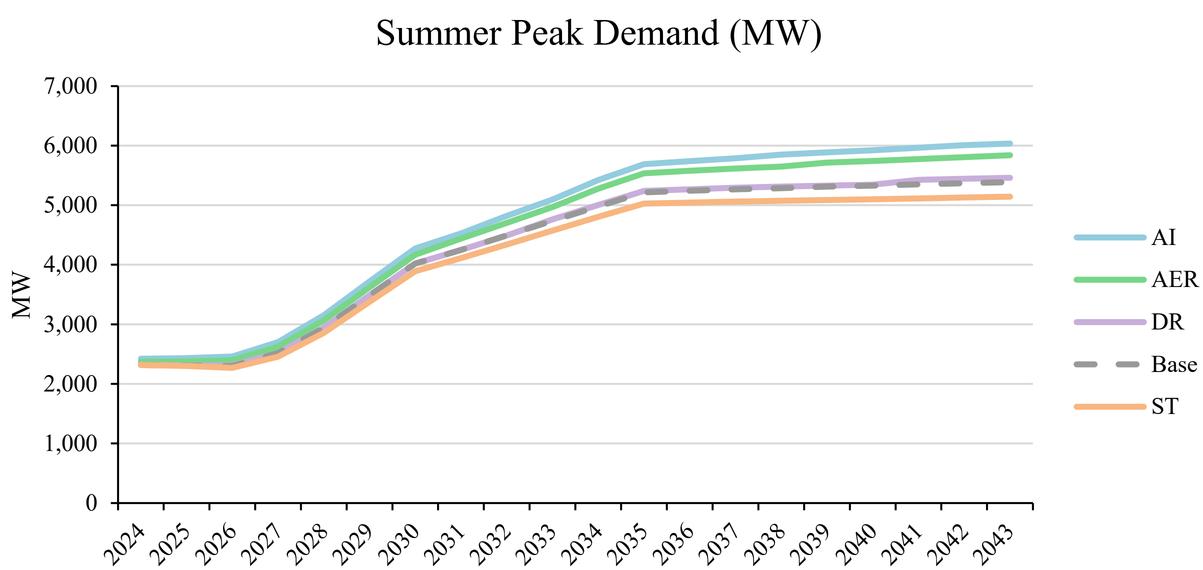
Figure 3-48: Total Net Energy for Load Forecast across Scenarios

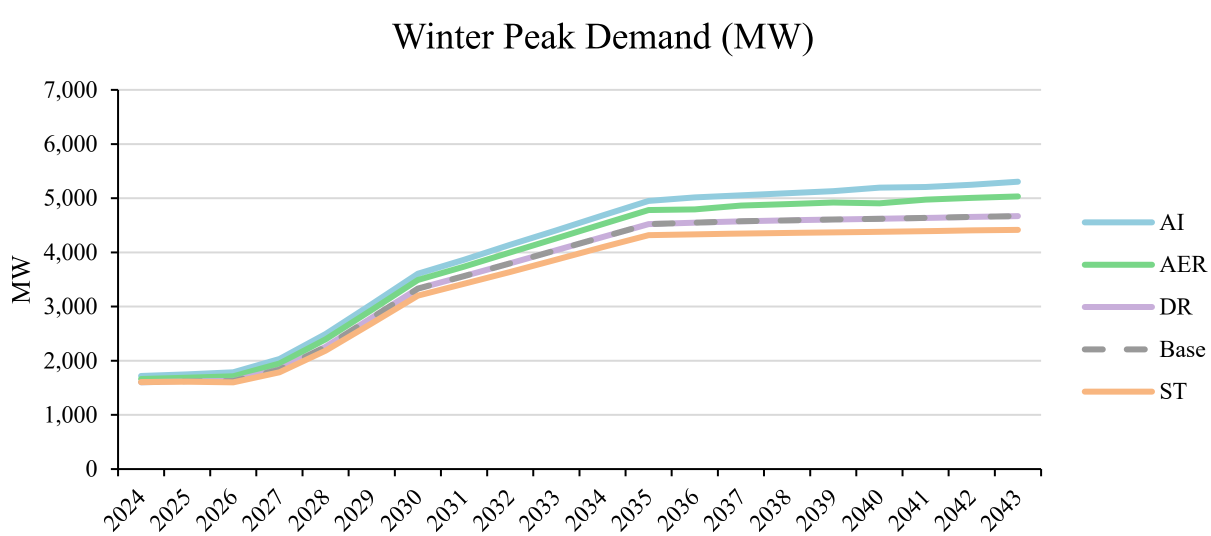


61 Note that the high data center load sensitivity described in Section 3.6 is not displayed in detail in these summaries. However, the additional load would be additive to all five scenarios.

Figure 3-49 depicts year-on-year demand in megawatts at the peak hour of each season across the five planning scenarios and under the base outlook for large economic development loads. In NIPSCO's 2024 load forecast, peak load is highest in the summer across the study period, indicating that the NIPSCO system is expected to be summer peaking across all scenarios. Compared to the trends in total net energy sales, the Reference (Base) and Domestic Resiliency cases diverge slightly as the hour in which demand is greatest shifts to later in the day. Additionally, the peak forecast provides a closer view at how the differences in electrification and EV assumptions drive variation across the scenario forecasts. The inclusion of 2,600 MW of Economic Development load in all scenarios by 2035 has overall caused load to be less dependent on variations in seasonal consumption and temperature.

Figure 3-49: Seasonal Peak Demand for Load Forecast across Scenarios





3.9 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 five scenarios.

Table 3-25: Customer Count Forecast by Major Customer Segment – Reference Case

Year	Residential	Commercial	Total Industrial
2024	426,564	58,798	2,180
2025	428,996	59,195	2,172
2026	431,867	59,673	2,174
2027	434,991	60,192	2,172
2028	438,219	60,728	2,165
2029	441,443	61,262	2,158
2030	444,644	61,790	2,150
2031	447,894	62,325	2,142
2032	451,275	62,880	2,136
2033	454,850	63,467	2,129
2034	458,602	64,081	2,122
2035	462,544	64,726	2,117
2036	466,657	65,397	2,113
2037	470,911	66,089	2,109
2038	475,345	66,809	2,105
2039	479,941	67,556	2,101
2040	484,694	68,327	2,097
2041	489,629	69,129	2,093
2042	494,752	69,960	2,089
2043	500,037	70,818	2,086
2024-2043 CAGR	**0.84%**	**0.98%**	**-0.23%**

Table 3-26: Electric Sales Forecast (Inclusive of Historical Energy Efficiency Programs Only and Prior to Other Adjustments) – Reference Case

Year	Residential	Commercial	Total Industrial	Other*	Total MWh (Before Adjustments)
2024	3,503,477	3,718,422	3,787,387	92,169	11,101,455
2025	3,514,494	3,766,036	3,773,392	92,169	11,146,090
2026	3,529,627	3,780,604	3,777,602	92,169	11,180,002
2027	3,532,326	3,784,527	3,774,703	92,169	11,183,726
2028	3,532,272	3,786,944	3,764,110	92,169	11,175,495
2029	3,554,454	3,790,559	3,751,459	92,169	11,188,642
2030	3,566,676	3,789,167	3,739,494	92,169	11,187,507
2031	3,579,386	3,807,605	3,733,065	92,169	11,212,225
2032	3,596,102	3,855,349	3,733,262	92,169	11,276,882
2033	3,628,006	3,910,399	3,732,019	92,169	11,362,594
2034	3,660,477	3,946,354	3,729,248	92,169	11,428,248
2035	3,682,470	3,964,104	3,724,461	92,169	11,463,205
2036	3,697,202	3,981,757	3,725,865	92,169	11,496,993
2037	3,711,092	3,996,678	3,723,603	92,169	11,523,543
2038	3,719,750	3,989,543	3,716,539	92,169	11,518,001
2039	3,728,274	3,986,334	3,709,475	92,169	11,516,253
2040	3,736,196	3,985,407	3,702,411	92,169	11,516,183
2041	3,743,898	3,984,567	3,696,228	92,169	11,516,863
2042	3,751,306	3,985,531	3,689,899	92,169	11,518,905
2043	3,758,286	3,983,727	3,683,416	92,169	11,517,598
2024-2043 CAGR	**0.37%**	**0.36%**	**-0.15%**	**0.00%**	**0.19%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-27: Summer Peak Load Forecast (Inclusive of Historical Energy Efficiency Programs Only and Prior to Other Adjustments) – Reference Case

Year	Residential	Commercial	Small Industrial	Large Industrial non-531	Large Industrial 531 T1	Other*	Total MW	System Wide Peak (Before Adjustments)
2024	1,062	639	282	53	165	13	2,214	2,316
2025	1,049	641	281	53	164	13	2,201	2,303
2026	1,045	643	281	53	164	12	2,198	2,300
2027	1,047	642	281	53	164	13	2,200	2,311
2028	1,049	643	280	53	164	13	2,202	2,331
2029	1,062	646	279	53	163	13	2,216	2,369
2030	1,062	645	278	52	163	13	2,214	2,391
2031	1,057	648	278	52	162	12	2,210	2,397
2032	1,073	656	278	52	162	13	2,235	2,433
2033	1,083	665	278	52	162	13	2,253	2,462
2034	1,093	671	278	52	162	13	2,269	2,489
2035	1,099	675	277	52	162	13	2,278	2,508
2036	1,105	678	277	52	162	13	2,287	2,518
2037	1,111	681	277	52	162	13	2,296	2,528
2038	1,116	681	277	52	162	13	2,300	2,533
2039	1,120	682	276	52	161	13	2,304	2,539
2040	1,125	683	275	52	161	13	2,309	2,544
2041	1,130	684	275	52	161	13	2,314	2,550
2042	1,135	685	275	52	160	13	2,320	2,557
2043	1,140	686	274	52	160	13	2,325	2,563
2024-2043 CAGR	**0.35%**	**0.38%**	**-0.16%**	**-0.16%**	**-0.16%**	**0.00%**	**0.19%**	**0.60%**

*Other includes Railroad, Street Lighting, Public Authority, and Company Use

Table 3-28: Reference Case Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In (Grossed Up for Losses after Adjustments)
2024	11,101,455	8,387	(96,434)	-	11,516,979
2025	11,146,090	17,333	(120,638)	-	11,547,732
2026	11,180,002	27,643	(153,370)	-	11,559,747
2027	11,183,726	42,832	(164,430)	1,677,648	13,323,122
2028	11,175,495	63,623	(175,489)	5,032,944	16,835,018
2029	11,188,642	113,184	(188,200)	9,227,064	21,275,231
2030	11,187,507	213,388	(201,181)	13,421,184	25,753,200
2031	11,212,225	311,898	(214,812)	15,098,832	27,623,025
2032	11,276,882	419,046	(229,041)	16,776,480	29,543,037
2033	11,362,594	517,016	(241,396)	18,454,128	31,477,436
2034	11,428,248	618,866	(251,751)	20,131,776	33,397,005
2035	11,463,205	729,158	(257,711)	21,809,424	35,297,891
2036	11,496,993	834,090	(261,968)	21,809,424	35,438,565
2037	11,523,543	934,292	(265,534)	21,809,424	35,567,444
2038	11,518,001	1,027,523	(268,813)	21,809,424	35,655,765
2039	11,516,253	1,111,218	(272,216)	21,809,424	35,737,946
2040	11,516,183	1,184,344	(276,205)	21,809,424	35,810,214
2041	11,516,863	1,272,435	(280,931)	21,809,424	35,898,151
2042	11,518,905	1,352,836	(285,280)	21,809,424	35,979,862
2043	11,517,598	1,425,081	(290,439)	21,809,424	36,048,688
2024-2043 CAGR	**0.19%**	**31.03%**	**5.97%**	**17.39%**	**6.19%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-29: Reference Case Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In
2024	2,316	1	(6)	-	2,311	1,602	2	-	-	1,604
2025	2,303	3	(7)	-	2,298	1,610	4	-	-	1,614
2026	2,300	4	(1)	-	2,302	1,617	6	-	-	1,623
2027	2,311	7	(9)	200	2,509	1,625	10	-	200	1,834
2028	2,331	10	(9)	600	2,932	1,643	14	-	600	2,257
2029	2,369	17	(10)	1,100	3,476	1,669	24	-	1,100	2,792
2030	2,391	29	(11)	1,600	4,008	1,692	40	-	1,600	3,332
2031	2,397	40	(2)	1,800	4,236	1,704	57	-	1,800	3,561
2032	2,433	59	(4)	2,000	4,487	1,720	77	-	2,000	3,797
2033	2,462	73	(5)	2,200	4,731	1,744	97	-	2,200	4,040
2034	2,489	89	(5)	2,400	4,973	1,765	117	-	2,400	4,282
2035	2,508	106	(5)	2,600	5,210	1,781	140	-	2,600	4,520
2036	2,518	123	(5)	2,600	5,236	1,788	160	-	2,600	4,548
2037	2,528	138	(5)	2,600	5,261	1,793	180	-	2,600	4,573
2038	2,533	152	(5)	2,600	5,280	1,792	198	-	2,600	4,590
2039	2,539	173	-	2,600	5,312	1,792	214	-	2,600	4,606
2040	2,544	184	-	2,600	5,329	1,792	227	-	2,600	4,619
2041	2,550	199	-	2,600	5,349	1,792	245	-	2,600	4,637
2042	2,557	212	-	2,600	5,369	1,793	261	-	2,600	4,654
2043	2,563	225	-	2,600	5,387	1,793	276	-	2,600	4,669
2024-2043 CAGR	**0.53%**	**30.87%**	**-**	**17.39%**	**4.56%**	**0.60%**	**29.74%**	**-**	**0.09%**	**5.79%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-30: ST Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In (Grossed Up for Losses after Adjustments)
2024	11,143,111	8,387	(94,777)	-	11,560,367
2025	11,242,166	13,749	(102,858)	-	11,657,835
2026	11,241,562	18,962	(108,170)	-	11,650,771
2027	11,197,073	25,733	(111,569)	1,677,648	13,357,508
2028	11,143,548	33,837	(113,654)	5,032,944	16,812,458
2029	11,144,584	43,866	(115,083)	9,227,064	21,204,277
2030	11,142,715	63,262	(116,539)	13,421,184	25,605,488
2031	11,164,977	110,122	(117,936)	15,098,832	27,431,503
2032	11,227,051	135,674	(119,352)	16,776,480	29,276,753
2033	11,310,312	166,762	(120,480)	18,454,128	31,150,300
2034	11,373,514	203,619	(121,409)	20,131,776	33,009,104
2035	11,406,853	248,603	(122,782)	21,809,424	34,844,637
2036	11,439,970	296,605	(124,049)	21,809,424	34,927,973
2037	11,466,264	349,142	(125,494)	21,809,424	35,008,803
2038	11,460,667	405,039	(127,040)	21,809,424	35,059,765
2039	11,458,710	461,555	(128,305)	21,809,424	35,115,485
2040	11,458,571	516,724	(129,273)	21,809,424	35,172,022
2041	11,459,009	581,606	(130,393)	21,809,424	35,239,126
2042	11,461,035	644,550	(131,432)	21,809,424	35,305,884
2043	11,459,442	704,082	(133,088)	21,809,424	35,364,732
2024-2043 CAGR	**0.15%**	**26.26%**	**1.80%**	**17.39%**	**6.06%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-31: ST Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In
2024	2,315	1	(6)	-	2,310	1,604	2	-	-	1,606
2025	2,293	2	(1)	-	2,294	1,610	3	-	-	1,613
2026	2,268	2	(1)	-	2,269	1,596	4	-	-	1,600
2027	2,252	4	(7)	200	2,449	1,580	6	-	200	1,786
2028	2,250	5	(7)	600	2,848	1,576	8	-	600	2,184
2029	2,270	7	(7)	1,100	3,370	1,581	10	-	1,100	2,691
2030	2,279	8	(1)	1,600	3,886	1,586	13	-	1,600	3,200
2031	2,294	14	(1)	1,800	4,107	1,597	21	-	1,800	3,418
2032	2,322	18	(8)	2,000	4,333	1,613	26	-	2,000	3,639
2033	2,350	23	(8)	2,200	4,565	1,635	32	-	2,200	3,867
2034	2,375	28	(8)	2,400	4,796	1,656	40	-	2,400	4,095
2035	2,394	34	(8)	2,600	5,020	1,669	49	-	2,600	4,318
2036	2,403	41	(8)	2,600	5,036	1,675	58	-	2,600	4,333
2037	2,412	49	(8)	2,600	5,053	1,680	69	-	2,600	4,348
2038	2,416	57	(8)	2,600	5,065	1,678	80	-	2,600	4,358
2039	2,421	65	(8)	2,600	5,078	1,677	91	-	2,600	4,368
2040	2,426	73	(8)	2,600	5,091	1,677	102	-	2,600	4,379
2041	2,432	82	(8)	2,600	5,106	1,677	115	-	2,600	4,392
2042	2,438	92	(9)	2,600	5,121	1,677	128	-	2,600	4,405
2043	2,443	100	(9)	2,600	5,135	1,677	141	-	2,600	4,418
2024-2043 CAGR	**0.28%**	**25.45%**	**1.80%**	**17.39%**	**4.29%**	**0.23%**	**25.22%**	**-**	**17.39%**	**5.47%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-32: DR Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In (Grossed Up for Losses after Adjustments)
2024	11,120,257	8,387	(102,460)	-	11,530,319
2025	11,167,010	17,333	(129,533)	-	11,560,283
2026	11,191,675	27,643	(164,823)	-	11,559,961
2027	11,186,115	42,832	(176,118)	1,677,648	13,313,390
2028	11,176,083	63,623	(184,750)	5,032,944	16,825,944
2029	11,189,974	113,184	(191,770)	9,227,064	21,272,887
2030	11,189,127	213,388	(199,663)	13,421,184	25,756,481
2031	11,213,264	311,898	(208,267)	15,098,832	27,630,958
2032	11,277,178	419,046	(216,911)	16,776,480	29,556,036
2033	11,363,459	517,016	(223,265)	18,454,128	31,497,309
2034	11,429,730	618,866	(227,863)	20,131,776	33,423,545
2035	11,463,643	729,158	(230,393)	21,809,424	35,326,928
2036	11,497,139	834,090	(232,017)	21,809,424	35,470,051
2037	11,523,543	934,292	(233,213)	21,809,424	35,601,259
2038	11,518,001	1,027,523	(234,175)	21,809,424	35,692,002
2039	11,516,253	1,111,218	(235,016)	21,809,424	35,776,865
2040	11,516,626	1,184,344	(235,784)	21,809,424	35,852,966
2041	11,517,014	1,272,435	(236,700)	21,809,424	35,944,582
2042	11,518,905	1,352,836	(237,565)	21,809,424	36,029,782
2043	11,518,048	1,425,081	(239,180)	21,809,424	36,102,785
2024-2043 CAGR	**0.19%**	**31.03%**	**4.56%**	**17.39%**	**6.19%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-33: DR Peak Demand Forecast with Adjustments

	Summer Peak (MW)					Winter Peak (MW)				
	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In	Base Load	EV Load	DERs*	New Large Econ. Dev. Loads**	All-In
2024	2,320	1	(7)	-	2,314	1,603	2	-	-	1,605
2025	2,302	2	(1)	-	2,303	1,614	4	-	-	1,618
2026	2,309	4	(1)	-	2,311	1,619	6	-	-	1,625
2027	2,312	7	(9)	200	2,510	1,625	10	-	200	1,835
2028	2,332	10	(10)	600	2,933	1,643	14	-	600	2,257
2029	2,371	17	(10)	1,100	3,477	1,669	24	-	1,100	2,792
2030	2,389	28	(2)	1,600	4,015	1,692	40	-	1,600	3,332
2031	2,405	40	(2)	1,800	4,244	1,704	57	-	1,800	3,561
2032	2,428	54	(2)	2,000	4,480	1,720	77	-	2,000	3,797
2033	2,487	73	(4)	2,200	4,756	1,744	97	-	2,200	4,040
2034	2,514	89	(4)	2,400	4,999	1,766	117	-	2,400	4,283
2035	2,533	106	(4)	2,600	5,235	1,781	140	-	2,600	4,520
2036	2,544	123	(4)	2,600	5,262	1,788	160	-	2,600	4,548
2037	2,554	138	(4)	2,600	5,287	1,793	180	-	2,600	4,573
2038	2,559	152	(4)	2,600	5,306	1,792	198	-	2,600	4,590
2039	2,564	165	(5)	2,600	5,324	1,792	214	-	2,600	4,606
2040	2,569	175	(5)	2,600	5,340	1,792	227	-	2,600	4,619
2041	2,625	199	-	2,600	5,424	1,792	245	-	2,600	4,637
2042	2,631	212	-	2,600	5,444	1,793	261	-	2,600	4,654
2043	2,637	225	-	2,600	5,462	1,793	276	-	2,600	4,669
2024-2043 CAGR	**0.68%**	**30.87%**	**-**	**17.39%**	**4.62%**	**0.59%**	**29.74%**	**-**	**17.39%**	**5.78%**

*DERs are reductions to the load served by NIPSCO.

**Note that this represents NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-34: AER Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	Other Electrification	DERs*	All-In (Grossed Up for Losses after Adjustments)**
2024	11,101,455	8,387	364,113	(110,684)	11,883,006
2025	11,146,090	19,019	436,056	(148,667)	11,976,375
2026	11,180,002	78,715	508,676	(193,922)	12,102,931
2027	11,183,726	177,807	581,469	(214,918)	14,019,846
2028	11,175,495	259,824	654,720	(233,887)	17,664,156
2029	11,188,642	310,016	727,467	(252,063)	22,175,419
2030	11,187,507	388,652	799,900	(269,098)	26,702,362
2031	11,212,225	505,329	872,112	(286,185)	28,663,126
2032	11,276,882	636,838	946,110	(302,337)	30,684,029
2033	11,362,594	784,224	1,018,064	(316,319)	32,743,703
2034	11,428,248	937,469	1,091,316	(328,362)	34,791,911
2035	11,463,205	1,091,471	1,163,947	(335,745)	36,813,024
2036	11,496,993	1,212,641	1,237,633	(341,850)	37,045,844
2037	11,523,543	1,322,595	1,308,023	(346,667)	37,257,259
2038	11,518,001	1,420,000	1,380,990	(351,519)	37,424,639
2039	11,516,253	1,503,947	1,454,377	(355,985)	37,582,749
2040	11,516,183	1,574,548	1,528,188	(360,104)	37,729,460
2041	11,516,863	1,664,493	1,603,435	(365,644)	37,897,210
2042	11,518,905	1,746,497	1,682,631	(370,751)	38,062,658
2043	11,517,598	1,821,055	1,766,567	(374,969)	38,222,704
2024-2043 CAGR	**0.19%**	**32.73%**	**8.67%**	**6.63%**	**6.34%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-35: AER 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**
2024	2,319	1	54	(7)	2,368	1,604	2	58	-	1,664
2025	2,302	2	65	(1)	2,368	1,613	4	67	-	1,685
2026	2,311	10	76	(2)	2,396	1,621	14	78	-	1,712
2027	2,306	23	87	(2)	2,615	1,630	29	89	-	1,947
2028	2,328	34	98	(2)	3,058	1,649	42	103	-	2,394
2029	2,368	40	109	(2)	3,616	1,675	53	111	-	2,939
2030	2,395	52	120	(2)	4,165	1,699	69	123	-	3,490
2031	2,438	70	131	(6)	4,433	1,711	92	134	-	3,737
2032	2,465	90	141	(6)	4,690	1,729	119	150	-	3,998
2033	2,496	113	152	(6)	4,955	1,753	150	156	-	4,259
2034	2,572	143	163	-	5,278	1,776	179	167	-	4,522
2035	2,592	168	174	-	5,535	1,792	211	178	-	4,781
2036	2,604	188	185	-	5,576	1,798	198	196	-	4,792
2037	2,615	206	196	-	5,617	1,806	256	201	-	4,863
2038	2,620	221	207	-	5,648	1,806	275	212	-	4,892
2039	2,644	251	218	-	5,714	1,806	290	223	-	4,919
2040	2,650	262	229	-	5,740	1,805	259	241	-	4,905
2041	2,657	277	241	-	5,774	1,807	321	246	-	4,974
2042	2,664	291	252	-	5,807	1,808	338	258	-	5,005
2043	2,670	304	265	-	5,839	1,809	354	271	-	5,034
2024-2043 CAGR	**0.74%**	**32.97%**	**8.70%**	**-**	**4.87%**	**0.63%**	**31.44%**	**8.49%**	**-**	**6.00%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-36: AI Electric Sales Forecast with Adjustments

	MWh Sales				
	Base Load	EV Load	Other Electrification	DERs*	All-In (Grossed Up for Losses after Adjustments)**
2024	11,101,455	8,387	669,314	(107,059)	12,206,099
2025	11,146,090	19,019	801,429	(140,088)	12,367,602
2026	11,180,002	78,715	934,873	(182,332)	12,560,943
2027	11,183,726	177,807	1,068,683	(202,275)	14,542,797
2028	11,175,495	259,824	1,203,463	(221,902)	18,250,789
2029	11,188,642	310,016	1,337,130	(242,976)	22,822,756
2030	11,187,507	388,652	1,470,195	(264,221)	27,408,727
2031	11,212,225	505,329	1,602,857	(283,626)	29,430,309
2032	11,276,882	636,838	1,739,038	(305,764)	31,510,005
2033	11,362,594	784,224	1,871,172	(325,100)	33,627,037
2034	11,428,248	937,469	2,005,966	(342,513)	35,734,013
2035	11,463,205	1,091,471	2,139,408	(355,144)	37,813,257
2036	11,496,993	1,212,641	2,274,969	(365,028)	38,106,856
2037	11,523,543	1,322,595	2,403,959	(374,979)	38,374,208
2038	11,518,001	1,420,000	2,538,123	(384,041)	38,601,207
2039	11,516,253	1,503,947	2,673,102	(391,856)	38,820,251
2040	11,516,183	1,574,548	2,809,060	(398,365)	39,029,480
2041	11,516,863	1,664,493	2,947,074	(404,350)	39,262,430
2042	11,518,905	1,746,497	3,092,513	(409,177)	39,497,475
2043	11,517,598	1,821,055	3,246,697	(413,614)	39,730,785
2024-2043 CAGR	**0.19%**	**32.73%**	**8.67%**	**7.37%**	**6.41%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Table 3-37: AI 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**
2024	2,321	1	100	(7)	2,416	1,607	2	110	-	1,718
2025	2,309	3	120	(8)	2,424	1,616	4	127	-	1,748
2026	2,314	10	134	(1)	2,457	1,624	14	148	-	1,786
2027	2,320	21	160	(11)	2,689	1,633	29	170	-	2,032
2028	2,342	30	179	(12)	3,139	1,653	42	196	-	2,492
2029	2,380	38	200	(14)	3,704	1,680	53	212	-	3,045
2030	2,400	52	211	(2)	4,260	1,704	69	233	-	3,606
2031	2,416	67	230	(2)	4,511	1,717	92	254	-	3,863
2032	2,471	90	259	(6)	4,814	1,736	119	285	-	4,140
2033	2,502	113	279	(7)	5,088	1,760	150	297	-	4,407
2034	2,578	143	299	-	5,421	1,783	179	318	-	4,680
2035	2,599	168	320	-	5,687	1,800	211	339	-	4,950
2036	2,611	188	339	-	5,738	1,808	235	373	-	5,016
2037	2,622	206	360	-	5,788	1,815	256	382	-	5,052
2038	2,646	238	364	(0)	5,848	1,815	275	403	-	5,092
2039	2,652	251	384	(0)	5,887	1,815	290	424	-	5,130
2040	2,658	262	401	-	5,921	1,766	330	501	-	5,196
2041	2,665	277	422	-	5,965	1,817	321	468	-	5,206
2042	2,672	291	443	(0)	6,007	1,819	338	491	-	5,248
2043	2,663	287	486	-	6,036	1,772	354	578	-	5,305
2024-2043 CAGR	**0.72%**	**32.57%**	**8.70%**	**-**	**4.94%**	**0.52%**	**31.44%**	**9.15%**	**-**	**6.11%**

*DERs are reductions to the load served by NIPSCO.

**Note that All-In load includes NIPSCO's base view on new large economic development loads. Refer to Section 3.6 for additional details on NIPSCO's high sensitivity.

Section 4. Supply-Side Resources

NIPSCO's generation fleet is in the midst of a transition as with much of the electric industry. This section identifies NIPSCO's existing fleet of supply-side resources, describes renewable generation currently in-service and planned to be in-service, and outlines a broad mix of future potential 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, but they must also operate within MISO, the Regional Transmission Organization, and are 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's fully owned generating resources consist of coal, natural gas, hydro, wind, solar, and solar plus storage units. Additionally, NIPSCO meets its customer needs with additional wind and solar purchase power agreements and joint ventures. The total NDC of the existing resources is 3,644 MW across multiple generation sites, including Schahfer (Units 16A, 16B, 17, and 18), Michigan City (Unit 12), Sugar Creek, two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro), and Cavalry Solar plus Storage. Of the total capacity, 33% is from coal-fired units, 20% is from natural gas-fired units, and 47% is from wind, solar plus storage, 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	578
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	1,000
Solar + Storage		Solar + Storage	710
NIPSCO			3,644

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. An 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)	310
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 an approximately 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. 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.[62]

62 Units 14 and 15 were retired effective October 1, 2021.

Table 4-3: Schahfer

	Unit 17	Unit 18	Unit 16A	Unit 16B
Net Output				
Min (MW)	135	135	------	------
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. Sugar Creek completed an AGP tech upgrade in the fall of 2023. This upgrade included a new thermal barrier coating for combustion turbine components, which enhanced the overall production capabilities of the combustion turbines. Subsequent RATA and GVTC testing was performed post-outage to validate the new capability and unit ratings. The individual unit characteristics of Sugar Creek are provided in Table 4-4.

Table 4-4: Sugar Creek

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	112	112	112
Max (MW)	175	175	228
Heat Recovery			
Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA.04	7FA.04	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

Calvary Solar + Storage is located in White County, Indiana, and was originally approved in Cause No. 45462 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Cavalry Energy Center, LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 45936 and went into commercial operation in May 2024. The individual unit characteristics of Cavalry are provided in Table 4-7.

Table 4-7: Cavalry Solar + Storage

	Cavalry
Solar Output	
Total Output (MW)	200
Storage Output	
Total Output (MW)	45
Output Period (Hrs.)	4
Discharge Limits (Cycles/Yr.)	100
In-Service	2024
Main Fuel	Solar + Storage

4.1.5 NIPSCO Wind and Solar Purchase Power Agreements and Joint Venture

NIPSCO is also engaged in a 20-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 is located in Benton and Warren counties, Indiana, near Williamsport, Indiana, and went into commercial operation in December 2020. The individual unit characteristics of Jordan Creek are provided in Table 4-8.

Table 4-8: 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 4-9.

Table 4-9: 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

Indiana Crossroads, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana, and went into commercial operation in January 2021. The individual unit characteristics of Indiana Crossroads are provided in Table 4-10.

Table 4-10: Indiana Crossroads Wind I JV

Indiana Crossroads Wind JV	
Net Output	
Per Unit (MW)	4.2
Number of Units	72
Total Output (MW)	300
In-Service	2021
Main Fuel	Wind

The Dunns Bridge I Solar project, developed and constructed by NextEra Energy Resources, LLC, is located in Jasper County, Indiana, and went into commercial operation in August 2023. The individual unit characteristics of Dunns Bridge I are provided in Table 4-11.

Table 4-11: Dunns Bridge I Solar JV

	Dunns Bridge I JV
Solar Output	
Total Output (MW)	265
In-Service	2023
Main Fuel	Solar

The Indiana Crossroads Solar project, developed and constructed by EDP Renewables North America, LLC, is located in White County, Indiana, and went into commercial operation in August 2023. The individual unit characteristics of Indiana Crossroads Solar are provided in Table 4-12.

Table 4-12: Indiana Crossroads Solar JV

	Indiana Crossroads Solar JV
Solar Output	
Total Output (MW)	200
In-Service	2023
Main Fuel	Solar

NIPSCO is engaged in 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, and went into commercial operation in December 2023. The individual unit characteristics of Indiana Crossroads II Wind are provided in Table 4-13.

Table 4-13: 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	

4.1.6 Total Resource Summary

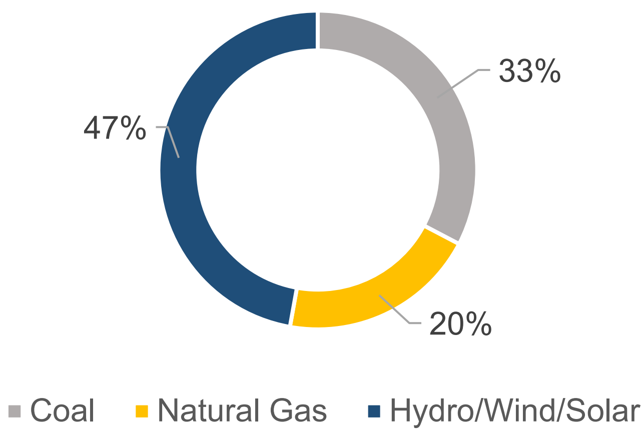
Table 4-14 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-1 illustrates NIPSCO's existing resources by fuel type.

Table 4-14: 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	578	2002
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind	Rosewater	Wind	100	2020
	Jordan Creek	Wind	400	2020
	Indiana Xrds I	Wind	300	2021
	Indiana Xrds II	Wind	200	2023
		Subtotal	1,000	
Solar + Storage	Dunns Bridge I	Solar	265	2023
	Indiana Xrds	Solar	200	2023
	Cavalry	Solar + Storage	245	2024
		Subtotal	710	
NIPSCO			3,644	

NG=Natural Gas

Figure 4-1: Existing Resources Net Demonstrated Capacity



4.2 Fuel, Energy, and Capacity Procurement Strategy for Existing Resources[63]

As NIPSCO operates as a public utility providing reliable 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 the requirements of 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 execute 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.

63 Due to the timing of the IRP, this section was written during the summer of 2024 and the market overview is based on the market conditions at that time. The IRP is an imperfect snapshot in time and changes in market conditions may occur. At the time of submission of the IRP, it is unknown how long current trends will continue. As always, NIPSCO will continue to monitor the markets and adjust procurement plans as necessary.

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.

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. In addition, the acceleration of coal unit retirements nationwide further 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. This became evident in early 2022 through mid-2023 as energy shortages in Europe cascaded through global markets. In addition, post-pandemic consumer demand recovery, increased energy demand, and railroad union labor disputes caused significant rail transportation disruptions domestically.

These factors led to a myriad of supply chain challenges globally and contributed to a spike in coal prices and related coal transportation rates as Europe increased coal imports and U.S. coal demand increased while supply reliability decreased. This has since reversed, and pricing has fallen back to pre-2022 levels. Going forward, several factors will likely limit the upside for coal prices in the long run. 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. Lastly, the competitiveness of natural gas generation and renewables will likely limit demand for coal.

Competition in energy markets has also driven a shift in coal supply regions over the last several years. 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 SO_2 limits and other emission standards. Some utilities in the Southeast are now using ILB coal, which 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 30 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 SO_2 emissions. U.S. coal exports have declined 1.6% annually over the last 10 years. India's demand for U.S. coal has grown on average by 20% annually over the same period offsetting declines in European demand.

In general, most export tonnage originates from Central Appalachian, ILB, 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, except for China and India, 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 are expected to remain relatively low and stable. NAPP coal and ILB coal market pricing spiked to record highs in 2022 but has fallen back to near historic lows and has been relatively flat. Pricing for PRB coal pricing spiked at the end of 2021, but also fell back to levels close the marginal cost of production and have remained relatively flat.

Domestic and international coal prices increased during 2021 as the economic recovery from the 2020 pandemic caused a surge in demand and prices spiked in 2022 due to the Ukraine-Russian conflict. 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 adjust inventory targets to account for changes in coal supply availability, transportation constraints, unit consumption, energy pricing, and to account for coal unit retirements. NIPSCO may modify target inventory levels on a unit-by-unit basis depending on the consumption, delivery rates, reliability of coal supply, station coal handling operations, and retirement plans. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates, variability in delivery performance, and higher energy market prices generally require higher levels of inventory to ensure reliability and minimize customer cost.

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 historical, current, and future coal supply requirements. All fuel procurement options are compared on a delivered cost basis, which includes a complete evaluation of all potential costs (e.g., operational, environmental, handling, etc.) and logistical considerations.

Coal deliveries 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 remained relatively flat over the last several years given the competition in the energy markets. Railroads have been willing to rationalize rail rates to remain competitive in the energy market. This pricing trend has kept NIPSCO's coal-fired generation competitive to a certain extent.

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 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 have declined in real terms 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 transportation 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 from 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 two years 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 2025. The planned projects have been filed with the Commission and are in various stages of development. The projects are summarized in Table 4-15.

Table 4-15: Planned Renewable Projects

Project	Technology	Expected ICAP (MW)	Battery Capacity (MW)	Expected In -Service
Carpenter	Wind	200	-	2025
Templeton	Wind	200	-	2027
Dunns Bridge II	Solar + Storage	435	56.25	2024
Green River	Solar	200	-	2024
Fairbanks	Solar	250	-	2025
Gibson	Solar	200	-	2025
Appleseed	Solar	200	-	2025
Total		1,685	56.25	

4.3.1 Planned Wind Resources

NIPSCO has entered into a 20-year PPA starting in 2025 with EDP Renewables North America, LLC, in which NIPSCO will purchase the power directly from Carpenter Wind, which will operate and maintain the facility. Carpenter Wind, located in Jasper County, Indiana, is expected to go into commercial operation by December 2025. The planned unit characteristics of Carpenter Wind are provided in Table 4-16.

Table 4-16: Carpenter Wind PPA

Carpenter Wind PPA		
Net Output		
Per Unit (MW)	4.5	4.3
Number of Units	33	12
Total Output (MW	148.5	51.6
In-Service	2025	
Main Fuel	Wind	

The Templeton wind project, currently under development by NextEra Energy Resources LLC, located in Benton County, Indiana, is expected to go into commercial operation in June 2027. It was originally contracted as a PPA with a 2025 in-service date and approved in Cause No. 45887 but has since been converted to a BTA. The individual unit characteristics of Templeton are provided in Table 4 17.

Table 4-17: Templeton Wind BTA

	Templeton Wind BTA
Net Output	
Per Unit (MW)	2.82
Number of Units	71
Total Output (MW)	200.22
In-Service	2027
Main Fuel	Wind

4.3.2 Planned Solar and Solar + Storage Resources

NIPSCO has five planned solar projects, one of which includes additional battery storage, that are expected to be in service by 2025.

Dunns Bridge II Solar + Storage is located in Jasper County, Indiana, and was originally approved in Cause No. 45462 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Dunn's Bridge II Solar and Storage Generation LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 45936 and will go into commercial operation in January 2025. The planned unit characteristics of Dunns Bridge II are provided in Table 4-18.

Table 4-18: Dunns Bridge II Solar + Storage

	Dunns Bridge II
Solar Output	
Total Output (MW)	435
Storage Output	
Total Output (MW)	56.25
Output Period (Hrs.)	4
Discharge Limits (Cycles/Yr.)	100
In-Service	2025
Main Fuel	Solar + Storage

NIPSCO has entered into a 20-year PPA starting in 2025 with NextEra Energy Resources, LLC, in which NIPSCO will purchase the power directly from Green River, which will operate and maintain the facility. Green River, located in Breckenridge and Meade counties, Kentucky, is expected to go into commercial operation by June 2025. The planned unit characteristics of Green River are provided in Table 4-19.

Table 4-19: Green River Solar PPA

	Green River PPA
Solar Output	
Total Output (MW)	200
In-Service	2025
Main Fuel	Solar

Fairbanks Solar is located in Sullivan County, Indiana, and was originally approved in Cause No. 45511 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Fairbanks Solar Generation, LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 46028 and will go into commercial operation in May 2025. The planned unit characteristics of Fairbanks are provided in Table 4-20.

Table 4-20: Fairbanks Solar

	Fairbanks Solar
Solar Output	
Total Output (MW)	250
In-Service	2025
Main Fuel	Solar

Gibson Solar is located in Gibson County, Indiana, and was originally approved in Cause No. 45926 as a BTA Energy Purchase Agreement or Contract for Differences between NIPSCO and Gibson Solar Generation, LLC. It was modified and approved as a NIPSCO wholly owned structure in Cause No. 46032 and will go into commercial operation in July 2025. The planned unit characteristics of Gibson are provided in Table 4-21.

Table 4-21: Gibson Solar

	Gibson Solar
Solar Output	
Total Output (MW)	200
In-Service	2025
Main Fuel	Solar

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 Appleseed, which will operate and maintain the facility. Appleseed, located in Cass County, Indiana, is expected to go into commercial operation by December 2025. The planned unit characteristics of Appleseed are provided in Table 4-22.

Table 4-22: Appleseed Solar PPA

	Appleseed Solar PPA
Solar Output	
Total Output (MW)	200
In-Service	2025
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 2023, MISO has members from 15 states and one Canadian province with a generation capacity of 191,000 MW and 75,000 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

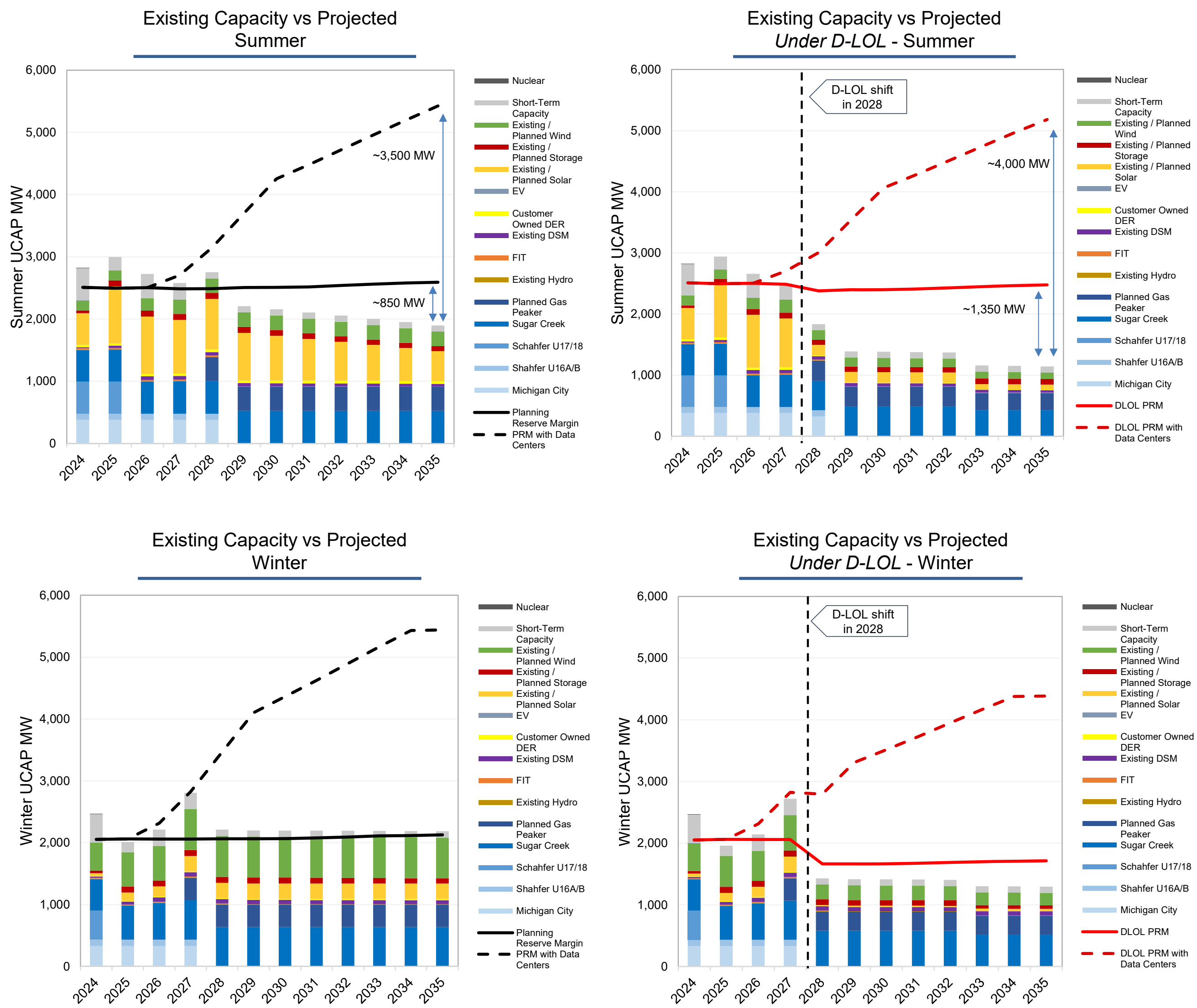
The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, 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 MISO peak demand to determine its capacity requirements across each of the four MISO planning seasons. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks.

With the onset of MISO's seasonal resource adequacy construct, NIPSCO now needs to track reserve margin compliance across four seasons. In addition, as renewable resources become a greater share of the broader MISO market system, the seasonal capacity credit will likely change over time and will need to be monitored, particularly in light of MISO's recent D-LOL filing, which proposes a new methodology for resource accreditation and load serving entity obligations. (See Section 2 for more information related to MISO's D-LOL filing, which FERC approved in October 2024.) NIPSCO's assessment of its existing and planned resources against the future needs of its customers for both the summer and winter seasons under current market rules expectations and the new D-LOL construct is shown in Figure 4-2. Note that NIPSCO's 2024 IRP is assessing all four seasons, but summer and winter are shown for simplicity.

Figure 4-2: Resource Adequacy Assessment



4.6 Future Resource Options

NIPSCO developed cost, operational, and availability assumptions for a comprehensive set of new resource options using information from actual market data received via Requests for Proposal, internal engineering analysis and project experience, and third-party data sources, along with the demand side management study documented further in Section 5. A summary of all resource options, their assumed availability, and their source of key cost and operational assumptions is provided in Figure 4-3, with the remainder of this section providing additional supporting detail.

Figure 4-3: Overview of New Resource Options

	Resource Option	Available through 2030	Available 2031-2034	Available 2035+
	Demand side management (EE and DR) programs	From MPS and DSM Study		
Resources offered in the RFP	Solar	From RFP Data	Benchmarked to RFP Data plus Third-Party Data Sources for the Long-Term	
	Li-Ion Battery Storage			
	Long Duration Storage			
	Solar + Storage Hybrid			
	Near-Term Thermal Options			
	Near-Term Capacity Purchases (ZRCs)			
	New Natural Gas Peaking Build (H2-enabled up to 30%)	From NIPSCO Internal Engineering Analysis and Project Experience		
	New Gas CC Build (H2- enabled up to 30%)			
	Wind		Benchmarked to NIPSCO Project Experience	
	New Gas CC with CCS		From NIPSCO and Third-Party Data Sources	
	New Gas with H2			
	CCS Retrofit (at Sugar Creek)			From NIPSCO and Third-Party Data Sources
	H2 Retrofit (at Sugar Creek)			
	Small modular reactor (SMR)			

4.6.1 Request for Proposal

As demonstrated in the 2024 IRP, the cost and operational estimates for future resource options modeled in the IRP should reflect the best available market data. In 2024, NIPSCO worked with CRA's Energy practice during the spring and early summer of 2024 to conduct four separate RFP events covering all sources. NIPSCO provided the RFP design summary to stakeholders on April 23, 2024, and solicited feedback. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the RFP events on May 1, 2024. The bid windows were RFP-specific, but all were closed by June 20, 2024. During NIPSCO's second Public Advisory meeting on June 24, 2024, CRA reviewed for stakeholders the RFP design and timeline and presented a preliminary assessment of the level of interest in the set of RFP.

The RFPs provided several guidelines to bidders, which are summarized below:

- <u>Technology</u>: The RFPs requested all solutions regardless of technology.
    - Event 1: RFP for intermittent resources including renewables and renewable paired with storage, located in LRZ6;
    - Event 2: non-intermittent resource RFP for LRZ6 resources;
    - Event 3: RFP for Bridge Resources including facilities offering near-term energy and capacity options located in LRZ6 or the broader MISO region; and
    - Event 4: RFP for up to 10 MW of Distributed Energy Resources.

- Size: Each solicitation included an estimate of the overall need, 400 MW, 600 MW, 1,000 MW, and 10 MW for RFPs 1 through 4, respectively. There were no specific size restrictions on individual projects or restrictions at the bidder levels.

- 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: Aside from RFP 3, Bridge Resources, the RFPs requested delivery beginning in 2027, 2028, and 2029, but indicated that alternative deliveries would be evaluated. The minimum contractual term and/or estimated useful life was requested to be five years. For RFP 3, NIPSCO was targeting resources available within 18-36 months and would consider durations as short as three years.

- Deliverability: For the All-Source RFP (RPF 1 and RFP 2), NIPSCO required that bidders have physical deliverability utilizing Network Resource Integration Service to MISO LRZ6. RFP 3 allowed for resources within the broader MISO region. RFP 4, for DER resources, considered distribution interconnected options.

- 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 116 total proposals received across a range of deal structures. Within those 116 proposals, NIPSCO received bids for 58 individual projects across five states/regions with over 9.63 GW of ICAP represented.[64] 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

Deal Structure	Solar	Solar + Storage	Standalone Storage	Thermal/ Other	ZRC	Wind	Total
Asset Sale	1	2	12	2	-	-	17
PPA/Toll	20	12	26	6	7	-	71
Asset Sale + PPA/Toll	1; 1	4; 4	9; 9	-	-	-	14 (28)
Total Count	23	22	56	8	7	-	116*
Locations	IN, KY	IN, KY	IN, KY	IN, PA	LRZ4, PJM	-	

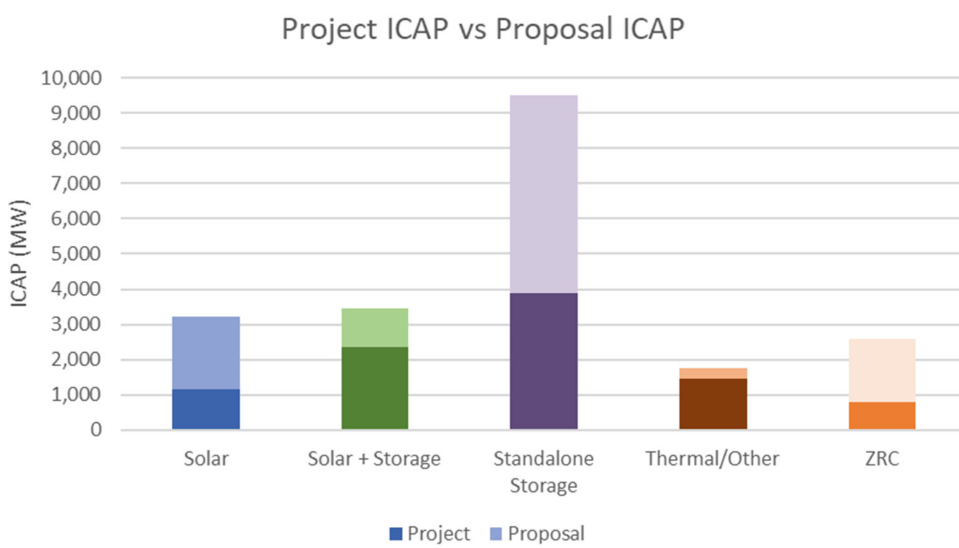
**Proposal count includes mutually exclusive projects. Projects offered as both Asset Sale and PPA/Toll are counted in the total as two proposals.*

On a total MW basis, 20.53 GW of proposals were submitted into the RFP, some of which were mutually exclusive. The 20.53 GW value represents multiple contract options for 58 projects with a total ICAP of 9.63 GW, providing a sufficiently large set of candidate options for NIPSCO to evaluate for capacity needs during the RFP delivery window. Because MISO is moving to a

64 CRA received a bid package from one bidder following the formal bid deadline. This bid included 3 proposals for 2 separate storage facility options.

seasonal construct for capacity credit, the UCAP value of each bid is dependent on the type of facility and MISO's final seasonal capacity metrics. 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)

Proposal MW ICAP by PPA Term Length (PPA or Both) and Technology

Term (Years)	Solar	Solar + Storage	Standalone Storage	Thermal/Other	ZRC	Wind	Total (MW)
1	-	-	-	-	800	-	800
2	-	-	-	150	800	-	950
3	-	-	-	-	800	-	800
4	-	-	-	-	200	-	200
5	-	-	-	450	-	-	450
6-15	201	300	796	-	-	-	1,297
>15	2,690	2,158	4,726	1,050	-	-	10,624
Total	2,891	2,458	5,522	1,650	2,600	-	**15,121**

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 RFPs 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. NIPSCO provided a summary of the various proposals by type and by price in NIPSCO's second Public Advisory meeting, with additional detail on bid price offered in Section 4.6.2 of this 2024 IRP report.

4.6.1.1 Storage at NIPSCO Sites in the RFP

As part of the All-Source RFP (RFP 1 and RFP 2), the Company requested support for potential development of storage resources located at existing NIPSCO renewable sites. Current, high-priority sites include Schahfer, Michigan City, Dunns Bridge I and II, Cavalry, Gibson, and Fairbanks. Through the RFP, NIPSCO provided interested developers available information to support potential development. NIPSCO anticipates using generator replacement at Schahfer and Michigan City associated with storage development. As a result, both would require NIPSCO asset ownership of storage assets, although ownership structures other than a BTA were considered acceptable. For other sites, NIPSCO intends to use surplus interconnection service and while not technically required, NIPSCO expressed a strong preference for ownership bids.

The RFP generated proposals from seven (7) bidders for development options related to storage at NIPSCO renewable sites. Eleven (11) facilities representing 1,512 MW were submitted for consideration.

4.6.1.2 Long-Duration Storage in the RFP

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.

NIPSCO received long-duration storage bids from three participating bidders. All submissions were for asset sales and based on the following technologies:

- **Iron-Air storage** is a technology that promises multi-day energy storage capability. Proposals stated the potential for up to 100 hours of storage based on reversible oxidation principles. The principle of operation is static, reversible rusting. Each cell consists of iron anodes and air cathodes submerged in water-based, non-flammable alkaline electrolyte. While discharging, the battery converts iron metal to rust using oxygen from ambient air. While charging, an electrical current converts the rust back to iron, releasing oxygen.

- **Compressed CO2** technology involves the compression of gaseous CO2, which heats it. Passing it through a heat exchanger and a thermal store cools the supercritical carbon dioxide gas enough to liquify it. The liquid CO2 can be stored in this state indefinitely in pressurized cylinders. When energy is required, the CO2 is passed back through the heat exchanger, where it is warmed by recovering heat from the heatstore and reverts to high-pressure gas. The gas is used to drive a turbine to generate electricity as it passes back into the low-pressure store, completing the closed cycle.

4.6.2 Incorporation of the RFP Results into the IRP

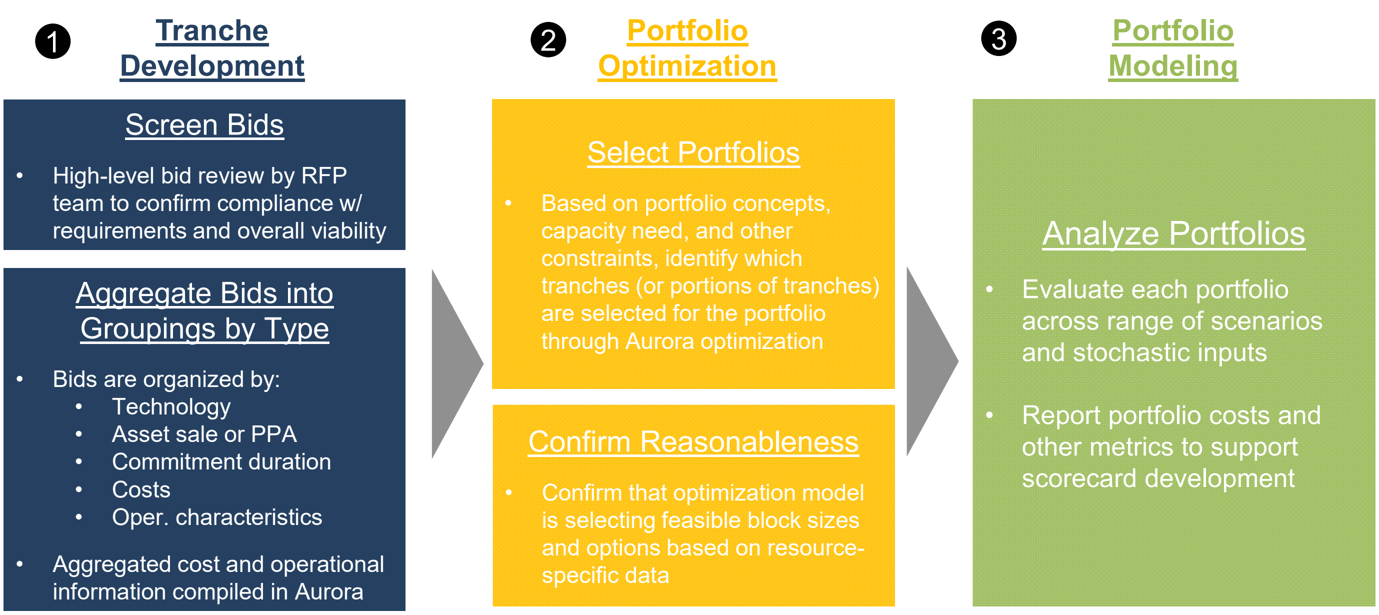
After gathering the bidder data from the RFP, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for RFP-IRP integration, which is outlined in Figure 4-7:

(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 (as discussed in more detail in Section 9), confirming option viability based on feasible block sizes of tranche data from the RFPs.

(3) Portfolio Modeling: Analyze comprehensive portfolios with selected tranches from the portfolio optimization step and other resource options and analyze them across the full set of scenarios and stochastic inputs.

Figure 4-7: Tranche Development and Assessment Process



4.6.2.1 Tranche Development

It was determined that a tranche approach would be most effective in aggregating the numerous data points from the RFPs into usable 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 nonconforming 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 29 total tranches. These are summarized by resource type Figure 4-8, Figure 4-9, Figure 4-10, and Figure 4-11. Note that in instances where single bids were used to develop tranche-level cost information, redactions have been made for the public version of this report.

Figure 4-8: Summary of Stand-Alone Storage RFP Tranches

	Installed Capacity (MW)	In-Service Year[1]	Storage Duration (Hours)	Round Trip Efficiency	PPA Price ($/kW-mo)	PPA Term (Years)	Asset Sale Price ($/kW)	ITC Assumption	Fixed O&M (2024 $/kW-yr)2
Storage PPA 1	768	2028	4	85%	$11.99	20	*N/A*	*N/A*	*N/A*
Storage PPA 2	200	2028	4	85%	$14.95	20	*N/A*	*N/A*	*N/A*
Storage PPA 3	261	2027	4	85%	$15.59	20	*N/A*	*N/A*	*N/A*
Storage PPA 4	166	2029	4	85%	$16.85	20	*N/A*	*N/A*	*N/A*
Storage Sale 1	1,750	2028	4	85%	*N/A*	*N/A*	$1,534	40%	$40
Storage Sale 2	900	2028	4	85%	*N/A*	*N/A*	$2,144	40%	$40
Storage Sale 3	18	2027	10	75%	*N/A*	*N/A*	***Redacted – single bid / tech data***	40%	***Redacted – single bid / tech data***
Storage Sale 4	100	2028	100	35%	*N/A*	*N/A*		40%	
DER Storage PPA	10	2027	4	85%	***Redacted – single bid***	20	*N/A*	*N/A*	*N/A*

Notes:
Each tranche listed represents a group of mutually exclusive projects, and certain cost data has been redacted, since it was developed from single RFP bids.
1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.
2: Baseline assumptions from NREL ATB used for tranche modeling purposes.

Figure 4-9: Summary of Solar RFP Tranches

	Installed Capacity (MW)	In-Service Year[1]	PPA Price ($/MWh)	PPA Term (Years)	Asset Sale Price ($/kW)	ITC Assumption	Fixed O&M (2024 $/kW-yr)[2]
Solar PPA 1	425	2028	$68.75	20	*N/A*	*N/A*	*N/A*
Solar PPA 2	325	2027	$69.42	20	*N/A*	*N/A*	*N/A*
Solar PPA 3	201	2028	***Redacted – single bid***	15	*N/A*	*N/A*	*N/A*
Solar PPA 4	200	2028	$75.45	25	*N/A*	*N/A*	*N/A*
Solar Sale 1	130	2027	*N/A*	*N/A*	$2,096	40%	$23
Solar Sale 2	200	2029	*N/A*	*N/A*	$2,350	40%	$23
DER Solar PPA 1	10	2028	***Redacted – single bid***	20	*N/A*	*N/A*	*N/A*

Notes:
Each tranche listed represents a group of mutually exclusive projects, and certain cost data has been redacted, since it was developed from single RFP bids.
1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.
2: Baseline assumptions from NREL ATB used for tranche modeling purposes.

Figure 4-10: Summary of Solar+Storage Hybrid RFP Tranches

	Installed Solar Capacity (MW)	Installed Storage Capacity (MW)	Storage Duration (Hours)	In-Service Year[1]	PPA Price ($/MWh)	PPA Price ($/kW-yr)	PPA Term (Years)[2]	Asset Sale Price ($/kW)[3]	ITC Assumption	Fixed O&M (2024 $ /kW-yr)[4]
Hybrid PPA 1	453	250	4	2028	$64.33	$10.94	20	N/A	N/A	N/A
Hybrid PPA 2	300	225	4	2027	$64.96	$11.26	20	N/A	N/A	N/A
Hybrid PPA 3	250	125	4	2028	$72.58	$13.13	20	N/A	N/A	N/A
Hybrid PPA 4	200	100	4	2027	$81.49	$12.05	25	N/A	N/A	N/A
Hybrid Sale 1	164	164	4	2027	N/A	N/A	N/A	$1,944	40%	$35
Hybrid Sale 2	300	125	4	2028	N/A	N/A	N/A	$2,007	40%	$30
Hybrid Sale 3	343	171	4	2028	N/A	N/A	N/A	$2,538	40%	$31

Notes:
Each tranche listed represents a group of mutually exclusive projects, and certain cost data has been redacted, since it was developed from single RFP bids.
1: In-service years are generally anchored to the latest online date for resources within the tranche, which may be in the middle of the reported calendar year.
2: For modeling purposes, the shortest PPA term in the tranche was used even though the Hybrid PPA 2 and Hybrid PPA 3 tranches have bids varying between 20 and 25 years.
3: Note that asset sale price is based on the total installed capacity (solar + storage) of the tranche.
4: Assumptions from NREL ATB used for tranche modeling purposes, weighted by solar:storage ratio within the tranche.

Figure 4-11: Summary of Thermal and ZRC RFP Tranches

	Installed Capacity (MW)	In-Service Year[1]	Comments	PPA Term (Years)
Thermal PPA 1	600	2028	New Gas CC	20
Thermal PPA 2-4	150	2026	Various contractual options (heat rate call or blocks)	5
Thermal PPA 5	150	2027	Coal-based energy and capacity	2
Thermal Sale 1	18	2027	Existing gas peaker	N/A
ZRC 1-4	200	2025/26 – 2029/30	PJM external resource delivered to MISO border	Multiple options
ZRC 5-7	600	2025/26 – 2026/27	LRZ 4 delivery	Multiple options

Notes:
Each tranche listed represents a group of mutually exclusive projects. Cost data is not provided, given the fact that these tranches align to individual bids.
1: In-service year may be in the middle of the reported year.

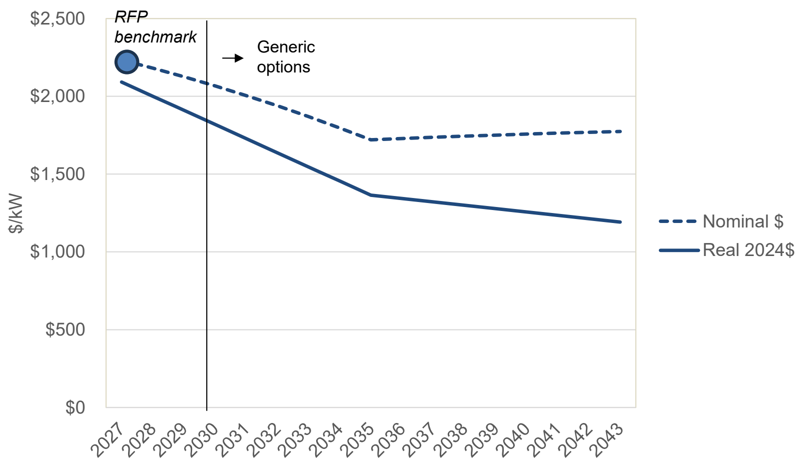
4.6.3 Longer-Term New Resource Assumptions – Mature Technologies

Beyond the RFP period, NIPSCO used a combination of RFP data, recent project experience, and third-party sources to develop cost and operational assumptions for well-established technologies like solar, short-duration storage, wind, and natural gas-fired peaking and combined cycle technologies.

4.6.3.1 Solar, Wind, and Four-Hour Lithium-Ion Storage

For solar, wind, and four-hour lithium-ion storage resource assumptions over the long term, NIPSCO benchmarked cost data to RFP results or recent project experience[65] and applied technology learning curves using the "moderate" decline rate from NREL's Annual Technology Baseline report. The capital cost projections and assumed fixed operations and maintenance costs for these three technologies are summarized in Figure 4-12, Figure 4-13, and Figure 4-14.

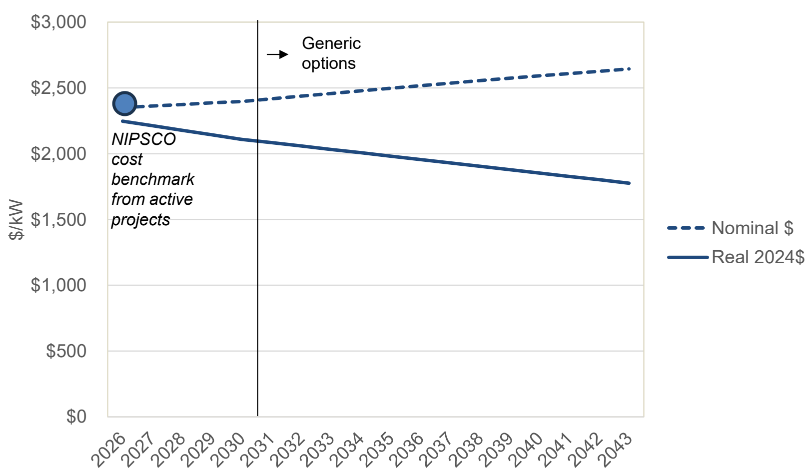
Figure 4-12: Long-Term Solar Cost Assumptions



Category	Assumption
Fixed O&M (2024$/kW-yr)*	$22
Capacity Factor	25%
Tax Credit Eligibility Assumption	40% ITC

**NREL ATB assumptions for 2027 benchmark year*

Figure 4-13: Long-Term Wind Cost Assumptions

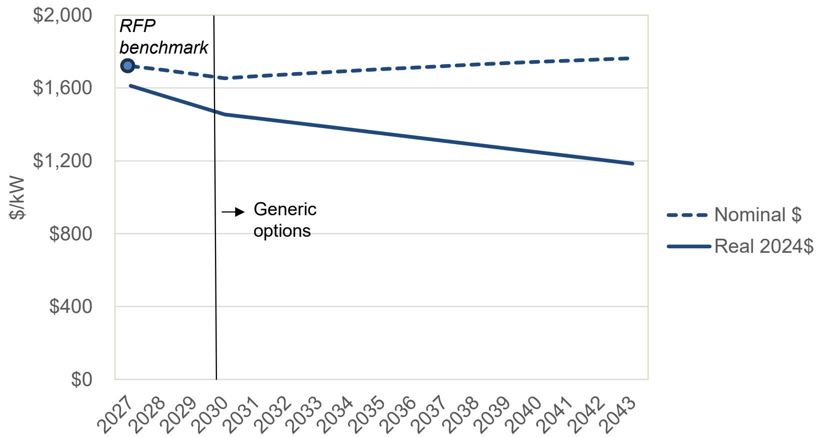


Category	Assumption
Fixed O&M (2024$/kW-yr)*	$34
Capacity Factor	39%
Tax Credit Eligibility Assumption	PTC

**NREL ATB assumptions for 2026 benchmark year*

65 Note that no wind resources offered into the RFP, so NIPSCO's cost benchmarking data relied upon information from NIPSCO projects currently under development.

Figure 4-14: Long-Term Four-Hour Lithium-Ion Storage Cost Assumptions



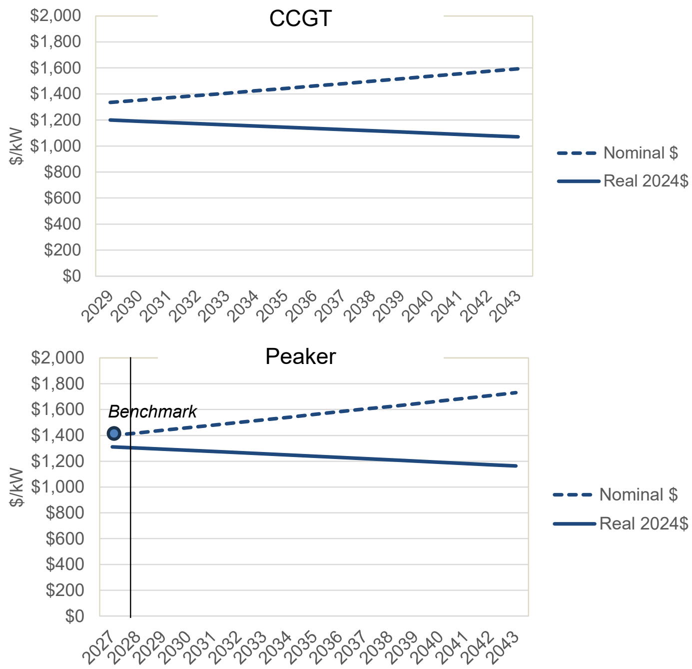
Category	Assumption
Fixed O&M (2024$/kW-yr)*	$40
Round Trip Efficiency	85%
Tax Credit Eligibility Assumption	40% ITC

**NREL ATB assumptions for 2027 benchmark year*

4.6.3.2 Natural Peaking and Combined Cycle

For new natural gas resource options, NIPSCO relied on internal engineering analysis and recent cost benchmarks for its recently proposed natural gas peaking project and applied technology learning curves using the "moderate" decline rate from NREL's Annual Technology Baseline report. In 2024 dollars, a new peaking resource was estimated at $1,284/kW based on NIPSCO's ongoing actual project experience. For new CCGTs, NIPSCO built the total "inside the fence" costs based on a high-level estimate provided by an external engineering consulting firm, based on 2 x 1 configurations in increments of 650 MW or 1,300 MW. Then for other costs, including electric interconnection, gas interconnections, water interconnection, owner's cost, and project contingency, NIPSCO escalated costs from an earlier IRP study at the historical inflation rate and projected inflation rate assumptions. This led to a total a total cost of $1,225/kW in 2024 dollars. The capital cost projections and assumed fixed operations and maintenance costs are summarized in Figure 4-15.

Figure 4-15: Long-Term Natural Gas Resource Option Cost Assumptions



Category	Peaker	CCGT
Fixed O&M (2024$/kW-yr)*	$24	$37
First Available Year	2028	2029

**NREL ATB assumptions for appropriate benchmark years*

4.6.4 Emerging Technologies – Hydrogen

The 2024 IRP incorporates the potential for significant system load growth, and NIPSCO recognizes that new, emerging technologies will be needed to achieve emission reduction levels that aim toward a net zero target. One such technology is the use of hydrogen as an alternative fuel to natural gas. 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, emerging investment across the energy value chain, federal encouragement, and significant tax credit opportunities may make the technology viable over the mid- to long term.

For the 2024 IRP, NIPSCO considered hydrogen as a possible resource option and developed cost inputs based largely on independent research and analysis. The remainder of this section provides additional context around hydrogen production and a discussion of NIPSCO's key input assumptions.

4.6.4.1 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). In addition, as electrolyzer and renewable prices become more competitive, and as federal tax credits offer significant subsidies for the production of clean hydrogen, the use of renewable energy to power the process of water electrolysis to produce “green” hydrogen may also become viable. 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 hydrogen tax credit, expectations for significant improvements in system cost components, continued market evolution toward increased renewable penetration, technology advancement associated with carbon capture and storage, and potential future carbon regulation may make green and blue hydrogen production more attractive in the long term.

4.6.4.2 Hydrogen Production Constructs

While clean 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 for the 2024 IRP. NIPSCO considered several hypothetical hydrogen deployment models, as summarized in Figure 4-16.

Figure 4-16: 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="4">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>Third Party
Modeled as a PPA cost for green H2 (inclusive of all production costs)</td><td>Third Party</td></tr>
</table>

The “islanded” model assumes 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. 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.

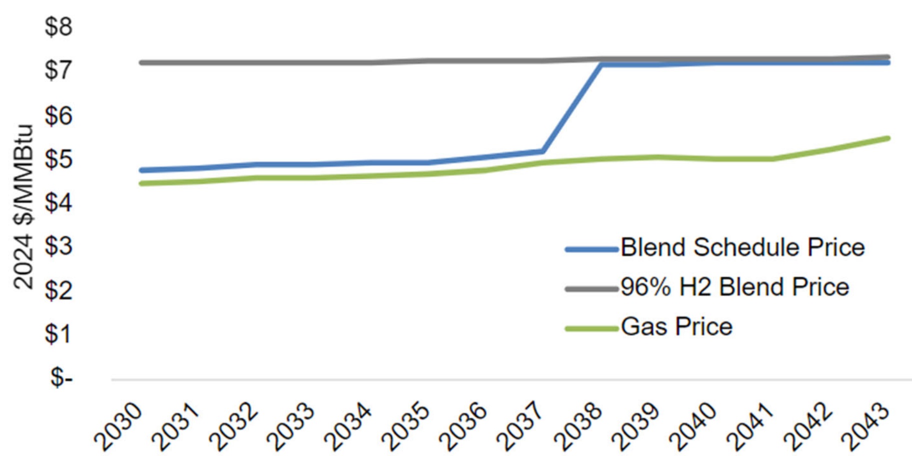
4.6.4.3 Hydrogen Modeling Input Assumptions Development

For modelling of hydrogen, NIPSCO assumed an all-in hydrogen cost of $30/MMBtu or approximately $4/kg in real 2024$ throughout the 2024 IRP's study period. The price assumption was based on a number of public sources, most notably Lazard's Levelized Cost of Hydrogen buildup[66] and The International Energy Agency's Hydrogen pricing map by region.[67]

For modeling purposes, NIPSCO anticipates the availability of green hydrogen in 2030 and beyond, allowing for Hydrogen Production Tax Credits (see Section 4.6.10 for additional detail on the Section 45V tax credits) to be earned. The green hydrogen credit of $3/kg is approximately worth $22.5/MMBtu, which translates to a net hydrogen price of $7.25-$7.5/MMBtu in real 2024$.

For modeling purposes, NIPSCO has assumed a 96% hydrogen blend by volume for new hydrogen-enabled resources and a potential blend schedule of 30% by volume until 2038 for NIPSCO's existing Sugar Creek facility. The resulting fuel prices per MMBtu for these two hydrogen blends and natural gas under the Reference Case are summarized in Figure 4-17.

Figure 4-17: Annual Hydrogen Fuel Price Assumptions



4.6.4.4 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. 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% to 20%) have been used in gas turbine technologies today, a plant can be upgraded to accommodate higher hydrogen blend concentrations as emissions restrictions

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66 Lazard, "Lazard's Levelized Cost of Hydrogen Analysis", 2021. https://www.lazard.com/media/12qcxl1j/lazards-levelized-cost-of-hydrogen-analysis-vf.pdf

67 International Energy Agency, "Levelized Cost of Hydrogen Maps", 2023. https://www.iea.org/data-and-statistics/data-tools/levelised-cost-of-hydrogen-maps

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 from past RFPs and information gathered from Original Equipment Manufacturers to project the costs required to achieve very high levels of blending (including up to 96% hydrogen by volume) over the long term. Thermal plants retrofitted or built to accommodate pure or close to 100% hydrogen were assumed to require approximately 30% of the original plant capex and operating costs, or about $400/kW in real 2024$.

4.6.4.5 Regional Hydrogen Projects

As a part of the U.S. Department of Energy's Hydrogen Hub Initiative, which is allocating $8 billion in federal funding to establish regional hydrogen hubs in the U.S., NIPSCO will likely be poised to access green and blue hydrogen supply from the MachH2 Hydrogen Hub located across Midwest states and including NIPSCOs service territory. The MachH2 hub has been awarded up to $1 billion in funding from the DOE for hydrogen projects and incorporates over 70 partners across various industries, with the expectation of creating 13,600 direct jobs.[68]

The MachH2 hub plans to incorporate at least two primary hydrogen production projects that will supply offtake to Indiana and Illinois. The first is located at BP's Whiting Refinery and plans to produce at least 200,000 tons per year of blue hydrogen beginning in 2031, with increases in production volume in later years.[69] BP has announced an investment of at least $4 billion into the project, which will begin construction in 2025.[70] Although a significant portion of this hydrogen will likely serve as captive supply for BP's refinery, it also poses a significant low-carbon hydrogen offtake opportunity for NIPSCO.

In addition to the BP Whiting Refinery, Constellation Energy has announced a low-carbon hydrogen project at its La Salle nuclear facility in Marseilles, Illinois that is also part of the MachH2 hydrogen hub. This project will produce an estimated 33,450 tons of hydrogen per year[71] for supply to the region and would be the largest nuclear-powered clean hydrogen facility upon completion in the early 2030s.

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68 Argonne National Laboratory, 2023.

69 Reuters, 2022

70 Northwest Indiana Times, 2024

71 Power Magazine - "Constellation Planning Significant Nuclear-Powered Hydrogen Facility at LaSalle"

4.6.5 Emerging Technologies – Renewable Natural Gas

Another potential emerging technology that could be deployed in NIPSCO's existing or future natural gas-fired power plants is RNG. RNG can be burned directly in the combustion chamber of gas turbines as a replacement for conventional natural gas. Since RNG is derived from organic waste and has the potential to be carbon-negative, its use in combined cycle gas turbines can significantly reduce greenhouse gas emissions from power generation.

Several primary production methods of RNG exist, including: (1) anaerobic digestion, which breaks down organic matter (agricultural waste, food waste, or manure) in the absence of oxygen to produce biogas as a feedstock for RNG; (2) landfill gas recovery, or the capturing of methane produced from decomposing organic waste in landfills; (3) gasification, which converts biomass into syngas through high-temperature processes, which can then be converted to RNG; and (4) pyrolysis, or the decomposition of organic material at high temperatures in the absence of oxygen. Currently, landfill recovery gas is often one of the more cost-effective methods due to its reliance on existing infrastructure rather than additional capital investment. A number of RNG production projects currently exist in Indiana, with Amp Americas operating the largest dairy RNG production facility in the U.S. in Jasper County.[72] Further, Kinder Morgan operates three RNG facilities in Wyatt and Monticello, Indiana,[73] which may be leveraged for offtake and use as a decarbonization fuel.

4.6.6 Emerging Technologies – 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. 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 NIPSCO for new or existing natural gas capacity. The remainder of this section provides an overview of the technology, potential cost ranges, and federal policy support considerations.

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72 DMT Clear Gas Solution

73 Kinder Morgan

4.6.6.1 CCUS Technology Overview

The CCUS value chain comprises three segments: capture, transport, and end-use, which includes both storage and utilization.

Capture

Point-source capture methods include post-combustion, pre-combustion, and oxy-combustion. These technologies are used across various industries such as ammonia production, coal and natural gas power generation, cement manufacturing, chemical and refining processes, ethanol production, hydrogen production, iron and steel manufacturing, natural gas processing, and pulp and paper production.

Post-combustion capture extracts CO2 from flue gas, syngas, or process streams after fuel combustion. In this process, chemical solvents (typically amines) absorb CO2 from the flue gas. The CO2-rich solution is then heated in a stripping column to release the CO2, which is compressed for transport and storage, while the solvent is reused.[74] These systems can be deployed at large scales and are well-suited for retrofitting existing facilities.

Pre-combustion methods, including gasification and pyrolysis, provide alternative CO2 capture approaches. In gasification, the fuel undergoes controlled partial oxidation in a gasifier, generating syngas consisting of H2, CO, and trace gases. A subsequent step in a water-gas-shift reactor converts CO to CO2 and enhances the concentrations of H2 and CO2 in the gas stream. Due to the high partial pressure of CO2 in syngas compared to flue gas, it becomes feasible to separate CO2 using various technologies, yielding nearly pure hydrogen fuel. Similarly, pyrolysis heats methane in the absence of oxygen until it separates into solid carbon and hydrogen gas. Although less technologically developed, pre-combustion methods may prove to be more commercially cost-effective relative to post-combustion approaches, as they require treatment of a smaller gas volume to achieve equivalent carbon capture quantities.

In the oxy-combustion approach, coal is burned in an enriched oxygen environment rather than air, which results in combustion products of CO2 and water.[75] The water can be condensed, leaving the CO2 ready for capture. Oxy-combustion lowers NOx and mercury emissions relative to conventional combustion, but its requirement of high-purity oxygen increases operational costs.

Transport

Once CO2 is captured, the next step is compression and transportation to suitable end-use sites. In the U.S., a relatively small network of around 5,000 miles of CO2 pipelines already exists in certain regions, developed primarily for other industries such as EOR.

While other transportation methods such as rail, truck, and ship are available, they generally prove to be significantly more expensive and are typically reserved for specific applications where pipeline transport is not feasible. Expanding the current pipeline network will

74 NETL – "Carbon Dioxide Capture Approaches"

75 Ibid

be a critical enabler for the scaling of CCUS, although permitting, environmental concerns, and community opposition pose significant threats as well.

End-Use

After transportation, captured carbon can either be stored or utilized. Storage methods for captured CO2 include saline aquifers, depleted oil and gas reservoirs, EOR reservoirs, and mineralization in geological structures. 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.[76]

With estimated storage capacities ranging from 2,400 to 21,000 billion tons, these methods can accommodate captured CO2 for hundreds to thousands of years. In the U.S., the DOE's CarbonSAFE initiative has been pivotal in advancing site development for CO2 storage. Currently, ten sites with at least 50 million tons of storage have undergone feasibility or characterization studies in addition to 300 million tons across 11 sites identified by other developers.

CO2 utilization involves converting captured carbon into commercial products, reducing emissions while creating value-added materials. Although currently smaller in scale compared to storage, demand for CO2 utilization is anticipated to grow substantially over the next 30 years. North America's demand is projected to reach approximately 40 MTPA by 2030 and 100 to 250 MTPA by 2050.[77] One utilization case for CO2 is in building materials, where it can be used in the production of cement or aggregates. In the plastics and chemicals industries, CO2-derived PEC and PPC are used to make polyurethane plastics. Additionally, CO2 can be converted into syngas via co-electrolysis for fuel synthesis.

4.6.6.2 Current Operational Landscape

As of the end of 2023, the Global CCS Institute recorded a dynamic global landscape with 41 operating CCS projects and an additional 351 projects in various stages of development.[78] This includes 11 new facilities in operation and 15 projects starting construction within the year. Collective global capture capacity across projects from operational to early development stages is approximately 361 MTPA of CO2.

In the U.S. and Canada, CCUS is gaining momentum across various industries. Currently, the ethanol sector supports the most CCUS facilities, followed closely by CO2 transport and storage infrastructure.[79] There are 21 operational CCUS facilities in the region, with nine under

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76 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/

77 DOE – "Pathways to Commercial Liftoff: Carbon Management"

78 Global CCS Institute – "Global Status of CCS 2023"

79 Ibid

construction, 80 in advanced development stages, and 92 in early development phases.[80] Current CCUS capacity in the U.S. exceeds 20 MTPA, although modeling indicates that achieving U.S. energy transition goals will necessitate the annual capture and storage of 400 to 1,800 MT of CO2 by 2050.[81]

4.6.6.3 Demonstration Projects

Carbon capture technologies vary in TRLs from 3 to 9. Established pre- and post-combustion methods are commercially available, with TRLs of 8 to 9, while oxy-fuel capture is at TRL 7. Storage technologies such as enhanced oil recovery and saline aquifers are also at TRLs of 8 to 9, indicating commercial readiness. Some current projects aim to convince the market of the viability of established technologies, while others are testing new carbon management configurations.[82] The following examples illustrate CCUS projects in both operational and developmental stages.

The $1 billion Petra Nova project, located at the 240 MW W.A. Parish Generating Station in Thompsons, Texas, captures CO2 using an amine-based solvent and transports it via pipeline to an enhanced oil recovery site near Houston. After operating from 2017 to 2020, the project was halted due to low oil prices but resumed operations in September 2023.[83] Capturing 90% of the plant's carbon emissions and possessing 1.4 MTPA of sequestration capacity, it is a prime example of large-scale commercial CCUS.

The Air Products and Chemicals Louisiana Clean Energy Complex, currently under construction, aims to produce over 750 million standard cubic feet of blue hydrogen daily and sequester more than five MTPA of CO2, with operations slated to begin in 2026. This project, which incorporates a CCUS unit at a natural gas gasification plant, highlights the critical role of existing infrastructure in determining project feasibility given its proximity to existing hydrogen pipelines.[84] However, it faces significant local opposition due to concerns about carbon storage under Lake Maurepas, a site used for fishing and recreation. Fears of potential construction impacts and leakage have sparked community efforts to halt the project, emphasizing the need for early and effective community engagement in new developments.

Clean Energy Systems is developing the Mendota BECCS facility, which is designed to capture 0.3 MTPA of CO2 while generating electricity for the grid.[85] Set to commence commercial operations in 2025, the facility will generate significant community benefits, including enhanced air quality from utilizing 200,000 tons of local agricultural waste and an increase in tax revenue.

80 DOE – "Pathways to Commercial Liftoff: Carbon Management"

81 Ibid

82 Global CCS Institute – "Global Status of CCS 2023"

83 Power Engineering – "Groundbreaking Petra Nova CCS project back up and running, owner says"

84 Air Products – "Louisiana Clean Energy Complex"

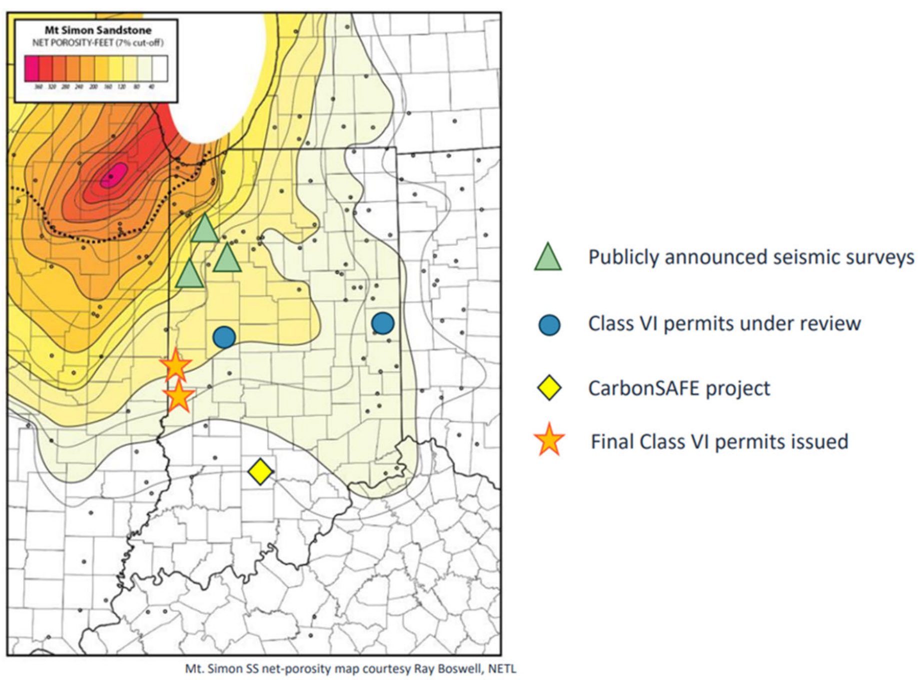
85 Clean Energy Systems – "Mendota Biomass Carbon Removal and Storage Project (BiCRS)"

This project exemplifies ongoing progress in unlocking the significant environmental benefits afforded by CDR technologies.

4.6.6.4 Local CCUS Feasibility

In addition to the previously described demonstration projects, several local CCUS projects are in advanced stages of development local to NIPSCO's service territory. The Wabash CarbonSAFE project was one of only six projects awarded for Phase II work by the US Department of Energy and will establish the feasibility of developing a carbon storage complex near Mitchell, Indiana, and may be operational as early as 2029. The project takes advantage of the Indiana region's favorable geological storage capacity for carbon dioxide, which is among the most significant in the continental United States.[86] In addition to the CarbonSAFE project, Wabash Carbon Services has been advancing several CCUS projects in proximity to NIPSCO's Sugar Creek facility in Vigo County, Indiana. The EPA issued final Class VI permits on these wells, which began construction in January 2024 and are anticipated to be able to sequester 1.67 million metric tons of carbon dioxide per year per well by 2034 to 2036.[87] Several other CCUS projects near or inside of NIPSCO's service territory remain in earlier stages of development, as summarized in Figure 4-18.[88]

Figure 4-18: Current CCUS Project Activity within Regional Mt. Simon Sandstone



86 Princeton University, Net-Zero America, 2021

87 EPA.gov

88 Indiana Geological and Water Survey

4.6.6.5 Federal Tax Incentives and Other Federal Policy

The U.S. tax code 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, were increased and extended by the Inflation Reduction Act to $85 per ton for geological storage. The tax credit is applied to all tons sequestered, is available for 12 years following project operation, and grows with inflation after 2026. Additionally, the BIL and the CHIPS Act support CCUS through substantial funding. The BIL allocates $12 billion for carbon capture research and demonstration until 2026, $8.5 billion for new capture and storage facilities, and $3.6 billion for direct air capture. The CHIPS Act supports carbon storage research and geologic computational science through the DOE.

4.6.6.6 CCUS Cost Estimates

Since the 2024 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, as described in more detail above:

- Capturing CO2 at the source of emission and compressing or liquifying it for transport;[89]
- Transporting the CO2 via pipeline, ship, or truck, as appropriate; and
- Sequestering the CO2 underground, including costs associated with injection, monitoring, and verification.

CRA developed CCUS costs and operational parameters for both retrofit of NIPSCO's existing Sugar Creek natural gas combined cycle unit and a new natural gas CCUS facility based on a range of public sources, including NREL and EPA.[90] Figure 4-19 summarizes CCUS cost and operational parameter assumptions for both Sugar Creek and a new CC with CCUS, while Figure 4-20 provides assumptions for new CC with CCUS capital costs over the full planning horizon based on NREL cost curves.

89 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.

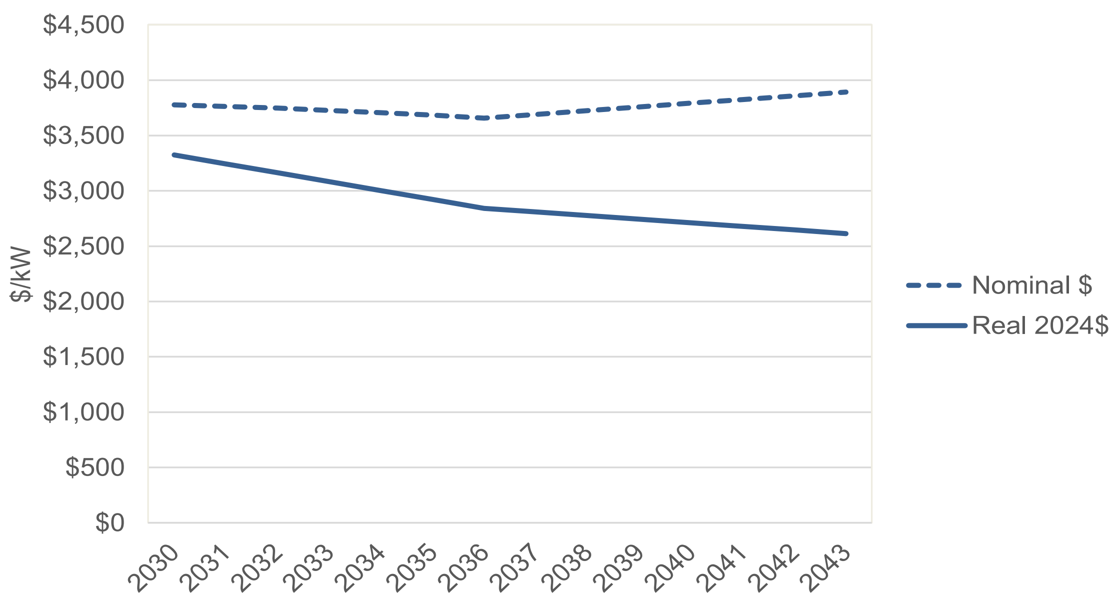
90 See 2023 NREL Annual Technology Baseline and U.S. Environmental Protection Agency CO2 Capture, Storage, and Transport Assumptions: [Chapter 6 - CO2 Capture, Storage, and Transport (epa.gov)]

Figure 4-19: CCUS Costs and Operational Parameters

Characteristic	Units	Sugar Creek Before Retrofit	Sugar Creek After Retrofit	New CC with CCUS
Net Capacity to Grid (Winter)	ICAP MW	650	585	585
Net Capacity to Grid (Summer)	ICAP MW	650	585	585
Heat Rate (Winter)	Btu/kWh	6,903	7,662[1]	6,704
Heat Rate (Summer)	Btu/kWh	6,912	7,672[1]	6,704
Installed CapEx	2024$/kW	-	1,860	3,325
VOM Costs	2024$/MWh	1.32	3.34[2]	4.64
Fixed Operations and Maintenance Costs	2024$/kW-yr	23.33	46.99[3]	82.02
CO2 Transportation Cost[5]	2022$/ton	7.50	7.50	7.50
CO2 Sequestration Cost[6]	2022$/ton	4.86	4.86	4.86
CO2 Emission Rate	lbs/MMBtu	119	11.9[4]	11.9[4]

Notes:
1: Assumes an increase in heat rate by a factor of 1.11x.
2: Assumes a 2.29x increase in VOM.
3: Assumes a 1.96x increase in FOM.
4: Assumes 90% carbon capture.
5: See https://www.epa.gov/system/files/documents/2024-04/table-6-5-co2-transportation-matrix-in-epa-2023-reference-case.xlsx
6: See https://www.epa.gov/system/files/documents/2024-04/table-6-4-co2-storage-cost-curves-in-epa-2023-reference-case.xlsx

Figure 4-20: Long-Term CCUS Cost Assumptions



4.6.7 Emerging Technologies – Long-Duration Energy Storage

Although a large majority of storage bidders in the RFP offered four-hour duration lithium-ion battery storage technologies, three bids incorporated longer duration technologies (see Section 4.6.1.2 above), and 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.

In general, short duration is defined as any technology with less than 10 hours of storage duration; inter-day LDES assets can shift power by 10-36 hours, filling diurnal needs by allowing excess power to be used within the same or following day; multi-day/week LDES shifts power by 36-160+ hours, enabling power supply during extended shortfalls; and seasonal duration storage provides several weeks to several months of storage, helping to address seasonal demand fluctuation. Long-duration storage technology can take many forms, as described in the next section of this Section.

4.6.7.1 Thermal Energy Storage

(TES stores high or low temperatures for hours, days, weeks, or seasons. Potential advantages include inexpensive materials, low environmental impact, versatility to release either electrical or thermal energy, ability for large scale storage, and superior safety.[91] However, this technology has limited applications at power generation facilities relative to other storage types as it often has lower RTE, lower energy density, a larger footprint, and limited scalability. Contributing to its inefficiencies are technology-specific operational requirements like passive heating during downtime.[92] Sensible heat, latent heat, and thermochemical heat constitute the three types of TES, each with tradeoffs of their own.

SHS involves raising the temperature of a solid or liquid medium to store heat.[93] This method provides wide duration flexibility from minutes to months and is currently the most commercially available among TES technologies. In power generation, the most common forms of SHS include molten salt TES (used in concentrated solar power), concrete TES, and chilled water TES. These systems typically achieve lower RTEs ranging from 40% to 90% and have long lifetimes spanning 25 to 30 years.

LHS captures heat in phase change materials, offering medium-storage durations from hours to days. Implementations of the technology span from laboratory stage to commercial availability. LHS is characterized by high modularity and energy density, high RTEs of 75% to 90%, a 10 to 30 year lifetime, minimal geographic constraints, and constant discharge temperatures

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91 LDES Technologies | LDES Council

92 NETL – "Thermal Energy Storage"

93 LDES Council – "Long Duration Energy Storage to accelerate energy system decarbonization"

over time. However, LHS uses corrosive, rare materials and is highly application specific, which exposes it to supply chain vulnerabilities.[94]

THS utilizes endothermic and exothermic chemical reactions to store thermal energy. It provides storage capabilities spanning hours to months and is predominantly in the R&D phase. It benefits from having minimal heat loss, a 10 to 30 year lifetime, very high RTEs of 80% to 99%, no geographic constraints, and the highest energy density among TES; however, it is limited by slow charging rates and materials that can degrade over time.[95]

4.6.7.2 Mechanical Energy Storage

MES harnesses kinetic or potential energy by exerting force to induce acceleration, compression, or displacement in a medium such that the energy can be later recovered. It is recognized for its potential to operate at large scales, long project lifetimes up to 30 years, high RTEs ranging from 70% to 90%, and rapid response.[96] However, this storage method can be constrained by geographic considerations, prolonged construction lead times, large physical footprints, high environmental impacts, and high initial capital costs. There are many different types of MES with varying levels of maturity and performance tradeoffs.

PHS utilizes surplus energy to pump water to an elevated reservoir, which can later be released through hydraulic turbines to generate electricity. Emerging pumped hydro systems strive to offer increased modularity and a smaller footprint compared to traditional installations, while still maintaining the high ramp rate and rapid response time of traditional designs. Like PHS, gravity-based storage stores the potential energy of large masses by raising them into an elevated position using excess energy and releasing them when energy is needed. Gravity-based systems offer high modularity, high RTE, quick response times, and inter-day storage durations, but they have seen limited commercial deployment to-date.

CAES involves using electricity to compress air, which can then be discharged on demand within a multi-day/week timeframe. It is highly modular, occupies a small footprint, and is cost-effective, although its geographic applicability is limited due to reliance on underground geological storage systems. LAES operates similarly to CAES but compresses air to the point of liquefaction, supporting storage durations from inter-day to multi-day/week. It provides enhanced modularity and occupies smaller footprints compared to CAES, although it comes with higher capital costs. Despite being the newest among mechanical storage technologies, LAES is anticipated to be competitive in terms of cost, response time, and modularity, while offering storage durations spanning multiple days to weeks.[97] Liquid CO_2 storage functions like LAES but

94 DOE – "Pathways to Commercial Liftoff: Long Duration Energy Storage"

95 NETL – "Thermal Energy Storage"

96 The Electricity Journal – "Technology readiness level and round trip efficiency of large-scale advanced compressed air energy storage"

97 As described in Section 4.6.1.2, NIPSCO received a bid in its RFP for the Energy Dome liquid CO_2 storage system, which utilizes an above-tank to achieve inter-day storage by compressing CO_2. The heat generated during compression is captured using two TES systems: one for direct heat transfer and another employing a heat exchanger to cool the CO_2 to a liquid phase for storage in a dome-shaped, above-ground pressure vessel. The discharge process reverses this cycle, reheating the stored CO_2 so that it can be expanded through a turbine.

leverages the uncommon property of pure CO2 streams to be condensed and stored as a liquid under pressure at ambient temperatures.

Flywheels store energy by rotating a mass around a fixed axis. They are characterized by modularity, rapid construction times, immediate dispatchability, and low maintenance requirements, although they typically have short discharge durations and limited storage capacities.[98]

4.6.7.3 Chemical Energy Storage

CES is achieved through the production of chemical fuels. It can be converted into electrical, thermal, or mechanical energy, making it versatile for use in industrial or grid applications.[99] This storage method offers several advantages, including large storage capacities; discharge durations ranging from days to months; long project lifetimes; ease of storage and transport; minimal energy loss; and various pathways for production, storage, and end use. Chemical fuels can also leverage alternate revenue streams beyond electricity sales with the help of extensive existing infrastructure. However, CES may be constrained by geographical considerations, require large amounts of land, and present safety hazards. Some chemicals have low volumetric energy densities, which can result in further constraints by requiring large, expensive storage volumes. Compared to batteries, CES generally has lower RTEs due to the energy intensive process it requires.

The main types of chemical fuels are methane, methanol, ammonia, and hydrogen.[100] Hydrogen is typically a primary option for CES due its low-carbon production methods, diverse-end use applications, and ability to provide clean energy.[101] Methane benefits from a higher volumetric energy density than hydrogen and widespread infrastructural support but causes significant greenhouse gas emissions. Ammonia, which can be formed from hydrogen and nitrogen, has existing transportation infrastructure largely due to its use as a fertilizer and is currently being studied for use in power generation. Methanol, formed through the hydrogenation of CO and CO2, can be more easily stored and transported relative to other fuels but may be more suited for use in transportation than power generation due to its low energy density, emissions, and difficult integration into existing natural gas infrastructure.

4.6.7.4 Electrochemical Energy Storage

EES, often classified as a subset of chemical energy storage, involves the cyclic conversion of energy between electrical and chemical forms through electron and ion transfer in electrodes.[102] While still largely in early stages of development for LDES purposes, these systems can offer inter-day and multi-day/week storage durations and are known for their safety, minimal geographic

98 NETL – "Mechanical Energy Storage"

99 NETL – "Chemical Energy Storage"

100 Ibid

101 Hydrogen for power generation is described in more detail in Section 1.6.5.1.

102 ScienceDirect – "Introduction to electrochemical energy storage technologies"

constraints, resilience to extreme temperatures, scalability, low self-discharge rates, ability to discharge deeply without significant degradation, and long operational lifespans. Common drawbacks of EES include safety hazards, high costs, temperature sensitivity, degradation over time, and reliance on rare minerals.

Lithium-ion batteries are currently at the forefront of electrochemical energy storage solutions, commonly featured in integrated resource planning due to their proven commercial viability and technological readiness. Although they are technically a short-duration storage option, lithium-ion batteries benefit from low capital costs, fast response rates, short construction times, high RTEs of 85% to 95%, discharge times from 1 second to 8 hours, and high energy density.

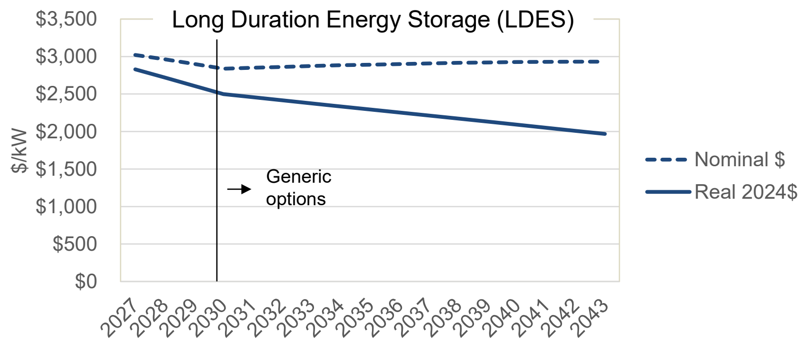
A few promising long duration technology categories identified by the U.S. Department of Energy include aqueous-electrolyte flow batteries, metal-anode batteries, and hybrid flow batteries. While this list is far from comprehensive, it helps to demonstrate some of the key characteristics of electrochemical LDES technologies. Aqueous-electrolyte flow batteries, like vanadium redox flow batteries and iron-chromium flow batteries, employ chemical cathodes and anodes separated by electrolytes. They are characterized by near instantaneous response times, long cycle lives, modular designs, RTEs between 65% to 85%, small footprints, and inter-day to multi-day/week durations, although they are subject to a form of relatively fast degradation known as crossover and can be expensive.[103] Hybrid flow batteries, which maintain tradeoffs similar to those of aqueous-electrolyte flow batteries, can offer enhanced performance by combining the strengths of conventional and flow battery chemistries. Metal-anode batteries are technologically similar to lithium-ion batteries, and have large specific and volumetric capacity, high energy density, quick response times, and small footprints. Finally, as described in more detail in Section 4.6.1.2, NIPSCO received a bid for iron air storage, which falls within this category.

4.6.7.5 LDES Cost Considerations

Since LDES encompasses a diverse range of technologies, costs have the potential to vary widely, although declines are likely in the future. This anticipated decline is driven by scaling benefits, technological advancements from ongoing research and development, and improved efficiency across the supply chain. For the purposes of 2024 IRP modeling, NIPSCO is benchmarking cost information to RFP data and observed cost premiums for longer-duration storage technology relative to four-hour lithium ion batteries. A single, *representative*, 100-hour technology will be modeled, in accordance with the assumptions summarized in Figure 4-21.

103 MIT Energy Initiative – "Flow batteries for grid-scale energy storage" and Power Efficiency – "Maximizing Flow Battery Efficiency: The Future of Energy Storage"

Figure 4-21: Long-Term LDES Cost Assumptions



Category	LDES
Fixed O&M (2024$/kW-yr)	$40
Round Trip Efficiency	35%
Tax Credit Eligibility Assumption	40% ITC

Given the expectation that energy storage will be an important 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. If new LDES technologies emerge with cost and operational parameters consistent with those evaluated in this IRP, NIPSCO will be able to pivot in the implementation of its short-term action plan accordingly. NIPSCO also expects to continue to assess LDES in future IRPs.

4.6.8 Emerging Technologies – 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 shut down in an emergency without requiring human interventions.

4.6.8.1 SMR Technology Overview

NPPs have long been a significant source of emissions-free, firm energy in the U.S. These facilities harness nuclear fission reactions, in which atoms split and release energy in the form of heat. This heat generates steam by heating water in a reactor core, which drives turbines to produce electricity. Inside the reactor core, fuel rods — comprising small ceramic uranium pellets — are grouped into fuel assemblies and immersed in water, which acts as both a coolant and reaction moderator. Conventional nuclear reactors can be either PWRs or BWRs. PWRs use high pressures to keep water in the reactor core from boiling. After being heated inside the core, the water is pumped into a heat exchanger, where it boils a secondary source of water into steam and then cycles back to the core. BWRs produce steam inside the reactor core, which is directly fed to a turbine and then recondensed into water to cycle back through the core.

Advanced nuclear energy employs modernized designs that offer a range of environmental, efficiency, safety, and reliability benefits over conventional nuclear.[104] Gen III+ and Gen IV are the two primary categorizations of advanced nuclear technologies. Gen III+ reactors are like conventional reactors in the sense that they use water as a coolant and LEU as a fuel, positioning them for near term deployment.[105] Gen IV reactors use new fuels such as HALEU fuel and novel coolants like molten salt or liquid metal. The approval of NuScale's 60 MW power module by the U.S. NRC marked the first approval of a Gen IV design, underscoring the advancing commercial viability of Gen IV technology.[106]

Several reactor types are in various stages of development and approval, each providing advantages of their own. Conventional water-cooled reactors, also known as light-water reactors, represent the predominant technology in current nuclear power generation. Liquid metal fast reactors, which employ sodium or lead as a coolant, have potential for greatly reducing nuclear waste by consuming fission products with long decay times such as neptunium. Molten salt reactors offer similar fuel reduction benefits and use molten fluoride or chloride salts as a coolant. HTGCRs naturally have high operating temperatures, allowing them to be used for non-electric applications like hydrogen production or desalination. As these reactor types progress through pre-application stages, forthcoming deployments will determine the most suitable candidates for commercial scalability.

Advanced nuclear technologies are further categorized by size, with large reactors operating at around the 1 GW scale, SMRs ranging from 50 to 300 MW, and microreactors sized at 50 MW or less. While each one may have a role to play in the decarbonization of the electric grid by 2050, SMRs have received the most attention given size flexibility and cost improvement potential.[107]

4.6.8.2 Current Operational Landscape

Among the 54 nuclear power plants currently operational in the U.S., there is a combined capacity of 103 GW, constituting about 8% of the nation's total generation capacity in 2023. Due to their high capacity factors, nuclear plants have consistently provided about 20% of U.S. electricity since the 1990s. However, recent growth in nuclear deployments has been slow, with only 2,386 MW of nuclear capacity additions between 2016 and 2023.[108] The most recent additions

104 NEI – "ADVANCED NUCLEAR ENERGY: Frequently Asked Questions for Community Stakeholders"

105 DOE – "Pathways to Commercial Liftoff: Advanced Nuclear"

106 DOE – "NRC Certifies First U.S. Small Modular Reactor Design"

107 Idaho National Laboratories – "Advanced Small Modular Reactors"

108 America's Electricity Generation Capacity Report, 2024 Update (publicpower.org)

to the U.S. nuclear fleet are Units 3 and 4 of the Alvin W. Vogtle Electric Generating Plant, construction of which started in 2009 by Georgia Power. Unit 3 commenced commercial operations on July 31, 2023, followed by Unit 4 on April 29, 2024, collectively adding 2,234 MW of capacity. These units feature the Westinghouse AP1000 Generation III+ reactor, marking the first deployment of advanced nuclear in the U.S.

Some of the early advanced nuclear demonstrations in the U.S. have encountered challenges related to costs and timelines. The Carbon Free Power Project, initiated by Utah Associated Municipal Power Systems in 2015, aimed to build twelve 60 MW NuScale Power Modules. Despite support from DOE funding, the project was terminated in November 2023 before construction began, largely due to cost overruns.[109]

However, several other SMR projects are currently in development or advanced stages. The DOE's Advanced Reactor Demonstration Program is a well-known project launched in 2020 to support advanced nuclear development in the U.S. Through the program, TerraPower's first-of-a-kind Natrium demonstration project — a 345 MW sodium fast reactor with a gigawatt-scale molten salt energy storage system — received $2 billion in DOE funding through a 50/50 cost-share arrangement.[110] The project submitted a construction permit in 2024 and is on track to achieve deployment by 2030, although securing a supply of HALEU remains a critical challenge.[111] X-energy has also partnered with the ARDP to develop the Xe-100 high-temperature gas reactor. The design consists of four 80 MW reactors and can be scaled by adding units to increase electrical output at the same facility. Currently in the process of obtaining a construction permit to build the reactor at a Dow industrial site in Seadrift, Texas, X-energy expects the reactor to be deployed within the decade.[112]

A range of SMR demonstrations are currently progressing through different stages of design, permitting, and construction worldwide. Leading SMR designs under consideration by utilities include the NuScale VOYGR, Holtec International SMR-160, Westinghouse AP300, Rolls-Royce SMR, Kairos Power KP-FHR, Terrestrial Energy Integral Molten Salt Reactor, and TerraPower Molten Chloride Fast Reactor. In the U.S., there are three GW of SMRs in early or pre-development stages, with an additional four GW of announced SMR projects, positioning the country as a leader among the 22 GW of SMR projects in the global pipeline.[113] China achieved a significant milestone by activating the first commercial Gen IV SMR in 2023 and plans to have its first water-cooled SMR online by 2026. Project Phoenix, an initiative by the U.S. Department of State aimed at accelerating global coal-to-SMR conversions, is currently enhancing SMR development in Eastern Europe. The Czech Republic, Poland, Slovakia, and Slovenia are among the initial beneficiaries of the program, receiving support that includes annual workshops on coal to SMR conversion, feasibility studies, site characterization, and advisory services. Feasibility

109 Utility Dive – "NuScale, UAMPS terminate small modular reactor project in Idaho"

110 TerraPower – "TerraPower Natrium"

111 Reuters – "First TerraPower advanced reactor on schedule but fuel a concern"

112 NRC hearing gives information on X-energy, Dow project -- ANS / Nuclear Newswire

113 Utility Dive – "Global small modular reactor pipeline hits 22 GW, with US leading the market: WoodMac"

studies are already underway, with plans to commence SMR operations in these countries by the early 2030s.

While light-water reactor designs are a mature and proven technology, their deployment on the SMR scale in the U.S. is still forthcoming. Gen IV reactors, including sodium reactors, high-temperature gas-cooled reactors, and microreactors, are at earlier stages of technological maturity and advantages and drawbacks.

4.6.8.3 Operational Considerations

SMRs offer numerous advantages over traditional nuclear power plants, particularly in terms of enhanced safety and reduced risk. They are best known for their modular design, which allows for shorter construction times, simpler and more standardized designs, more efficient transportation of components, and lower overall costs, all of which minimize the risk of project abandonment. They also incorporate advanced safety features such as passive safety systems, allowing plants to shut down and self-cool without operator intervention or additional water or power input. Advancements in fuel technology have further minimized the risk of nuclear leakage or meltdown. SMRs can be sited closer to demand centers because of their reduced safety radius, higher power density, and lack of geographical constraints in terms of wind/solar resource availability, which reduces the need for transmission infrastructure that is costly and often difficult to procure. The potential for coal to nuclear power plant conversions could further increase transmission availability and help reduce capital costs.

SMRs offer significant reliability benefits, including firm power, load-following capabilities, and black start capability.[114] They achieve high capacity factors ranging from 80% to 95% and have high peak capacity accreditation, allowing them to ensure stable energy supply across seasons, protect against blackouts, and maintain a reasonable reserve margin year-round. Their ability to integrate electricity into the grid or operate independently makes them suitable for powering critical facilities such as hospitals, military bases, or isolated communities. Other diverse use cases including hydrogen generation, industrial heat production for chemical plants and refineries, and desalination of water for municipalities bolsters their grid flexibility. The modular design of SMRs allows for refueling and maintenance on individual reactors without requiring an outage of the entire facility, which translates to reduced operational downtime. Moreover, their capability for multi-year on-site fuel supply addresses fuel security concerns, particularly in winter when extreme cold weather may disrupt fuel production and delivery.

SMRs embody several environmental advantages typical of advanced nuclear technologies. They feature low life cycle emissions compared to major generation sources, zero emissions during power generation, and less toxic waste than conventional NPPs.[115] Nuclear energy also boasts the highest electrical capacity per acre of land among major energy sources. It produces approximately 57,000 MWh/year per acre, with the next highest being geothermal at

114 DOE – "5 Key Resilient Features of Small Modular Reactors"; and Small Modular Reactors – "SMR load-following capabilities"

115 NREL – "Life Cycle Assessment Harmonization | Energy Analysis"

9,000 MWh/year per acre.[116] These environmental benefits help mitigate challenges associated with high land costs, permitting complexities, spent fuel storage, and emissions regulations.

4.6.8.4 Federal Policy Support

Advanced nuclear technologies can receive the federal PTC or ITC as per the IRA provisions that make them available for new plants with zero greenhouse gas emissions that commence operations after December 31, 2024. Additionally, legislation will play a major role in enabling the significant capacity increases that will be needed across the nuclear supply chain. Recently, the ADVANCE Act was signed into law,[117] encouraging first movers by reducing NRC licensing and applications fees, introducing large prize competitions, directing the NRC to establish a licensing and regulation process for microreactors, supporting reuse of brownfield sites for nuclear energy, and strengthening domestic HALEU availability.

4.6.8.5 SMR Cost Considerations

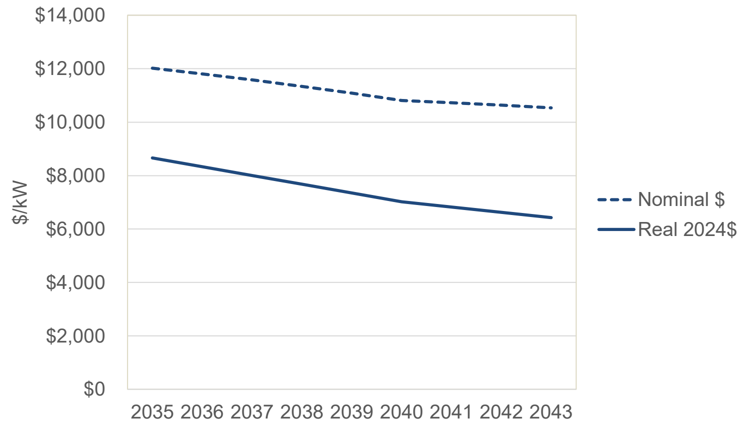
In general, SMRs are characterized by high capital costs and relatively low variable costs. Their small size and modular designs enable mass production, rapid assembly of components, and transportation of entire units, leading to significantly reduced financing and capital expenses relative to larger plants. While refined uranium fuel prices introduce some cost uncertainty, they constitute a smaller portion of operating expenditures compared to natural gas electricity generation, thus mitigating fuel price risks.

Recent nuclear projects in the U.S. have reported overnight capital costs around $10,000/kW. While the DOE estimates that deploying 10-20 reactors at a 12% to 15% learning rate could result in significant learnings and cost efficiencies over time, future costs remain highly uncertain. For modeling purposes, NIPSCO is assuming availability in 2035 and beyond, with cost estimates taken from NREL's ATB, as documented in Figure 4-22.

116 DOE – "Pathways to Commercial Liftoff: Advanced Nuclear".

117 DOE – "Newly Signed Bill Will Boost Nuclear Reactor Deployment in the United States"

Figure 4-22: Long-Term SMR Cost Assumptions



Category	Assumption
Fixed O&M (2024$/kW-yr)*	$144
First Available Year	2035
Tax Credit Eligibility Assumption	30% ITC

**NREL ATB assumptions for 2035 benchmark year*

4.6.9 Long-Term Uncertainties with Emerging Technologies

NIPSCO recognizes that the landscape for all emerging technologies is subject to significant change over the long term, particularly as associated with technology evolution, federal policy initiatives, and investment 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 emerging technology deployment:

- Technology advancement associated with electrolyzer costs, nuclear technologies, LDES technologies, and CCUS;
- The evolution of federal incentives, including direct subsidies or other federal investment;
- Developments in hydrogen transmission, distribution, and storage infrastructure and how they interact with current natural gas infrastructure;
- MISO market dynamics, including the potential for evolving value opportunities associated with capacity accreditation, renewable curtailment risk (which could otherwise be diverted to hydrogen production or LDES charging), or local congestion;
- Broader carbon emission reduction policies, which could put a price on carbon or further incentivize the use of clean energy sources.

4.6.10 Federal Tax Incentives for Clean Energy Resources

Federal tax incentives are currently in place for clean energy and storage resources as a result of the passage of the IRA in 2022. Clean energy resources are eligible for a PTC or an ITC, while storage resources are eligible for the ITC. In addition, federal tax credits are available for the geological sequestration of carbon dioxide emissions and the production of green hydrogen. Figure 4-23 provides a summary of key federal tax credits relevant to new resource options for NIPSCO's portfolio.

Figure 4-23: Summary of Available Federal Tax Credits for Clean Energy

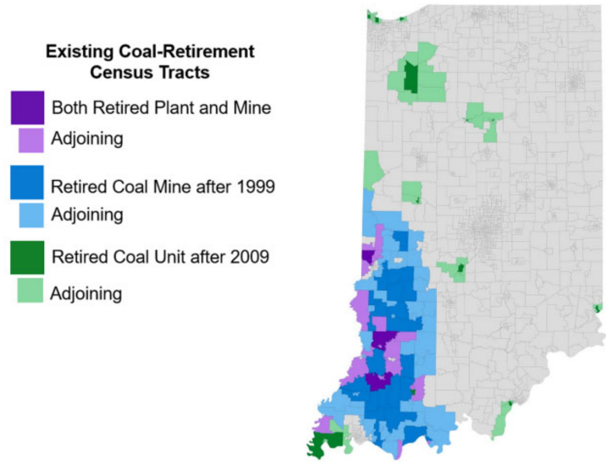
In-Service Year[6]	Production Tax Credit[1, 2]	Investment Tax Credit[1, 2]	CCS (Section 45Q)[1]	Hydrogen PTC (Section 45V)[1, 3]
	10-year $/MWh	*Up front portion of investment*	*12-year $/metric ton-CO2*	*10-year $/kg*
	$30/MWh in 2024$[5]	*%*	*$85 in 2026$[5]*	*$3/kg[4] in 2022$[5]*
2024-2035	100% of value	30%	Available	Available
2036	75% of value	22.5%		
2037	50% of value	15%		
2038+	0%	0%	$0	$0

Notes:
1. Assumes prevailing wage and apprenticeship requirements met.
2. A 10% "energy community" bonus is available for projects located in proximity to retired coal infrastructure or in statistical areas with high historical employment in the fossil fuel sector and unemployment rates greater than the national average. The bonus adds 10% to the ITC and increases the PTC amount by 10%.
3. For modeling purposes, NIPSCO is assuming a price for hydrogen (net of tax credits) rather than investment in an electrolyzer and associated green hydrogen production. Since the hydrogen PTC has a 10-year term, tax credits are expected to be eligible for hydrogen fuel purchased through the fundamental modeling horizon through 2043.
4. Assuming green hydrogen with a lifecycle emission rate below 0.45 kg CO2e/kg-H2.
5. The tax credit values are tied to inflation. Baseline years are provided for reference.
6. Tax credit eligibility is defined by commence construction dates. For modeling purposes, safe harbor construction periods are assumed, and these assumptions are presented for projects entering into service during the specified years.

The IRA provides a schedule of tax credit phaseouts over time based on the resource's begin construction date. Some of the phaseout schedules are dependent on U.S. power sector emissions achieving a 75% reduction from 2022 baseline levels, although for modeling purposes, NIPSCO assumes tax credit eligibility in line with the dates summarized in Figure 4-23. NIPSCO's scenario analysis also incorporates one scenario in which tax credits are phased out earlier (see details in Section 8).

In addition to the tax credit levels outlined in Figure 4-23, the IRA offers a 10% "energy community" bonus for projects located in proximity to retired coal infrastructure or in statistical areas with high historical employment in the fossil fuel sector and unemployment rates greater than the national average. Several such sites exist in NIPSCO's service territory and Indiana as a whole. The bonus adds 10% to the ITC and increases the PTC amount by 10%. Based on RFP data and recent NIPSCO project experience, several new resource types are assumed to be eligible for the 10% energy community bonus.

Figure 4-24: IRA Energy Community Bonus Areas in Indiana



NIPSCO has the ability to monetize federal tax credits for the benefit of customers through a variety of pathways, including:

- Via a PPA where tax credits flow to the developer and are reflected in PPA pricing;
- Via direct ownership of a project, where NIPSCO can directly monetize tax credits against its federal tax liability;
- Via direct ownership of a project, where NIPSCO can sell tax credits for cash to a third party through the tax credit transfer provisions in the IRA;
- Via a joint venture with a tax equity partner, where a third-party 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 time frame. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.

NIPSCO's tax credit monetization strategy will be project-specific and thus not evaluated in detail in the IRP. For modeling purposes, NIPSCO has assumed monetization either through PPAs or direct ownership and potential tax credit transfer. Based on available resource cost and operational data, the following tax credit assumptions were made: solar: 40% ITC; storage: 40% ITC; wind: PTC; SMR: 30% ITC; CCUS: 45Q credit at $85/ton (real 2026$).

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 October 18, 2023, the Commission issued a Final Order in Cause No. 45849 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, 2024 through December 31, 2026 (the "2024-2026 Plan"). To support the continuation of its program offerings for the period 2024 through 2026, 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 the three program years.

2024-2026 Residential Programs

Home Rebates

The Home Rebates program is designed to provide incentives to residential customers to replace inefficient HVAC equipment and other home products with energy-efficient alternatives. These measures are 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 electric program promotes 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. This program will also offer products through a midstream channel that works with distributors.

Retail Products

The Retail Products program is designed to increase the purchase and use of energy-efficient products among NIPSCO's residential electric customers. The program provides instant discounts by using upstream wholesale incentives to buy down the incremental costs on products such as lighting fixtures, air purifiers, and smart power strips.

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 (in kWh) consumption and promote additional efficiency work. This program will provide homeowners with the direct installation of no-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. TRC will continue to utilize a qualified subcontractor for the implementation of this program.

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 and high school 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. TRC will continue to utilize a qualified subcontractor for the implementation of this program.

Multi-Family Direct Install

The Multi-Family Direct Install 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 generates 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 program, along with complementary incentive offers available through other NIPSCO programs. Property managers are 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 downlight fixtures, low-flow showerheads, faucet aerators, pipe wrap, and programmable thermostats. Educational materials about home operation, maintenance, and behavior that may reduce energy consumption are provided to tenants in each living unit. To encourage participation, property managers may be paid an incentive upon completion of the project. TRC will continue to utilize a qualified subcontractor for the implementation of this program.

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 manufactured and other single-family homes. This program produces long-term, cost-effective savings by incentivizing builders 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 Energy Efficiency Calculator

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 the audit, at no cost to the customer. The audit tool effectively: (1) identifies low-cost/no-cost measures that a NIPSCO residential customer can easily implement to manage electric consumption; (2) allows eligible customers to request a free home energy kit; (3) educates customers about the variety of programs available to them through the residential energy efficiency portfolio; and (4) assists customers in finding qualified and experienced contractors through a network of trade allies.

Income Qualified Weatherization

The Income Qualified Weatherization 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 who 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 three years from the date of application. Qualifying participants receive the direct installation of no-cost energy efficiency measures, including a refrigerator replacement, 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.

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 provides customers with home energy reports that contain personalized information about their energy use and provides 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 empowers 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.

Income Qualified Home Energy Report

The Income Qualified Home Energy Report program (also known as the Income Qualified Behavioral program) is designed to encourage energy savings through behavioral modification. The program provides income qualified customers with home energy reports (print and email) that contain personalized information about their energy use and provide ongoing recommendations to make their homes more efficient as well as at-risk language to support customers with energy saving tips, ways to seek additional assistance from utility, local, state, and federal agencies and inform them of potential higher than average usage compared to prior months before receiving their bill. Customers are 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, including programs offered both by NIPSCO and by other entities focused on income qualifications. The program empowers 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. Table 5-1 shows the projected energy savings (MWh) by year for each of the Residential programs.[118]

[118] **Error! Reference source not found.** Table 5-1 represents incremental, gross savings at the meter from the plan approved by the Commission in Cause No. 45849. 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.

Table 5-1: 2024-2026 Projected Residential Energy Savings (MWh)

Residential Programs	2024	2025	2026	2024-2026
Home Rebates	2,404	3,795	5,128	11,327
Retail Products	5,884	5,917	5,967	17,768
HEA	614	650	691	1,955
Appliance Recycling	2,226	2,449	2,694	7,369
School Education	1,568	1,568	1,568	4,704
MFDI	1,466	1,592	1,731	4,789
Residential New Construction	605	661	723	1,989
HomeLife EE Calculator	276	276	276	828
IQW	1,076	1,132	1,193	3,401
Residential Online Marketplace	824	856	878	2,558
Home Energy Report	19,674	21,162	21,460	62,296
Income Qualified Home Energy Report	6,646	6,178	5,660	18,484
Total Residential Programs	43,263	46,236	47,969	137,468

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.[119]

[119] 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 2024-2026 DSM Plan budget approved by the Commission. These budgets do not reflect the potential adjustment.

Table 5-2: 2024-2026 Residential Program Budget

	2024	2025	2026	Total
Home Rebates	$ 2,534,082	$ 3,587,890	$ 4,460,734	$10,582,706
Retail Products	$ 1,361,527	$ 1,219,595	$ 1,078,262	$ 3,659,384
HEA	$ 436,364	$ 458,753	$ 484,960	$ 1,380,077
Appliance Recycling	$ 427,664	$ 408,394	$ 380,993	$ 1,217,051
School Education	$ 988,365	$ 963,449	$ 939,047	$ 2,890,861
MFDI	$ 897,666	$ 939,095	$ 981,935	$ 2,818,696
Residential New Construction	$ 130,979	$ 126,220	$ 119,537	$ 376,736
HomeLife EE Calculator	$ 133,021	$ 127,341	$ 121,704	$ 382,066
IQW	$ 1,171,491	$ 1,239,900	$ 1,316,365	$ 3,727,756
Residential Online Marketplace	$ 379,332	$ 391,251	$ 397,021	$ 1,167,604
Home Energy Report	$ 1,050,182	$ 918,357	$ 918,357	$ 2,886,896
Income Qualified Home Energy Report	$ 521,447	$ 455,097	$ 455,097	$ 1,431,641
Total Residential Programs	$10,032,120	$10,835,342	$11,654,012	$32,521,474

2024-2026 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 who 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 projects 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 cannot be included as an EE measure 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 Small Business Direct Install 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 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.

Strategic Energy Management

The Strategic Energy Management program will provide NIPSCO customers with a tailored self-service platform when they opt in to the program. The 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.[120]

Table 5-3: 2024-2026 Projected C&I Energy Savings (MWh)

C&I Programs	2024	2025	2026	Total
Prescriptive	25,975	26,701	25,710	78,386
Custom	32,779	31,297	29,917	93,993
C&I New Construction	13,662	13,045	12,469	39,176
SBDI	1,574	1,504	1,437	4,515
C&I Online Marketplace	3,936	3,758	3,592	11,286
SEM	787	752	718	2,257
Total C&I Programs	**78,713**	**77,057**	**73,843**	**229,613**

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: 2024-2026 C&I Program Budget

C&I Programs	2024	2025	2026	Total
Prescriptive	$ 4,496,951	$ 5,083,376	$ 4,965,423	$14,545,750
Custom	$ 5,817,162	$ 5,570,304	$ 5,742,130	$17,129,596
C&I New Construction	$ 2,319,671	$ 2,262,194	$ 2,299,311	$ 6,881,176
SBDI	$ 341,431	$ 332,587	$ 328,620	$ 1,002,638
C&I Online Marketplace	$ 700,442	$ 705,736	$ 712,239	$ 2,118,417
SEM	$ 142,622	$ 138,905	$ 137,405	$ 418,932
Total C&I Programs	**$13,818,279**	**$14,093,102**	**$14,185,128**	**$42,096,509**

120 Table 5-3 represents incremental, gross savings at the meter from the Final Order in Cause No. 45849. At the time of the IRP, slightly different adjustments were used for modeling but were universally applied.

Table 5-5 shows the projected energy savings (MWh) by year for all Residential and C&I programs included in the 2024-2026 Plan. NIPSCO also included Emerging Technologies in the plan for programs and measures that have not yet been identified.

Table 5-5: 2024-2026 Projected Combined Energy Savings (MWh)

	2024	2025	2026	Total
Total Residential Programs	43,263	46,236	47,969	137,468
Total C&I Programs	78,713	77,057	73,843	229,613
Emerging Technologies				8,041
Total 2024-2026 Plan	**121,976**	**123,293**	**121,812**	**375,122**

Table 5-6 shows the annual total program budget for all Residential, C&I, and Emerging Technology programs included in the 2024-2026 Plan.

Table 5-6: 2024-2026 Combined Program Budget

	2024	2025	2026	Total
Total Residential Programs	$10,032,120	$10,835,342	$11,654,012	$32,521,474
Total C&I Programs	$13,818,279	$14,093,102	$14,185,128	$42,096,509
Emerging Technologies				$ 1,859,883
Total 2024-2026 Plan Budget	**$23,850,399**	**$24,928,444**	**$25,839,140**	**$76,477,866**

Table 5-7 shows the eligible customer classes and rate schedules for each of the Residential and C&I programs included in the 2024-2026 Plan.

Table 5-7: Eligible Customers

Program	Customer Class	Electric Rate Schedule
Home Rebates	Residential	511
Retail Products	Residential	511
HEA	Residential	511
Appliance Recycling	Residential	511
School Education	Residential	511
MFDI	Residential	511
Residential New Construction	Residential	511
HomeLife EE Calculator	Residential	511
IQW	Residential	511
Residential Online Marketplace	Residential	511
Home Energy Report	Residential	511
Income Qualified Home Energy Report	Residential	511
Prescriptive	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
Custom	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
C&I New Construction	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
SBDI	C&I	520, 521, 522, or 523 who have not had a billing demand of 200 kW or greater in any month during the previous 12 months
C&I Online Marketplace	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544
SEM	C&I	520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, or 544

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, which revised its industrial service structure by removing Rider 775 and Rate 734 and added Rate 831 and the Commission approved the continuation of this industrial rate structure in Cause No. 45772 with Rate 531 (formerly Rate 831). This industrial service structure requires NIPSCO's largest industrial customers on Rate 531 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 structure, unless those Rate 531 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, 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 581 and 582, respectively. These Riders are available to a customer on Rates 523, 524, 525, 526, 531, 532, and 533 that has a consistent 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 581 and 582, 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 to other NIPSCO customers through an overall lower electric system demand, which can help NIPSCO to 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 581 as a DRR1. No customers are participating in Rider 582 as an 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 (2027-2046).[121]

[121] Near term (2025-2026) 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.

The study included 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 2021 MPS, NIPSCO's electric load and customer forecasts, NIPSCO's load research data, electric avoided costs, program evaluation reports, and NIPSCO's 2024-2026 DSM 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, 2023, 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 11% of commercial kWh sales have opted out of utility-based electric energy efficiency programs, while roughly 81% 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.

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 and CRA, provided the GDS Team with an electric load forecast for 2024 through 2046. GDS used this load forecast to calculate the percentage of electric MWH sales and peak demand saved each year by DSM programs. Without hyperscaler data center load, NIPSCO's load forecast projects that total MWh sales to ultimate customers will only increase 0.1% per year, on average, through the year 2043. For energy efficiency, the load forecast absent any potential new hyperscaler data center load was utilized because these potential new loads would likely be eligible to opt out of the energy efficiency charge. These additional loads were considered in development of the demand response potential.

NIPSCO also provided GDS with updated planning assumptions for avoided energy, avoided capacity, and avoided transmission and distribution costs, 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.[122] GDS used these assumptions to develop the 2024 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 the 2024-2026 NIPSCO DSM plan 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 recently updated Indiana TRM, the Illinois TRM, and the Michigan Energy Measures Database to inform a large portion of the data requirements. Additional data sources were only used if these sources either did not address a certain measure or contained outdated information. Additional source documents included the NREL Energy Measures Database, American Council for an Energy-Efficient Economy research reports, and other market potential study databases.

In addition to measure assumption development, the GDS Team developed estimates of equipment penetration, saturation, and efficiency characteristics, as well as customer willingness to participate in program offerings data, across select end-uses/technologies. GDS primarily leveraged the market research results from the 2021 NIPSCO MPS, which included a combination of online/mail surveys, as well as a limited amount of on-site site visits, to form the basis of 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 Efficiency Standards and Tax Rebates

The DOE develops and implements federal appliance and equipment standards to improve energy efficiency, saving consumers energy and money. 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. The sources used to develop measure assumptions for the study reflect recent updates to federal efficiency standards. Although not exhaustive, key measures that have been impacted by updates to federal standards since the prior MPS include:

- Residential air-source heat pumps in 2023

[122] NIPSCO provided the GDS Team with both average and peak line loss factors. The GDS Team used the peak line loss factors (LLF) 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 7.5%.

- Residential central air conditioners in 2023
- Commercial single-package and split system unitary air conditioners in 2023

In addition to accounting for federal efficiency standards, the study recognized the implications of federal tax credits and rebates. The IRA includes various pathways for residents to receive credits and/or rebates for installing energy efficiency measures. The study accounted for the IRA in multiple ways, including in the assessment of measure-level cost-effectiveness and estimating how the rate of adoption of energy efficiency measures could be impacted by the availability of federal tax rebates and credits. The study also estimated what portion of future savings potential may be attributable to programs aligned with federal funding versus what could be achieved by NIPSCO. This is addressed further in Section 5.3 Future Resource Options.

5.2.5 Energy Efficiency Measures & Potential

5.2.5.1 Measures Considered

For the residential sector, there were 197 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[123]

End Use	Measure Types Included		
Appliances	ENERGY STAR Air Purifier ENERGY STAR Refrigerator Refrigerator Recycling ENERGY STAR Clothes Washer ENERGY STAR Dishwasher Ultrasonic Clothes Dryer	ENERGY STAR Dehumidifier Dehumidifier Retirement ENERGY STAR Freezer Freezer Recycling ENERGY STAR Clothes Dryer	Heat Pump Dryer Ozone Laundry Smart Dryer Sensor ENERGY STAR Water Coolers Induction Cooktop
Audit	Assessment Recommendations		
Behavioral	Home Energy Reports Home Energy Management System AMI Data Portal		
Consumer Electronics	Advanced Power Strip – Tier 1 Tier 2 Advanced Power Strips (APS) – Residential Audio Visual		

[123] Some of the unique measures have been collapsed into broader categories to summarize the list.

End Use	Measure Types Included		
	ENERGY STAR Television Smart Sockets		
Electric Vehicle Charging	L2 ESVE		
HVAC Equipment	ASHP 15.2 SEER2 ASHP 16.2 SEER2 ASHP 17.1 SEER2 ASHP 18.1 SEER2 Ground Source Heat Pump Ductless HP 8.5 HSPF2 Ductless HP 9.4 HSPF2 Ductless HP 10.8 HSPF2 Ductless HP 11.7 HSPF2 AC Tune Up Central AC 15.2 SEER Central AC 16.2 SEER	Indirect-Evaporative Cooler Radiant Panels Advanced Wall Heater Wi-Fi Smart Thermostat Programmable Thermostat Optimized Thermostat Integrated HVAC Controls ECM HVAC Motor Advanced Furnace Fan ENERGY STAR Room AC Room AC Recycling Smart Vents/Sensors	Whole House Attic Fan HVAC Economizer Efficient Bathroom Fan ENERGY STAR Ceiling Fan Energy Recovery Ventilator Filter Cleaning/Replacement Efficient Kitchen Fan Eco-Snap Air Conditioning Residential Wet Bulb Chiller Solar-Assisted AC Electro Caloric Heat Pump
Lighting	LED A-line LED Globe LED PAR/R/BR LED Candelabra LED Nightlights Exterior LED Lamp	LED String Lighting Linear LED LED Fixture Occupancy Sensor Exterior Lighting Controls LED Exit Signs	Connected LED Lamps EISA Exempt LED Ultra-Efficient LED Advanced Lighting
New Construction	ENERGY STAR New Home Integrated Design		
Pools/Pumps	Heat Pump Swimming Pool Heater Variable Speed Pool Pump	Pool Timer Well Pump	
Shell	Duct Sealing Air Sealing Basement Sidewall Insulation Floor Insulation Above Crawlspace Wall Insulation Advanced Walls Insulation Ceiling/Attic Insulation	Rim/Band Joist Insulation Low-E Storm Window High Performance Windows Insulated Cellular Shades Multifamily Whole Building Aerosol Sealing Insulated Concrete Forms	Phase Change Blanket Basement Wall InsulationNanoinsulation Ceiling / Attic Insulation Nanoinsulation Crawlspace InsulationNanoinsulation Floor InsulationNanoinsulation Rim and Band Joist Insulation - Nanoinsulation Wall InsulationNanoinsulation
Water Heating	Water Heater Temperature Setback Domestic Hot Water Pipe Insulation Bathroom Aerator 1.0 gpm	Thermostatic Restrictor Shower Valve Heat Pump Water Heater (UEF 2.0)	Water Heater Wrap Drain-water Heat Recovery Shower Timer Recirculating Pump Controls

End Use	Measure Types Included		
	Kitchen Flip Aerator 1.5 gpm Low Flow Showerhead 1.5 gpm	Heat Pump Water Heater (UEF 2.6) Water Heater Timer	

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		
Compressed Air	Efficient Air Compressors (VSD) Efficient Air Nozzles No Loss Condensate Drain Compressed Air Leak Repair Rcx_Compressed Air Optimization Efficient Air Compressor Equipment Efficient Air Compressor Controls Process Improvement - Air Compressor		
Cooking	Combination Oven Convection Oven Electric Griddle Electric Steam Cooker	ENERGY STAR Dishwasher Electric Fryer Insulated Holding Cabinets Advanced Cooking	
Cooling	AC - 16 SEER AC - 18 SEER AC - 21 SEER Air Conditioner - 17 IEER Air Conditioner - 18 IEER Air Conditioner - 21 IEER Air Conditioner - 14.3 IEER Air Conditioner - 15 IEER	PTAC AC Tune-up Air Side Economizer Air Cooled Chiller Water Cooled Chiller	HVAC Occupancy Controls Smart Thermostat Window Film Triple Pane Windows Energy Recovery Ventilator
Heating	HP - 16 SEER HP - 18 SEER HP - 21 SEER HP - 15.0 IEER COP 3.6 HP - 16.0 IEER COP 3.8 HP - 14.5 IEER COP 3.5	HP - 15.5 IEER COP 3.7 HP - 12 IEER 3.4 COP HP - 13 IEER 3.6 COP Geothermal HP - 17 EER Geothermal HP - 19 EER	PTHP Garage Door Hinge
Hot Water	Heat Pump Water Heater Low Flow Faucet Aerator Ozone Commercial Laundry Pre-Rinse Spray Valves		
HVAC	Advanced Rooftop Controls Demand Control Ventilation	Retro-commissioning_Bld Optimization Commercial Weatherstripping	

End Use	Measure Types Included		
	High Efficiency DOAS HVAC - Energy Management System GREM Controls	Advanced HVAC Efficient HVAC Equipment Efficient HVAC O&M	
Lighting	Exterior LED Replacing Metal Halide LED Interior Direction LED Linear Lamp LED Troffers LED Linear Ambient Fixture LED Low-Bay Fixture LED High-Bay Fixture	LED Exit Sign Fluorescent Delamping Lighting Occupancy Sensor Lighting Daylight Sensor Dual Occupancy / Daylight Sensor Luminaire-Level Lighting Controls	Networked Lighting Control Advanced Lighting Efficient Lighting Equipment Efficient Lighting O&M Advanced Lighting Controls Efficient Lighting Grow Lighting
Miscellaneous	Non-Refrigerated Vending Machine Controls Kitchen Exhaust Demand Ventilation Control System	High Efficiency Hand Dryers ENERGY STAR Uninterrupted Power Supply Miscellaneous Custom	
Motors	Variable Frequency Drive Controls Power Drive Systems Switch Reluctance Motors Advanced Motors Efficient Machine Drive Equipment Efficient O&M Efficient Motor Pmp Equipment Efficient Motor Pmp O&M		
Plug Loads	Advanced Power Strip – Teri 1 Commercial Use Smart Socket Energy Star Printer/Copier/Fax Energy Star Server Server Virtualization Electrically Commutated Plug Fans in DataCcenters High Efficiency CRAC Unit Computer Room Air Conditioner Economizer Data Center Hot/Cold Aisle Configuration Advanced IT		
Process	Efficient Process Heat Equipment Efficient Process Heat O&M Efficient Process Refrigeration Equipment Efficient Process Refrigeration O&M Process Equipment	Process O&M Process Improvement - Heat Process Improvement - Other Process Improvement - Refrigeration and Cooling	
Refrigeration	Automated Door Closer for Refrigerator Aerofoils for Open Display Cases	Evaporator Fan Motor Controls Strip Curtains Night Covers	Commercial Ice Marker LED Refrigerated Display Case Refrigeration - Custom

End Use	Measure Types Included		
	Automated Door Closer for Freezer ESTAR Refrigerated Vending Machine Refrigerated Vending Machine Controls Door Heater Controls for Cooler Door Heater Controls for Freezer ECM for Evaporator	Evaporator Fan Motor Variable Speed Condenser Fan Display Case Door Retrofit, Medium Temp Floating Head Pressure Controls	RCx Refrigeration Advanced Refrigeration Efficient Refrigeration Refrigeration O&M
Ventilation	VFD Controls Cogged V-Belt (Synchronous) Efficient Ventilation		
Whole Building	Power Distribution Whole Building Retrofit COM Competitions Business Energy Reports Building Benchmarking	Strategic Energy Management BEIMS Building Operator Certification Efficient Dehumidification Efficient HVAC	Mid-Tier IT Improvements High End IT Improvements Hyperscale IT Improvements

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 2027 to 2046 and estimates of the annual NIPSCO energy efficiency budgets for the residential sector.[124] Cumulative annual residential MWh savings represent 24% and 18% of residential sales in the maximum achievable and realistic achievable potential scenarios, respectively.

Table 5-10: Achievable Residential Sector Annual Energy Efficiency Potential and Annual Utility Budgets

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2027	64,672	19.3	$23,192,756	50,575	12.6	$10,519,160
2028	108,667	35.2	$27,937,935	78,203	20.4	$12,296,863
2029	153,581	51.9	$30,160,372	106,311	28.4	$13,235,799
2030	199,056	69.5	$32,016,573	134,931	36.8	$14,207,522
2031	242,779	84.8	$33,868,763	163,391	44.6	$15,117,341
2032	289,272	101.4	$37,655,268	194,012	53.1	$16,739,498
2033	336,339	119.5	$43,912,595	226,058	62.5	$19,300,726
2034	387,042	137.9	$51,128,069	261,135	72.2	$22,736,831
2035	440,263	157.2	$55,380,771	298,430	82.5	$24,439,390
2036	494,310	177.0	$58,943,898	336,693	93.1	$25,888,556
2037	548,768	196.6	$61,978,625	375,756	103.7	$27,341,096
2038	601,860	215.4	$63,439,508	414,469	114.0	$28,159,380
2039	652,696	232.8	$64,511,729	451,943	123.7	$28,660,711
2040	700,351	248.2	$63,922,935	487,630	132.5	$28,476,395
2041	745,432	262.1	$65,516,656	521,698	140.6	$29,585,240
2042	787,982	274.5	$66,278,332	554,127	148.1	$29,854,785
2043	826,525	285.7	$66,125,283	583,457	154.9	$29,688,014
2044	862,084	296.1	$65,493,837	610,583	161.4	$29,323,415
2045	894,625	305.4	$65,595,063	635,499	167.3	$29,349,148
2046	924,753	313.8	$65,416,740	661,253	173.6	$29,396,758

[124] All achievable potential savings are gross and do not include any adjustments for expected free-ridership and/or spillover.

Table 5-11 below provides the UCT benefit/cost ratios for the period 2027 to 2046 for the residential sector maximum and achievable potential.[125] The overall UCT benefit/cost ratio for the residential portfolio of energy efficiency programs is 2.50 in the realistic achievable potential scenario. In the maximum achievable potential scenario, the overall UCT drops to 1.85.[126]

Table 5-11: Utility Cost Test Benefit/Cost Ratios for Residential Programs

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$984,479,685	$531,699,914	$452,779,771	1.85
RAP	$591,948,901	$236,440,722	$355,508,180	2.50

C&I Achievable Electric Energy Efficiency Savings

Table 5-12 shows the cumulative annual achievable energy efficiency savings for the years 2027 to 2046 and estimates of the annual energy efficiency budgets. Cumulative annual savings by 2046 for the MAP and RAP scenarios represents 24% and 17% of C&I sales, respectively.[127]

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
2027	99,074	16.7	$39,255,766	71,173	11.8	$10,360,372
2028	195,047	32.6	$38,458,634	139,874	23.1	$10,163,890
2029	286,104	47.4	$36,938,615	204,936	33.5	$9,856,851
2030	370,214	60.9	$35,629,196	264,831	43.1	$9,836,659
2031	447,641	73.3	$33,211,602	319,888	51.8	$9,287,855
2032	519,055	84.7	$31,732,504	370,607	59.9	$9,301,386
2033	590,181	97.7	$36,172,390	420,198	68.7	$10,254,498
2034	656,577	110.1	$35,523,645	466,338	77.1	$10,320,037
2035	719,332	122.1	$34,938,435	509,763	85.2	$10,223,970
2036	776,947	133.6	$34,896,361	549,443	92.8	$10,574,611

125 NIPSCO utilized the UCT as the test for screening measures for inclusion.

126 Economic screening for cost-effectiveness was performed assuming incentive levels consistent with historical levels.

127 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.

	Maximum Achievable			Realistic Achievable		
	Cumulative Annual			Cumulative Annual		
Year	MWh	MW	Budget	MWh	MW	Budget
2037	829,601	144.6	$42,166,903	585,941	100.2	$12,393,030
2038	876,710	155.2	$41,210,843	618,703	107.3	$12,075,038
2039	918,659	165.4	$40,549,554	647,698	114.0	$12,227,582
2040	956,320	175.3	$38,618,689	673,627	120.6	$11,653,371
2041	990,757	184.7	$36,911,374	697,366	126.8	$11,515,578
2042	1,011,779	191.9	$44,710,104	712,257	131.7	$14,464,039
2043	1,029,880	198.4	$42,175,314	725,142	136.0	$13,958,534
2044	1,045,370	204.1	$38,682,732	736,200	139.9	$13,039,591
2045	1,058,618	208.9	$36,310,855	745,751	143.2	$12,754,581
2046	1,069,271	212.9	$32,862,096	753,508	146.0	$11,780,106

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: Utility Cost Test Benefit/Cost Ratios for C&I Programs

Achievable Potential Type – C&I	NPV Benefits	NPV Costs	Net Benefits	UCT Ratio
MAP	$1,079,823,362	$950,494,866	$129,328,495	1.1
RAP	$716,158,046	$124,077,509	$592,080,537	5.8

5.2.6 DR Potential

Prior to NIPSCO's rate case in 2018, NIPSCO's demand response portfolio comprised 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 165 MW in total). However, NIPSCO can no longer claim the remaining "non-firm" portion of these customers' loads – nearly 450 MW – as demand response. See above for a description of Rate 531.

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 531 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. Like the 2021 MPS and 2022 IRP, the "non-firm" load associated with Rate 531 customers was excluded from both the demand response potential assessment and NIPSCO's future capacity requirements for the 2024 MPS and the 2025 IRP.

NIPSCO did not have any active DR offerings during 2024 but is in negotiations with vendors to launch two DR offerings in 2025; a Residential Bring Your Own Thermostat program and a C&I Load Curtailment program. The timeline and budgets for these offerings are pending NIPSCO DSM OSB review and regulatory approval.

The DR portion of the MPS considered the following DR program types:

- C&I Load Curtailment
- Data Center Load Curtailment
- Residential Connected Thermostats
- Electric Vehicle Managed Charging
- Residential Time-Varying Rates[128]
- Residential Water Heater Load Control
- Residential Behavioral Demand Response
- Residential Behind-the-Meter Battery Storage

Like the energy efficiency portion of the MPS, the DR portion of the MPS 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. The realistic achievable potential represents more "middle-ground" assumptions around program incentives and design. Thus, the RAP scenarios generally 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. Table 5-14 shows the UCT cost-effectiveness screening results by program based on the MPS avoided cost inputs. To increase optionality in the modeling process, all DR options were included in the DR MPS outputs and considered in the IRP.

Table 5-14: UCT Results by DR Program Type and Scenario

Program	RAP	MAP
Connected Thermostats	Pass	Fail

[128] Includes daily time-of-use, critical peak pricing, and peak time rebates. 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.

Water Heaters	Fail	Fail
Behavioral DR	Pass	Pass
Dynamic Rates	Pass	Pass
EV Managed Charging	Fail	Fail
BTM Storage	Fail	Fail
C&I Load Curtailment	Pass	Pass
Data Centers	Pass	Pass

The 2021 MPS and 2022 IRP only considered summer DR potential. Given the transition to a seasonal capacity construct at MISO, the 2024 MPS modeled DR potential separately for the spring, summer, fall, and winter seasons. The summer MAP and RAP demand response by program over the 2027-2046 MPS horizon are shown in Figure 5-1 and Table 5-2, respectively. The difference between aggregate MAP potential and aggregate RAP potential is due to the Connected Thermostat DR offering failing UCT screening under MAP incentive levels.

Figure 5-1: Maximum Achievable DR Potential by Program

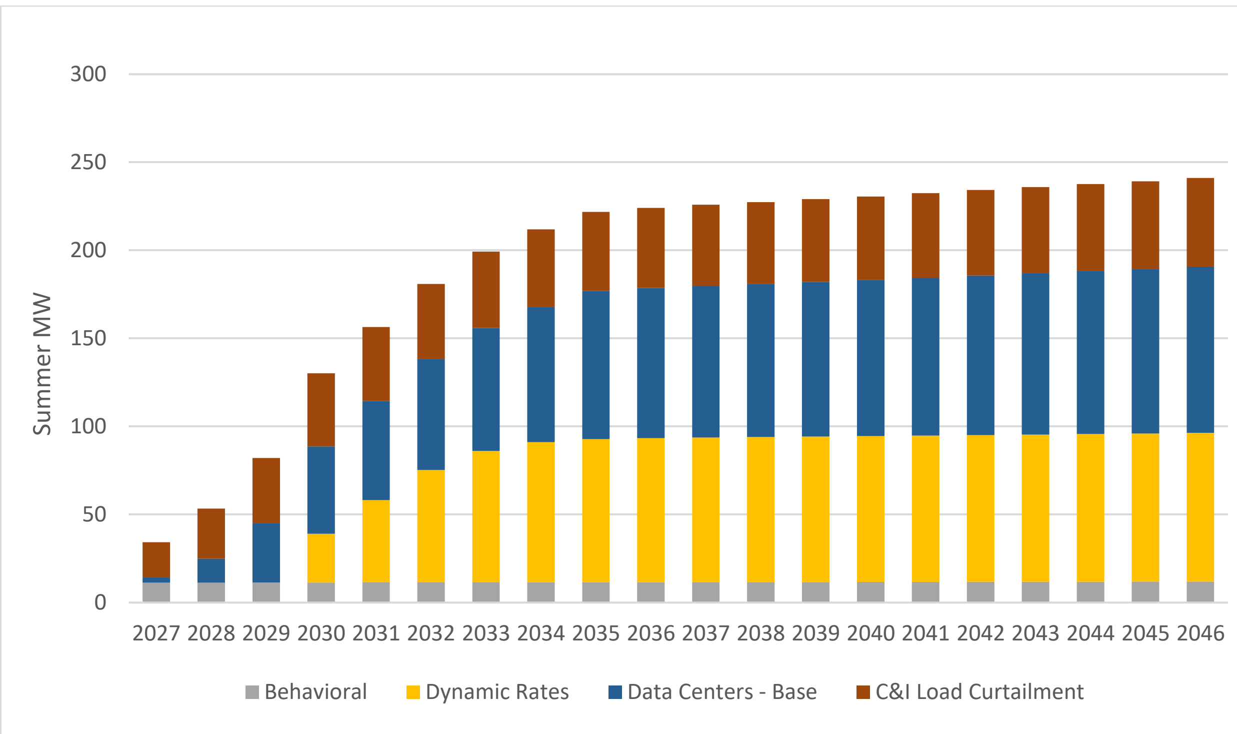
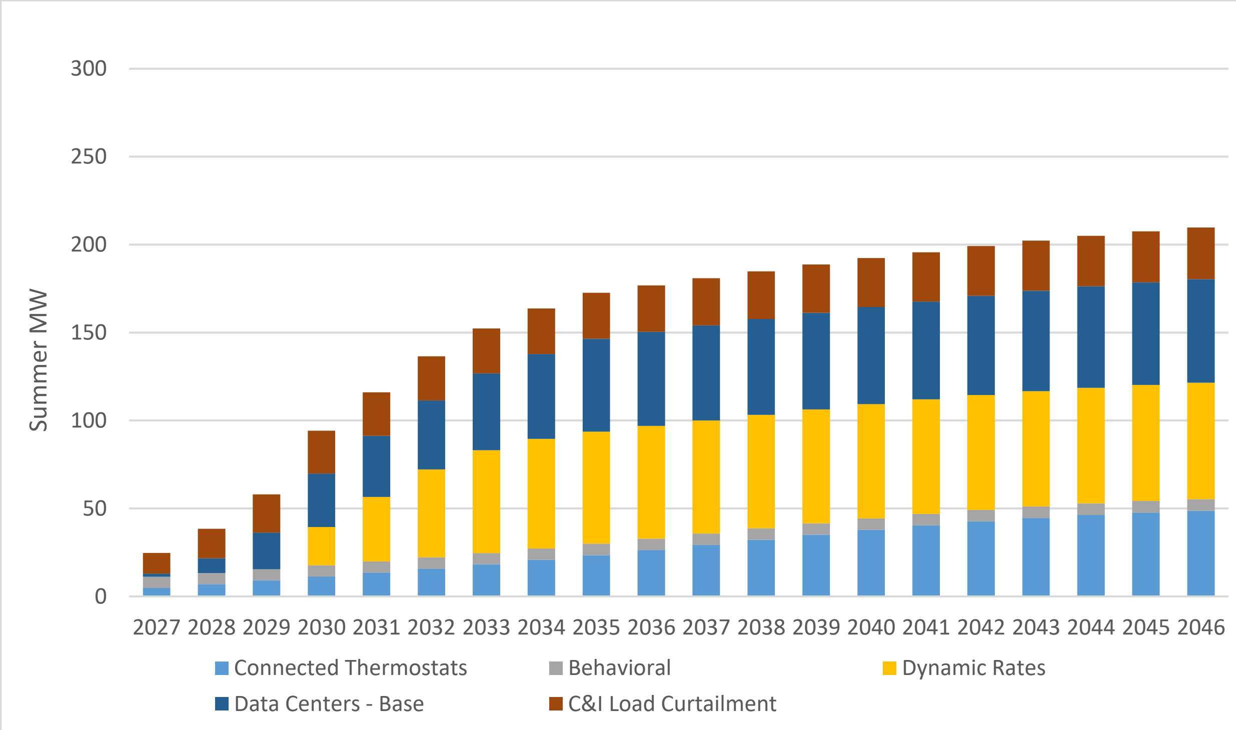


Figure 5-2: Realistic Achievable DR Potential by Program



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.[129] Based on coordination between NIPSCO and the NIPSCO OSB, the GDS Team also developed an Enhanced RAP scenario, which attempted to optimize the cost-effectiveness of the RAP scenario by adjusting incentive levels in certain cases. For both the RAP and Enhanced RAP scenarios, the GDS Team allocated all C&I measures into a single bundle but segmented the residential sector savings into high-cost measures (Tier 2) and low-/mid-cost measures (Tier 1). In addition, the residential sector was further sub-divided into three more bundles, one for behavior measures, due to the unique nature of these types of measures, which have a one-year useful life and have recurring annual costs, and two for income-qualified measures. The first income-qualified bundle (IQW) correlates to measures traditionally offered by NIPSCO, and the second (IQ HEAR) captures savings associated with measures installed by income-qualified customers as a result of participating in federally funded programs associated with the Inflation Reduction Act.[130] The IQW bundle has 10% of the IQ HEAR measure savings and costs allocated toward it,

[129] 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.

[130] The Inflation Reduction Act established the Home Electrification and Appliance Rebate (HEAR) program, which provides rebates and credits for a variety of measures, including weatherization, HVAC equipment, and heat pump water heaters.

to account for the possibility that NIPSCO will expand its IQW programs in the future to capture some of these savings opportunities. The GDS Team provided the energy efficiency IRP inputs across three different vintage bundles: 2027-2029, 2030-2032, and 2033-2046 to better optimize the value of energy efficiency to the system over different time periods.

In addition, two 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 program evaluation results and NTG ratios to the MPS estimates of gross realistic achievable savings.

The second 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 energy efficiency impacts provided to NIPSCO for IRP modeling, by vintage block, are shown in Table 5-15 through Table 5-17 below, for the RAP scenarios, and Table 5-18 through 5-20, for the Enhanced RAP scenario.[131] The EE MWh 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. The costs were adjusted to represent program costs minus the NPV of the lifetime avoided T&D benefits from the programs.

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.

[131] MW represents the summer impact.

Table 5-15: 2027-2029 Energy Efficiency Base Case Bundles – RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2027	16,362	$3,419,923	2,450	$2,013,267	29,307	$1,669,981	63,372	$7,859,797	1,188	$978,984	977	$860,890
2028	35,071	$3,997,693	5,584	$2,497,028	30,179	$1,757,633	124,647	$7,843,644	2,369	$1,002,121	2,157	$1,048,576
2029	54,055	$4,243,790	8,812	$2,725,808	30,855	$1,836,729	182,724	$7,729,304	3,557	$1,024,847	3,542	$1,240,538
2030	53,571		7,869				177,249		3,527		3,542	
2031	52,524		7,163				170,783		3,527		3,542	
2032	51,994		6,803				162,913		3,514		3,542	
2033	50,254		6,648				159,983		3,500		3,542	
2034	43,721		6,404				155,407		3,487		3,542	
2035	37,338		6,304				152,992		3,487		3,542	
2036	32,269		6,184				148,855		3,487		3,542	
2037	29,166		5,993				135,308		3,452		3,542	
2038	25,539		5,650				120,597		3,417		3,542	
2039	22,327		5,201				106,545		3,382		3,542	
2040	20,981		5,051				102,776		3,382		3,542	
2041	20,482		4,958				101,006		3,382		3,542	
2042	19,951		4,758				65,938		3,339		3,489	
2043	18,399		4,355				33,308		3,180		2,498	
2044	16,629		3,911				3,430		2,998		1,303	
2045	15,427		3,727				3,298		2,845		28	
2046	15,427		3,346				3,298		2,845		28	
2047	13,053		2,366				2,941		2,007		28	
2048	10,208		1,161				2,529		1,172		28	
2049	7,247		240				2,065		342		28	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2050	7,055		161				2,046		342		28	
2051	6,904		86				2,021		342		28	
2052	6,325		17				1,979		341		20	
2053	5,657		17				1,966		340		11	
2054	4,909		17				1,951		339			
2055	4,909		17				1,947		339			
2056	4,909		17				1,945		339			
2057	3,745		13				1,221		225			
2058	1,980		7				565		112			

Table 5-16: 2030-2032 Energy Efficiency Base Case Bundles – RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2030	19,772	$4,164,551	4,370	$3,089,242	31,375	$1,908,955	58,956	$7,898,094	1,235	$1,048,799	1,586	$1,433,374
2031	40,246	$4,366,344	8,768	$3,312,755	31,468	$1,956,740	114,619	$7,555,035	2,462	$1,072,188	3,361	$1,620,830
2032	61,975	$4,818,094	13,314	$3,769,135	31,556	$2,005,334	167,844	$7,753,039	3,702	$1,094,603	5,310	$1,798,357
2033	61,249		11,212				156,804		3,677		5,310	
2034	59,878		9,928				145,470		3,677		5,310	
2035	59,348		9,251				133,955		3,663		5,310	
2036	57,462		9,061				130,873		3,650		5,310	
2037	52,176		8,671				124,151		3,637		5,310	
2038	47,250		8,487				121,756		3,637		5,310	
2039	42,840		8,284				117,492		3,637		5,310	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**
2040	39,590		7,944				105,266		3,602		5,310	
2041	35,437		7,472				92,026		3,567		5,310	
2042	32,070		6,828				81,055		3,532		5,310	
2043	30,178		6,646				77,795		3,532		5,310	
2044	29,437		6,534				76,627		3,532		5,310	
2045	28,176		6,153				49,658		3,480		5,180	
2046	25,188		5,542				25,567		3,252		3,570	
2047	21,905		4,857				3,167		3,003		1,765	
2048	19,894		4,594				3,021		2,799		36	
2049	19,894		4,183				3,021		2,799		36	
2050	16,953		2,823				2,511		1,974		36	
2051	13,943		1,500				1,960		1,153		36	
2052	10,654		205				1,369		337		36	
2053	10,461		142				1,328		337		36	
2054	10,340		82				1,276		337		36	
2055	9,422		25				1,197		336		25	
2056	8,532		25				1,177		335		13	
2057	7,425		25				1,154		333			
2058	7,425		25				1,146		333			
2059	7,425		25				1,142		333			
2060	5,293		18				669		221			
2061	2,932		10				291		110			

Table 5-17: 2033-2046 Energy Efficiency Base Case Bundles – RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2033	25,337	$5,703,875	7,195	$4,598,831	31,636	$2,054,631	58,890	$8,515,863	1,276	$1,115,749	2,102	$1,963,013
2034	58,815	$7,548,044	14,258	$5,178,993	31,729	$2,106,106	116,719	$8,690,559	2,535	$1,135,403	4,339	$2,112,945
2035	93,473	$8,107,835	20,996	$5,606,652	31,823	$2,158,974	170,172	$8,647,683	3,800	$1,153,441	6,688	$2,246,954
2036	129,121	$8,473,335	27,527	$6,141,943	31,917	$2,213,208	213,572	$8,966,885	5,069	$1,169,784	9,131	$2,364,313
2037	167,230	$8,988,161	34,324	$6,473,824	32,011	$2,268,764	267,182	$10,728,527	6,337	$1,184,423	11,649	$2,465,086
2038	205,591	$9,360,616	40,874	$6,614,348	32,105	$2,325,648	314,251	$10,260,650	7,591	$1,197,464	14,226	$2,550,047
2039	242,397	$9,599,470	47,113	$6,751,402	32,200	$2,384,042	359,084	$10,471,723	8,840	$1,206,911	16,827	$2,601,547
2040	275,017	$9,596,845	52,734	$6,598,125	32,295	$2,443,803	398,734	$9,737,190	10,082	$1,215,646	19,446	$2,645,775
2041	306,575	$10,767,833	57,909	$6,369,654	32,390	$2,504,969	435,324	$9,483,427	11,318	$1,223,793	22,080	$2,683,582
2042	336,259	$10,830,681	62,823	$6,549,695	32,486	$2,567,694	494,814	$13,512,061	12,545	$1,230,332	24,724	$2,716,062
2043	363,647	$10,809,438	66,862	$6,426,694	32,582	$2,632,027	542,194	$12,708,462	13,730	$1,237,440	27,375	$2,744,318
2044	388,456	$10,671,654	70,375	$6,193,093	32,678	$2,697,948	582,919	$11,720,972	14,910	$1,244,243	30,030	$2,769,354
2045	411,467	$10,585,530	73,454	$6,262,606	32,774	$2,765,419	618,172	$11,392,845	16,084	$1,249,937	32,684	$2,784,297
2046	433,531	$10,410,533	76,565	$6,435,549	32,871	$2,834,554	648,599	$10,319,709	17,252	$1,255,696	35,335	$2,799,568
2047	415,177		65,444				603,179		17,179		35,335	
2048	390,026		57,930				532,620		17,065		35,082	
2049	364,554		52,881				469,227		16,730		32,945	
2050	339,648		49,838				419,664		16,381		30,676	
2051	314,845		46,675				374,423		16,019		28,297	
2052	290,383		43,685				335,119		15,662		25,830	
2053	262,820		39,204				297,174		14,485		23,294	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2054	239,478		34,873				264,221		13,309		20,706	
2055	216,692		30,424				233,535		12,137		18,099	
2056	195,659		25,908				207,431		10,969		15,478	
2057	176,610		22,119				158,034		9,844		12,847	
2058	157,613		18,553				113,797		8,723		10,196	
2059	138,289		15,217				73,880		7,609		7,540	
2060	118,711		12,113				38,808		6,503		4,886	
2061	99,845		9,283				7,753		5,404		2,235	
2062	89,307		7,602				6,198		4,409		127	
2063	79,168		6,329				4,644		3,555		113	
2064	68,470		5,136				3,233		2,707		99	
2065	57,690		3,792				1,950		1,865		85	
2066	46,772		2,834				810		1,029		70	
2067	38,235		2,192				611		921		56	
2068	30,266		1,554				412		814		42	
2069	22,927		948				214		708		28	
2070	16,511		459				153		603		14	
2071	10,954		39				92		499			
2072	8,050		29						398			
2073	5,575		20						297			
2074	3,455		12						197			
2075	1,618		6						98			

Table 5-18: 2027-2029 Energy Efficiency Base Case Bundles – Enhanced RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2027	19,868	$5,788,648	2,291	$1,394,054	29,307	$1,669,981	65,417	$12,092,901	1,187	$979,095	977	$860,891
2028	42,897	$6,632,135	4,997	$1,614,881	30,179	$1,757,633	129,111	$12,084,214	2,391	$1,002,291	2,157	$1,048,578
2029	66,471	$6,929,202	7,756	$1,755,827	30,855	$1,836,729	189,592	$11,761,999	3,606	$1,025,072	3,541	$1,240,542
2030	65,866		6,928				184,009		3,526		3,541	
2031	65,104		5,685				177,406		3,520		3,541	
2032	64,893		4,791				169,415		3,507		3,541	
2033	62,862		3,926				166,540		3,494		3,541	
2034	55,366		3,807				162,011		3,480		3,541	
2035	48,039		3,715				159,592		3,480		3,541	
2036	42,722		3,599				155,401		3,480		3,541	
2037	39,239		3,374				141,512		3,445		3,541	
2038	35,213		2,990				126,320		3,410		3,541	
2039	32,093		2,334				111,791		3,375		3,541	
2040	30,934		2,013				107,736		3,375		3,541	
2041	30,584		1,722				105,946		3,375		3,541	
2042	29,905		1,645				69,332		3,332		3,488	
2043	27,832		1,449				35,077		3,173		2,497	
2044	25,444		1,215				3,800		2,991		1,303	
2045	23,705		1,090				3,668		2,838		28	
2046	23,537		1,055				3,668		2,838		28	
2047	19,069		765				3,309		2,001		28	
2048	13,827		510				2,889		1,168		28	
2049	8,603		264				2,412		341		28	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2050	8,412		186				2,394		341		28	
2051	8,260		110				2,369		341		28	
2052	7,544		41				2,328		340		20	
2053	6,670		41				2,315		339		11	
2054	5,695		41				2,299		338			
2055	5,695		41				2,296		338			
2056	5,695		41				2,294		338			
2057	4,339		31				1,522		225			
2058	2,291		16				743		112			

Table 5-19: 2030-2032 Energy Efficiency Base Case Bundles – Enhanced RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2030	24,625	$7,081,671	3,714	$1,955,144	31,375	$1,908,955	61,459	$ 11,615,088	1,310	$1,049,135	1,585	$1,433,381
2031	50,206	$7,261,766	7,265	$2,070,751	31,468	$1,956,740	120,091	$ 11,188,912	2,560	$1,072,614	3,358	$1,620,841
2032	77,550	$7,756,698	10,608	$2,247,118	31,556	$2,005,334	176,061	$ 10,983,642	3,830	$1,094,913	5,305	$1,798,373
2033	76,461		8,804				164,749		3,675		5,305	
2034	75,199		7,065				153,120		3,670		5,305	
2035	74,745		6,107				141,356		3,656		5,305	
2036	72,326		5,349				138,337		3,643		5,305	
2037	66,049		5,106				131,697		3,616		5,305	
2038	60,287		4,936				129,297		3,616		5,305	
2039	55,469		4,739				124,958		3,616		5,305	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**	**MWh**	**Budget**
2040	51,725		4,345				112,371		3,581		5,305	
2041	47,026		3,837				98,330		3,546		5,305	
2042	43,737		2,946				86,720		3,512		5,305	
2043	42,066		2,590				82,934		3,512		5,305	
2044	41,481		2,287				81,656		3,512		5,305	
2045	40,034		2,054				53,321		3,460		5,176	
2046	36,200		1,650				27,699		3,232		3,566	
2047	31,918		1,194				3,859		2,983		1,763	
2048	29,021		999				3,714		2,780		36	
2049	28,853		934				3,714		2,780		36	
2050	23,540		631				3,186		1,959		36	
2051	18,214		426				2,610		1,144		36	
2052	12,610		240				1,991		335		36	
2053	12,418		178				1,950		335		36	
2054	12,297		117				1,898		335		36	
2055	11,136		60				1,820		334		25	
2056	9,980		60				1,799		332		13	
2057	8,541		60				1,775		331			
2058	8,541		60				1,768		331			
2059	8,541		60				1,763		331			
2060	6,082		43				1,081		220			
2061	3,368		24				488		109			

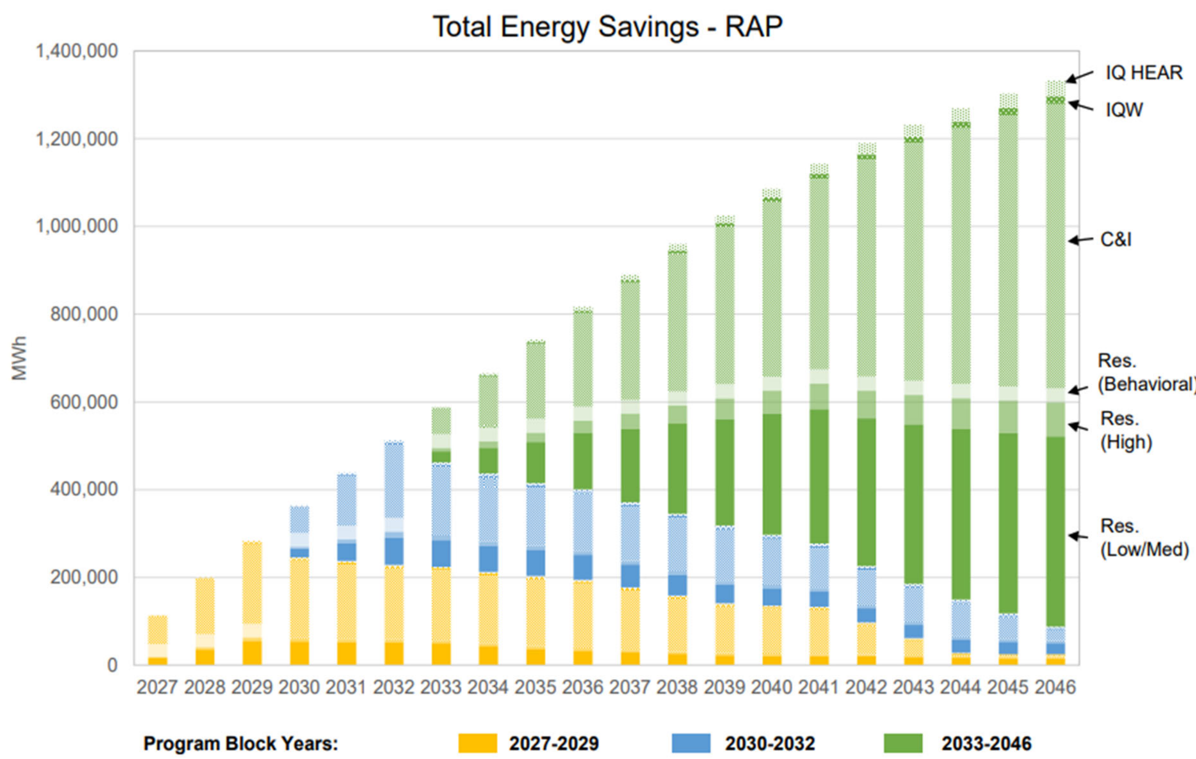
Table 5-20: 2033-2046 Energy Efficiency Base Case Bundles – Enhanced RAP

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2033	31,676	$8,720,124	5,553	$2,719,282	31,636	$2,054,631	62,987	$11,916,407	1,434	$1,116,181	2,099	$1,963,036
2034	72,023	$10,667,326	10,710	$3,082,800	31,729	$2,106,106	123,728	$11,658,184	2,725	$1,135,984	4,332	$2,112,977
2035	113,737	$11,296,524	15,446	$3,372,699	31,823	$2,158,974	179,974	$11,440,014	4,015	$1,154,201	6,676	$2,246,997
2036	156,326	$11,794,105	20,375	$3,756,617	31,917	$2,213,208	225,924	$11,591,134	5,305	$1,170,750	9,112	$2,364,368
2037	201,697	$12,366,923	25,184	$4,219,260	32,011	$2,268,764	282,598	$12,975,460	6,642	$1,182,602	11,622	$2,465,154
2038	246,613	$12,453,276	30,302	$4,559,573	32,105	$2,325,648	333,163	$12,514,244	7,948	$1,195,832	14,190	$2,550,128
2039	288,538	$12,661,045	35,785	$4,999,291	32,200	$2,384,042	381,184	$12,157,896	9,246	$1,205,486	16,781	$2,601,641
2040	325,506	$12,548,387	41,241	$5,229,868	32,295	$2,443,803	424,082	$11,433,519	10,535	$1,214,431	19,390	$2,645,880
2041	360,714	$13,676,630	47,002	$5,500,003	32,390	$2,504,969	463,991	$11,176,659	11,816	$1,222,798	22,012	$2,683,698
2042	392,802	$13,768,017	53,275	$6,066,473	32,486	$2,567,694	527,745	$12,902,636	13,123	$1,227,448	24,643	$2,716,188
2043	421,926	$13,777,318	59,202	$6,373,409	32,582	$2,632,027	579,064	$12,459,673	14,398	$1,234,713	27,281	$2,744,453
2044	447,878	$13,546,326	65,259	$6,578,958	32,678	$2,697,948	622,782	$11,747,953	15,665	$1,241,667	29,923	$2,769,497
2045	471,701	$13,509,422	71,100	$6,889,287	32,774	$2,765,419	660,601	$11,531,846	16,924	$1,247,490	32,562	$2,784,447
2046	494,467	$13,399,619	76,958	$6,984,706	32,871	$2,834,554	693,475	$10,801,640	18,175	$1,253,360	35,199	$2,799,724
2047	472,474		67,682				646,759		17,549		35,199	
2048	443,384		62,233				572,187		17,355		34,946	
2049	413,677		59,104				506,012		16,946		32,813	
2050	386,423		55,945				453,852		16,522		30,548	
2051	359,319		52,453				405,822		16,086		28,174	
2052	332,604		48,962				363,565		15,694		25,714	
2053	300,705		44,961				322,348		14,492		23,186	

	Residential - Low/Medium		Residential - High		Residential - Behavior		C&I		IQW		IQ HEAR	
Year	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget	MWh	Budget
2054	273,056		40,939				286,108		13,292		20,607	
2055	246,108		36,544				252,294		12,097		18,010	
2056	221,903		31,741				223,218		10,910		15,400	
2057	200,578		27,191				169,958		9,764		12,782	
2058	179,524		22,243				122,361		8,625		10,143	
2059	158,232		17,112				79,587		7,483		7,501	
2060	137,053		11,723				42,175		6,351		4,860	
2061	116,955		6,180				8,760		5,229		2,222	
2062	102,540		5,445				7,155		4,250		126	
2063	89,784		4,815				5,379		3,424		112	
2064	76,593		4,119				3,778		2,607		98	
2065	63,346		3,507				2,333		1,797		84	
2066	50,276		2,851				1,021		996		70	
2067	40,937		2,207				689		890		56	
2068	32,280		1,569				426		785		42	
2069	24,379		966				221		682		28	
2070	17,522		482				158		580		14	
2071	11,634		68				96		479			
2072	8,485		48						382			
2073	5,831		32						285			
2074	3,587		19						189			
2075	1,668		9						94			

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.

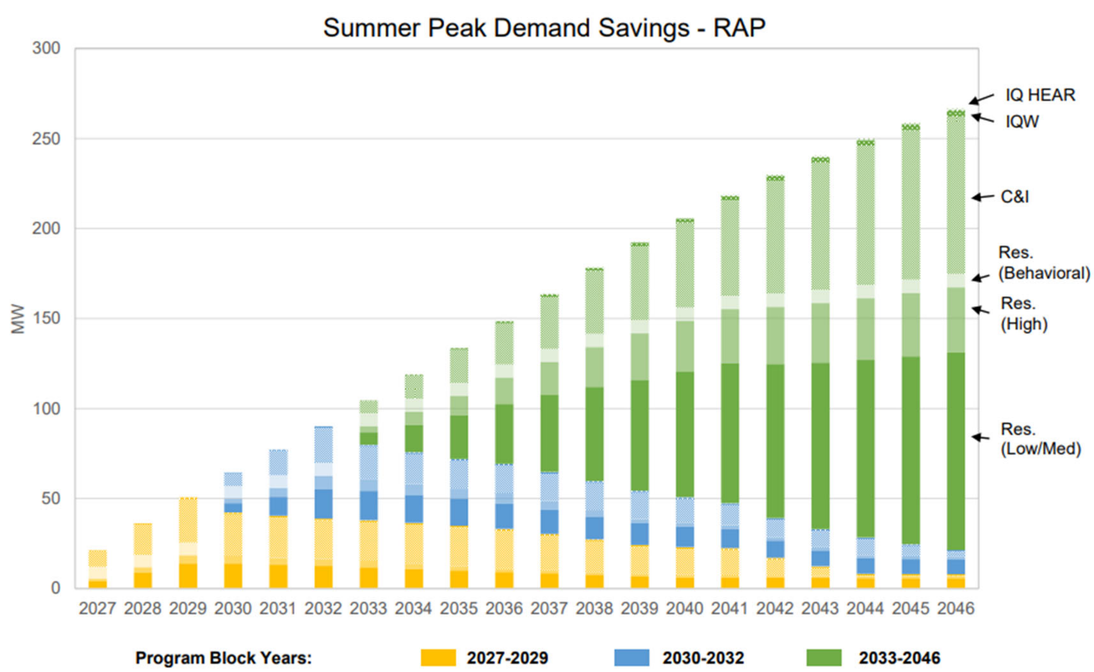
Figure 5-3: Energy Efficiency MWh Savings Bundle Illustration - RAP

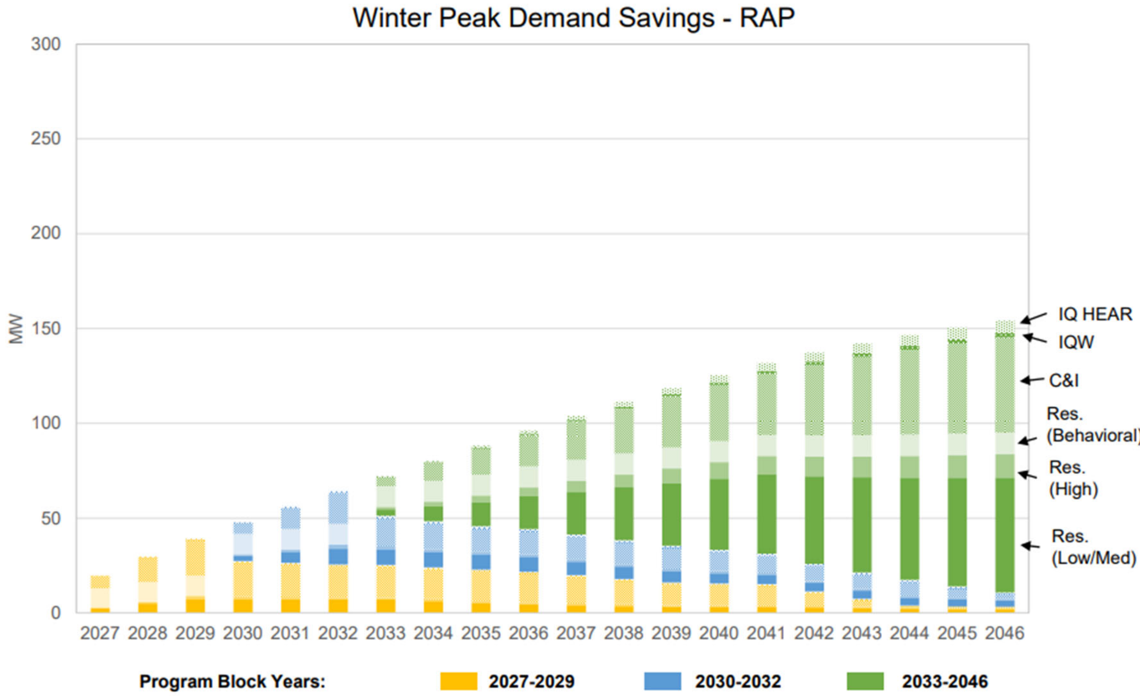


Bundle	Lifetime Levelized Cost ($/MWh) 2027-2029	2030-2032	2033-2046
IQ HEAR*	89.09	91.67	99.93
IQW*	77.50	80.02	87.62
C&I	15.81	18.69	22.35
Res. (Behavioral)	58.21	62.13	73.39
Res. (High)	101.51	102.34	106.77
Res. (Low/Med)	26.56	24.95	27.84

**The HEAR bundle is for savings associated with measures allocated towards income qualified customers but which would be offered through a program tied to federal funding rather than a NIPSCO-funded program. The IQ HEAR and IQW savings are "hardcoded" into the IRP modeling.*

Figure 5-4: Energy Efficiency Peak MW Savings Bundle Illustration - RAP





5.3.2 DR Programs

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 eight program sub-segments. Each DR program type was modeled separately with its own seasonal MW potential and annual cost profile. Avoided transmission and distribution capacity benefits were treated as a reduction in annual DR program cost. The new data center load is assumed to be transmission-connected, so it does not receive the avoided cost of distribution capacity under either avoided cost scenario.

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 and a higher cost of transmission and distribution capacity 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. Under the alternate avoided cost scenario, EV Managed Charging had a UCT ratio greater than 1.0 for both RAP and MAP and the Connected Thermostat MAP scenario passed cost-effectiveness screening. For the C&I Load Curtailment program, the incentive levels, and therefore the enrollment rates, were increased to reflect the higher avoided costs. The result is an increase in the total demand response potential as well as in the overall program costs per kW of capacity.

Table 5-21 provides the DR inputs used in the IRP modeling based on the RAP scenario in the summer season. Table 5-22: shows the MAP program options for the summer season.

Aggregate DR potential is highest in the summer season and lowest in the spring season, largely due to the variation in available loads and the expected timing of system constraints.

Table 5-21: DR Program Options – Summer Potential – RAP

	RAP															
	Connected Thermostats		Water Heaters		Behavioral		Dynamic Rates		EV Managed Charging		Behind the Meter Storage		Data Centers - Base		C&I	
Year	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)
2027	4.85	$242.35	2.30	$1,058.80	6.30	$86.55			0.74	$760.97	0.37	$1,993.83	1.87	$90.41	11.75	$80.29
2028	6.98	$136.34	2.19	$180.55	6.33	$65.01			1.02	$325.62	0.40	$481.28	8.46	$89.71	16.68	$81.13
2029	9.15	$130.41	2.09	$187.37	6.35	$67.34			1.39	$311.72	0.45	$506.15	20.80	$91.58	21.75	$82.91
2030	11.34	$128.03	1.98	$196.59	6.37	$69.75	21.73	$246.81	1.89	$303.02	0.50	$496.21	30.40	$93.87	24.40	$85.49
2031	13.56	$127.61	1.88	$206.84	6.39	$72.23	36.64	$146.23	2.55	$304.79	0.56	$496.38	34.75	$97.44	24.70	$88.48
2032	15.85	$128.57	1.78	$218.53	6.41	$74.79	50.00	$130.66	3.37	$305.58	0.63	$482.47	39.18	$100.99	25.12	$89.59
2033	18.26	$130.41	1.67	$232.03	6.42	$77.45	58.46	$117.82	4.32	$306.19	0.67	$446.27	43.68	$104.57	25.54	$92.50
2034	20.81	$132.85	1.58	$247.85	6.44	$80.20	62.33	$110.15	5.35	$305.95	0.71	$426.09	48.25	$108.16	25.87	$95.42
2035	23.50	$135.72	1.47	$266.68	6.46	$83.06	63.68	$108.08	6.38	$305.76	0.72	$312.37	52.88	$111.75	26.13	$98.35
2036	26.33	$138.84	1.37	$289.23	6.48	$86.02	64.12	$109.81	7.32	$305.01	0.71	$314.71	53.46	$115.36	26.38	$101.26
2037	29.24	$142.14	1.27	$316.41	6.50	$89.08	64.35	$113.19	8.10	$305.47	0.71	$327.15	53.98	$118.96	26.83	$105.34
2038	32.18	$145.60	1.17	$349.23	6.52	$92.23	64.54	$117.11	8.71	$309.07	0.70	$335.49	54.45	$122.56	27.16	$109.41
2039	35.06	$149.18	1.07	$389.10	6.54	$95.49	64.73	$121.24	9.13	$314.19	0.70	$359.19	54.88	$126.17	27.47	$113.48
2040	37.81	$152.86	0.97	$437.70	6.56	$98.86	64.92	$125.52	9.36	$321.72	0.71	$376.62	55.26	$129.77	27.77	$117.51
2041	40.35	$156.69	0.87	$497.38	6.58	$102.33	65.11	$129.92	9.74	$319.40	0.72	$398.68	55.58	$133.38	28.03	$121.53
2042	42.62	$160.72	0.77	$573.99	6.59	$105.91	65.31	$134.48	9.98	$318.26	0.72	$398.28	56.35	$138.18	28.29	$125.53
2043	44.60	$164.98	0.68	$666.58	6.61	$109.63	65.50	$139.20	10.08	$318.24	0.73	$416.73	57.07	$142.98	28.51	$129.52
2044	46.26	$169.48	0.59	$781.26	6.63	$113.46	65.71	$144.14	10.06	$319.21	0.74	$434.91	57.74	$147.79	28.70	$133.50
2045	47.61	$174.22	0.51	$921.58	6.65	$117.41	65.93	$149.17	9.94	$321.39	0.74	$434.53	58.33	$152.59	29.06	$138.63
2046	48.66	$179.23	0.44	$1,098.79	6.67	$121.49	66.15	$154.36	9.87	$336.80	0.75	$448.97	58.86	$157.39	29.42	$143.73

Table 5-22: DR Program Options – Summer Potential - MAP

MAP															
Connected Thermostats		Water Heaters		Behavioral		Dynamic Rates		EV Managed Charging		Behind the Meter Storage		Data Centers - Base		C&I	
DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Season Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)
7.29	$427.69	4.61	$924.71	11.21	$78.76			1.31	$308.62	0.75	$2,926.77	2.98	$140.51	20.04	$149.05
11.40	$260.06	4.38	$216.14	11.25	$67.73			1.80	$212.14	0.81	$552.33	13.61	$143.37	28.43	$153.17
15.28	$241.25	4.16	$224.55	11.29	$70.17			2.48	$214.79	0.91	$609.55	33.67	$147.84	37.05	$157.84
18.95	$233.27	3.95	$234.78	11.32	$72.69	27.73	$657.92	3.36	$219.55	1.01	$618.03	49.50	$152.57	41.54	$162.97
22.43	$230.57	3.74	$246.27	11.36	$75.29	46.76	$280.98	4.53	$228.61	1.13	$645.13	56.21	$157.35	42.02	$168.33
25.84	$231.45	3.53	$259.51	11.39	$77.97	63.79	$201.19	5.98	$238.75	1.26	$652.66	62.97	$162.12	42.70	$172.57
29.24	$234.49	3.31	$275.02	11.42	$80.75	74.59	$129.87	7.68	$250.03	1.35	$573.98	69.79	$166.91	43.40	$177.87
32.70	$238.94	3.10	$293.51	11.45	$83.63	79.53	$80.53	9.51	$262.35	1.43	$555.16	76.66	$171.70	44.18	$184.36
36.24	$244.21	2.88	$315.98	11.48	$86.62	81.25	$56.01	11.35	$275.85	1.44	$316.34	84.16	$177.70	44.83	$190.86
39.85	$249.89	2.66	$343.49	11.52	$89.71	81.81	$48.42	13.01	$290.49	1.43	$300.26	85.20	$183.70	45.46	$197.35
43.44	$255.68	2.44	$377.56	11.55	$92.91	82.10	$47.95	14.40	$306.58	1.42	$313.23	86.15	$189.70	46.03	$203.81
46.97	$261.60	2.21	$420.01	11.59	$96.21	82.35	$49.44	15.48	$324.54	1.41	$326.68	87.01	$195.70	46.39	$210.27
50.31	$267.41	1.98	$473.50	11.62	$99.63	82.59	$51.35	16.23	$344.23	1.42	$356.82	87.81	$201.70	46.97	$217.91
53.34	$273.15	1.76	$541.68	11.66	$103.15	82.84	$53.36	16.65	$365.92	1.43	$387.24	88.51	$207.71	47.51	$225.52
55.98	$278.94	1.53	$630.16	11.69	$106.78	83.08	$55.43	17.31	$375.89	1.45	$411.88	89.62	$214.91	47.99	$233.10
58.18	$284.93	1.31	$751.74	11.72	$110.54	83.33	$57.58	17.73	$386.43	1.45	$400.96	90.65	$222.11	48.46	$240.68
59.89	$291.24	1.09	$912.88	11.76	$114.43	83.57	$59.81	17.92	$397.52	1.46	$434.95	91.60	$229.31	48.87	$248.24
61.14	$297.95	0.89	$1,136.24	11.79	$118.44	83.85	$62.40	17.88	$409.16	1.48	$455.99	92.47	$236.52	49.42	$256.97
61.93	$305.03	0.71	$1,452.68	11.83	$122.58	84.12	$64.78	17.67	$421.38	1.49	$457.27	93.23	$243.72	49.93	$265.68
62.30	$312.66	0.54	$1,936.68	11.86	$126.86	84.40	$67.24	17.55	$436.11	1.50	$473.50	94.36	$252.12	50.43	$274.36

The IRP team converted the annual program cost estimate and cumulative DR potential, by season, into a levelized cost by DR program option. The DR programs were then allowed to compete in the broader resource selection process.

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 the 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 2024 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 portfolio analysis phase (*see* Section 9).

In accordance with the DSM Statute, NIPSCO intends to request approval in 2025 of an EE and DR plan, for implementation in 2027, that includes:

- EE and DR goals that are: (1) reasonably achievable; (2) consistent with NIPSCO's 2024 IRP; and (3) designed to achieve an optimal balance of energy resources in its service territory;
- EE and DR 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 EE and DR programs; (2) costs associated with the EM&V of program results; (3) recovery of lost revenues and performance incentives;[132] and
- EM&V procedures that involve an independent EM&V.

NIPSCO intends to develop a DSM Plan, prior to its filing in 2025, based on the EE and DR selected by the IRP model. This may be updated if another MPS has been completed. The

[132] 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;

DSM Plan will take into account the results of the IRP for implementation and evaluation of the EE and DR plan.

The benefit of a DSM Plan is that it uses various forms of information, including the IRP, to develop the best strategy for an energy efficiency and demand response plan. The DSM 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 a DSM 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 the development of the DSM RFPs and the creation of the DSM 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.

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 a DSM program. That means that the programs included in the plan 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 that 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 DSM plan will be without change. Until the programs are administered to the customer base and the firsthand experiences with energy efficiency and demand response 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 ongoing mechanism to adjust to changing market conditions, including codes and standards and new technologies, and to ensure NIPSCO is capturing as much energy efficiency and demand response 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 the availability, reliability and efficiency of the electric delivery system; and
- 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 2024 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 Reliability First 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 certain circumstances, NIPSCO can request expedited review of these projects.

NIPSCO is situated on a very significant boundary (seam) between MISO and PJM. As such, 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 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 combined benefit to cost ratio) before 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 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.

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:

- Rebuild Marktown 138 kV Substation
- Rebuild Lagrange-Angola 69 kV line
- MISO LRTP-15 (IL-IN Border to Morrison 345 kV)
- MISO LRTP-16 (Morrison to Reynolds to Hiple 345 kV)
- Upgrade Roxanna-Mittal #2 138 kV
- Upgrade Leesburg Substation 138 kV
- 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:

- 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
- Aetna 138 kV Synchronous Condenser

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. In December 2021 this plan was approved by the IURC. 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 comprises 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).

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).[133] 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.

[133] 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.

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 at their utility retail rate for their excess generation that can be applied to future usage. The Net Metering program ended for new customer applications for non-residential customers as of October 1, 2021, and for residential customers as of June 20, 2022. The EDG Tariff replaced Net Metering. An EDG credit is applied to a customer's bill if a customer generates more energy than they consume. The EDG credit amount is calculated annually and is 125% of the average wholesale price of power for the prior calendar year.

The renewable feed-in tariff (renewable energy payments) is another policy mechanism designed to encourage the adoption of renewable energy sources that has 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 a significant amount of renewable generation projects which began coming "online" in 2012 and continued to grow. NIPSCO's net metering, feed-in tariff, and EDG 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.

By the end of 2023, renewable generation data identified 60.8 MWs of interconnected capacity associated with the net metering program, 36.8 MWs of interconnected capacity associated with the feed-in tariff program and 3.4 MWs of interconnected capacity associated with the EDG 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 Interconnected Capacity:

- 58.6 MWs - Solar Generation
- 1.9 MWs - Wind Generation
- 0.3 MWs - Solar/Wind Combination Generation

Feed-In Tariff Interconnected Capacity:

- 22.3 MWs - Solar Generation
- 0.2 MWs - Wind Generation
- 14.3 MWs - Biomass Generation

EDG Interconnected Capacity:

- 3.4 MWs - Solar 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 114.6 MWs of generation capacity is interconnected into NIPSCO's distribution system.

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 43% in 2021 to its current level of 53% of all associated stations. Distribution circuit coverage stands at approximately 57% 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 is anticipated to continue.

NIPSCO initiated a new program for technology upgrades on existing control schemes and systems associated with its legacy DA systems. Older system control schemes and equipment are scheduled to be upgraded to new SEL distribution network automation control systems. There were eleven legacy DA systems. Eight out of the eleven will have been upgraded to SEL DA by the end of this year. 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. 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.

FERC issued Order 2222 in 2020, which is a rule requiring regional grid operators like MISO to allow Distributed Energy Resources to participate in the wholesale markets. NIPSCO has been monitoring how MISO is progressing with its implementation of FERC Order 2222. NIPSCO has been involved in EDC workshop and has attended MISO's DER Task Force meetings. NIPSCO will continue to monitor how FERC Order 2222 progresses and how to comply with the FERC Order.

NIPSCO has experienced some EV charger growth throughout the service territory. Most adopters of EVs are charging at home with level 1 or 2 chargers. To date the loading of Level 1 or 2 EV chargers has not been an issue on NIPSCO's distribution service transformers. If penetration of at home charging increases, it could spur service transformer upgrades. At home charging should be managed, and by increasing visibility and programs it could potentially offset any distribution service transformer upgrade costs. DC fast charging stations can range from 50 to 350 kW per stall, and NIPSCO has seen some locations go up to 2-3 MW of demand. If EV DC fast chargers are placed at every gas station location, it could cause significant distribution system impacts resulting in more infrastructure investment to meet the growing demand of EV DC fast chargers. The current rate of adoption for DC fast chargers has been mild, and we expect that to continue in the coming years until EV cars are widely adopted.

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, air emissions, water withdrawal and discharge, and generation of coal ash have significantly reduced. Specifically, as of the end of 2023, NIPSCO had reduced carbon dioxide emissions from electric generation by 76% from 2005 levels. This progress is helping NiSource advance toward its goal of net zero Scope 1 and 2 emissions by 2040.

NIPSCO has invested in environmental control systems across its coal and natural gas generation fleet to comply with environmental requirements while NIPSCO transitions to a more environmentally sustainable generation portfolio. See Table 7-1 for these environmental control systems.

Table 7-1: Environmental Controls on Coal and Natural Gas Generation

Unit	Year In Service	Fuel Source	Particulate Matter (PM) Control	SO_2 Control	NO_x Control	Mercury Control	Coal Ash	Planned Retirement[(1)]
MCGS U12	1974	Coal	Baghouse	Dry FGD	OFA & SCR	ACI & FA	SFC	2028
RMS U16A	1979	Natural Gas	--	--	Water Injection	--	--	2027
RMS U16B	1979	Natural Gas	--	--	Water Injection	--	--	2027
RMS U17	1983	Coal	ESP	Wet FGD	Advanced LNB w/ OFA & SNCR	--	--	2025
RMS U18	1986	Coal	ESP	Wet FGD	Advanced LNB w/ OFA & SNCR	--	--	2025
Sugar Creek	2002	Natural Gas	--	--	SCR	--	--	--

(1) As of November 2024.

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 NiSource's Environmental, Health and Safety, Climate Change, and Sustainability Policies and is implemented through a comprehensive environmental management system.

Compliance plans are developed and implemented to meet new and changing environmental policy developments.

7.3 Environmental Regulations

7.3.1 Solid Waste Management

The EPA finalized a rule regulating the management and disposal of CCR which became effective on October 19, 2015. The 2015 CCR Rule regulates CCRs under the RCRA Subtitle D as nonhazardous. The 2015 CCR Rule is implemented in phases establishing requirements related to groundwater monitoring, CCR management and disposal, reporting, recordkeeping, and corrective action.[134] The rule allows NIPSCO to continue its byproduct beneficial use program, significantly reducing CCR that must be disposed.

NIPSCO has completed several projects and has active ongoing projects to comply with the 2015 CCR Rule. Retirement of Schahfer Generating Station Units 17 and 18 by 2025 avoids significant capital cost needed to comply with the 2015 CCR Rule and other environmental requirements.

On May 8, 2024, the EPA finalized changes to the CCR regulations that address inactive surface impoundments at inactive facilities, referred to as legacy impoundments, and CCR management units at inactive and active facilities. This Legacy CCR Rule, which is not expected to impact generation resource planning, requires these newly regulated units to conform to requirements such as groundwater monitoring, closure, and post-closure care.

7.3.2 Clean Water Act and Effluent Limitations Guidelines (ELG)

EPA first promulgated the ELG Rule in 1974, and has amended the regulation many times, with the latest revision effective date of July 8, 2024. 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 expected for NIPSCO to comply with the ELG Rule given the expected retirement dates of the coal units at, as well as the dry FGD and CCR-related investments at Michigan City.

7.3.3 Clean Air Act

While several Clean Air Act regulations apply to NIPSCO's operations, including the Cross State Air Pollution Rule and Mercury and Air Toxics Standards, these regulations are not significant drivers of resource considerations in this IRP due to the emission control technologies already installed at NIPSCO's electric generating stations and NIPSCO's plans to retire coal-fired generation. However, as discussed in more detail below, the EPA recently finalized greenhouse gas emissions standards for fossil fuel-fired electric generating units that are examined in this IRP.

134 https://www.nipsco.com/about-us/ccr-rule-compliance-data-information

7.4 Climate-Related Considerations

On May 9, 2024, the EPA published final New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units and Emission Guidelines for Greenhouse Gas (GHG) Emissions From Existing Fossil Fuel-Fired Electric Generating Units. EPA's final rule will not affect NIPSCO's existing generation but is expected to impact other steam generating units. As designed by the EPA, new gas generation would be required to meet certain emission limits based on capacity factor, which could impact needed resources under several of the IRP scenarios. NIPSCO has included the GHG Rule in four of the five IRP scenarios.

Although several legislative and executive actions related to GHG emissions have been promulgated over the last decade, there is currently no federal price on carbon. However, given multi-faceted efforts through the legislative and executive branches to reduce GHG emissions, the AER scenario assumes GHG emissions from the power sector are regulated more heavily. In this AER scenario, NIPSCO has implemented a carbon price curve that limits warming to ~2°C by 2100, based on research by the Brookings Institution.[135] This price curve represents a range of potential future environmental policy options that may impact the cost of emitting carbon, rather than an explicit carbon tax policy. Refer to Section 8 for further discussion of carbon policy and prices.

[135] Hansel et al, "Climate Policy Curves: Linking Policy Choices to Climate Outcomes," Brookings Institution, December 2022.

Section 8. Managing Risk and Uncertainty

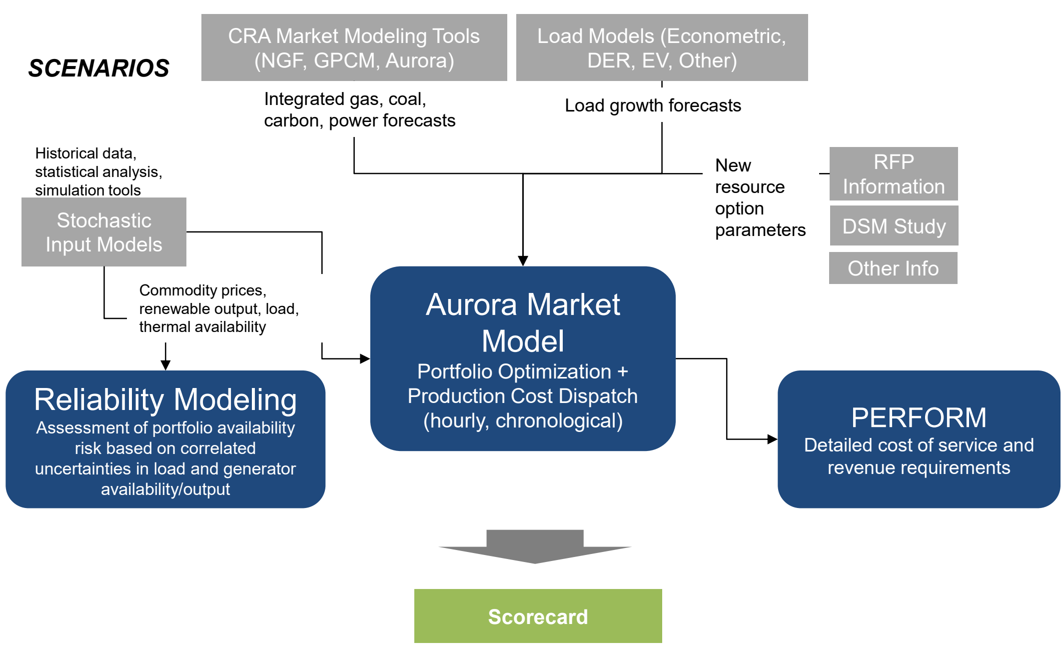
8.1 Introduction & Process Overview

In the 2024 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 uncertainty around this Reference Case. NIPSCO developed the major inputs and associated uncertainty ranges for the 2024 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, probabilistic input development tools designed by CRA, 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: Resource Planning Approach and Uncertainty Modeling Tools



8.2 Reference Case Market Drivers and Assumptions

This section provides an overview of the fundamental drivers that underpin the NIPSCO Reference Case for natural gas prices, coal prices, environmental policy including carbon prices, and power market prices.

8.2.1 Natural Gas Prices

Figure 8-2 provides an overview of the key inputs that drive CRA's fundamental forecast of natural gas prices in the NGF model. NIPSCO's 2024 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 provides 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

Gas Supply

- Total resource in place, proved and unproven
- Resource growth over time
- Wet / dry product distribution
- Historic wells drilled and ongoing production
- Conventional & associated production
- Existing tight and coal bed methane
- Existing offshore production

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- Initial production rates
- Changing drilling and production efficiencies over time
- Productivity decline curve
- Well lifetime
- Distribution of performance

Gas Demand

- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)

Other Market Drivers

- Value of natural gas liquids and condensates
- Natural gas storage

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 2022 "Minimum" resource, and grows the resource base to achieve PGC 2022 "Most Likely" volumes by 2050 to reflect pace of incremental discoveries over time.
Well Productivity	• Initial Production ("IP") rates based on historic drilling data • IP improves as per Energy Information Agency ("EIA") Tier 1 assumptions	CRA bases individual well productivity on historic data analyzed for each producing region; IP rates improve annually, consistent with EIA assumptions.
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.
Associated Gas Volumes	• Natural gas from shale and tight oil plays enters the market as a price taker	CRA uses EIA's forecast of domestic oil prices and production; this includes the impact of oil production and environmental regulations associated with flaring.

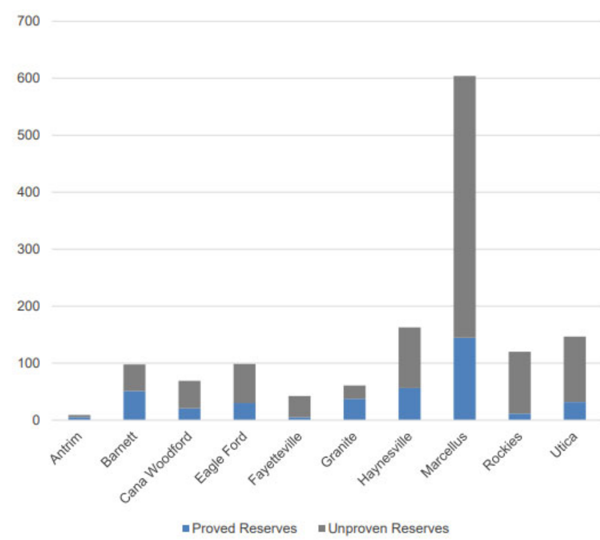
Figure 8-4: Demand Side Natural Gas Price Drivers – Reference Case

Driver	CRA Approach	Explanation
Domestic Demand	• CRA electric power sector simulation • Other sector natural gas demand synthesized from EIA	CRA expects natural gas domestic demand to be relatively stable to slightly declining under the Reference Case, with power sector declines driving the biggest long-term change.
LNG Exports	• Based on review of proposed projects • General uptick in under-construction projects completed and total exports	CRA expects no further export capacity beyond projects that are already operating or which have already achieved Final Investment Decision and are under construction, due to increased competition from suppliers with lower production costs or located closer to demand centers. However, existing and new facilities also have the potential to operate at higher utilization rates over time.
Pipeline Exports	• EIA predictions for net imports	CRA expects modest growth in pipeline exports to Mexico as well as decreasing imports from Canada.

8.2.1.1 Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on a weighted average between the PGC 2022[136] "minimum" and "most likely" estimates as the value of unproven shale reserves. "Minimum" corresponds to a 100% probability that the resource is recoverable, while "most likely" refers to what is most likely to be recovered, with reasonable assumptions about source rock, yield factor, and reservoir conditions. On the other hand, the amount of proven reserves was taken from EIA's "Annual Report of Domestic Oil and Gas Reserves". The assumed available reserve estimates by basin are shown in Figure 8-5.

Figure 8-5: Available Shale Reserves by Basin

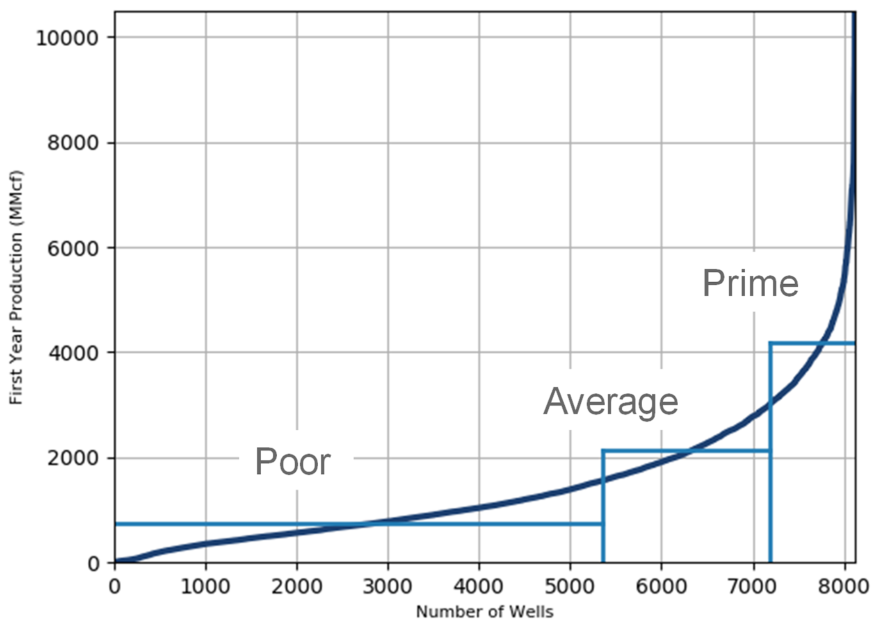


136 Note that the PGC 2022 view was released in July 2023, with PGC 2024 not available at the time of the development of NIPSCO's 2024 IRP assumptions. Scenario development (discussed further below) incorporates a range of views on the future resource base, anticipating potential ranges of resource base in the PGC 2022 report.

8.2.1.2 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 toward 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.[137]

Figure 8-6: Well Productivity Distribution Illustration for Appalachia



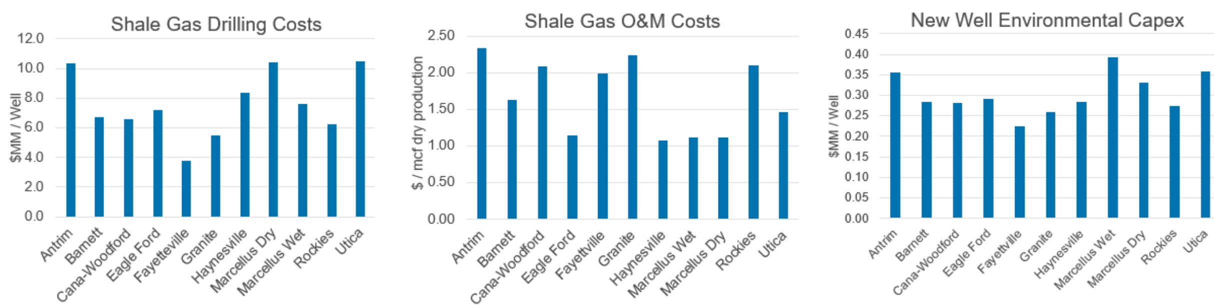
Well Costs

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 shale basins, and CRA broadly assumes that these improvements will continue over time, largely due to technological innovation, such as advances in machine learning. Figure 8-7 summarizes current drilling costs, O&M costs, and environmental Capex in the major production regions.

137 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.

For going forward costs, CRA relies on the EIA's AEO, as well as documentation from publicly traded drilling companies as well as projections for improvements in drilling and O&M costs from S&P Global's UCCI. Drilling costs are expected to increase by 2% per year through 2025 due to inflationary effects on supply chains, followed by a decline rate of 1.5% through 2050, reflecting the aforementioned advances in drilling technology. Equipment and operating costs are expected to decline by 0.5-1% per year.

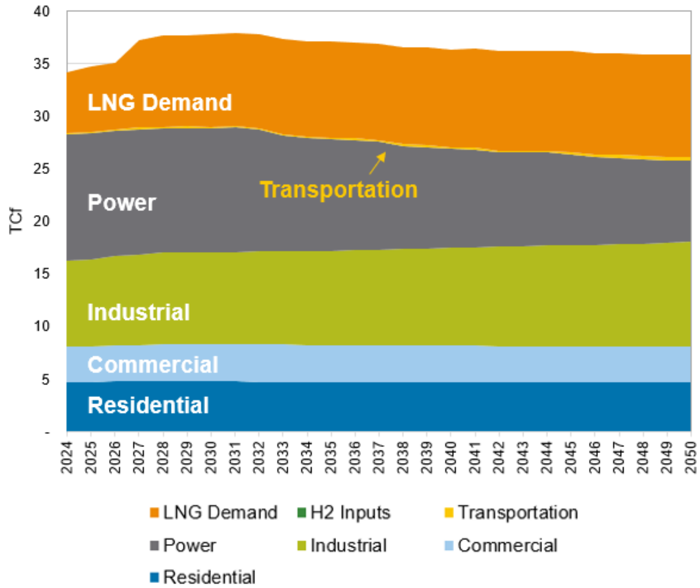
Figure 8-7: Shale Gas Drilling Costs



8.2.1.3 Demand

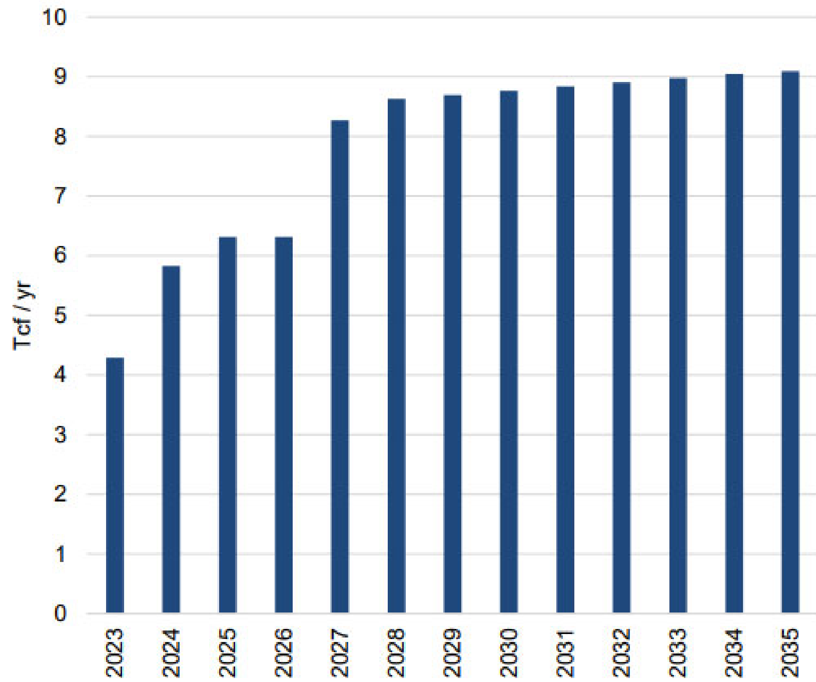
In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for total demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-8 presents the projected domestic demand assumptions through 2050 from the aforementioned sources. Electric sector demand is expected to be relatively flat through the mid-term and then decline in the Reference Case. The AEO's growth expectations for other sectors are also relatively flat, with some positive growth expected in the industrial sector.

Figure 8-8: Natural Gas Demand Assumptions – Reference Case



CRA develops estimates for LNG demand based on a review of existing and proposed export projects. An increase in LNG demand is expected through 2027 and 2028 as several new projects enter into service. CRA's Reference Case assumes small increases in LNG terminal utilization factors over the long-term but does not include any projects not currently approved and under construction. The demand from LNG exports included in the Reference Case through 2035 is summarized in Figure 8-9.

Figure 8-9: LNG Export Demand Projections – Reference Case

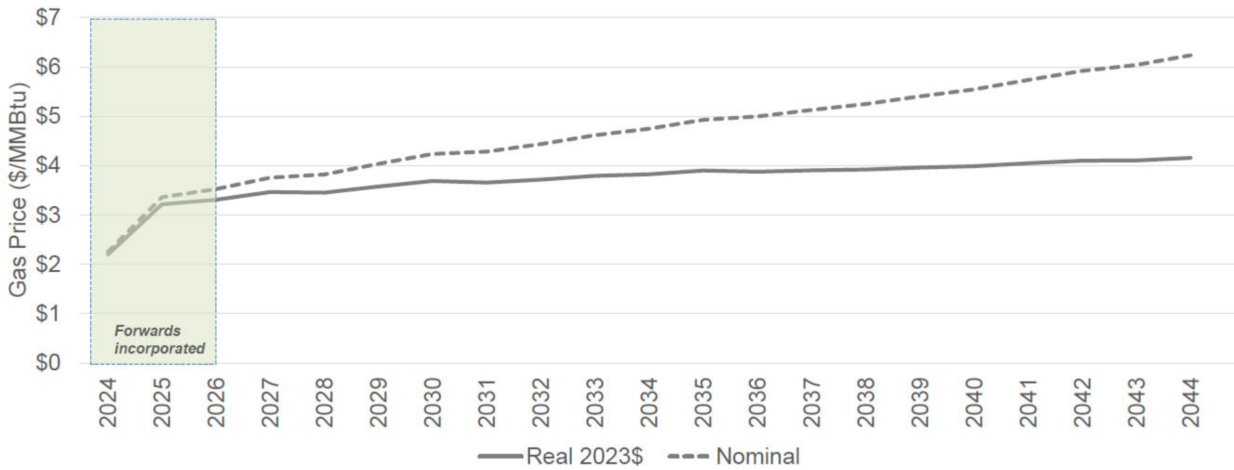


8.2.1.4 Reference Case Price Forecast

CRA's Reference Case price forecast was developed based on each of the supply and demand inputs discussed above and is shown in Figure 8-10. Beyond the forward period, prices are projected to be in the $3.50-$4.00/MMBtu range (real 2023$) for most of the study period. A brief summary of the key drivers of the expectation for increasing prices follows:

- CRA's Reference case view reflects upward pressure in the near term largely as a result of an increase in LNG export demand;
- Modest declines in overall demand resulting from slowing LNG demand growth and declining power sector demand, balanced with both slight increases in marginal production costs and crowding in prime regions leads to a slightly positive trend in real prices from 2035 onward.

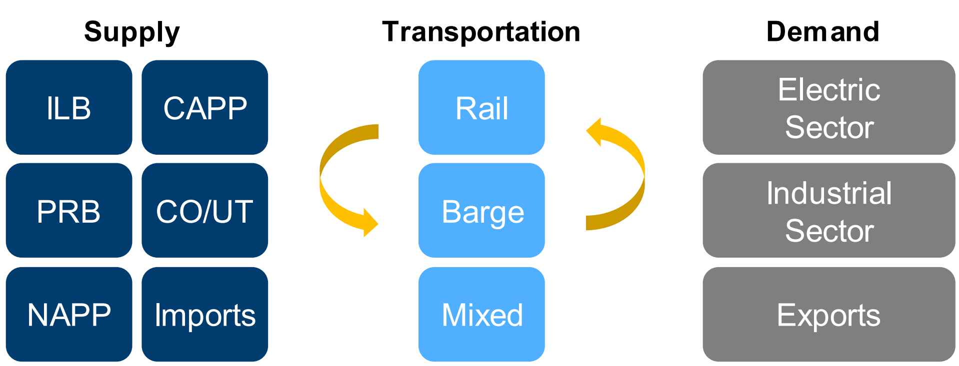
Figure 8-10: Reference Case Gas Price Forecast



8.2.2 Coal Prices

NIPSCO's reliance on coal-fired generation is expected to continue to decline, as Units 17 and 18 at the Schahfer Generating Station are planned to retire in 2025 and Unit 12 at the Michigan City Generating Station (NIPSCO's last coal-fired unit) is planned to retire in 2028. NIPSCO's 2024 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 policy and 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 8-11. 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.

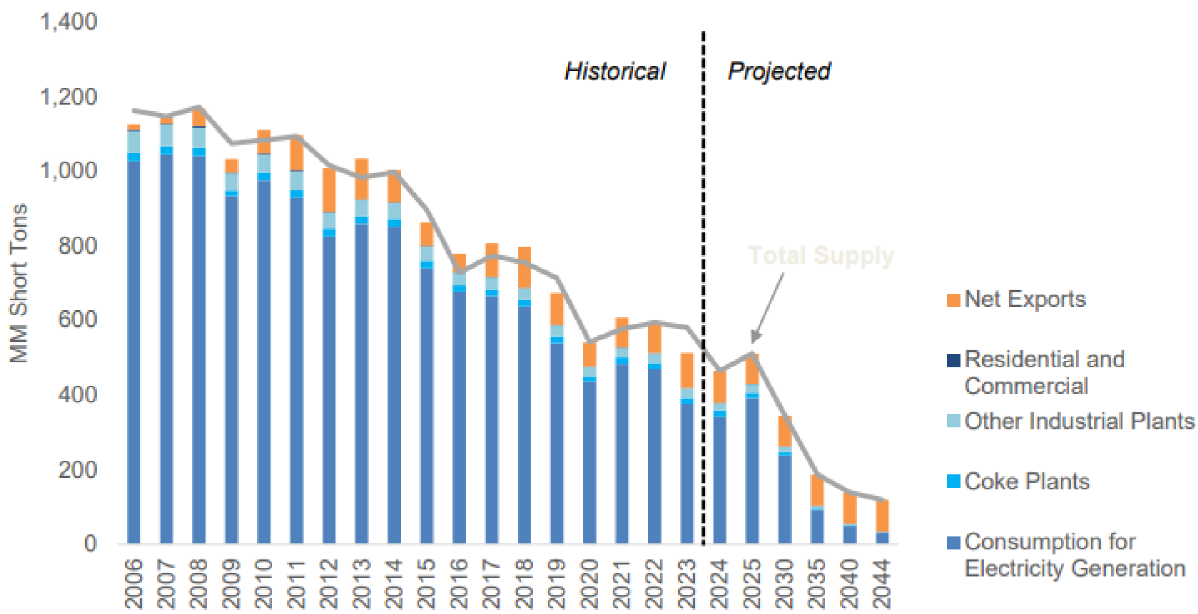
Figure 8-11: Coal Forecasting Process Overview



8.2.2.1 Coal Supply and Demand Trends

Figure 8-12 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. Coal retirements have accelerated in recent years, and low natural gas prices have continued to dampen demand, such that total demand for U.S. coal has declined to around 500 million short tons per year, less than half of where it was in 2010. Declines are expected in the next five years, with more substantial declines expected after 2030, particularly as the power sector transitions to other generating resource types.

Figure 8-12: Supply-Demand Balance for U.S. Coal – 2006-2041[138]

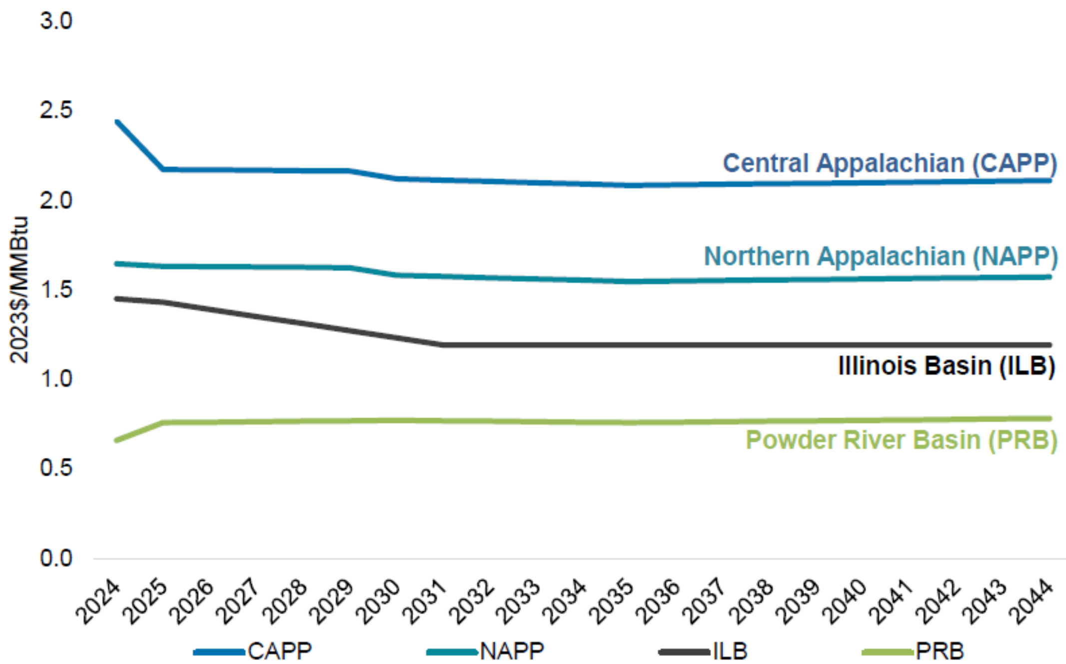


8.2.2.2 Reference Case Price Forecast

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 8-13 presents the Reference Case price outlook by coal supply region. Overall, spot prices for U.S. steam coal have continued to decline since last year, and over the long-term, coal prices are expected to be flat to declining due to falling domestic demand as a result of the ongoing energy transition in the power sector. Demand for coal exports is also expected to stabilize over the long-term as international markets also decarbonize.

138 2006-2023 data is from EIA and the Mine Safety and Health Administration.

Figure 8-13: Reference Case Coal Price Forecast



8.2.3 Carbon Emission Regulation

Given recent policy and regulatory momentum associated with federal incentives for clean energy resources and regulatory pressures for fossil fuel resources, NIPSCO's Reference Case for the 2024 IRP does not include an explicit price on carbon. However, it does incorporate the GHG Rule for fossil fuel-fired EGUs finalized in April 2024 and published on May 9, 2024.[139] For existing coal-fired EGUs, the final rule establishes subcategories based on expected retirement date:

- Units operating in 2039 and beyond must achieve an emission rate based on CCUS application;
- Units that retire by 2039 must achieve an emission rate based on 40% natural gas co-firing by 2030; and
- Units that plan to retire prior to 2032 have no emission reduction obligations.

For new combustion turbines, the final rule establishes subcategories based on capacity factor:

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[139] See EPA fact sheets here: https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-overview.pdf and here: https://www.epa.gov/system/files/documents/2024-04/cps-table-of-all-bser-final-rule-4-24-2024.pdf

- Units operating at a capacity factor greater than 40% must achieve an emission rate consistent with CCUS by 2032;

- Units operating between 20% and 40% capacity factor must achieve an emission rate of 1,170 lbs/MWh; and

- Units operating at a capacity factor below 20% have no effective emission rate limitation if burning natural gas.

In addition to inclusion of the EPA greenhouse gas rules in four out of five of NIPSCO's scenarios, NIPSCO's AER scenario incorporates an implicit price on carbon emissions starting in 2030.

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 8-14. 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;

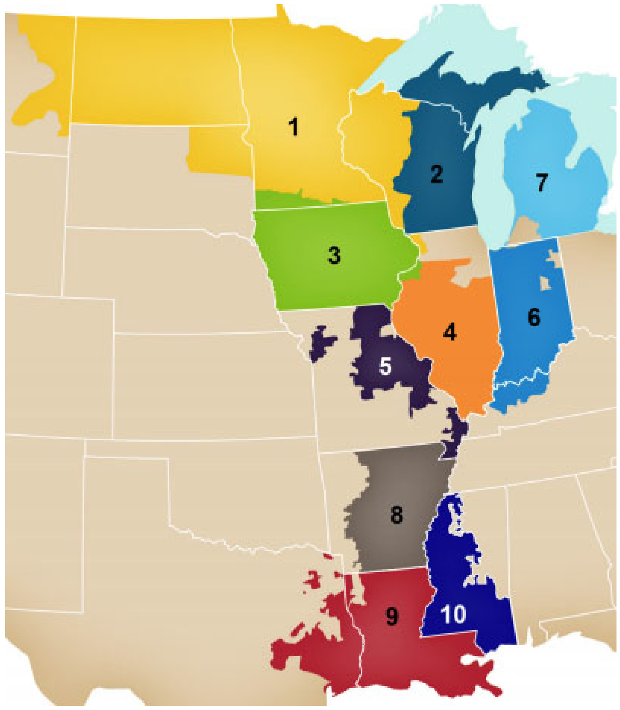
- Coordinates with utilities, states, and federal entities (FERC and NERC) to ensure the reliable, non-discriminatory operation of the bulk power transmission system; and

- Provides an estimated $5 billion in annual benefits[140] to members due to efficient use of power system for resource adequacy and dispatch across a broad geographic territory.

NIPSCO's service territory and resources fall within LRZ6, 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, environmental policy, and the future capacity mix in the region.

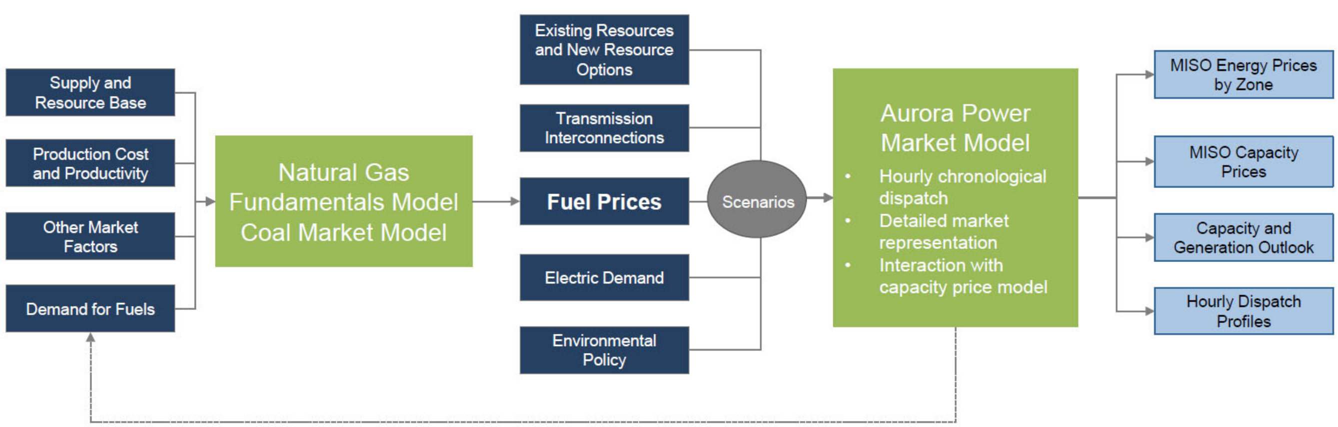
140 See https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

Figure 8-14: MISO Footprint



Based on the market inputs for fuel prices and environmental policy, 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 and capacity prices according to the process shown in Figure 8-15.

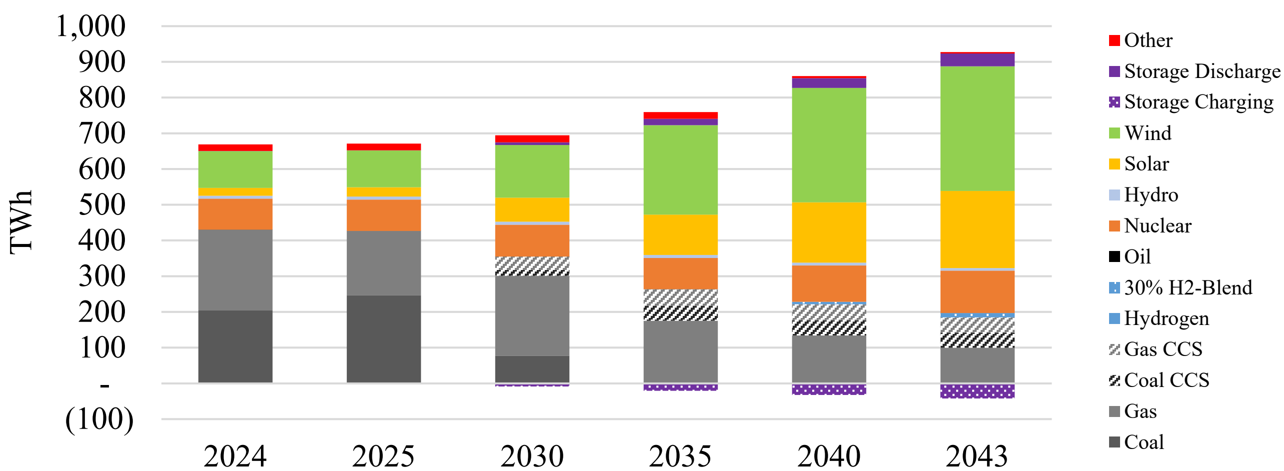
Figure 8-15: Power Market Modeling Process



8.2.4.1 MISO Capacity Mix

CRA's Reference Case analysis expects a continued shift from fossil fuel-fired generating resources towards cleaner energy over the next two decades, particularly in response to the assumed implementation of the EPA GHG rule discussed in the prior section. Since 2015, coal generation has declined from approximately 50% of the total MISO mix to closer to 33%, and the Reference Case forecast projects that it will decline rapidly over the next decade as a result of required retirements or conversions. Meanwhile, the Reference Case expects significant growth in renewable energy from wind and solar, such that by 2043 over 75% of energy generation throughout the region is expected to be from zero-emitting resources, including nuclear. In addition, both coal and natural gas CCUS are expected to grow post-2030. CRA's Reference Case projection of the evolution of the MISO energy mix is presented in Figure 8-16.

Figure 8-16: MISO Generation by Fuel Type –Reference Case Projections



8.2.4.2 Reference Case Energy Price Forecast

CRA's Reference Case MISO energy market price forecast is presented in Figure 8-17 on an annual basis and in Figure 8-18 on a monthly basis. The Reference Case expects that power prices will be relatively flat in real terms in the near-term, due to relatively flat natural gas and coal prices. Longer-term prices are expected to decline slightly in real terms as a result of increased low or zero variable cost generation resources entering the market. Convergence in peak and off-peak prices is projected over time in the Reference Case due largely to growing solar energy output, which tends to reduce peak period pricing.

Figure 8-17: LRZ6 (Indiana) Reference Case Annual Price Projections

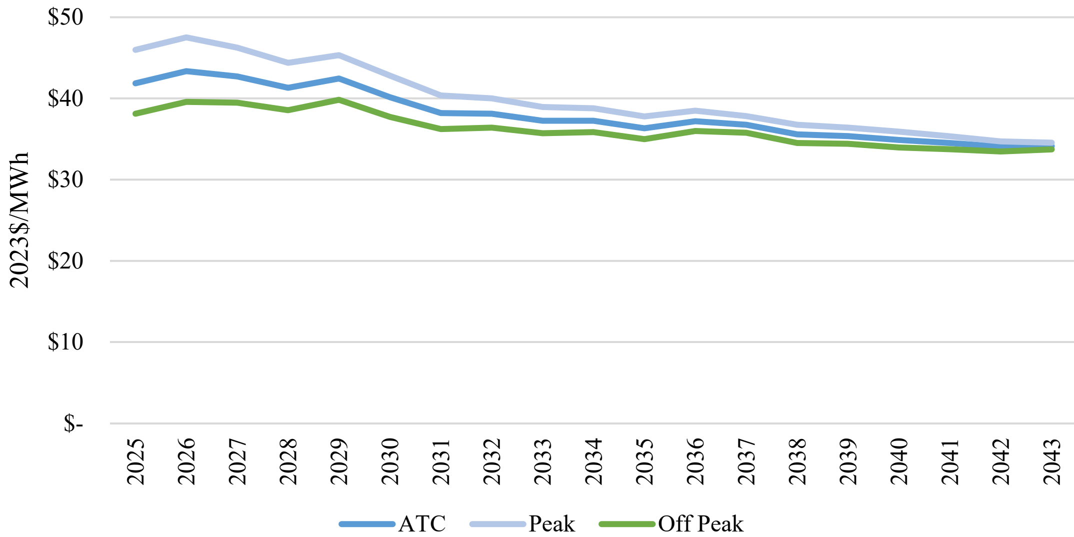
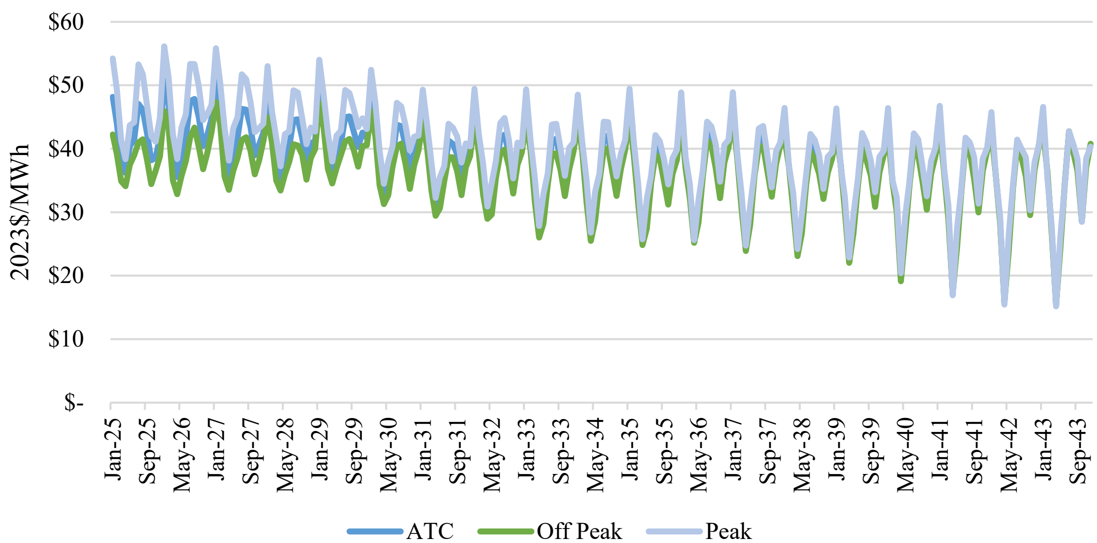
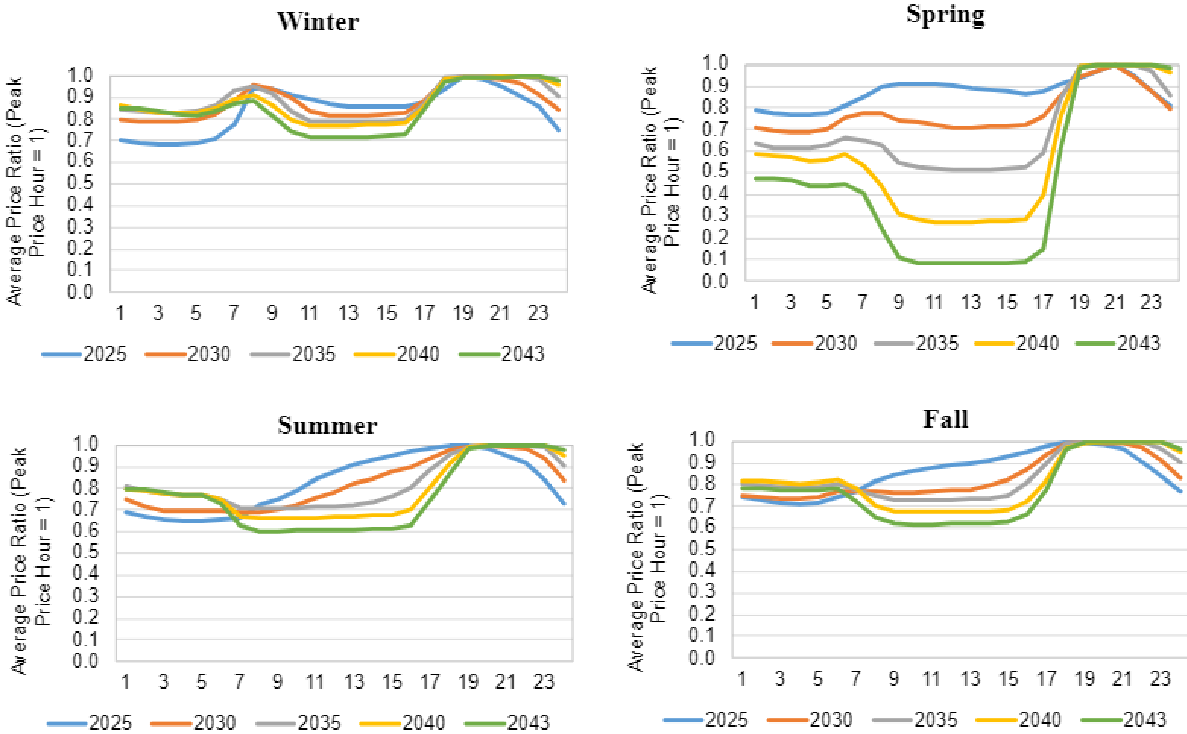


Figure 8-18: LRZ6 (Indiana) Reference Case Monthly Price Projections



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 late afternoon to evening hours, in line with solar generation patterns. This is illustrated in Figure 8-19.

Figure 8-19: MISO Hourly Energy Price Shape Projections Over Time

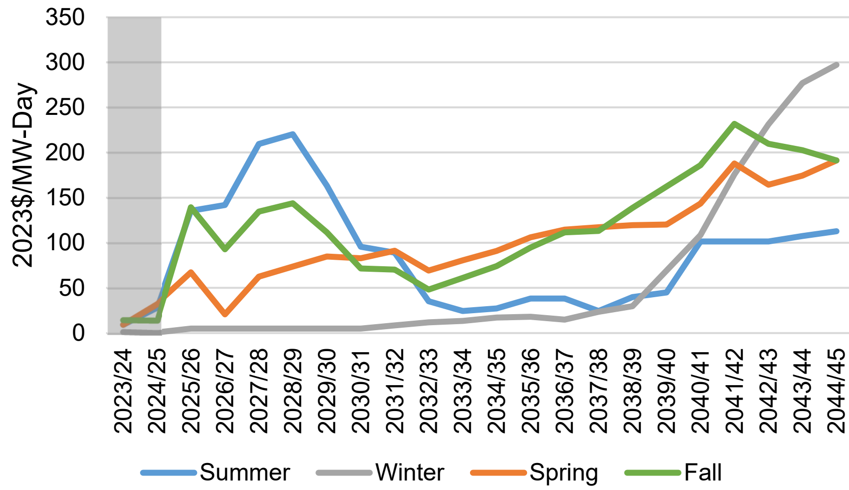


8.2.4.3 Reference Case Capacity Price Forecast

In addition to the energy market, MISO also operates a capacity market which procures capacity in a seasonal auction. The capacity market is based on an administratively set demand requirement and supply offers from market participants that are willing to sell capacity. MISO's first seasonal capacity auction took place in April 2023, followed by the second seasonal auction in April 2024. The 2023/24 auction prices retreated from the price spike observed in the 2022/23 auction, while the 2024/25 auction showed slight upticks in seasonal clearing prices, driven by a combination of higher demand requirements and tighter supply dynamics.

Going forward, CRA expects capacity prices to experience upward pressure over the near term, as the reserve margin throughout the system continues to tighten and MISO's D-LOL rule is implemented. During this period, summer is projected to remain the tightest season. Over the longer-term, the supply-demand balance will likely further tighten as coal resources are replaced by intermittent capacity over time. CRA's price forecast considers expected seasonal resource accreditation trends and demand requirements, and into the 2040s, risks in the winter season are projected to emerge. Figure 8-20 presents the Reference Case capacity price projections over time and by season.

Figure 8-20: 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;
- Load growth, including uncertainty associated with economic growth, EV penetration, DER penetration, electrification, industrial load, and data center 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.[141] In the 2024 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 feedback, while stochastic

141 Scenarios represent future states of the world. Scenario risk represents risk due to lack of knowledge around factors like regional demand growth, environmental policies, structural trends in commodity prices, etc. These sources of uncertainly will reduce with further knowledge as the future evolves. Stochastic risk is driven by randomness which cannot be reduced. Such uncertainties include exact hourly loads, short-term commodity prices, or hour-to-hour and day-to-day renewable generation.

analysis was performed to evaluate more granular volatility and tail risk, largely based on historical data observations. Figure 8-21 provides a summary of the primary purposes and benefits of deploying each approach. In the 2024 IRP, NIPSCO evaluated uncertainty variables in the following fashion:

- Scenario variables:
  - Annual and monthly natural gas prices;
  - Federal carbon policy regulation, including through a carbon price or the EPA power sector GHG Rule;
  - Federal technology incentives, including potential cancellation of 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, data center load, and industrial load risk; and
  - Alternative capacity accreditation and obligation requirements across alternative market design concepts and based on MISO market outcomes.
- Stochastic variables:
  - Daily natural gas prices;
  - Hourly MISO power market prices;
  - Hourly NIPSCO load;
  - Hourly renewable generation output for wind and solar resources; and
  - Hourly availability from thermal generators.

Figure 8-21: Scenario and Stochastic Uncertainty Approaches

Scenarios
Single, Integrated Set of Assumptions

- **Can be used to answer the "What if…" questions**
  - Major events can change fundamental outlook for key drivers
    - New policy or regulation (carbon emissions regulation, tax credits)
    - Fundamental gas price change
    - Major load shifts
- **Can tie portfolio performance directly to a "storyline"**

Stochastic Analysis:
Probabilistic Distributions of Inputs

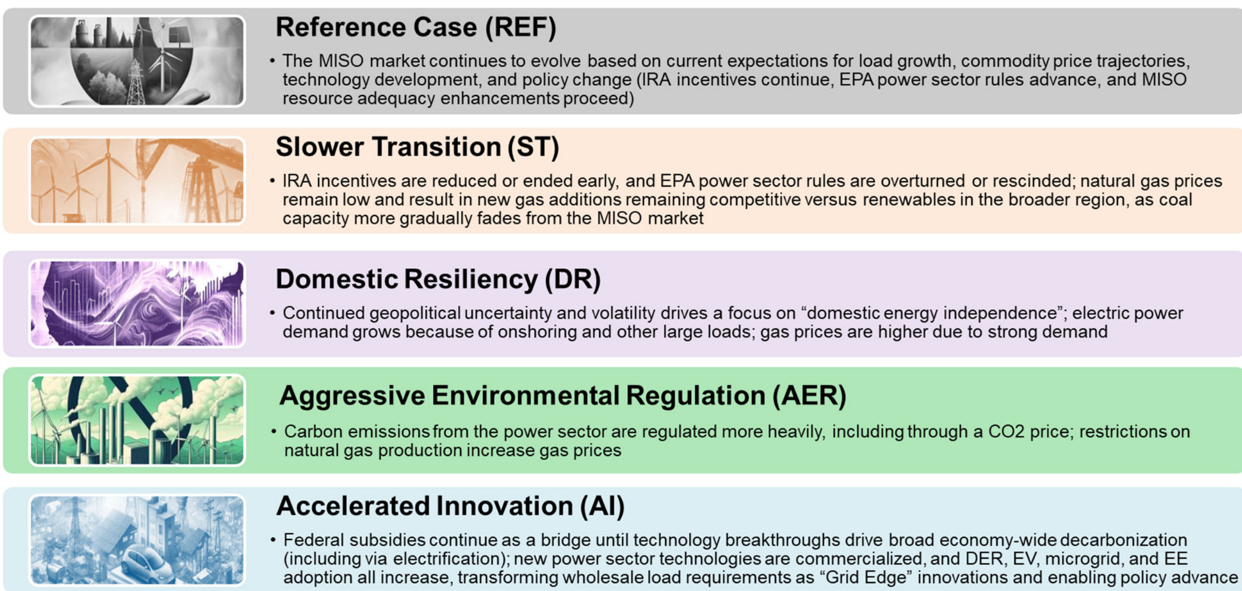
- **Can evaluate volatility and "tail risk" impacts**
  - Uncertainty in renewable resource output, generator availability, and load can impact portfolio costs and key reliability metrics
- **For the 2024 IRP, this analysis will be expanded to include more robust treatment of the correlations between renewable generation, load, resource availability, and commodity prices**

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 four scenarios to supplement the Reference Case, relying on the foundation that was built in its 2016, 2018, and 2021 IRP processes. The 2024 IRP Reference Case incorporates recent market and regulatory trends and positions a baseline outlook against which alternative scenarios were developed. A summary of the scenario themes is shown in Figure 8-22.

Figure 8-22: 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 commodity prices, carbon policy, technology costs, electric demand or load growth, and market design considerations. Figure 8-23 summarizes the directional movement of the key input assumptions relative to the Reference Case, while the subsequent sections of this Section outline the detailed inputs that were developed for each scenario.[142]

[142] 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. Note also that NIPSCO-specific portfolio analysis (discussed further in Section 9) incorporates additional information regarding NIPSCO-specific technology costs for new resources (largely informed by the RFP results summarized in Section 4) and NIPSCO-specific load uncertainties (summarized in Section 3).

Figure 8-23: Summary of Major Scenario Parameters

Scenario	Commodity Prices	Carbon Policies	Technology Costs	Demand	Market Design
Reference Scenario (REF)	Baseline	Current Policy, including EPA power sector CO2 emission rules	Baseline	Baseline	Examine alternative capacity accreditation and obligation requirements across alternative market design concepts and based on MISO market outcomes
Slower Transition (ST)	Low gas price due to abundant resource	IRA pull-back and withdrawn EPA power sector rules	Slower decline for new tech costs; stable IC costs	Low DER and EV	
Domestic Resiliency (DR)	Higher gas price due to strong demand	Current policy, including EPA power sector CO2 emission rules	Higher due to supply chain constraints, onshoring	New large loads (data centers, industrial onshoring)	
Aggressive Environ. Regulation (AER)	Highest gas price due to production restrictions	EPA power sector CO2 emission rules *plus* carbon price	Baseline	Higher DER and EV; some electrification	
Accelerated Innovation (AI)	Lower gas price due to demand erosion	Current policy, including EPA power sector CO2 emission rules	New tech. advancement and decline in costs; IC cost pressures	High EV and electrification plus new large loads; higher DER	

8.4.2 Slower Transition Scenario

8.4.2.1 Summary Description

The ST scenario represents a future with persistently low natural gas prices, a pull-back of tax credits authorized via the IRA, and withdrawal of the EPA GHG Rule. The scenario addresses the combined risks of low commodity prices for natural gas and power and a roll-back of federal incentives and regulations which incentivize a transition away from fossil-fuel fired generation. Given the large amount of uncertainty related to long-term implementation of the EPA GHG Rule, 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.

8.4.2.2 Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the ST scenario's price trajectory. Overall, lower prices are realized through the following assumptions:

- Larger resource size: The ST scenario assumes a higher weighting in available unproven resources towards the PGC's maximum trajectory as opposed to its "most likely."

- Higher well productivity: Improvements in well productivity are assumed to be realized more quickly in this scenario.

Figure 8-24 summarizes the major natural gas price drivers for the ST scenario relative to those in the Reference Case.

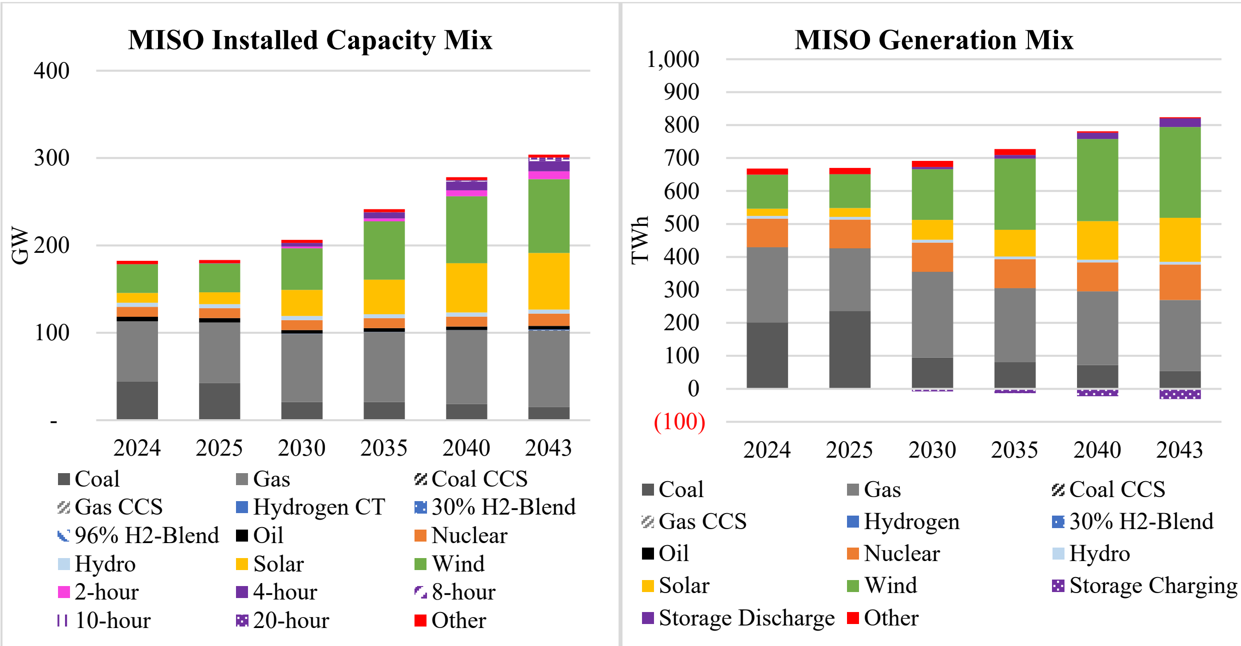
Figure 8-24: Summary of Natural Gas Price Drivers for ST Scenario

Driver	Reference Case	ST
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	• Base View
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Base View

8.4.2.3 MISO Power Market Dynamics

In the ST scenario, load growth is expected to be slightly lower than in the Reference Case, largely due to slower electric vehicle growth. In addition, 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, withdrawal of the EPA GHG Rule, and an early phase-out of clean energy tax credits from the IRA. While the Reference Case expects over 75% of all energy in MISO to come from zero-emitting resources by 2043, the ST scenario expects closer to 60-65% of total energy produced to be zero-emitting by the same period. Meanwhile, natural gas and coal generation are projected to retain an energy share close to 40% by 2043, with most fossil-fired energy produced by natural gas. Unlike the Reference Case, the ST scenario does not expect deployment of CCUS for coal and natural gas capacity. The projected MISO installed capacity mix and generation mix over time for the ST scenario are illustrated in Figure 8-25.

Figure 8-25: MISO Power Market Evolution for ST Scenario



8.4.3 Domestic Resiliency Scenario

8.4.3.1 Summary Description

The DR Scenario represents a future in which continued geopolitical uncertainty and volatility drive a focus on domestic energy independence, while electric power demand grows significantly as a result of manufacturing onshoring and the emergence of other large loads like data centers. In addition, this scenario assumes gas prices are higher due to strong demand and technology costs decline more slowly due to supply chain constraints and high demand. Overall, the scenario addresses the risk of high load growth, higher technology costs, and high fuel costs.

8.4.3.2 Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the DR Scenario's price trajectory. Overall, higher prices are realized primarily through expected increases in demand for natural gas. Specifically, instead of using AEO's base view for domestic gas demand, a higher trajectory, representing an approximate five tcf annual increase by the end of the study period, was used. This demand growth is expected to come from both the power sector (as a result of additional electric demand) and the industrial sector. Figure 8-26 summarizes the major natural gas price drivers for the DR scenario relative to those in the Reference Case.

Figure 8-26: Summary of Natural Gas Price Drivers for DR Scenario

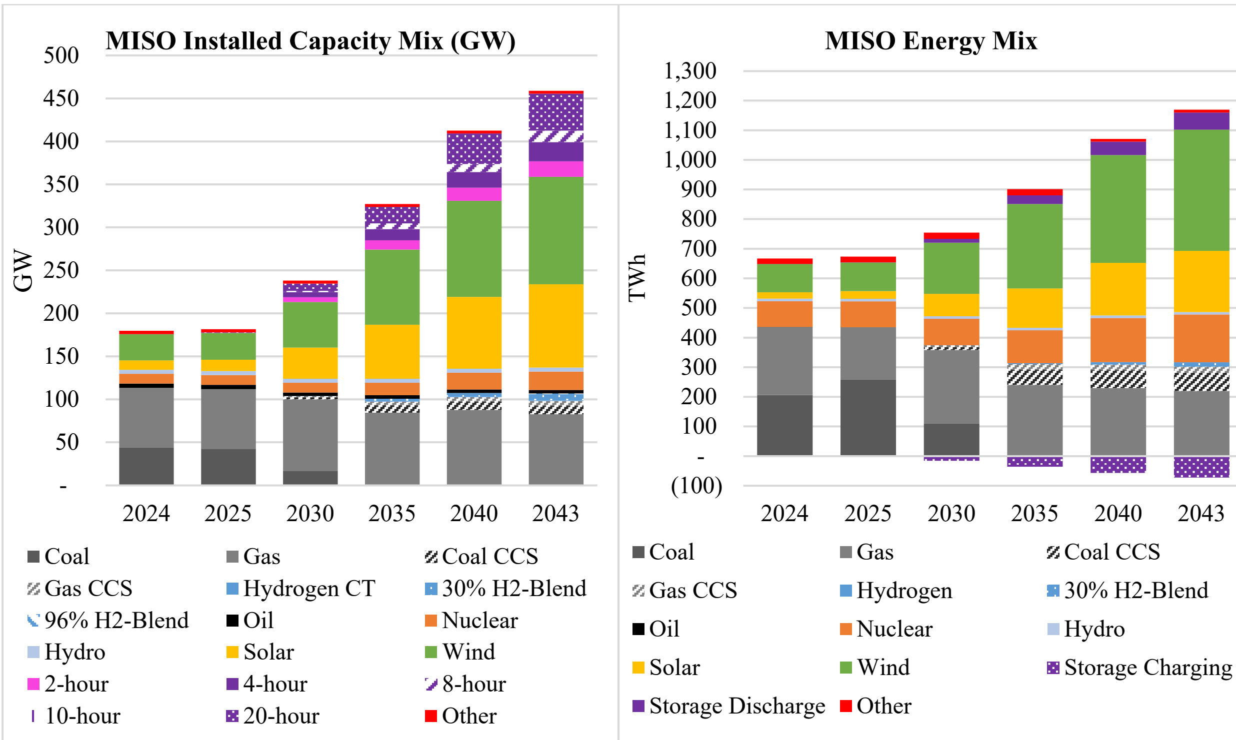
Driver	Reference Case	DR
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Base View
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Base View
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Base View
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Increased power sector & other demand ↑

8.4.3.3 MISO Power Market Dynamics

As noted, increased electric demand is a primary driver of the DR scenario. By 2045, across the MISO footprint, net energy for load across the MISO footprint is projected to be around 300 TWh higher than the Reference Case, with peak demand around 40 GW higher. Given baseline load levels for MISO in 2024 of approximately 700 TWh and 120 GW of net energy for load and peak demand, respectively, the increase in power sector demand for the DR scenario is a significant driver of overall outcomes.

As a result of this significant load growth, additional dispatchable capacity across the MISO footprint is needed to maintain regional reliability and serve growing energy needs. Therefore, although all coal capacity is projected to either retire or retrofit to CCUS by 2032 as a result of the EPA GHG Rule, significant amounts of natural gas capacity is also expected to remain in the system, along with new nuclear, wind, solar, storage, and hydrogen-enabled thermal capacity. Overall, the MISO market is projected to generate over 70% of its energy from clean, non-CO2 emitting resources by 2043, while serving a much larger amount of load when compared to the Reference Case. The remaining generation is expected to come from natural gas. The projected MISO installed capacity mix and generation mix over time for the DR scenario are illustrated in Figure 8-27.

Figure 8-27: MISO Power Market Evolution for DR Scenario



8.4.4 Aggressive Environmental Regulation Scenario

8.4.4.1 Summary Description

The AER Scenario represents a future in which environmental regulations are more stringent than anticipated in the Reference Case. More specifically, beyond the implementation of the EPA GHG Rule, 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.

8.4.4.2 Natural Gas Prices

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). This is also achieved by anchoring more toward the PGC minimum values for unproven reserves.
- 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.

Figure 8-28 summarizes the major natural gas price drivers for the AER scenario relative to those in the Reference Case.

Figure 8-28: Summary of Natural Gas Price Drivers for AER Scenario

Driver	Reference Case	AER
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Limited resource growth, prospective drilling ban
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Base View
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Slower improvement as policy drives investment into clean sectors • Higher environmental costs
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Base View

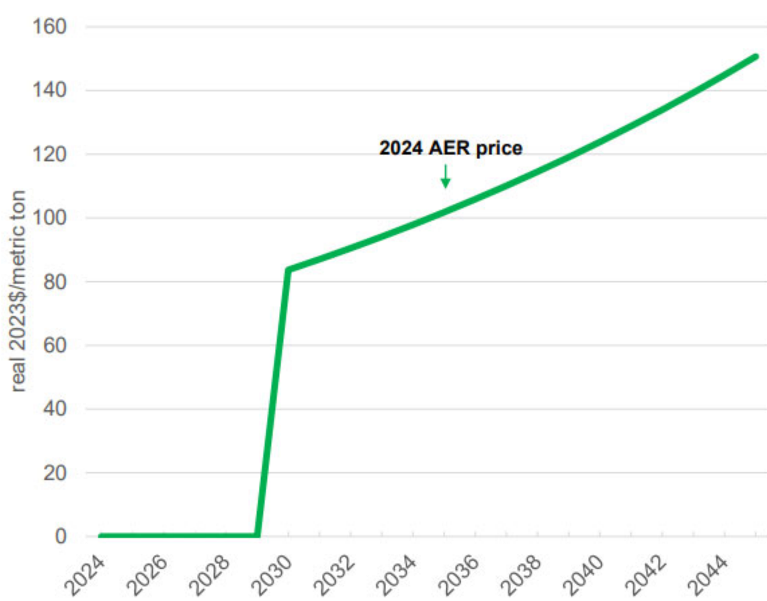
8.4.4.3 Carbon Regulation

As noted above, the AER scenario assumes a significant price on carbon, which was developed by NIPSCO using public sources to reflect a price on carbon that would be required to limit global warming to 2 degrees Celsius (3.6 degrees Fahrenheit) above pre-industrial levels by 2100.

In the AER scenario, the carbon price starts at $83/metric ton (in real 2023$) in 2030 and increases at a constant rate of 4% annually, as summarized in Figure 8-29.[143] This price would make renewable resources and other clean energy generation more economically attractive, resulting in increased adoption of clean energy resources to meet U.S. electricity demand.

It is important to note that an implicit cost of carbon captures not only an explicit tax on emissions, but a range of possible climate policy outcomes that would increase the overall cost of emitting CO2 into the atmosphere. This approach allows NIPSCO's 2024 IRP to incorporate price outcomes, while also recognizing the significant uncertainty associated with policy design and ultimate implementation.

Figure 8-29: AER Scenario Carbon Price Forecast



8.4.4.4 MISO Power Market Dynamics

In the AER scenario, higher carbon prices and higher natural gas prices are expected to accelerate both 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 CCUS by 2032 under the AER scenario. In addition, new nuclear capacity is projected, and consumption of some hydrogen fuel is expected in both new and 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 2043. This is illustrated in Figure 8-30.

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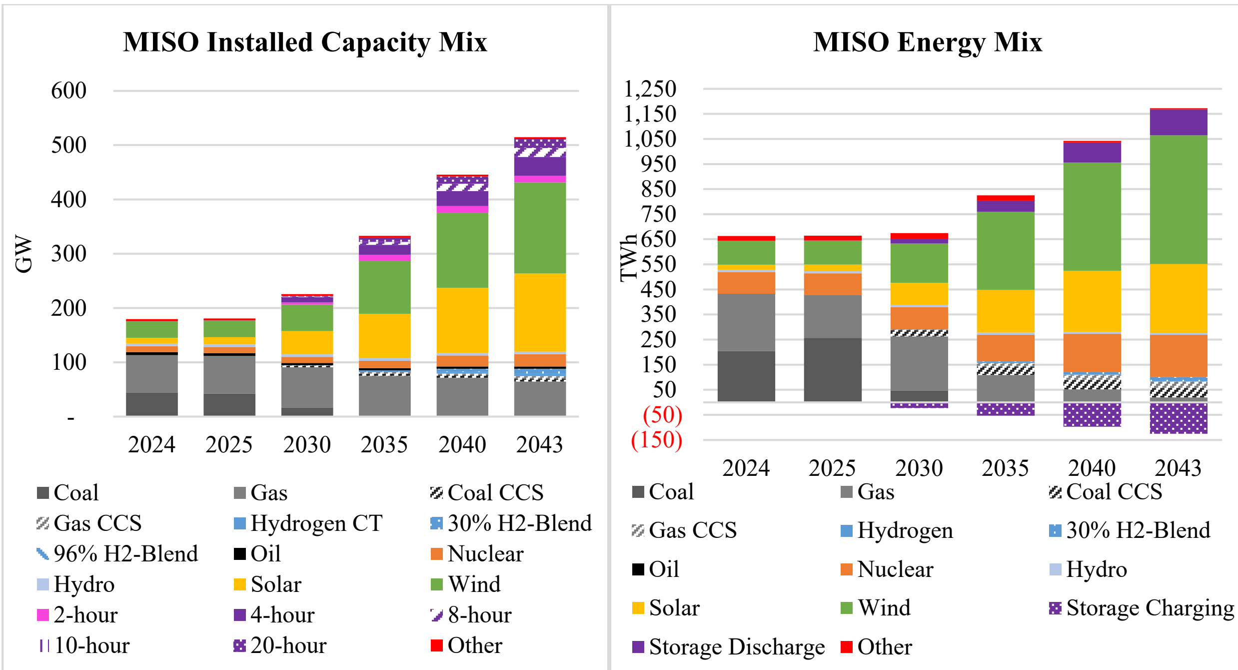
[143] The price trajectory was drawn from work published by the Brookings Institution: Hansel et al, "Climate Policy Curves: Linking Policy Choices to Climate Outcomes," Brookings Institution, December 2022.

Figure 8-30: MISO Power Market Evolution for AER Scenario



8.4.5 Accelerated Innovation Scenario

8.4.5.1 Summary Description

The AI Scenario represents a future in which technological breakthroughs and federal environmental regulations and subsidies 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 substantial technological advancement which reduce the costs of new power sector technologies, including distributed energy resources, electric vehicles, microgrid deployment, and advanced energy efficiency. These innovations are supported by federal rules and incentives, like the EPA GHG Rule and IRA incentives. In addition, electrification measures are projected to significantly increase power demand, with most of this growth concentrated in the winter months due to heating electrification. Overall, the scenario addresses the risk of substantial electrification of the economy (and thus substantial growth in overall load) and transition toward new power sector technologies.

8.4.5.2 Natural Gas Prices

CRA used its fundamental natural gas market modeling framework (as discussed above) to develop drivers for the AI Scenario's price trajectory. Overall, lower prices are realized primarily through changes in demand for natural gas. Instead of using the AEO Reference Case, the demand for the AI Scenario was based on the Princeton Net Zero Report E-Minus case[144] – a

[144] See https://netzeroamerica.princeton.edu/the-report for the report details.

case which adopts an aggressive net-zero by 2050 goal. Specifically, there is a roughly 20% overall decrease in demand over the forecast period, largely driven by roughly half of the electric demand diminishing.

Figure 8-31 summarizes the major natural gas price drivers for the AI scenario relative to those in the Reference Case.

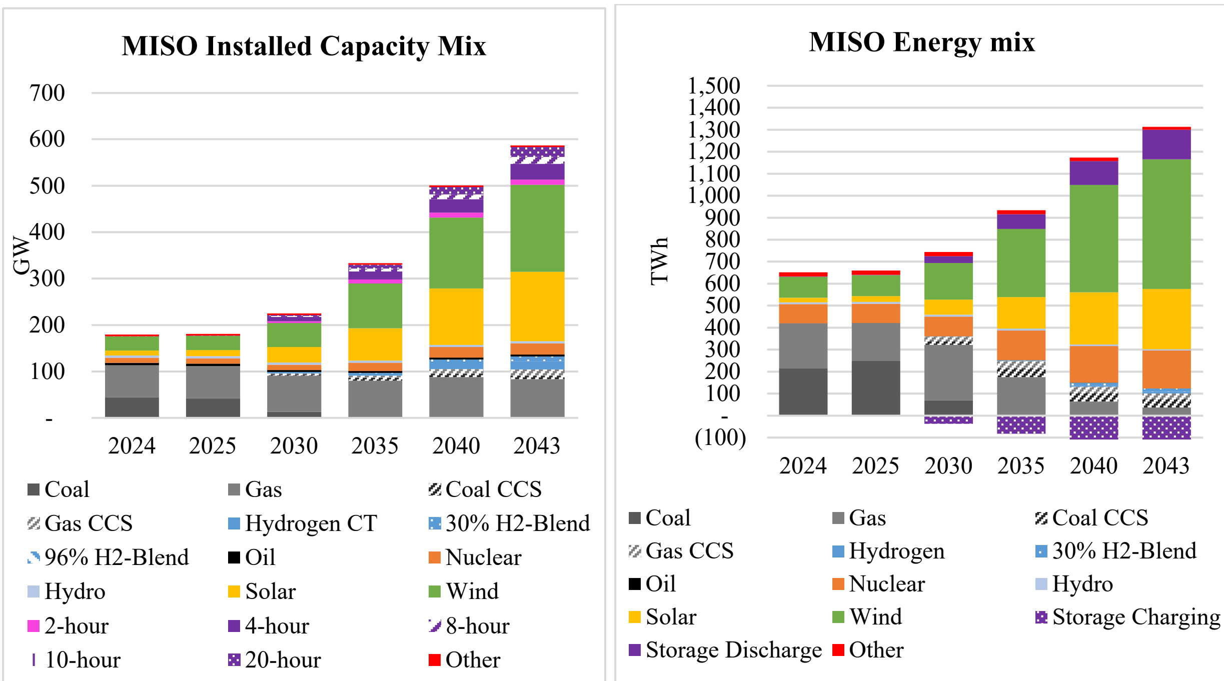
Figure 8-31: Summary of Natural Gas Price Drivers for AI Scenario

Driver	Reference Case	DR
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Base View
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Base View
Fixed & Variable Well Costs	• Fixed and variable costs based on reported data • Costs improve as per EIA assumptions	• Base View
Domestic Demand	• Electric demand taken from AURORA base case, RCI demand based on AEO 2021 Reference Case	• Significantly decreased electrification demand

8.4.5.3 MISO Power Market Dynamics

In the AI scenario, electrification growth is expected to significantly increase overall demand across the MISO footprint. By 2045, across the MISO footprint, net energy for load across the MISO footprint is projected to be around 200 TWh higher than the Reference Case, with peak demand nearly 40 GW higher. This demand growth is higher than in all other scenarios except for DR. In addition, all coal capacity is projected to either retire or retrofit to CCUS by 2032, while low gas prices are expected to also support natural gas with CCUS generation. Significant demand growth combined with significant capacity retirements is expected to drive the highest overall capacity buildout across scenarios. This includes new nuclear capacity, as well as hydrogen and storage capacity additions which are expected to provide dispatchable capacity to support significant amounts of new wind and solar. Overall, the MISO market is projected to generate over 90% of its energy from clean, non-CO2 emitting resources by 2043. The projected MISO-wide capacity and energy mixes over time for the AI scenario are presented in Figure 8-32.

Figure 8-32: MISO Power Market Evolution for AI Scenario



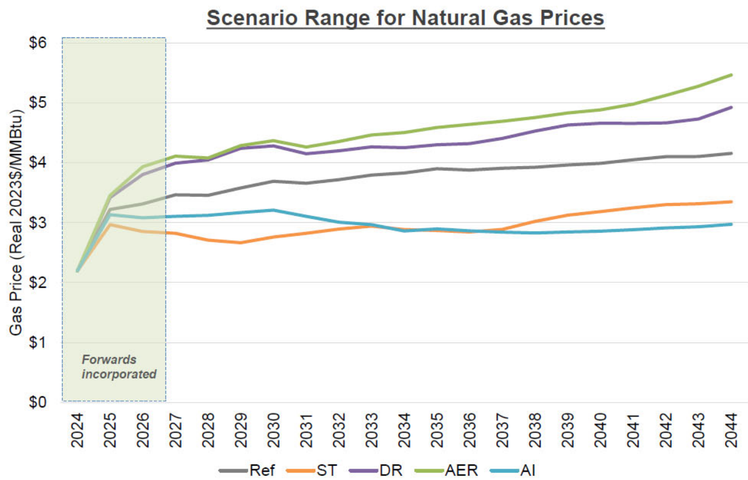
8.4.6 Scenario Comparisons

The following section provides a series of summary comparisons across all five planning scenarios to illustrate the ranges of outcomes NIPSCO has evaluated for key metrics including natural gas prices, carbon regulation, and MISO power market dynamics.

8.4.6.1 Natural Gas Prices

Figure 8-33 summarizes natural gas price projections for the Henry Hub across all five scenarios. The prices range from approximately \$2.85 to \$4.60/MMBtu (real 2023\$) in 2035 and approximately \$2.90 to \$5.30/MMBtu (real 2023\$) by 2043, with the AER scenario ultimately having the highest prices and AI having the lowest.

Figure 8-33: Natural Gas Price Range across Scenarios



	Henry Hub Price (in real 2023$/MMBtu)		
	2025	2035	2043
AER	$3.46	$4.59	$5.28
DR	$3.42	$4.30	$4.73
REF	$3.22	$3.90	$4.11
ST	$2.97	$2.87	$3.32
AI	$3.13	$2.90	$2.93

8.4.6.2 Carbon Regulation

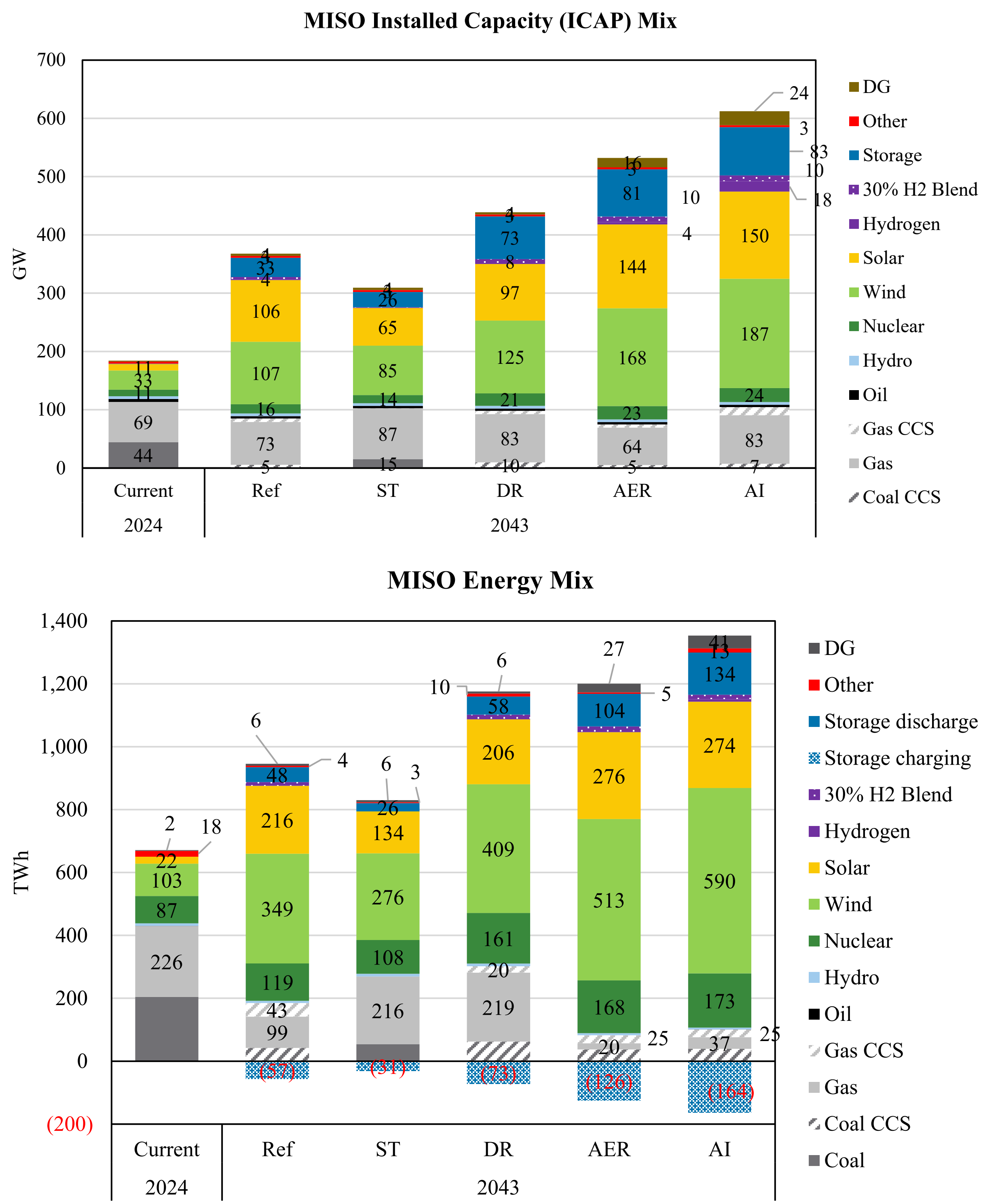
As noted earlier, NIPSCO's scenarios incorporate a range of potential carbon regulation outcomes. Four out of the five scenarios include the EPA GHG Rule, while additional bookend assumptions incorporate the possibility that carbon emissions are not regulated at the federal level over the study horizon as well as the possibility that additional regulation (modeled via a carbon price) pushes towards commitments made by the Biden Administration to limit global temperatures at 2° Celsius above pre-industrial levels by 2100.

8.4.6.3 MISO Power Market Dynamics

The MISO power market is projected to evolve very differently across NIPSCO's five 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 ST scenario projects a stronger role for fossil capacity and energy over time, while the DR scenario expects the highest overall load growth, with a significant role for a diverse set of generation technologies, including renewables, natural gas, and nuclear. Finally, the AER and AI scenarios project significant shifts towards renewables and new clean energy technologies, including nuclear, CCUS, and hydrogen. These dynamics are illustrated in Figure 8-34, which summarizes the current MISO capacity and energy mix and the projections in 2043 across all four scenarios.[145]

[145] Note that storage charging MWh are shown below the zero point on the x-axis, while discharging MWh are shown towards the top of the stacked bars.

Figure 8-34: 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 the expected dispatch of various resource types and market prices at the hourly level. Figure 8-35, Figure 8-36, Figures 8-37, and Figure 8-38 all display projected hourly generation projections by resource type at the MISO level for a sample summer, winter, spring, and fall month for 2040, respectively. 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, DR, and AI scenarios.

- In the winter, higher overnight loads need to be met when solar is unavailable, particularly in the AI 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 8-35: MISO Hourly Generation Projections – Summer, 2040

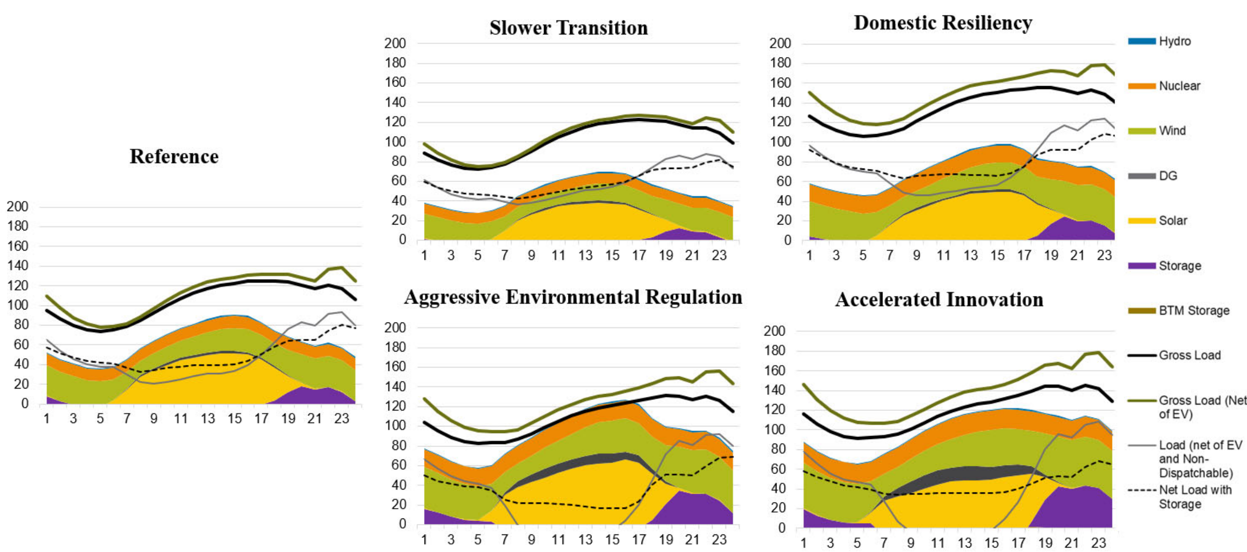


Figure 8-36: MISO Hourly Generation Projections – Winter, 2040

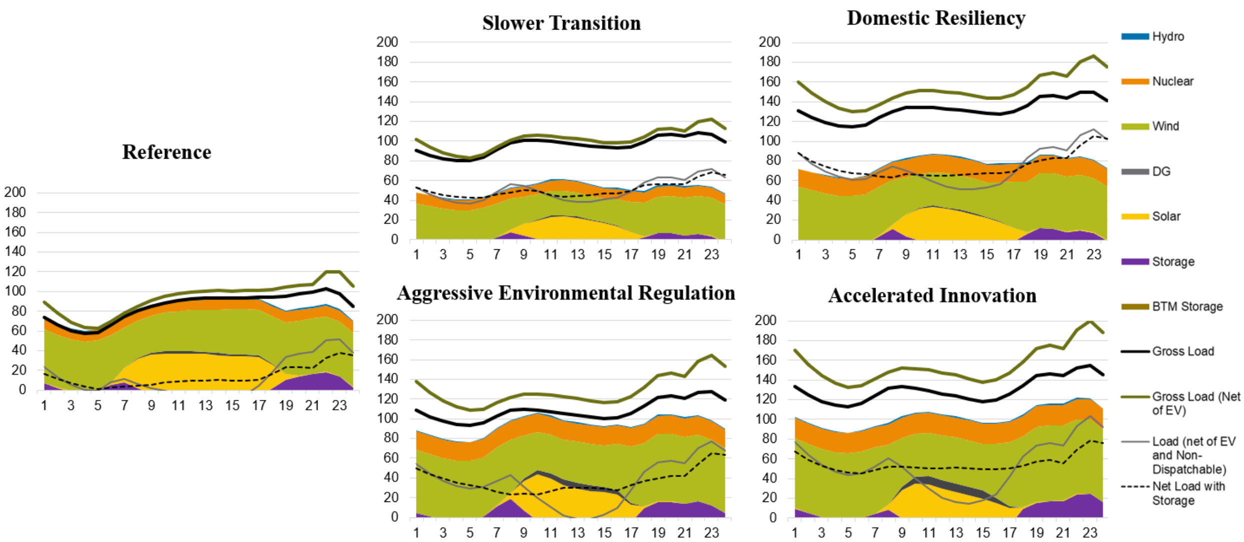


Figure 8-37: MISO Hourly Generation Projections – Spring Shoulder Month, 2040

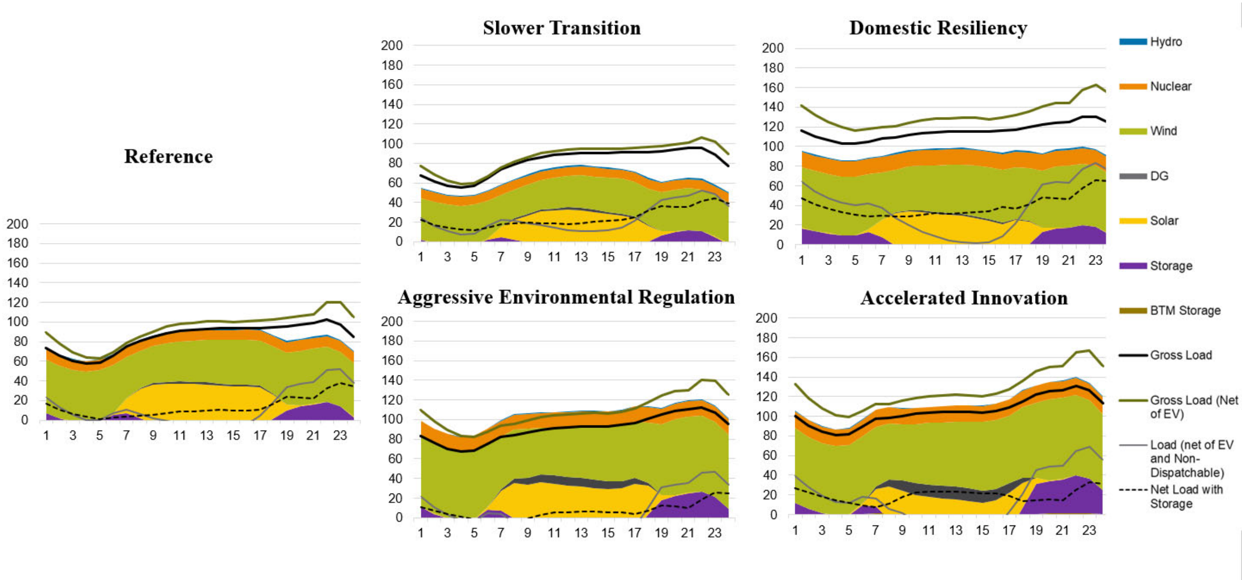
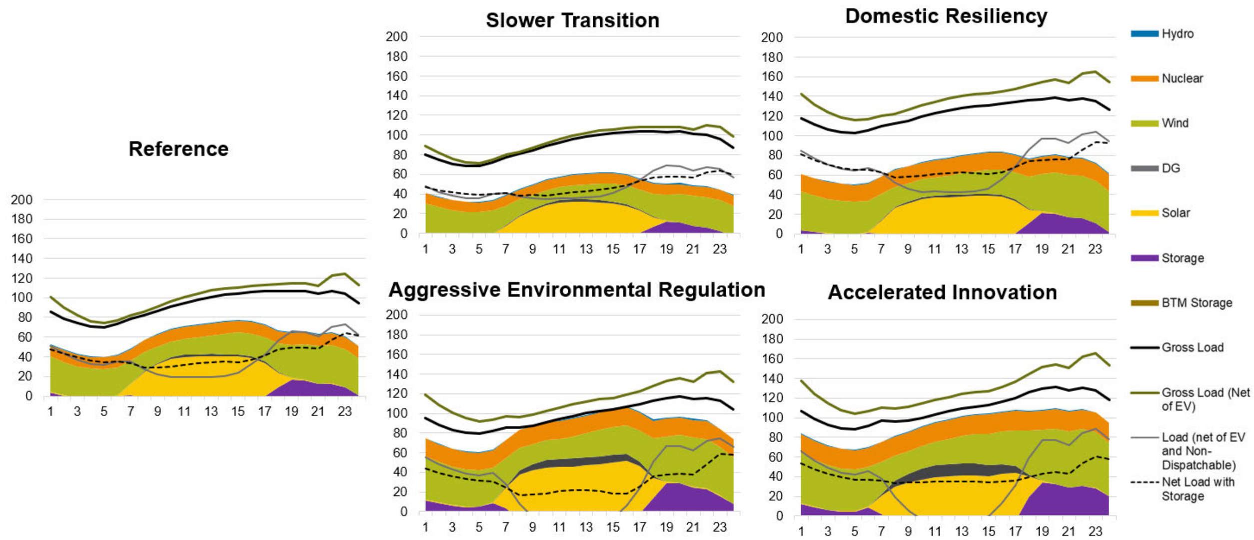


Figure 8-38: MISO Hourly Generation Projections – Fall Shoulder Month, 2040



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 55% to 75% by 2030 and between 65% to 90% by 2043. Figure 8-39 summarizes the projected clean energy percentages over time across scenarios.[146] Similarly, a range of carbon emission reductions across MISO are projected across the five scenarios. The MISO market has already achieved an approximate 35% reduction in CO2 emissions relative to a 2005 baseline, with an expected reduction of over 50% by 2030 across all scenarios and between 65% and 90% by 2043. This is illustrated in Figure 8-40.[147]

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146 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.

147 Historical data from 2005 is taken from MISO Futures documentation.

Figure 8-39: MISO Clean Energy Percentage Projections across Scenarios

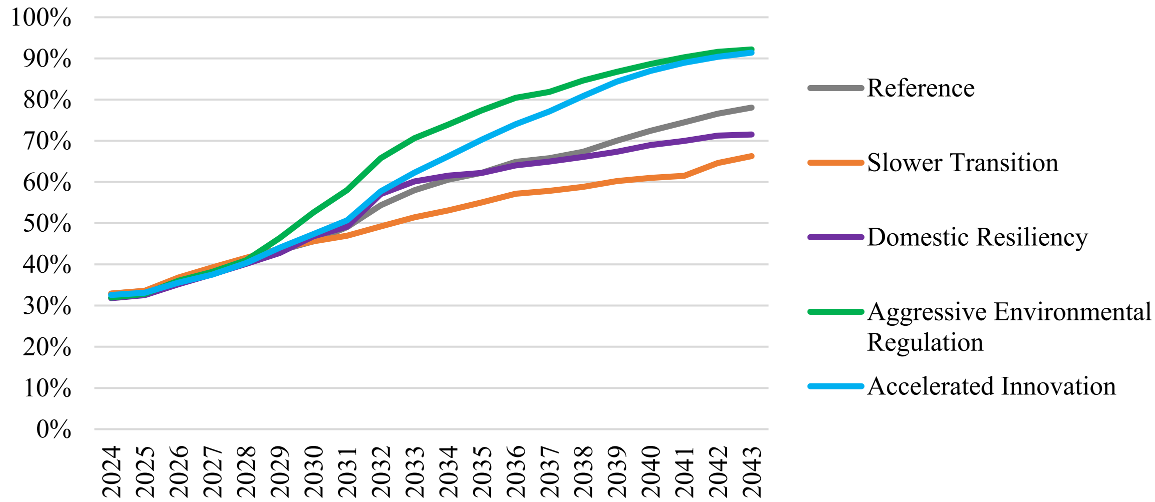
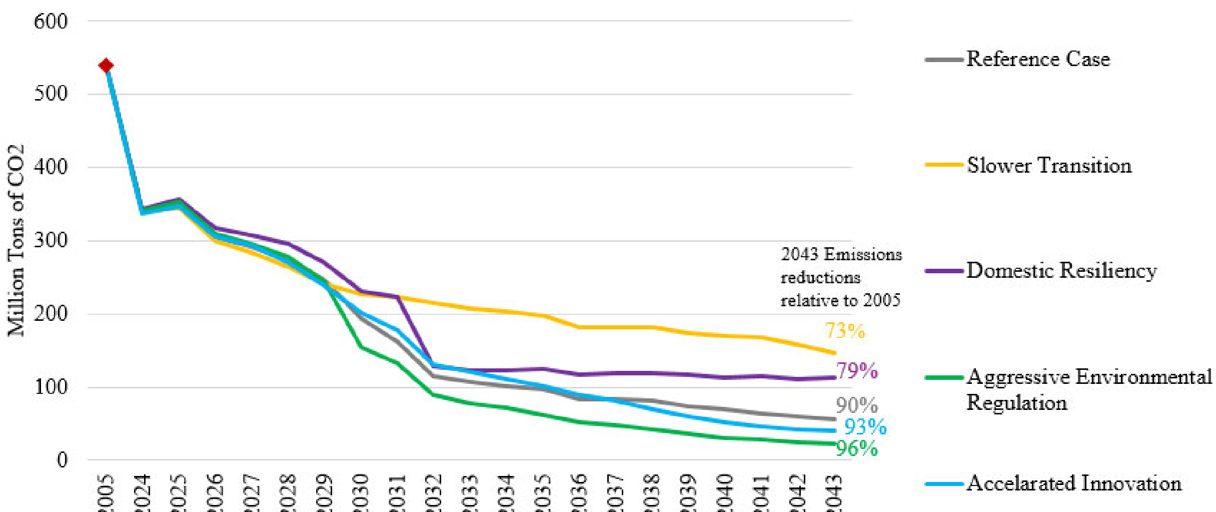
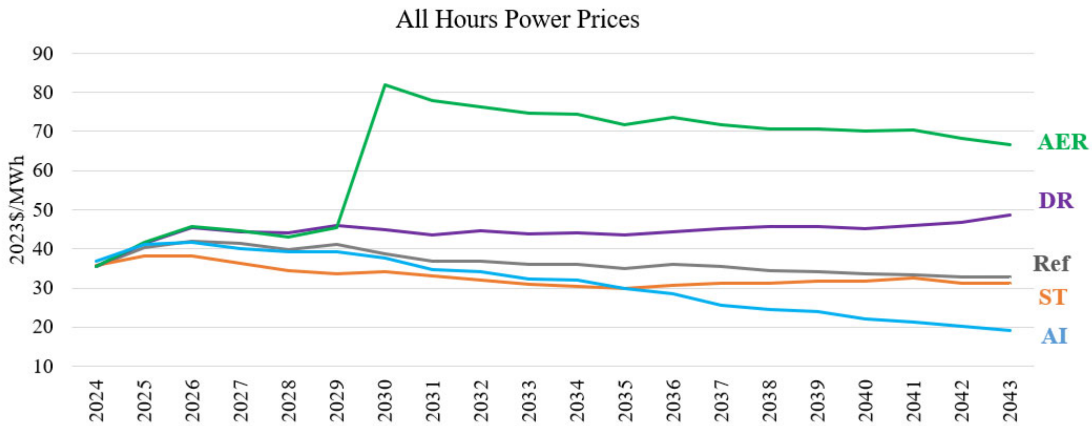


Figure 8-40: MISO CO2 Emission Reduction Projections across Scenarios



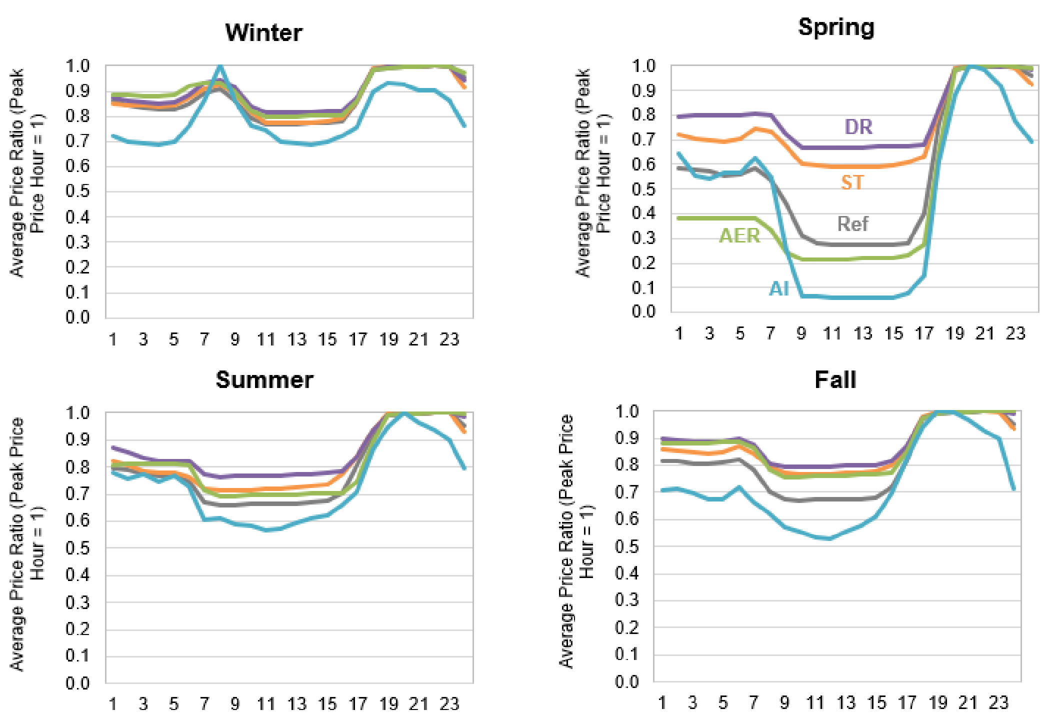
MISO energy prices are projected to vary considerably across scenarios as well. On an "all-hours" or ATC basis, the Reference Case projects prices to be relatively flat in real terms across the study period (as described above) and close to \$35/MWh (real 2023\$) by 2043, while the scenarios include prices that range between below \$20/MWh to above \$70/MWh (real 2023\$) by the same time. Rising natural gas and carbon prices drive the AER scenario's prices highest, while the ST and AI scenarios have flatter pricing in real terms due to lower gas price expectations, the lack of a carbon price, and expectations for growing zero variable cost renewable energy penetration. Prices in the DR scenario are projected to decline above the Reference Case due to increasing load from industrial onshoring and other large loads, as well as higher natural gas prices. The ATC price projections across scenarios are summarized in Figure 8-41.

Figure 8-41: 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 AI scenarios. This dynamic is shown in Figures 8-42, which illustrates the wide range of hourly market price risk that NIPSCO is evaluating across its scenarios.

Figure 8-42: MISO Zone 6 Hourly Price Shapes by Season (2040) across Scenarios



8.5 Stochastic Modeling and Analysis

As discussed above, NIPSCO identified commodity prices, renewable generation output, and generator availability as stochastic variables for evaluation in its 2024 IRP to help assess resource adequacy metrics and tail risk cost exposure for its potential future portfolio.

8.5.1 Stochastic Analysis Motivation and Key Metrics

NIPSCO operates within the MISO market and is not its own balancing authority, meaning that it does not need to produce a portfolio that meets the desired resource adequacy target ("1-Day-in-10 Years"[148]) on its own. Rather, it benefits from integration into the broader MISO market by pooling reliability risks and responsibilities toward meeting resource adequacy targets. However, NIPSCO is committed to ensuring reliable service to its customers and recognizes that it must bring its fair share of resource adequacy to the broader MISO system. Thus, as part of its stochastic analysis for the 2024 IRP, NIPSCO has performed an assessment of the frequency and magnitude of events when it might be forced to rely on the market.

During normal operations, NIPSCO will operate the system economically and buy and sell energy on the market when it is cost-optimal to do so. However, NIPSCO may experience periods of forced market exposure when its native load is greater than its owned and contracted generating capacity, due to planned or unplanned generating outages, low renewable generation, and/or unusually high load demand. During these "pseudo-loss of load" events, NIPSO *must* rely on the market. This leaves NIPSCO potentially exposed to high market prices during these forced market exposure events and in extreme cases, exposed to loss of load events if these periods of NIPSCO stress align with periods of MISO-wide stress events.

To evaluate these risks, NIPSCO elected to employ a loss of load style study – treating NIPSCO's system as an island – to identify pseudo-loss of load events when NIPSCO is forced to rely on the MISO-market to meet its customers' electricity demand. This entails evaluation of portfolios against metrics like loss of load expectation and unserved energy, which are proxies for the frequency and magnitude of "forced market exposure" events. NIPSCO has also qualitatively compared the periods of NIPSCO system stress with the periods of stress identified by MISO in its recent loss of load studies.[149]

In addition, NIPSCO explored the impact of a sample of stochastic inputs to assess the customer cost impact of various portfolio options. Using the Monte Carlo samples generated in the stochastic analysis study, NIPSCO selected 100 representative samples to assess the 95th and 5th percentiles of customer costs for a sample year.

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148 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

149 https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

8.5.2 Stochastic Modeling Approach

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, weather, and generator availability data (both forced and planned outages);

2. **Statistical and fundamental analysis**, including developing statistical models to generate multiple weather outcomes, including around physical climate risk; converting these weather outcomes to wind/solar generation, *future looking* load demand, and generator availability; and learning the impact of net load on the power price;

3. **Stochastic modeling**, including generating a large number of simulated commodity prices and renewable generation, load demand, and generator availability for a single study year (2030); and

4. **Portfolio analysis and results** using the stochastic models to evaluate and report 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, analysis, and statistical model development and simulation. The portfolio analysis and results are reported in next Section.

8.5.3 Input Data Development

8.5.3.1 Fundamental Forecasts

The commodity price stochastic inputs were developed around the Reference Case natural gas and power price forecasts outlined earlier in this Section. NIPSCO's stochastic analysis for the 2024 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 natural gas and power prices. Historical prices from the period January 1, 2014 through December 31, 2023 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 Citygate and the day-ahead ATC price strip from the NIPSCO zone within MISO (Zone 6) were the specific pricing points used in this analysis.[150]

8.5.3.2 Historical Weather and Solar / Wind Availability Data

Historical weather data was gathered at locations of present and potential future utility scale wind and solar farms. Solar data was obtained from the NREL NSRDB[151] for weather years 2002 to 2022. The data included key meteorological descriptors including diffuse horizontal irradiance, direct normal irradiance, albedo, wind speed (meters per second) at surface level, temperature, snow depth, elevation above sea level, atmospheric pressure, and wind direction, among others. The weather data was converted to solar generation using Sandia National Laboratories' open source python-based tool pvlib-python[152]. This python-based tool takes data in the NSDRB format and provides relevant solar generation. Wind data was obtained from the NREL Wind Integration Datasets[153] for weather years 2007 to 2014. This data included wind speed and wind temperature at various elevations (i.e., 80-meter height). The weather data was converted to wind generation using publicly available power curves,[154] based on the actual or assumed turbine type.

The annual solar and wind generation were then checked to ensure the correct average annual and monthly capacity factors were achieved based on NIPSCO-specific project historical performance or future expectations. The weather data was also utilized to synthesize a representative temperature time series, wind speed at hub height time series, and wind speed at surface level using a weighted average of the various renewable sites, based on the respective installed capacities. This is a reasonable approximation to represent the weather variables as a single weighted average time series, since these values are highly correlated (correlation coefficients between .8 and .95).

The process outlined above resulted in eight historical hourly trajectories for wind generation at each wind farm location (representing historical weather years 2007 through 2014) and twenty-one historical hourly trajectories for solar availability (representing historical weather years 2002 through 2022). The NREL simulations produced reasonable annual average capacity factors for wind and for solar in the selected location (around 35-40% for a representative wind resource and around 25% for a representative solar resource).

150 Data was retrieved from S&P Global Market Intelligence: Commodity Charting Tool.

151 NREL NSRDB, https://nsrdb.nrel.gov/

152 https://github.com/pvlib/pvlib-python

153 NREL Wind Integration Datasets, https://www.nrel.gov/grid/wind-integration-data.html

154 Wind energy database (thewindpower.net)

8.5.4 Statistical and Fundamental Analysis

Next, statistical models were developed to generate random iterations of commodity prices, generator availability, load demand, and wind/solar generation and to capture the correlations between them.

8.5.4.1 Integrating Renewable Output Uncertainty

The integration of renewable output uncertainty into NIPSCO's stochastic analysis process was an enhancement originally deployed 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. This 2024 IRP continues to further develop this integration of uncertainty into the IRP process to better assess the risk associated with anomalous weather conditions and unusual market prices by generating multiple synthetic weather years (and corresponding renewable generation) to stress test a wide range of weather conditions.

To generate these synthetic wind/solar shapes, statistical models were developed to simulate possible iterations using *CRA AdequacyX* – Charles River Associates' proprietary probabilistic reliability analysis tool. Importantly, CRA used recent weather data to train the probabilistic model to ensure recent weather trends, including those associated with recent local climate change impacts, are incorporated rather than relying on a 30 to 40 year history. Consistent weather data was used across processes associated with the development of wind and solar output, NIPSCO load, and thermal unit availabilities.

These weather shapes include potential annual temperature shapes and possible wind shapes at hub height. These wind speeds at hub height were mapped to the wind speed at the surface, using a machine learning model. These simulated weather conditions mapped to the respective wind and solar generation using the calibrated wind power curve and the calibrated solar power curve (pvlib) described above. Sample illustrations of the temperature, wind, and solar output profiles are shown in Figure 8-43, Figure 8-44, and Figure 8-45. The figures display the range (shown in light blue) and average outcomes generated from 100 Monte Carlo simulations. As highlighted in these figures, the exact renewable generation can vary within a given Monte Carlo iteration, but these iterations capture characteristic daily and seasonal variations.

Figure 8-43: Sample Monte Carlo Iterations for Ambient Temperature

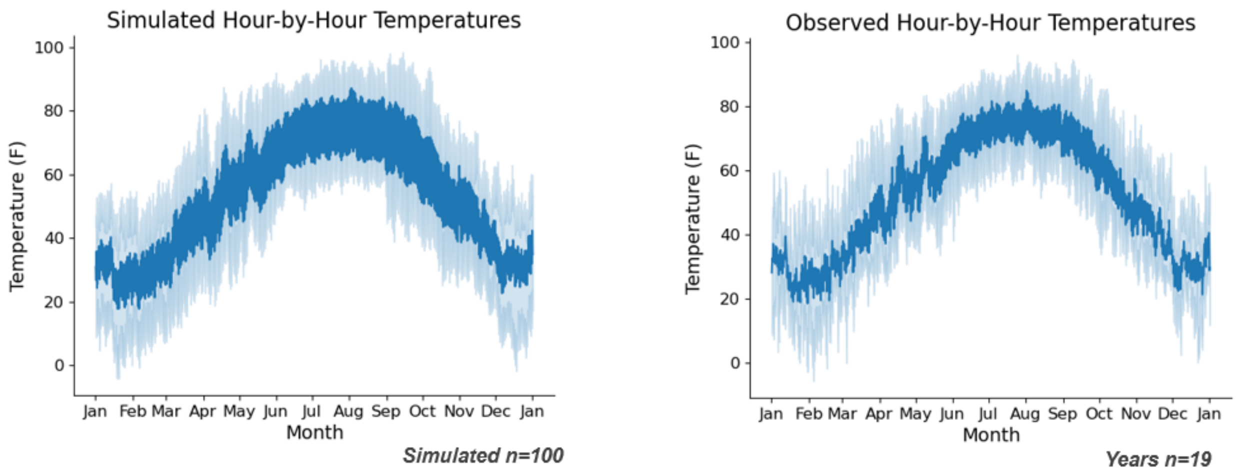


Figure 8-44: Sample Monte Carlo Iterations for Solar Generation

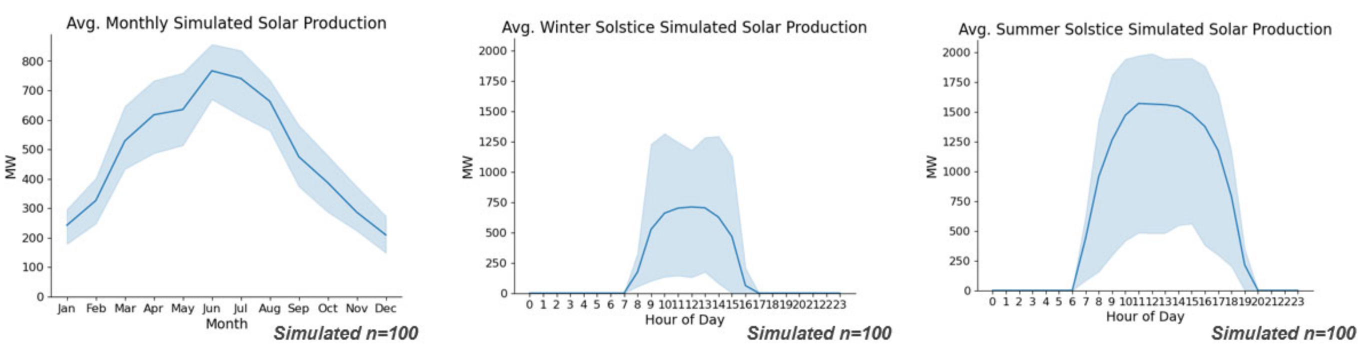
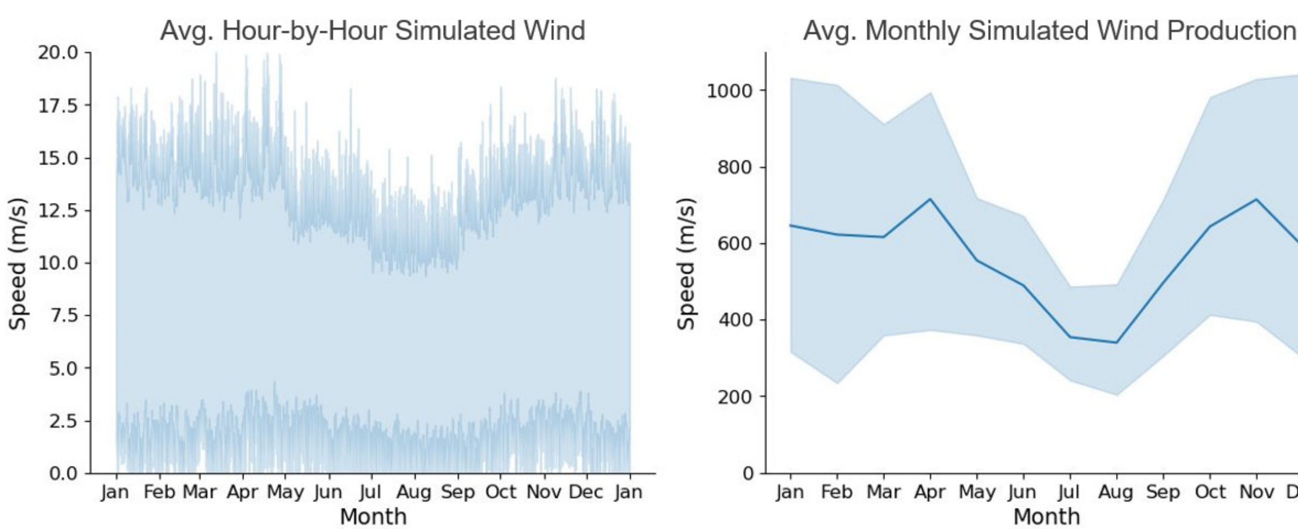


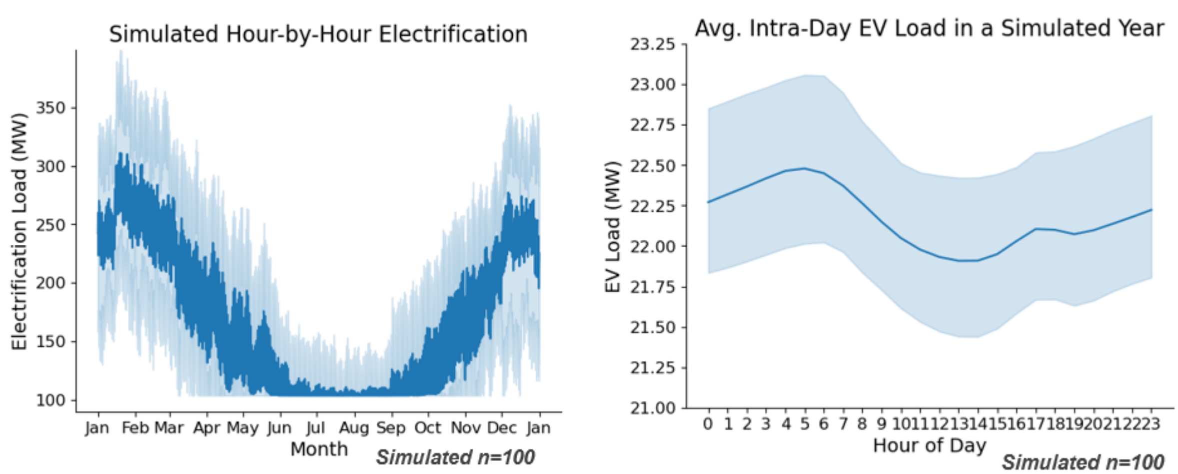
Figure 8-45: Sample Monte Carlo Iterations for Wind Speed and Generation



8.5.4.2 Integrating Load Uncertainty

In addition to driving the wind and solar generation, weather conditions greatly impact demand for electricity in NIPSCO's system. To capture these temperature impacts on demand, NIPSCO developed a regression model between HDD and CDD and load. Using this regression model, NIPSCO generated synthetic load shapes by "temperature shocking" a randomly selected historical hourly load shape (from years 2013 to 2022) by removing the temperature impact of historical temperature and adding back the predicted temperature impact of the synthetic temperature shape. NIPSCO also simulated changes occurring within the load shapes due to the addition of new technologies like electric vehicles, grid electrification, and data centers. NIPSCO developed additional regression models to model the impact of ambient temperature on the electric vehicle charging behavior and electrification (See Figure 8-46). In this manner, NIPSCO generated high-fidelity synthetic load shapes which simulate stress periods over a wide range of times and capture changing load shapes.

Figure 8-46: Sample Monte Carlo Iterations of Additional EV Charging and Demand from Electrification



8.5.4.3 Integrating Thermal Generator Availability Uncertainty

The availability of thermal resources also impacts the resource adequacy and cost exposure of NIPSCO's potential portfolios. A resource may not be available to meet the net load demand due to a planned or unplanned outage, and simulating generator availability was an enhancement for the 2024 IRP relative to previous IRPs. The planned outages were simulated using the historical outage schedules, while forced outages were simulated assuming an exponential distribution, based on the historical seasonal mean time between failure and the mean time to repair. In some regions (including MISO as a whole[155]), weather conditions have been shown to have an impact on the failure rates of generators. Some generators have been shown to be more likely to fail due to very high or very low temperature. Unlike other resources in the MISO

155 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

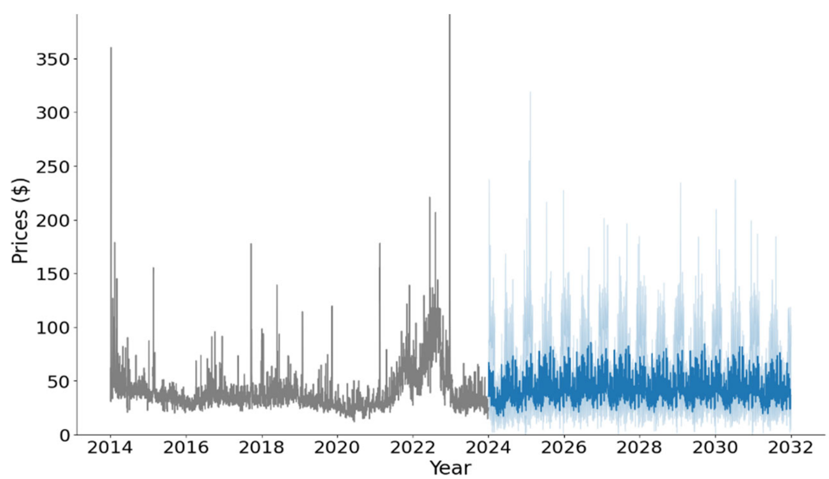
footprint, historical outages at NIPSCO's Sugar Creek natural gas combined cycle unit were not found to be correlated with temperature but were found to have seasonal variations. As such, these generator outages were simulated independently of the weather, while any additional thermal resources were modeled as matching the published MISO forced outage rates.[156]

The ambient temperature can also impact the maximum generating capacity of various technologies, and the temperature impact on the contribution of wind generation, solar generation, and natural gas-based technologies was also modeled.

8.5.4.4 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[157] that takes as input expected paths for electricity and natural gas prices developed through the fundamental forecasting analysis described earlier in this Section. The tool's Monte Carlo engine simulates price deviations around the expected paths based on historical volatility and natural 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. The distribution of possible future electricity prices that NIPSCO developed for its stochastic analysis is shown in Figure 8-47, and the distribution of possible future natural gas price iterations is shown in Figure 8-48. As illustrated, the stochastic price paths exhibit a wide range of possible outcomes and can experience short spikes in price. This is consistent with historical behavior.

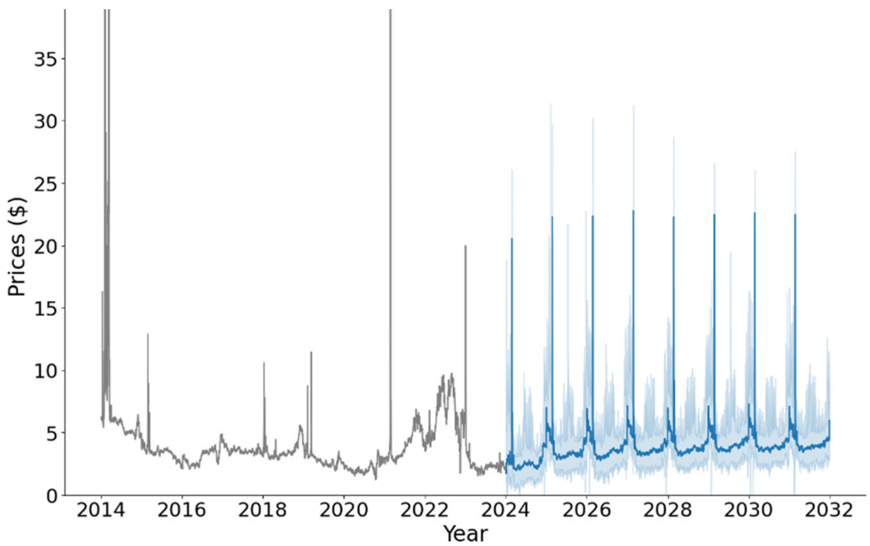
Figure 8-47: Future Electricity Price Iterations (Hourly)



156 https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

157 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.

Figure 8-48: Future Natural Gas Price Iterations (Daily)



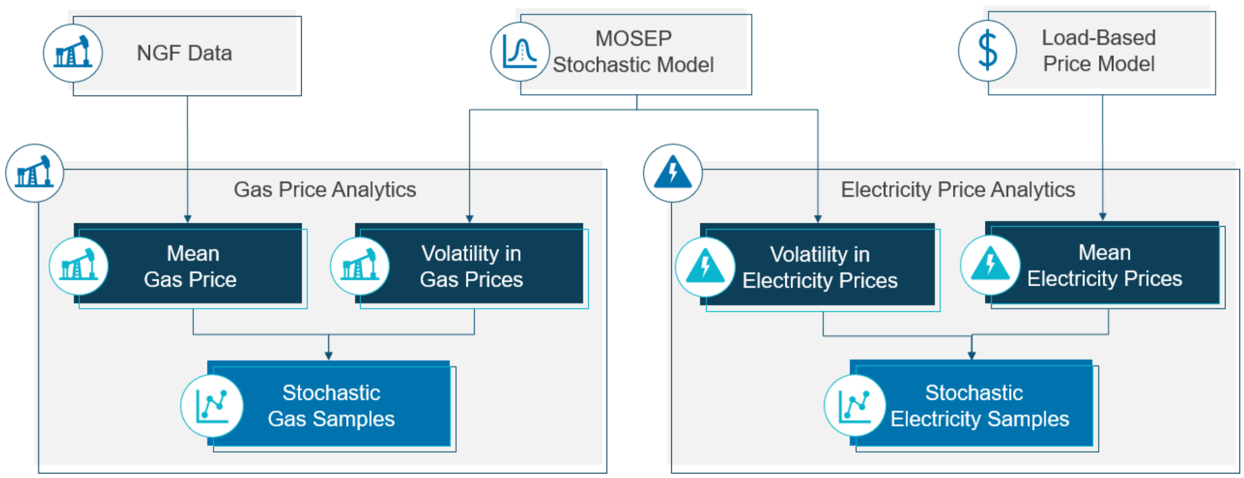
MOSEP generates its potential power prices in a manner that assumes power prices and NIPSCO's net load (load less renewable output) and the highly correlated Zone 6 net load evolve independently of each other. This assumption does not account for the fact that lower than expected net load will generally depress prices by reducing the generating capacity needs to meet the net load. Thus, an additional step was added to the analysis to capture this correlation by modifying the expected electricity price (the assumed mean in the MOSEP model), based on the NIPSCO/Zone 6 net load conditions. To this end, a machine learning model was trained to predict the Zone 6 prices as a function of the NIPSCO/Zone 6 net load, NIPSCO/Zone 6 gross load, and month of year.[158] This model was a regression model trained using the Aurora market simulations. The inputs to this model were the net load, natural gas prices, and timestamp variables from the Aurora market model, and the model's output was the Zone 6 market price.

Additionally, the expected electricity price was adjusted to account for realized conditions before feeding it into the MOSEP model.[159] This process is summarized in Figure 8-49. It is important to note that other factors – like MISO-wide net load, generator outages (both for NIPSCO and non-NIPSCO entities), congestion, and power trading – can all have a substantial impact on NIPSCO's market price (LRZ6). The impacts of these factors are captured through the deviations from the mean and random shocks simulated through the MOSEP model.

[158] This machine learning model represents a "surrogate model" proxy for the computationally time-consuming Aurora model. See Koziel, S., Ciaurri, D. E., & Leifsson, L. (2011). Surrogate-based methods. Computational optimization, methods and algorithms, 33-59.

[159] The predicted electricity price is shifted by the delta between the model's prediction using the percentage realized net load and the expected net load. In this manner, lower than expected net load conditions will shift electricity prices up, and lower than expected net load conditions will shift electricity prices down.

Figure 8-49: Illustration of Renewable Availability Integration in Stochastic Process



Section 9. Portfolio Analysis

9.1 Portfolio Development

9.1.1 Process Overview

As discussed in more detail in Section 2, NIPSCO performed its portfolio analysis in the context of emerging market trends associated with MISO capacity accreditation rules and GHG Rule (*See* also Section 7). As such, different portfolio concepts were evaluated across a range of capacity accreditation expectations and carbon emissions intensity limits. To develop different portfolio concepts, NIPSCO deployed least cost portfolio optimization analysis and then subjected the portfolios to a range of risks and uncertainties, as described in Section 8. To evaluate portfolios, NIPSCO used an integrated scorecard approach, as outlined in more detail in Section 2. In addition to the net present value of revenue requirements in the Reference Case, NIPSCO has also considered rate stability, carbon emissions, reliability, and local economic impact metrics. The overall process included the following major steps:

- Identify six thematic portfolio concepts based on MISO capacity accreditation rules and portfolio carbon emission intensity.
- Identify the least-cost capacity additions to fill incremental capacity needs based on the constraints within each of the six portfolio themes and 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 in the IRP tools for each scenario and across the stochastic risk distributions (as defined in Section 8). The evaluation includes a full accounting of the variable and fixed costs of providing generation service.
- Record costs, risks, and other metrics in the integrated scorecard to identify the preferred portfolio.

Importantly, and consistent with prior NIPSCO IRPs, the process of portfolio development focuses on overall cost of each portfolio (in terms of NPVRR) and does not address cost allocation or cost recovery.

9.1.2 Portfolio Concepts

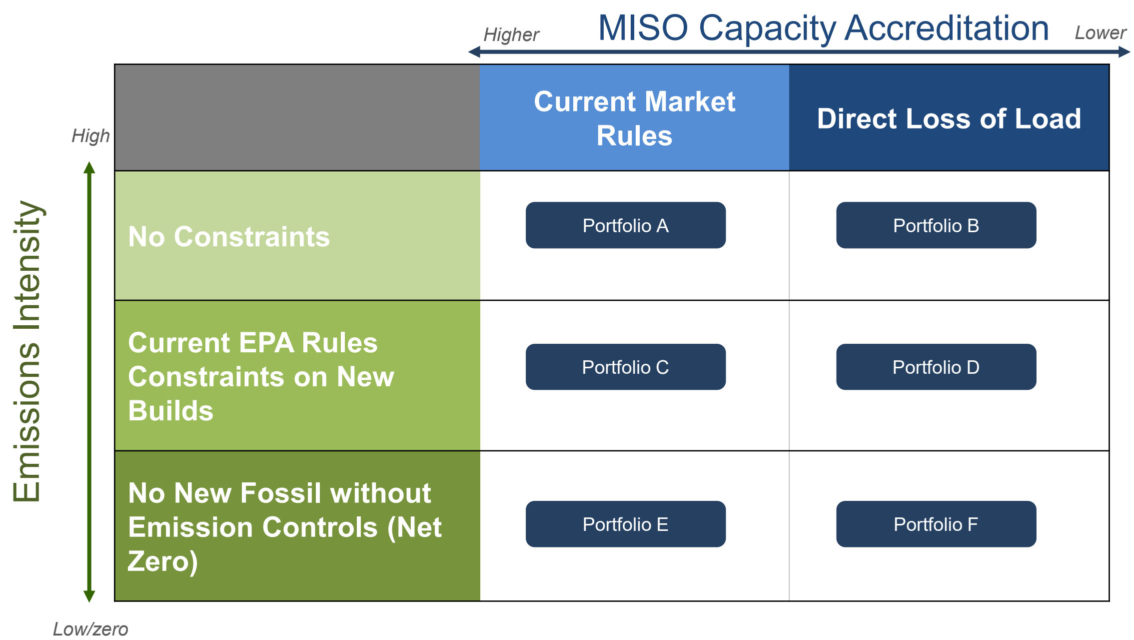
NIPSCO initially developed six portfolio concepts to highlight the two primary market trends and operational uncertainties currently facing the portfolio, as summarized in Figure 9-1:

- MISO's D-LOL rules[160], which are likely to reduce the capacity value, primarily for solar and wind resources; and

- EPA's GHG emissions rules[161], which constrain output or increase cost of new gas generation.

This framework allowed for the definition of six portfolio concepts within a two by three matrix (Portfolios A through F as shown in Figure 9-1). Portfolios were developed under expectations for market capacity accreditation under the current MISO rules and those associated with MISO's D-LOL construct and across three different carbon emission intensity levels: (i) no constraints, (ii) enforcement of capacity factor constraints on new natural gas additions, and (iii) the disallowance of any new fossil-fired resources without carbon emission controls.

Figure 9-1: Overview of Existing Fleet Portfolios



9.1.3 Portfolio Optimization Analysis

As in the 2018 and 2021 IRPs, 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

160 As discussed further in Section 2, MISO's D-LOL filing was approved by the Federal Energy Regulatory Commission on October 25, 2024 and is expected to be implemented in the 2028/29 planning year. NIPSCO's portfolio development process was initiated prior to this approval and included analysis based on both the D-LOL construct and the prevailing market construct prior to D-LOL implementation. Given continued lack of clarity regarding *actual* future resource accreditations under the D-LOL reforms, the "Current Market Rules" construct remains instructive with regard to the portfolio implications associated with higher resource accreditation values for certain technology types.

161 As discussed further in Section 7, the EPA's GHG rules were issued on April 25, 2024. Most importantly for NIPSCO's portfolio construction, they would place operational limits on new natural gas-fired resource additions.

addition, NIPSCO identified other resource options (*See* Section 4) and bundles of DSM resource options over time (*See* Section 5) to include in the analysis.

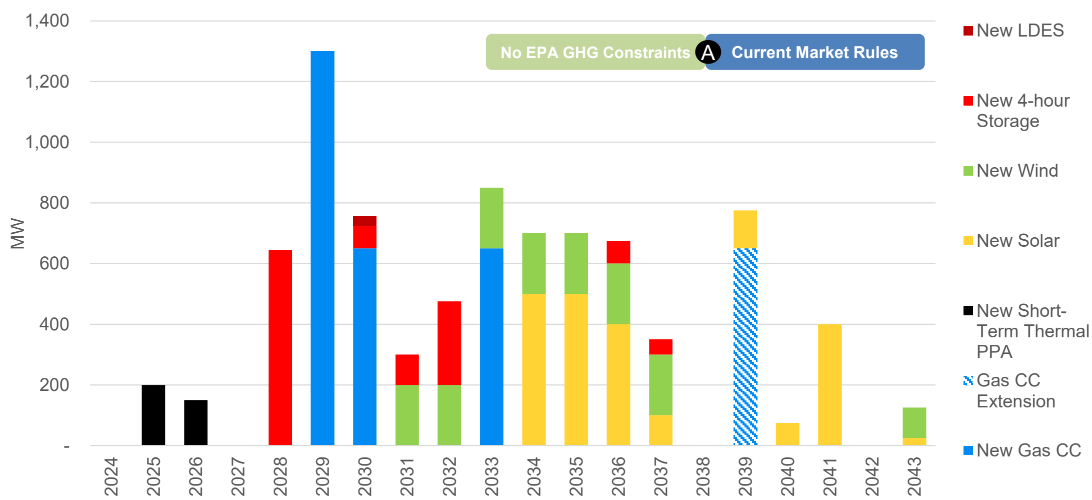
With these resource options, a least cost capacity expansion analysis was performed within Aurora's portfolio optimization tool under each of the six portfolio concepts to identify least-cost sets of new resources under Reference Case market conditions. The portfolio optimization modeling was performed to find the least cost portfolio that would simultaneously meet all MISO seasonal reserve margin requirements along with any other resource constraints.[162]

The remainder of this section documents the resource additions identified in the portfolio optimization process for each of the six portfolio themes.

9.1.3.1 Portfolio A – No EPA GHG Constraints and Current Market Rules

Portfolio A included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,600 MW of combined cycle capacity (1,300 MW through 2029), 1,249 MW of new storage capacity (644 MW through 2029), 1,500 MW of wind, and 2,125 MW of solar over the twenty-year study period. Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio A.

Figure 9-2: Portfolio A – Annual Resource Additions (Nameplate MW)



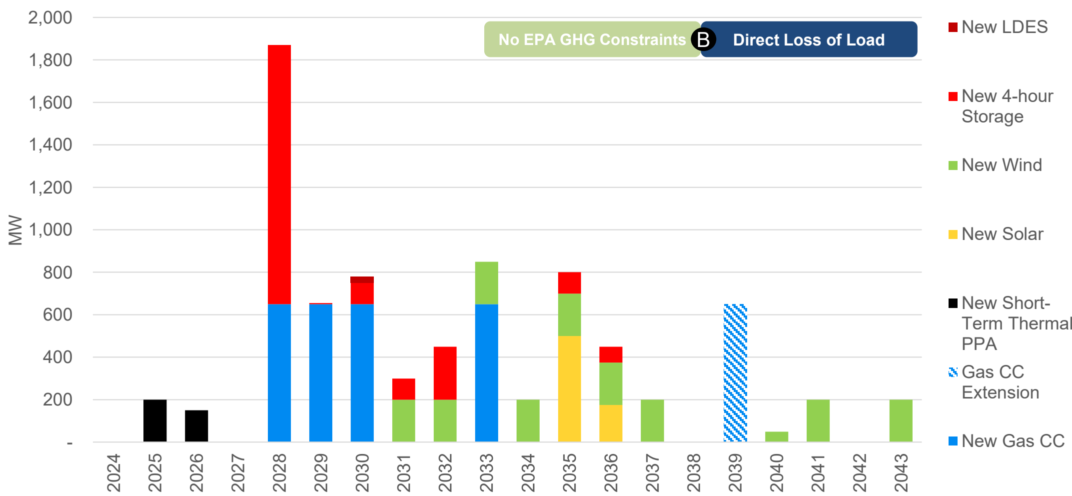
Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

162 A maximum net energy sales limit of 10% after 2028 (after the retirement of NIPSCO's last coal-fired plant) was targeted, along with a maximum net energy purchases sales limit of 20%. The limits were ultimately input on a monthly level to coincide with the monthly capacity and reserve margin optimization that was performed.

9.1.3.2 Portfolio B – No EPA GHG Constraints and D-LOL

Portfolio B included a total of 350 MW of short-term thermal PPAs and Zonal Resource Credits ("ZRCs"), 2,600 MW of combined cycle capacity (1,300 MW through 2029), 1,882 MW of new storage capacity (1,227 MW through 2029), 1,850 MW of wind, and 675 MW of solar over the twenty-year study period. Relative to Portfolio A, Portfolio B included additional near-term storage capacity to meet near-term capacity accreditation needs under the D-LOL construct and fewer long-term solar additions. Figure 9-3Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio B.

Figure 9-3: Portfolio B – Annual Resource Additions (Nameplate MW)

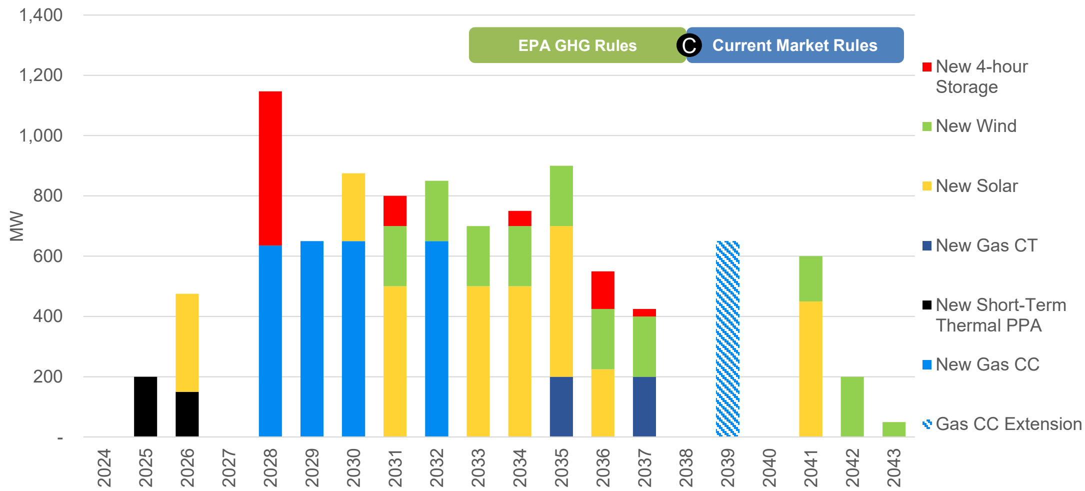


Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

9.1.3.3 Portfolio C – EPA GHG Rules and Current Market Rules

Portfolio C included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,585 MW of combined cycle capacity (1,285 MW through 2029), 400 MW of natural gas peaking capacity, 811 MW of new storage capacity (511 MW through 2029), 1,800 MW of wind, and 3,235 MW of solar (335 MW through 2029) over the twenty-year study period. Relative to the No EPA GHG constraints portfolios, Portfolio C included significantly more solar additions as a result of the EPA rules combined with more favorable capacity accreditation than what is assumed under the D-LOL construct. Figure 9-4 provides a summary of the annual nameplate capacity resource additions for Portfolio C.

Figure 9-4: Portfolio C – Annual Resource Additions (Nameplate MW)

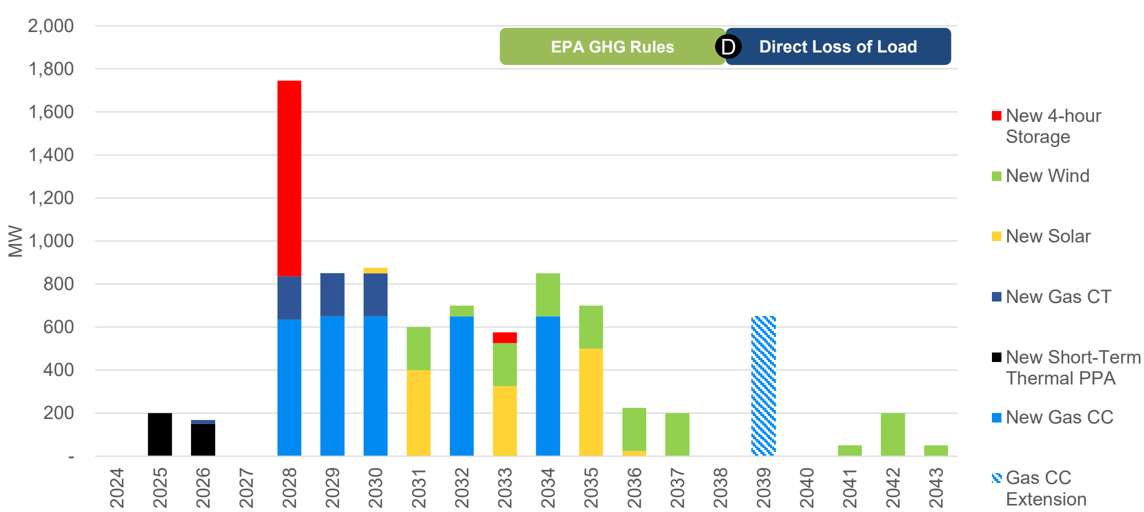


Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

9.1.3.4 Portfolio D – EPA GHG Rules and D-LOL

Portfolio D included a total of 350 MW of short-term thermal PPAs and ZRCs, 3,235 MW of combined cycle capacity (1,285 MW through 2029), 618 MW of natural gas peaking capacity, (418 MW through 2029), 959 MW of new storage capacity (909 MW through 2029), 1,550 MW of wind, and 1,275 MW of solar over the twenty-year study period. Relative to Portfolio C, Portfolio D included additional near-term storage and natural gas peaking capacity to meet near-term capacity accreditation needs under the D-LOL construct. Figure 9-5Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio D.

Figure 9-5: Portfolio D – Annual Resource Additions (Nameplate MW)

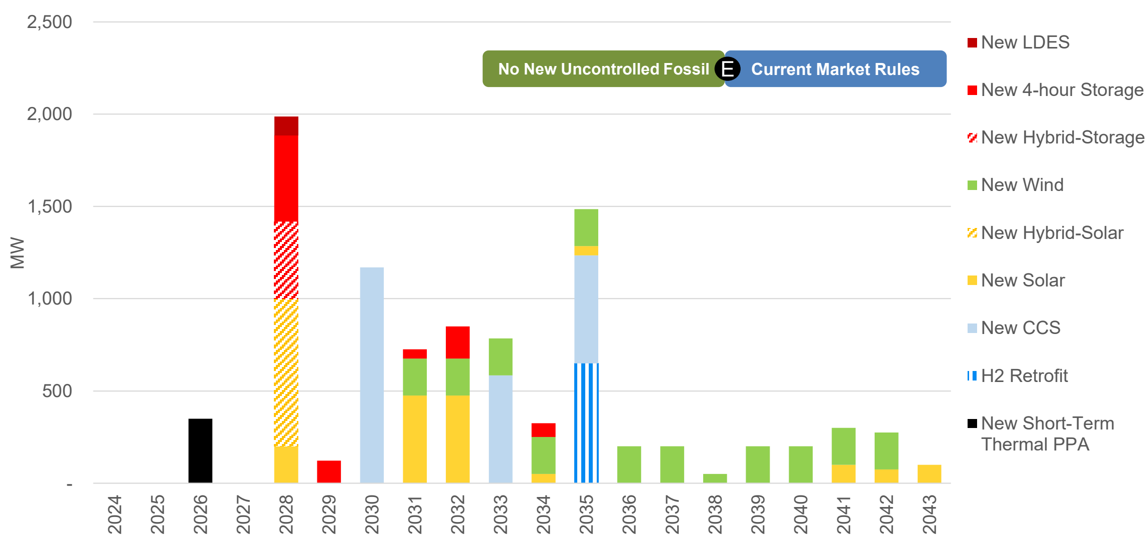


Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

9.1.3.5 Portfolio E – No New Uncontrolled Fossil and Current Market Rules

Portfolio E included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,340 MW of combined cycle capacity with CCUS in 2030 and beyond, 1,409 MW of new storage capacity (1,109 MW through 2029), 2,250 MW of wind, and 2,322 MW (997 MW through 2029) of solar over the twenty-year study period.[163] Relative to the other portfolios, Portfolio E included significant solar and storage through 2029 to meet growing energy needs without availability of new thermal resources without environmental controls until 2030 and beyond. Figure 9-6 provides a summary of the annual nameplate capacity resource additions for Portfolio E.

Figure 9-6: Portfolio E – Annual Resource Additions (Nameplate MW)



Note: There are two short-term PPAs in 2026. 200 MW lasts from 2026-2029. and 150 MW lasts from 2026-2030.

9.1.3.6 Portfolio F – No New Uncontrolled Fossil and D-LOL

Portfolio F included a total of 350 MW of short-term thermal PPAs and ZRCs, 2,340 MW of combined cycle capacity with CCUS in 2030 and beyond, 2,111 MW of new storage capacity (1,986 MW through 2029), 2,350 MW of wind, and 1,922 MW (797 MW through 2029) of solar over the twenty-year study period. Relative to the Portfolio E, Portfolio F included significantly more near-term storage additions to meet near-term capacity accreditation needs under the D-LOL construct. Figure 9-7 provides a summary of the annual nameplate capacity resource additions for Portfolio F.

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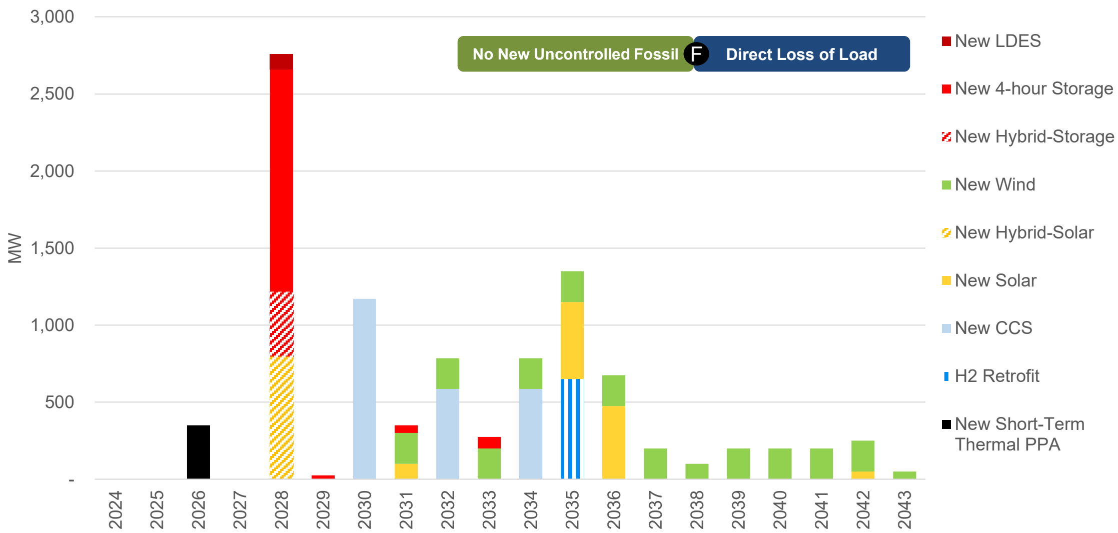
163 Note that both Portfolio E and Portfolio F included the assumed conversion of NIPSCO's existing Sugar Creek combined cycle facility to burn high blends of hydrogen fuel, starting in 2035. See Section 4 for additional information on hydrogen fuel cost assumptions.

Figure 9-7: Portfolio F – Annual Resource Additions (Nameplate MW)



Note: There are two short-term PPAs in 2026. 200 MW lasts from 2026-2029, and 150 MW lasts from 2026-2030.
**Credit represents seasonal capacity accreditation values for PY 2033 for illustration purposes.*

9.1.4 Additional Portfolio Variants

After the development of Portfolios A-F, NIPSCO identified the need to develop two additional portfolio concepts to assess potential portfolio variants that would allow new fossil resource additions without emission controls at the initial construction in the near-term, but still achieve net zero by 2040. These variants included:

- Portfolio "D_CCUS"
  - Preserved the optimized expansion plan from original inputs and constraints.
  - Assumed future CCUS retrofit on up to 2,000 MW of new combined cycle capacity over the 2035-2037 time period.
  - Assumed remaining combined cycle capacity is retrofit to burn up to 100% hydrogen over the long-term.
- Portfolio "D_H2"
  - Preserved optimized expansion plan from original inputs and constraints.
  - Assumed all combined cycle capacity is retrofit to burn up to 100% hydrogen over the long-term.

Figure 9-8 illustrates the cumulative new capacity additions for all six portfolio concepts (A-F) plus the additional "D variants" through 2043, while Figure 9-9 shows the projected energy mix for the eight portfolios in the same year in the Reference Case.

Figure 9-8: Resource Additions across all Portfolios – Cumulative Nameplate Capacity through 2043

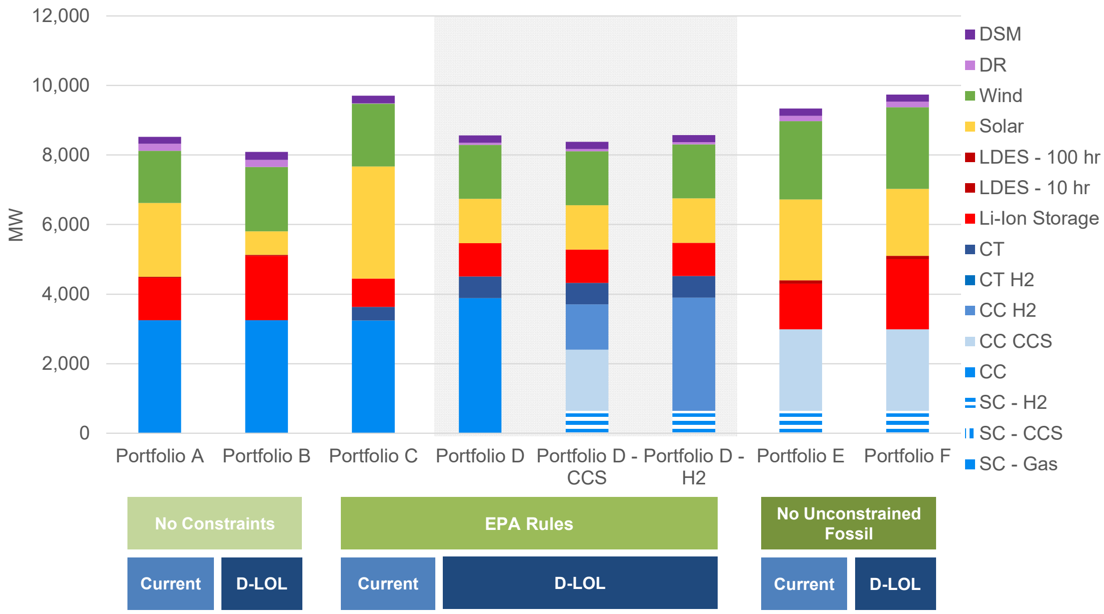
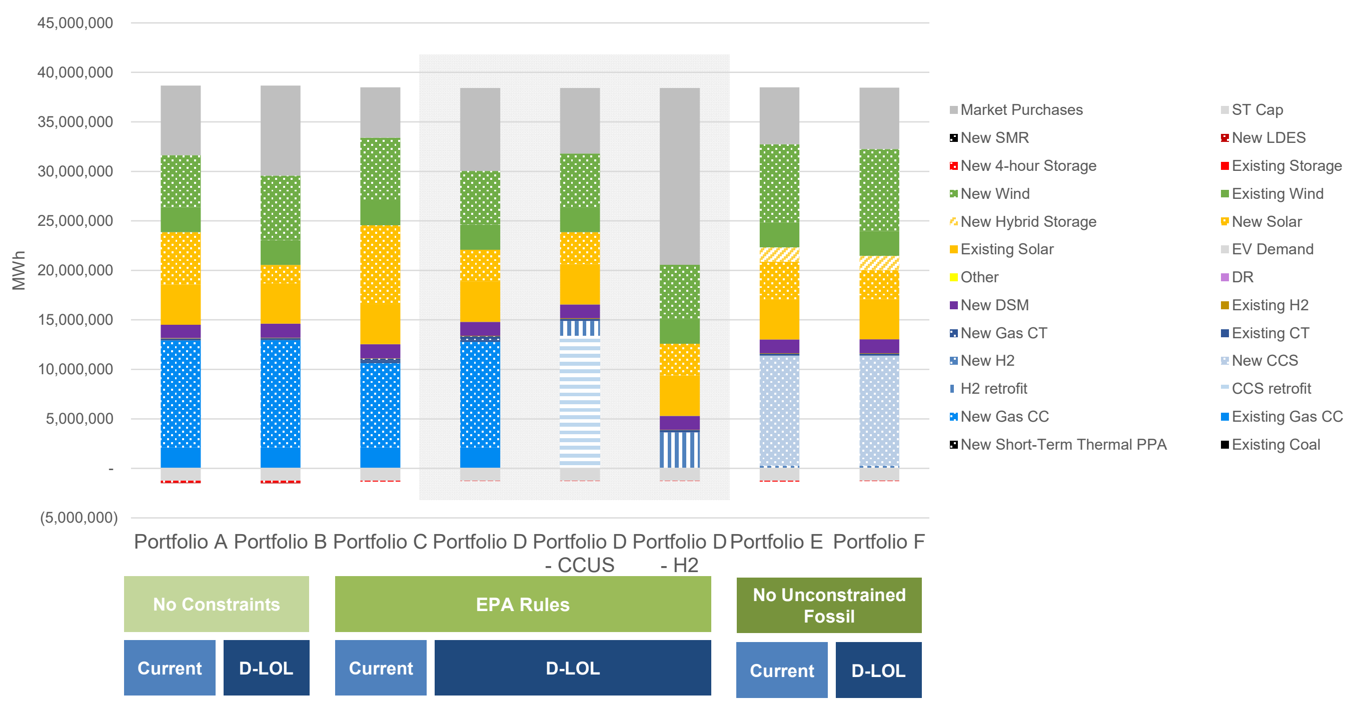


Figure 9-9: Projected Energy Mix across All Portfolios – 2043



9.1.5 DSM Program Selection

As described in detail in Section 5, NIPSCO's portfolio optimization analysis incorporated EE and DR bundles for selection. Overall, most EE bundles were selected across the portfolios. In particular, the Low/Medium cost Residential and Commercial and Industrial bundles were nearly always selected across all planning periods. However, the high Residential and Behavioral bundles were observed to be more marginal, but still selected across many years and portfolios. In general, more EE was selected in Portfolios C, D, E, and F relative to Portfolios A and B. This is primarily a result of greater energy savings need under conditions when the EPA GHG Rules and their consequent limits on new combined cycle capacity factors are in place. A full summary of EE selection by program bundle and time period across all portfolios is summarized in Figure 9-10.

Figure 9-10: Energy Efficiency Selection across Portfolios

Program	Portfolio A			Portfolio B			Portfolio C			Portfolio D			Portfolio E			Portfolio F		
	’27-’29	‘30-’32	‘33-’46	’27-’29	‘30-’32	‘33-’46	’27-’29	‘30-’32	‘33-’46	’27-’29	‘30-’32	‘33-’46	’27-’29	‘30-’32	‘33-’46	’27-’29	‘30-’32	‘33-’46
Res (Low/Med)	o	x	x	o	x	x	o	o	x	x	x	x	x	x	x	x	x	x
Res (High)	o	o	o	o	x	x	x	o	x	x	x	o	o	o	o	x	x	o
Res (Behavioral)	o	o	x	x	o	x	x	x	x	x	x	x	x	o	x	o	x	x
C&I	o	x	x	o	x	x	x	x	x	x	x	x	x	x	x	x	x	x
IQW	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
IQHear	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x

X = Selected
o = Not Selected

On the DR side, the Behavioral, data center, C&I, and dynamic rates programs were most often selected across portfolios. The thermostat program was selected in Portfolios A and B, while the water heater, EV managed charging, and BTM storage programs were not selected at all. In general, less DR was selected in Portfolios C and D relative to the others, given greater amounts of alternative resources needed for both energy and capacity needs in those portfolios. A full summary of DR selection by program bundle across all portfolios is summarized in Figure 9-11.

Figure 9-11: Demand Response Selection across Portfolios

Program	Portfolio A	Portfolio B	Portfolio C	Portfolio D	Portfolio E	Portfolio F
RAP Thermostats	X	X	O	O	O	O
RAP Water Heaters	O	O	O	O	O	O
RAP Behavioral	X	X	X	X	X	X
RAP Dynamic Rates	X	X	O	O	X	X
RAP EV Managed Charging	O	O	O	O	O	O
RAP BTM Storage	O	O	O	O	O	O
RAP C&I	X	X	O	O	X	X
RAP Data Center	X	X	O	X	X	X

X = Selected
O = Not Selected

Overall, Figure 9-12 summarizes the nameplate capacity additions and other resource additions and changes for all of the portfolios through 2043.

Figure 9-12: Summary of Incremental Resource Additions across Portfolios

	A	B	C	D (all)	E	F
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	Late 2030s	At Start-up	At Start-up
Wind	1,500	1,850	1,800	1,550	2,250	2,350
Solar	2,125	675	3,225	1,275	2,322	1,922
Storage[1]	1,250	1,885	811	959	1,410	2,111
Gas CCGT	2,600	2,600	2,588	3,240		
Gas Peaking			400	620		
Gas CCGT w/CCUS					2,340	2,340
Sugar Creek	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DR / DSM[2]	400	430	230	270	365	365
Total ICAP Additions (excl. DSM/DR)	7,475 MW	7,010 MW	8,824 MW	7,641 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer)	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

[1] *Includes both 4-hour Lithium-ion and long-duration storage*
[2] *DR/DSM additions calculated as peak capacity contribution in summer of 2043*

9.2 Portfolio Evaluation – Scorecard Metrics

In order to evaluate the performance of the eight portfolios, NIPSCO developed a scorecard of objectives, indicators, and key metrics. As illustrated in Figure 9-13, these objectives and metrics included:

- Cost to customer metrics associated with the NPVRR over 10- and 30-year time periods under Reference Case conditions.
- Risk metrics associated with cost certainty across scenarios and across the distribution of stochastic uncertainty variables: cost risk was measured at the 95th percentile and lower cost opportunity was measured at the 5th percentile.
- Environmental sustainability was measured with the carbon emission intensity of the portfolio over the 2024-2040 time period.
- Reliability was measured through a probabilistic risk assessment to measure "forced market exposure" risk and via reporting of the amount of new capacity in the portfolio able to respond within 30 minutes.
- Positive social and local economic impacts were measured through tracking the net present value of property taxes paid as a result of the generation portfolios.

Figure 9-13: Scorecard Metrics

Objectives	Indicators	Metrics
Affordability	**Cost to Customer**	• Near-term and long-term Impact to customer bills • Metric: 10-year and 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: 95th%-50th% cost risk from probabilistic analysis
	Lower Cost Opportunity	• Potential for lower cost outcomes • Metric: 50th%-5th% cost risk from probabilistic analysis
Environmental Sustainability	**Carbon Emissions**	• Carbon intensity of portfolio • Metric: Cumulative carbon emissions / cumulative generation (2024-40 short tons/MWh of CO2)
Reliable, Flexible, and Resilient Supply	**Reliability, Flexibility**	• The ability of the portfolio to provide reliable and flexible supply for NIPSCO in light of evolving market conditions and rules • Metric: Loss of Load Expectation proxy ("Forced market exposure") metrics for NIPSCO system from probabilistic reliability analysis • Metric: Capacity able to respond within 30 mins
Positive Social, & Economic Impacts	**Local Investment in Economy**	• The effect on the local economy from new projects and ongoing property taxes and targeted investment • Metric: NPV of property taxes from the entire portfolio

9.3 Portfolio Evaluation – Analysis Results

9.3.1 Reference Case Customer Cost Results

The eight 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 9-14. Key observations under the Reference Case market conditions include:

- Implementation of D-LOL will likely drive more capacity additions and raise portfolio costs. Over the 30-year NPVRR period, portfolio costs are projected to be ~$450-500 million higher in Portfolios B and D relative to A and C; a similar cost increase is evident over the initial 10 years of the study period as well, due to additional near-term capacity needs.

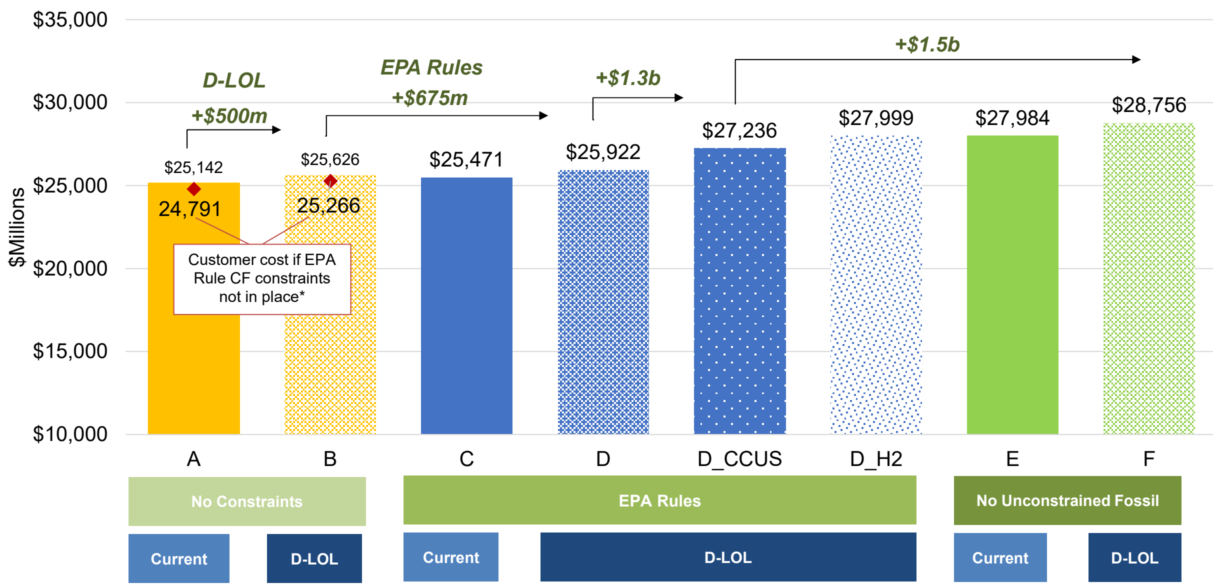
- Customer costs are projected to be higher in Portfolios C/D relative to Portfolios A/B due to new EPA GHG rules. The level of cost premium is around $675 million in NPVRR assuming no constraints on combined cycle operation under Reference Case market conditions. If the optimized portfolios were held to the 40% capacity factor constraints, available energy market purchases would still result in lower costs for A and B relative to C and D.

- With the assumed load growth, a cost premium is associated with meeting net zero goals and restricting new fossil resources to only those with emission controls. Assuming no technology cost and performance risk with CCUS and assuming full monetization of all 45Q tax credits:

    - There is a ~$1.3 billion 30-year NPVRR premium associated with meeting NIPSCO's 2040 net zero goal with CCUS and H2 relative to continuing to operate Portfolio D with combined cycle additions and no subsequent retrofits.

    - There is an incremental ~$1.5 billion 30-year NPVRR premium associated with restricting new fossil resources to only those with emission controls (Portfolio F). Over the first 10 years, the incremental NPVRR impact is about $300 million.

Figure 9-14: Reference Case Cost to Customer (30-year NPVRR – millions of $)



9.3.2 Scenario Customer Cost Results

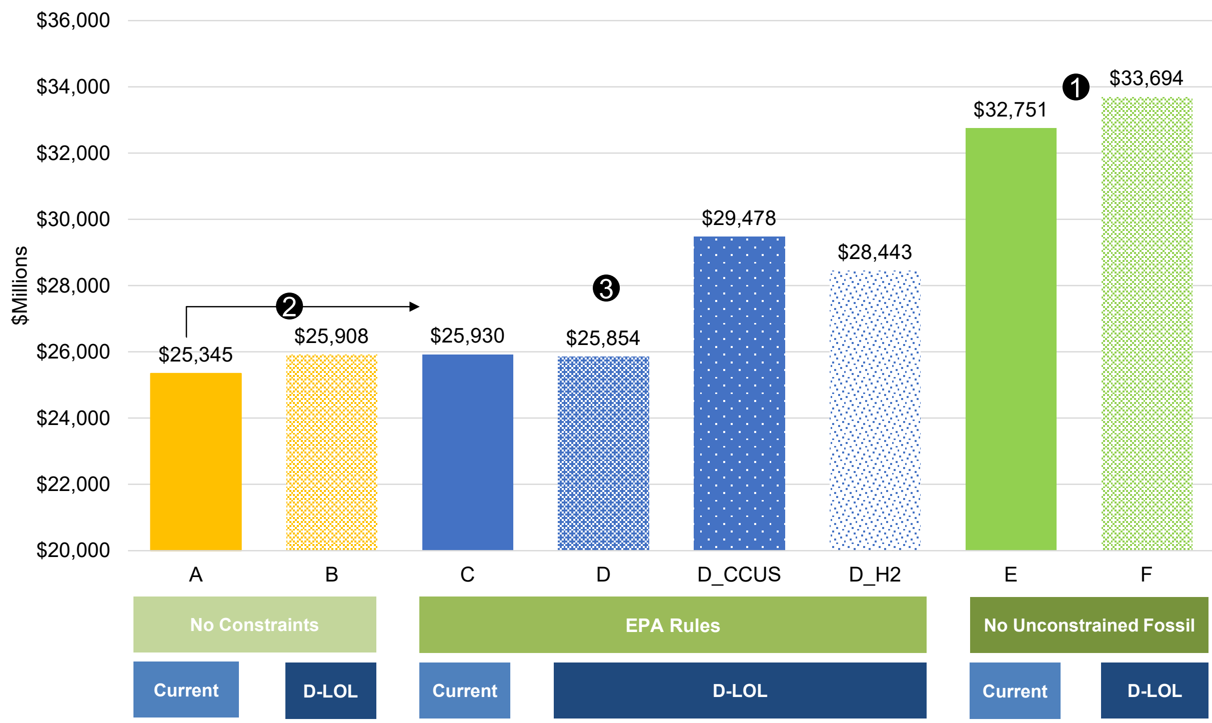
In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each portfolio against each scenario, as described earlier in Section 8. Under the Slower Transition scenario, relative to the Reference Case, as shown in Figure 9-15:

1. Costs for Portfolios that rely heavily on federal tax credits for significant clean energy additions (E, F, and D_CCUS) face the largest cost increases.

2. The premium associated with Portfolio C (developed under EPA Rule constraints) relative to Portfolio A decreases when both portfolios are not subject to capacity factor constraints.

3. Portfolio D (with an additional CCGT built under D-LOL) is lower cost than Portfolio C, given no constraints on capacity factor and lower gas prices.

Figure 9-15: Slower Transition Scenario Cost to Customer (30-year NPVRR – millions of $)



Under the Domestic Resiliency scenario, relative to the Reference Case, as shown in Figure 9-16:

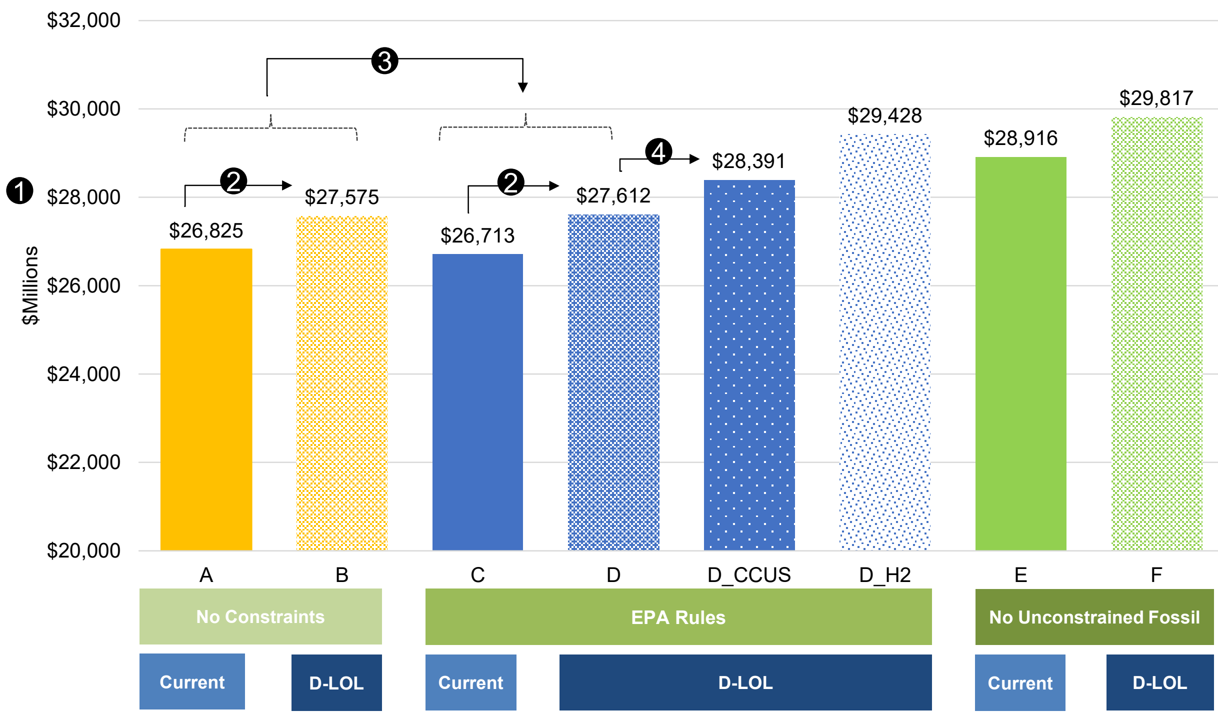
1. Overall portfolio costs are higher, driven by elevated natural gas and power prices.

2. There is a greater premium associated with D-LOL portfolios, as they have fewer renewable additions and are more exposed to higher gas and power prices.

3. The cost premium for portfolios constructed under EPA Rules (Portfolios C/D) is lower, as the cost of market purchases for Portfolios A/B is higher. Portfolio C is lower cost than A.

4. The cost premium for Portfolio D_CCUS relative to Portfolio D is lower, as higher MISO prices advantage high CCUS capacity factors relative to CCGT capped at 40% CF.

Figure 9-16: Domestic Resiliency Scenario Cost to Customer (30-year NPVRR – millions of $)



Under the Aggressive Environmental Regulation scenario, relative to the Reference Case, as shown in Figure 9-17:

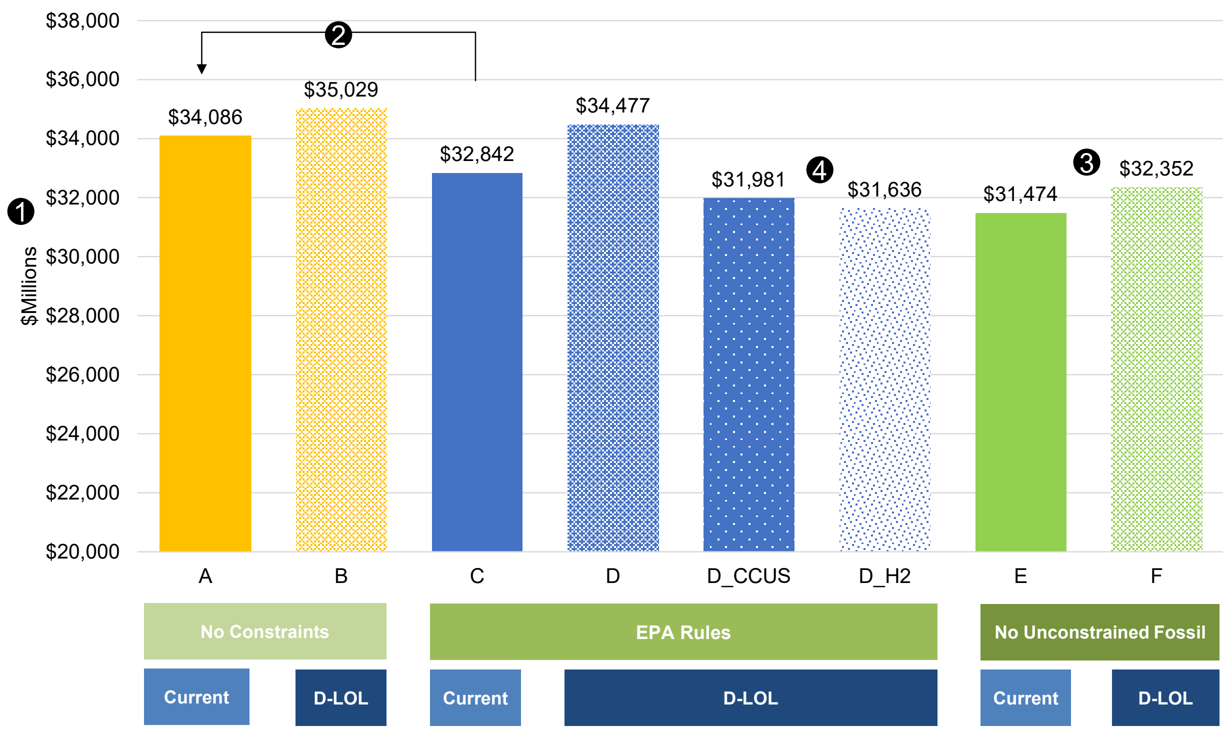
1. Overall portfolio costs are significantly higher, driven by higher natural gas prices and implementation of a CO2 price.

2. Costs for portfolios optimized without EPA Rules are higher than those optimized with the rules in place: Portfolio A/B higher cost than Portfolio C/D.

3. Portfolios E and F are lower cost than Portfolios A/B and Portfolios C/D due to the high CO2 price in the AER scenario.

4. Hydrogen optionality lowers long term costs for the Portfolio D variants when natural gas and carbon prices are high. Both are lower cost than Portfolio F.

Figure 9-17: Aggressive Environmental Regulation Scenario Cost to Customer (30-year NPVRR – millions of $)

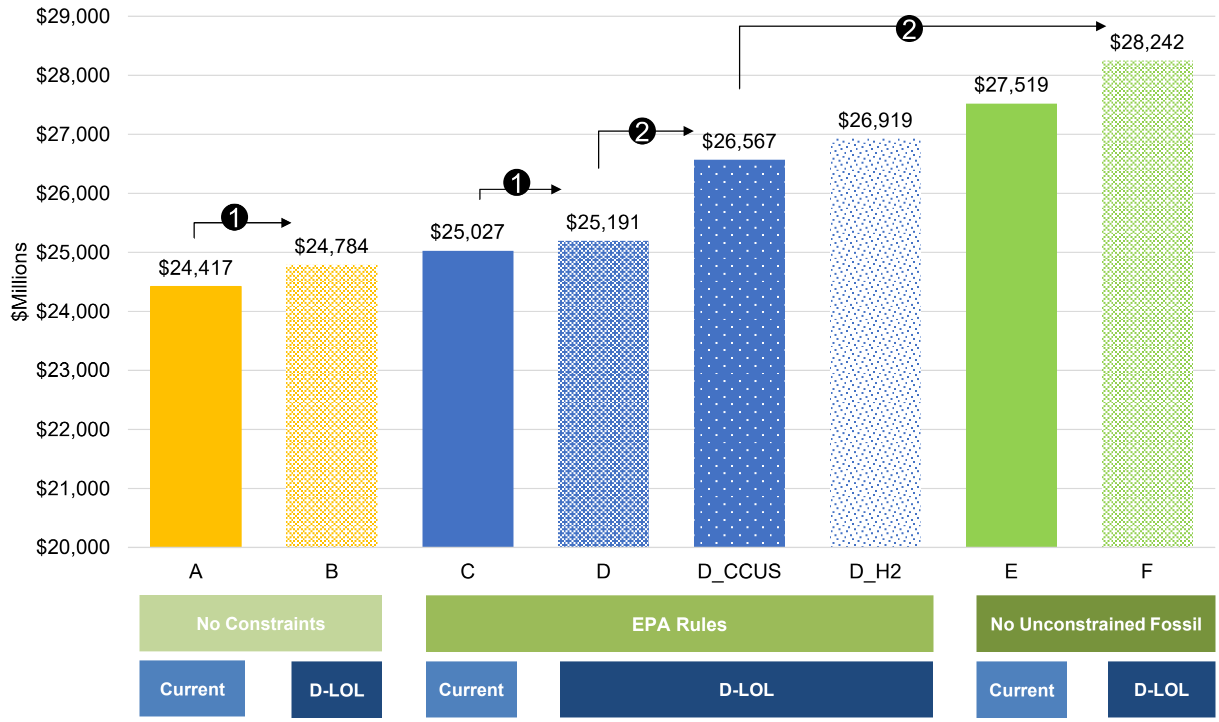


Under the Accelerated Innovation scenario, relative to the Reference Case, as shown in Figure 9-18:

1. Higher overall load growth increases costs for portfolios with fewer capacity additions (Portfolio A and Portfolio C) relative to those with more (Portfolio B and Portfolio D), and the "D-LOL premium" is narrower.

2. Lower long-term natural gas prices slightly increase the premium associated with the portfolios that move towards net zero by 2040.

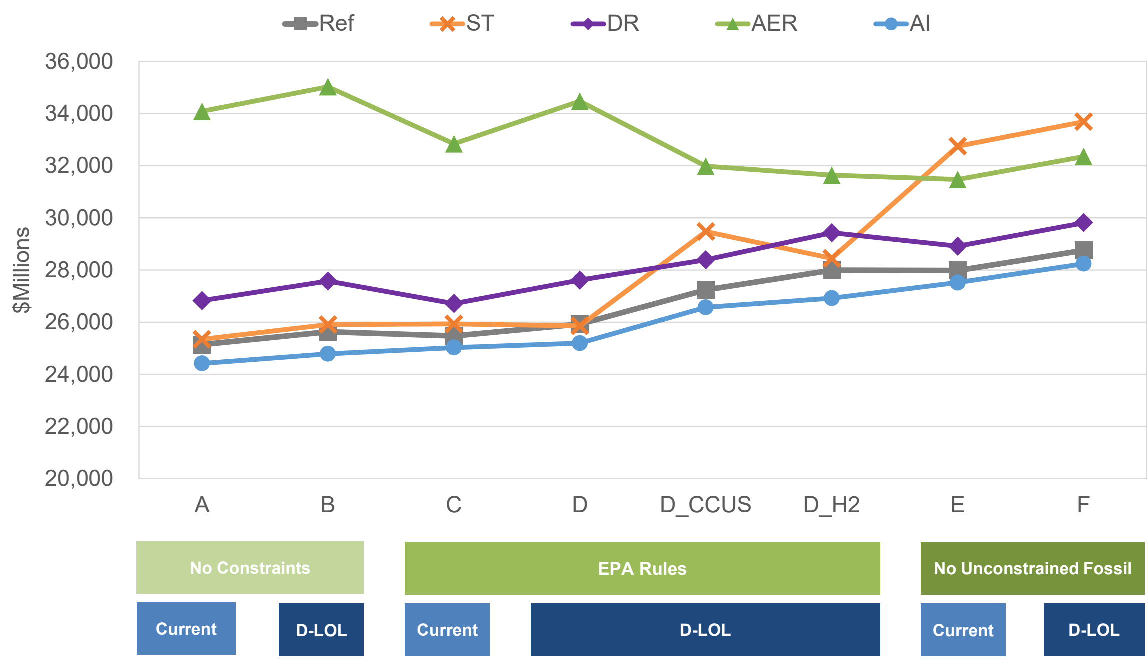
Figure 9-18: Accelerated Innovation Scenario Cost to Customer (30-year NPVRR – millions of $)



Overall, across scenarios, as illustrated in Figure 9-19, the following key observations were made:

- Portfolios A, B, C, and D are generally lower cost than the D Variants and Portfolios E and F. However, since they do not control long-term CO2 emissions, Portfolios A, B, C, and D are the highest cost in the AER scenario, which has a high carbon price.
- Portfolios relying heavily on near-to-mid-term tax credits (particularly Portfolios E and F) have the highest cost premium in the Slower Transition scenario.
- The optionality to phase-in CO2 control technologies embedded in Portfolio D_CCUS and Portfolio D_H2 results in a low scenario range.

Figure 9-19: NPVRR Summary across Scenarios



9.3.3 Stochastic Analysis Results

In addition to assessing each portfolio against each market scenario, NIPSCO also evaluated the six portfolios against the full stochastic distribution of potential outcomes for commodity prices (fuel and MISO power prices), NIPSCO load, wind and solar output, and thermal resource outages, as described in more detail in Section 8. The stochastic assessment was used to further evaluate the risk of each of the portfolios and produce key outputs within two scorecard categories:

- **Reliability** – An evaluation of "forced market exposure" risk was performed to assess the likelihood of NIPSCO having insufficient native resources to meet load at any given point time, thus resulting in forced exposure to the MISO market.
- **Rate stability** – An assessment of the portfolios' cost risk associated with the 95th percentile of the cost distribution and the lower cost opportunity associated with the 5th percentile of the cost distribution.

9.3.3.1 Forced Market Exposure Risk

Forced market exposure risk is calculated by comparing NIPSCO's available resources to NIPSCO's load obligation across every hour of the sample study year (2030) and across all 1,000 iterations of stochastic inputs that were developed. The risk can be visualized by assessing the long or short position of the portfolio at various percentiles across the distribution and at various times of day and across the year. This is illustrated in Figure 9-20, Figure 9-21, and Figure 9-22 for the six portfolios at the 90th percentile.

Figure 9-20: 90th Percentile of Forced Market Exposure - Portfolios A and B

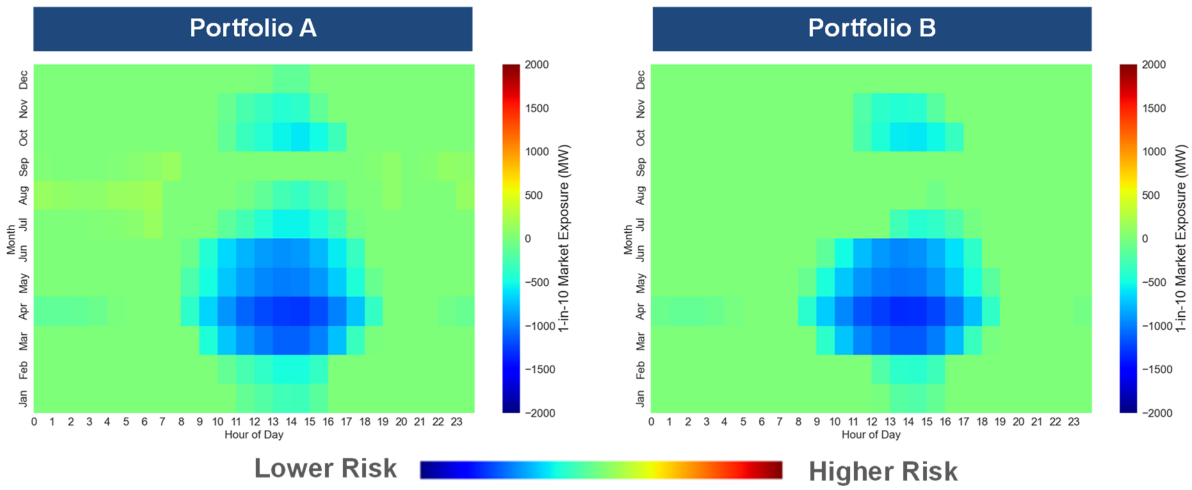


Figure 9-21: 90th Percentile of Forced Market Exposure - Portfolios C and D

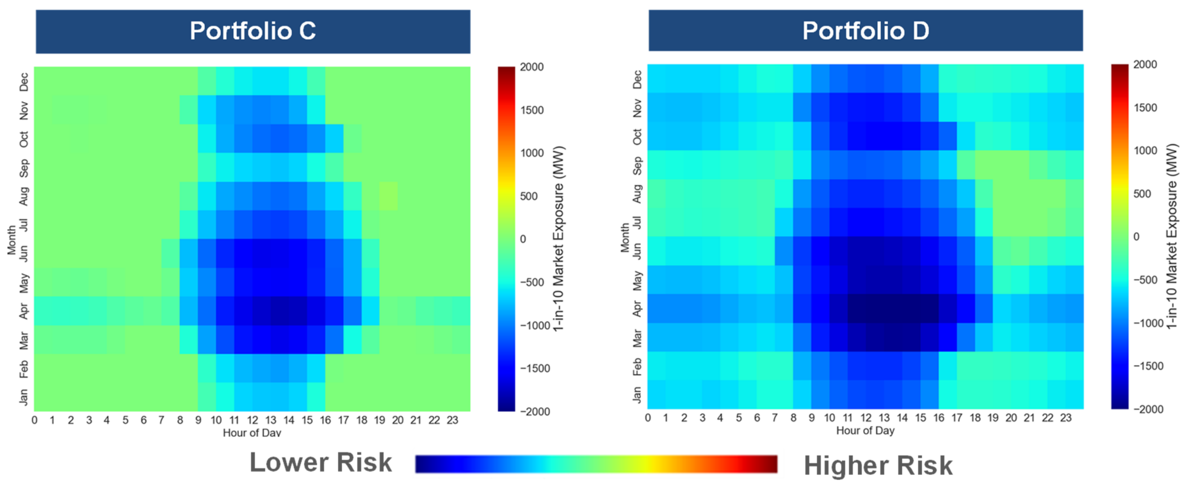
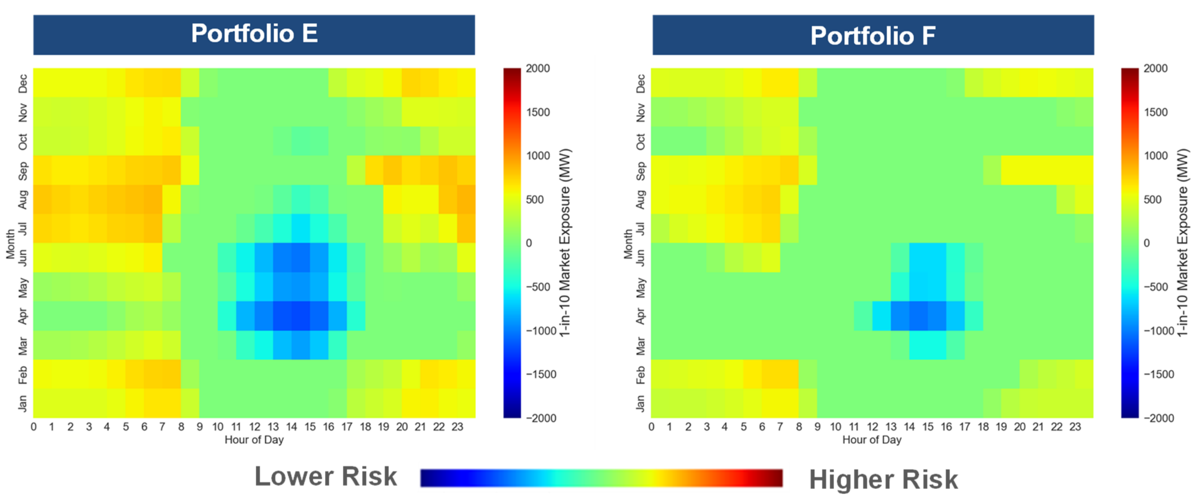


Figure 9-22: 90th Percentile of Forced Market Exposure - Portfolios E and F



These illustrations depict a "1-in-10" level event (i.e., only 10% of the simulated events during that month and hour exceed the reported level of forced market exposure). The magnitude of forced market exposure is also reported in Figure 9-23 as a measure of the expected amount of energy each year for which NIPSCO would be forced to purchase from the market, regardless of economic dispatch decisions. The percentage of expected forced market purchases is also reported by normalizing the expected forced market purchases by the total system energy sales.

In these graphics, a negative number (shown in blue colors with a greater long position shown with a darker shade) represents an event when the NIPSCO portfolio is long on capacity and has the option to operate economically by buying from the market or dispatch its own resources based on what is the lowest cost option for customers. A positive number (shown in orange and red with a darker red representing a greater short position) represents an event when NIPSCO would be *forced* to purchase from the market, no matter the cost or tightness of the broader MISO system at that time. If these periods of forced market exposure coincide with periods of stress in the broader MISO market, the event could result in a loss of load event if there is not sufficient energy on the market to cover NIPSCO's native shortfall.

Overall, Portfolios E and F are at risk of experiencing the most significant forced market exposure, amounting to between 2-3% of total MWh served in 2030, as summarized in Figure 9-23. The D Portfolios are in the strongest position to mitigate against forced market exposure risk and be "in control of their own destiny." Only a small portion of the total MWh served would be forced to be purchased from the market.

Figure 9-23: Reliability Scorecard Metric – Forced Market Exposure

Portfolio	Forced Market Exposure – Expected Value (GWh)	Forced Market Exposure Relative to Total Load (%)
A	235	0.91
B	86	0.33
C	89	0.34
D (all variants)	4	0.02
E	793	3.08
F	515	2.00

9.3.3.2 Cost Risk

Cost risk is calculated by evaluating the uncertainty in NIPSCO's portfolio costs across the distribution of stochastic variables, including those evaluated in the forced market exposure risk analysis plus natural gas prices and MISO market power prices. To assess cost risk in a representative year (2030), NIPSCO down-sampled 100 iterations from the overall distribution of one thousand iterations from the forced market exposure risk analysis. This smaller sub-set of samples was selected as representative of the entire distribution, and using a smaller number of scenarios substantially reduces the required amount of computer run-time while still providing a robust overview of the stochastic risk posed to each of NIPSCO's portfolio options. This representative set of 100 samples was run through the Aurora portfolio model to simulate dispatch against different generator forced outages, wind generation, solar generation, electricity price, and natural gas price outcomes. In this manner, NIPSCO was able to evaluate the variable cost exposure for the different portfolios and provide a unified analysis between the stochastic market exposure analysis and the production cost modeling in Aurora.

To find this smaller sub-set, a clustering analysis was performed on the average annual electricity price, natural gas price, and net load across the entire collection of stochastic iterations to divide the population into representative samples which span the range of possible outcomes. Each of the 1000 samples was assigned to one of the 100 clusters. A random choice was selected from each of these clusters. The resulting sub-set of 100 iterations provides a sound representation of the types of random shocks that NIPSCO might experience (i.e., higher/lower than expected net load or higher/lower than expected commodity prices).

For each of these representative 100 samples, NIPSCO performed a production cost model simulation, which dispatched the portfolio resources using the wind generation, solar generation, demand, market electricity price, and natural gas price from that stochastic iteration. The resulting 100 outcomes represent the range of possible all-in costs that can be incurred by each portfolio, depending on the randomness of possible events. The 95th and 5th percentile cost outcomes were reported as the range of possible cost outcomes.

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 for the 2030 sample year that was evaluated, Portfolios A through D have broader distributions of cost uncertainty overall (higher and lower) as a result of the impact of natural gas price uncertainty. Although Portfolios E and F have more comparable 75th percentile risk due to significant MISO market exposure, both have lower tail risk than Portfolios A through D. This is illustrated in Figure 9-24 and Figure 9-25, which summarize the rate stability metrics associated with NIPSCO's integrated scorecard.

As noted, natural gas price is a key driver to the all-in cost outcome. This is shown in Figure 9-26, which plots the annual average natural gas price across the 100 iterations evaluated in Aurora versus the annual impact on portfolio costs for Portfolio D relative to the median outcome. As natural gas prices increase, the variable cost of the portfolio also increases linearly, and a strong correlation between total costs and natural gas prices is evident. In fact, for Portfolio D, a $1 increase in natural gas price corresponds to an expected $125M increase in portfolio costs. Overall, natural gas prices show significant volatility within a year, and daily or monthly spikes are typically coupled with short-term market electricity price spikes, increasing the overall operating costs of the portfolios, especially those with higher levels of natural gas generation.

Figure 9-24: Distribution of Cost Risk across Portfolios – 2030, Normalized to the Median Cost

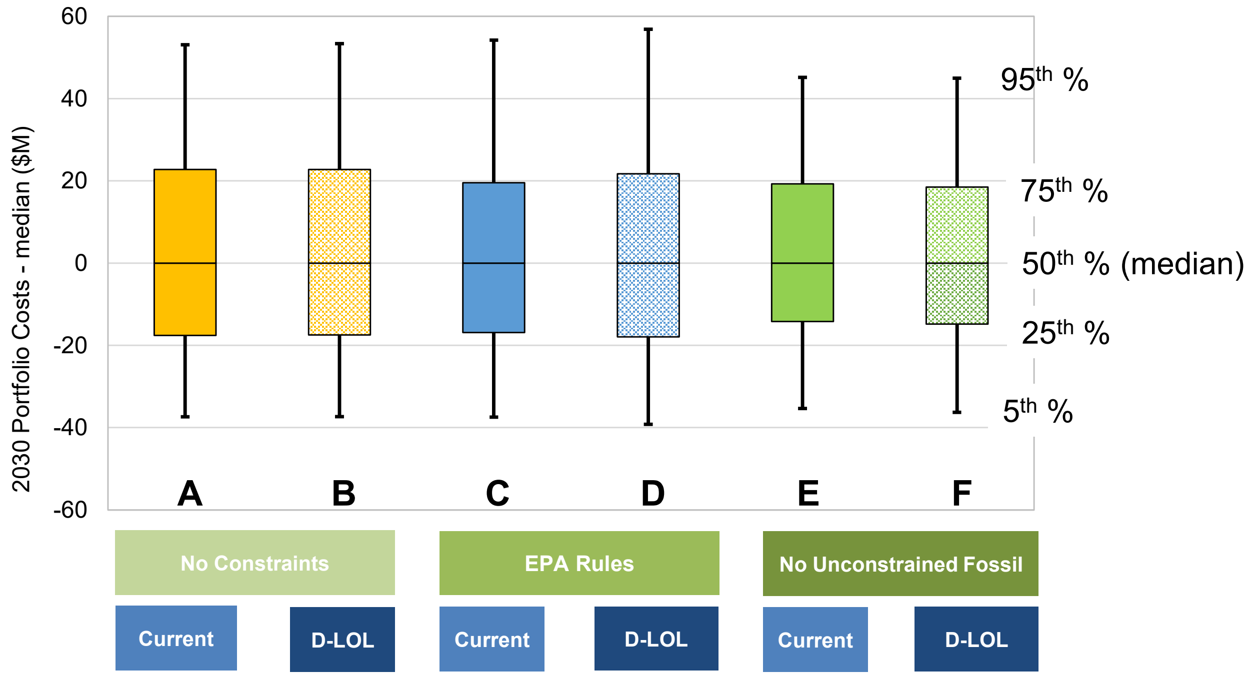
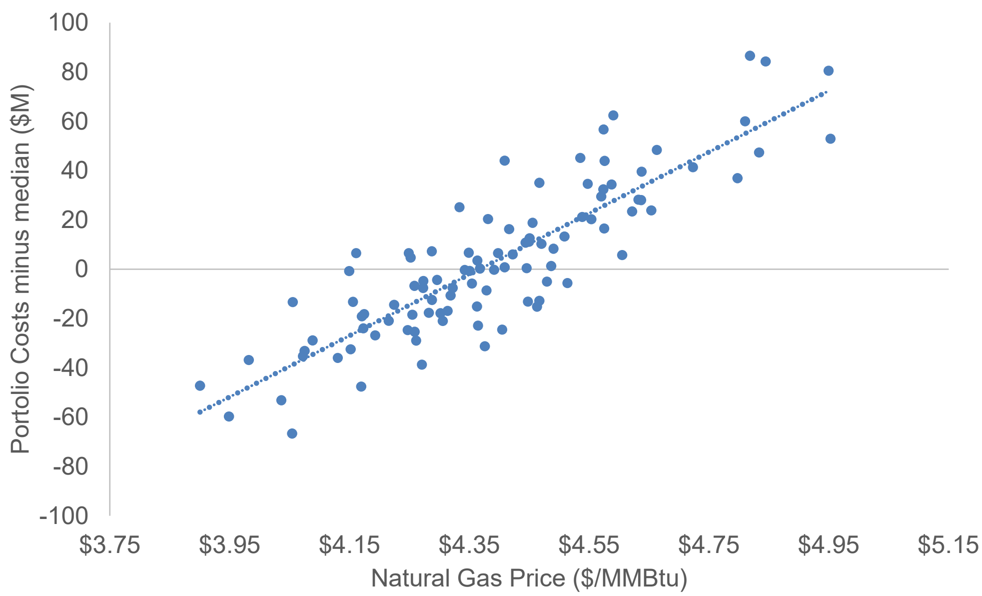


Figure 9-25: Rate Stability Scorecard Metric – Cost Risk and Low Cost Opportunity (millions of $)

Portfolio	50th Percentile *minus* 5th Percentile	75th Percentile *minus* 50th Percentile	95th Percentile *minus* 50th Percentile
A	37.4	22.8	53.1
B	37.3	22.7	53.3
C	37.4	19.5	54.2
D	39.2	21.7	56.8
E	35.4	19.2	45.1
F	36.3	18.5	45.0

Figure 9-26: Relationship between Annual Average Natural Gas Price and Annual Portfolio Cost across Stochastic Distribution (Portfolio D)



9.3.4 CO2 Emissions

NIPSCO tracked its projected CO2 emissions[164] for all portfolios relative to its historical emissions since its baseline accounting year of 2005, as illustrated in Figure 9-27. As shown, all portfolios that add uncontrolled new combined cycle resources towards the end of the 2020s and into the 2030s would be expected to realize increases in CO2 emissions, offsetting expected declines associated with the upcoming planned retirements of Schahfer Units 17 and 18 and Michigan City Unit 12. If the EPA GHG rules are not in place (Portfolios A and B),[165] CO2 emissions would be expected to remain between 6 and 7 million tons per year through the mid-2030s, with expected declines thereafter, as a result of lower anticipated economic dispatch for combined cycles in the MISO market. If the EPA GHG rules associated with capacity factor constraints for new combined cycles take effect in 2032 (Portfolios C and D), emissions would be expected to fall closer to 5 million tons per year thereafter and through the study period.

For portfolios that immediately control the emissions of new combined cycle capacity additions via CCUS (Portfolios E and F), annual emissions would be projected to fall to around 2 million tons per year after the retirement of Michigan City Unit 12, with potential additional reductions by the end of the 2030s associated with conversion of NIPSCO's existing Sugar Creek combined cycle to burn hydrogen. For the D variants (Portfolios D_CCUS and D_H2), emissions

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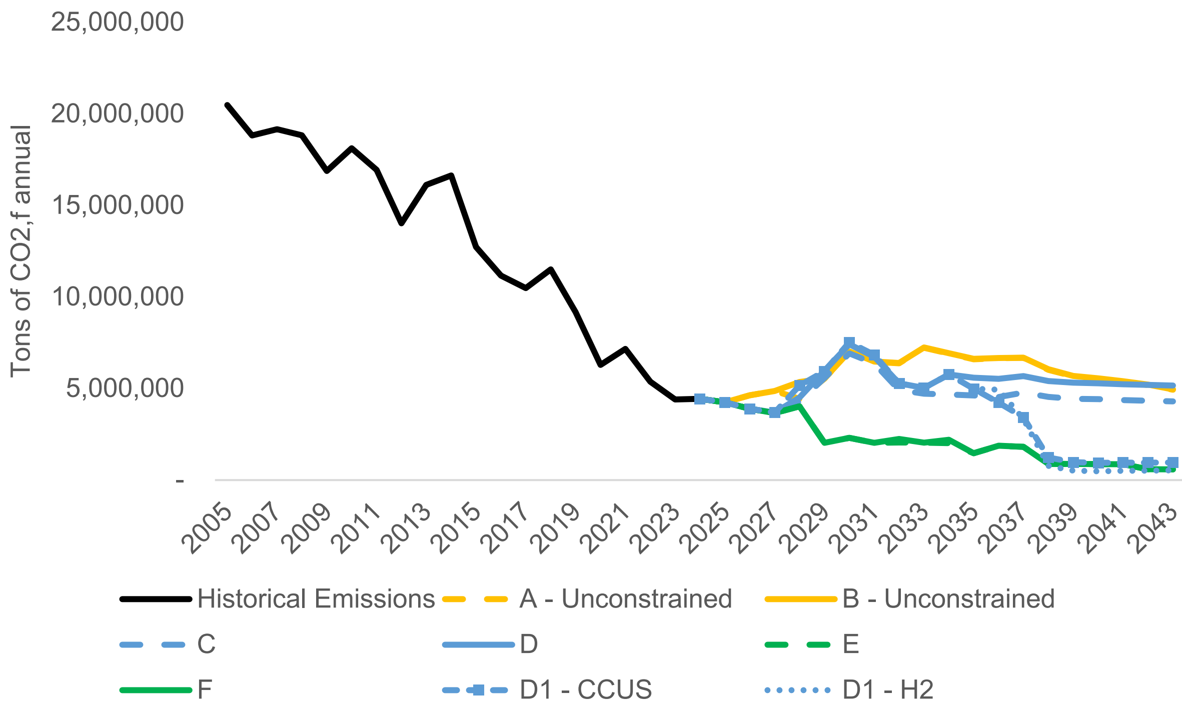
164 NIPSCO's projected emissions include emissions from owned resources and contracted resources. The accounting does not include the impact of energy purchases and sales with the MISO market.

165 Note that all emission summaries are shown with Portfolios A and B not complying with EPA GHG rules even though certain scenarios evaluated their performance under these constraints.

controls implemented on combined cycle units in the mid-2030s would be expected to drive emissions towards the levels expected in Portfolios E and F by the end of the 2030s.

Figure 9-27: Annual CO2 Emission Projections for Portfolios



Given the significant load growth expected in NIPSCO's 2024 IRP, an emissions intensity metric was also developed, dividing the total tons of CO2 emissions by total MWh generated by the NIPSCO portfolio.[166] As shown in Figure 9-28, the emissions intensity of the portfolio is expected to decline from 2024 through 2043, with the largest declines associated with the portfolios that control emissions from combined cycle capacity (E, F, D_CCUS, and D_H2). Figure 9-29 summarizes both cumulative tons of CO2 and the emission intensity for the various portfolio options over the 2024-2040 period.

166 Both the projected emissions and projected generation include owned and contracted resources.

Figure 9-28: Annual CO2 Emission Intensity Projections for Portfolios

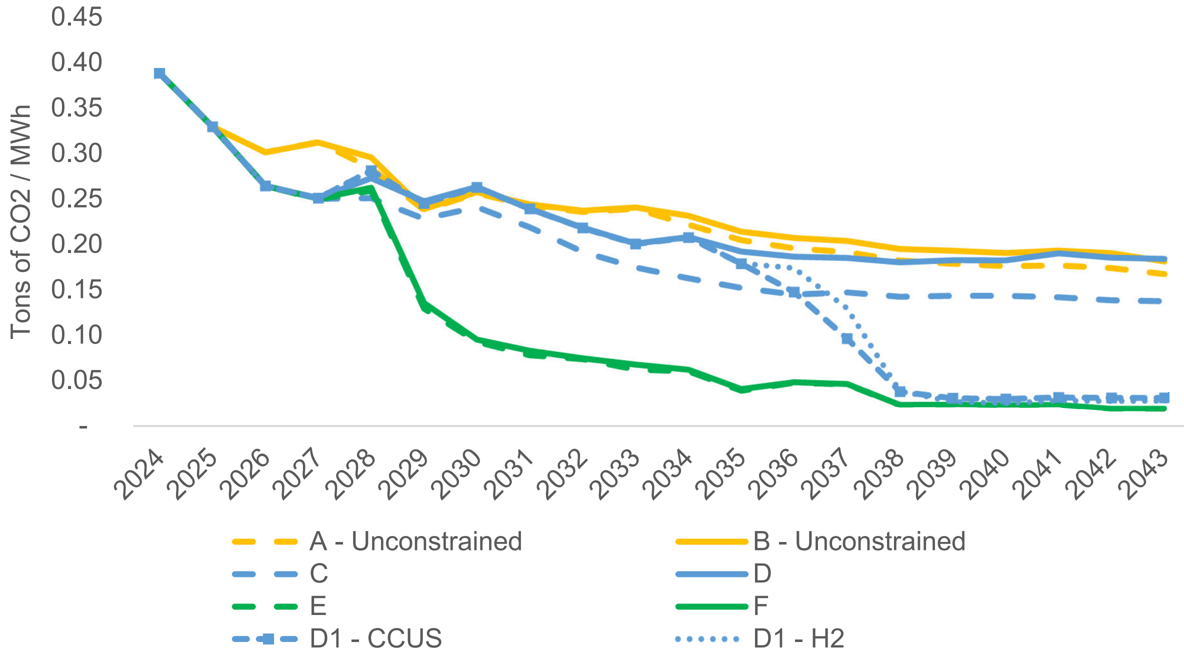


Figure 9-29: Total Emissions and Emission Intensity Average for 2024-2040

Portfolio	Cumulative Tons of CO2 (2024-2040)	Emission Intensity – tons/MWh (2024-2040)
A	99,172,714	0.23
B	100,300,258	0.24
C	80,942,519	0.19
D	89,701,019	0.22
D_CCUS	73,479,336	0.18
D_H2	72,713,688	0.20
E	40,444,963	0.09
F	40,817,177	0.09

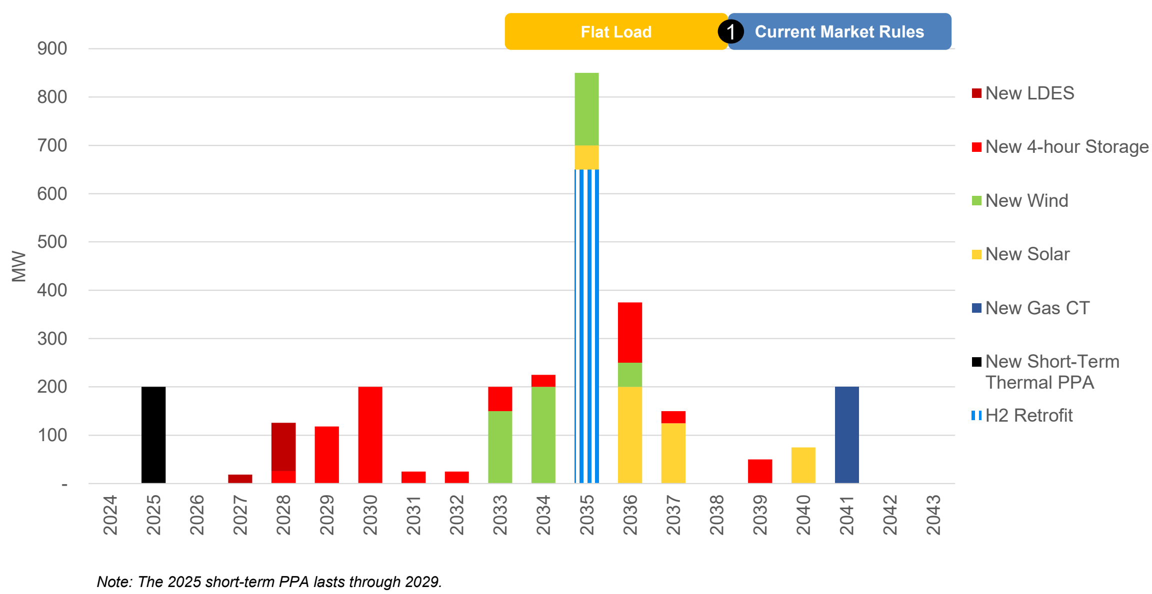
9.3.5 Sensitivity Analysis – Flat Load Growth

In addition to the portfolio evaluation under Reference Case load growth conditions, NIPSCO also performed portfolio optimization analysis under conditions without any new large load growth additions from data centers. "Flat load growth" portfolios were developed under the current market rules construct and under the D-LOL construct,[167] as summarized in the subsequent sections of this Section.

9.3.5.1 Flat Load 1 – Current Market Rules

The Flat Load 1 Portfolio included a total of 200 MW of short-term thermal PPAs and ZRCs, 200 MW of natural gas peaking capacity, 786 MW of new storage capacity (261 MW through 2029), 550 MW of wind, and 450 MW of solar over the twenty-year study period. In addition, the portfolio included all EE programs except for first tranche of C&I (2027-2029) and the Residential High and Behavioral programs. All DR programs were selected except for Water Heaters, EV Charging, and BTM Storage. Figure 9-30 provides a summary of the annual nameplate capacity resource additions for the Flat Load 1 Portfolio.[168]

Figure 9-30: Flat Load Portfolio 1 – Annual Resource Additions (Nameplate MW)



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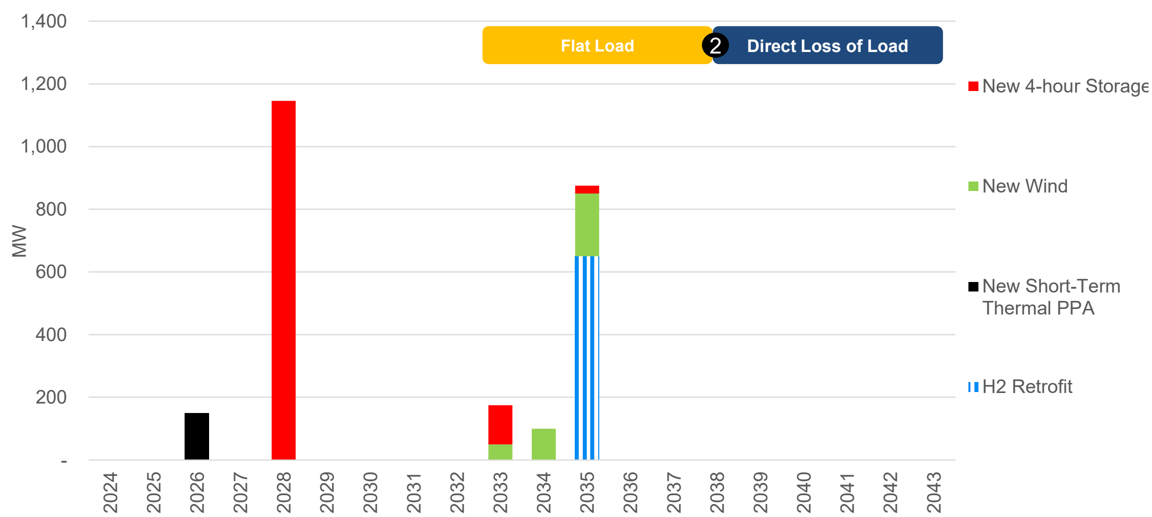
[167] Note that NIPSCO found that the current portfolio's energy position means that additional combined cycle capacity additions would not fit within the energy constraints. Thus, the EPA GHG rules and potential limitations on fossil-fired resources additions without emission controls are irrelevant under the flat load construct. As such, the original six portfolio themes were collapsed into two, varying only the capacity accreditation rules.

[168] Note that for modeling purposes, NIPSCO's existing Sugar Creek combined cycle was assumed to retrofit to enable hydrogen blending in 2035.

9.3.5.2 Flat Load 2 – D-LOL

The Flat Load 2 Portfolio included a total of 150 MW of short-term thermal PPAs and ZRCs, 1,296 MW of new storage capacity (1,146 MW through 2029), and 350 MW of wind over the twenty-year study period. Relative to Flat Load Portfolio 1, Flat Load Portfolio 2 included additional near-term storage to meet near-term capacity accreditation needs under the D-LOL construct and slightly less renewable energy over the long-term. In addition, the portfolio included all EE programs except first tranche of C&I and Residential (2027-2029) and the first two tranches of Behavioral programs (2027-2032). All DR programs were selected except for Water Heaters, EV Charging, and BTM Storage. Figure 9-31Figure 9-2 provides a summary of the annual nameplate capacity resource additions for Portfolio D.[169]

Figure 9-31: Flat Load Portfolio 2 – Annual Resource Additions (Nameplate MW)



Note: The 2026 short-term PPA lasts from 2026-2030.

Overall, Figure 9-32Figure 9-12 summarizes the nameplate capacity additions and other resource additions and changes for the flat load portfolios relative to the six other portfolio concepts developed under Reference Case load conditions through 2043.

169 Note that for modeling purposes, NIPSCO's existing Sugar Creek combined cycle was assumed to retrofit to enable hydrogen blending in 2035.

Figure 9-32: Summary of Incremental Resource Additions across All Portfolios, Including Flat Load Concepts

	Flat Load	Flat Load DLOL	A	B	C	D (all)	E	F
Data Center Load	None	None	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW	2,600 MW
MISO Capacity Rules	Current	D-LOL	Current	D-LOL	Current	D-LOL	Current	D-LOL
EPA GHG rule constraints (capacity factor)	CCGT<40%	CCGT<40%	None	None	CCGT<40%	CCGT<40%	CCGT<40%	CCGT<40%
New gas emissions controls	None	None	None	None	None	Late 2030s	At Start-up	At Start-up
Wind	550	350	1,500	1,850	1,800	1,550	2,250	2,350
Solar	450		2,125	675	3,235	1,275	2,322	1,922
Storage[1]	786	1,296	1,249	1,882	811	959	1,409	2,111
Gas CCGT			2,600	2,600	2,585	3,235		
Gas Peaking	200				400	618		
Gas CCGT w/CCUS							2,340	2,340
Sugar Creek	H2 (or CCUS) Retrofit	H2 (or CCUS) Retrofit	Extend on Gas	Extend on Gas	Extend on Gas	H2 (or CCUS) Retrofit	H2 Retrofit	H2 Retrofit
DSM (DR/EE)[2]	390	440	400	430	230	270	365	365
Total ICAP Additions Through 2043 (excl. DSM/DR)	1,986 MW	1,646 MW	7,474 MW	7,007 MW	8,831 MW	7,637 MW	8,322 MW	8,723 MW
2035 Supply-Demand Capacity Gap (Summer) Covered	~850 MW	~1,350 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW	~3,500 MW	~4,000 MW

[1] Includes both 4-hour Lithium-ion and long-duration storage
[2] DSM additions calculated as peak capacity contribution in summer of 2043

9.3.5.3 Flat Load Portfolio Customer Cost Results

Given significantly lower load relative to the Reference Case, the total revenue requirements for the Flat Load portfolios are significantly lower than those developed under the Reference Case load. As shown in Figure 9-33, the 10-year NPVRR is approximately 65% of the NPVRR for the Reference Case portfolios, and the 30-year NPVRR is approximately 50% of the value.

On a levelized cost basis, over the 30-year planning horizon, the costs for the Flat Load portfolio are *higher than* all other Reference Case load portfolios aside from Portfolio F. This suggests that incremental costs associated with larger levels of resource additions in the Reference Case load outlook can be spread over more MWh, such that the per MWh system cost goes down. This is true particularly given NIPSCO's current portfolio composition and the need to bring in new capacity resources like storage even without significant new load growth in the near-term. This is illustrated in Figure 9-34.[170]

170 Note that this figure just shows portfolios developed under the MISO D-LOL construct. NIPSCO observed similar trends for portfolios developed under current market rules.

Figure 9-33: NPVRR for Flat Load Portfolios

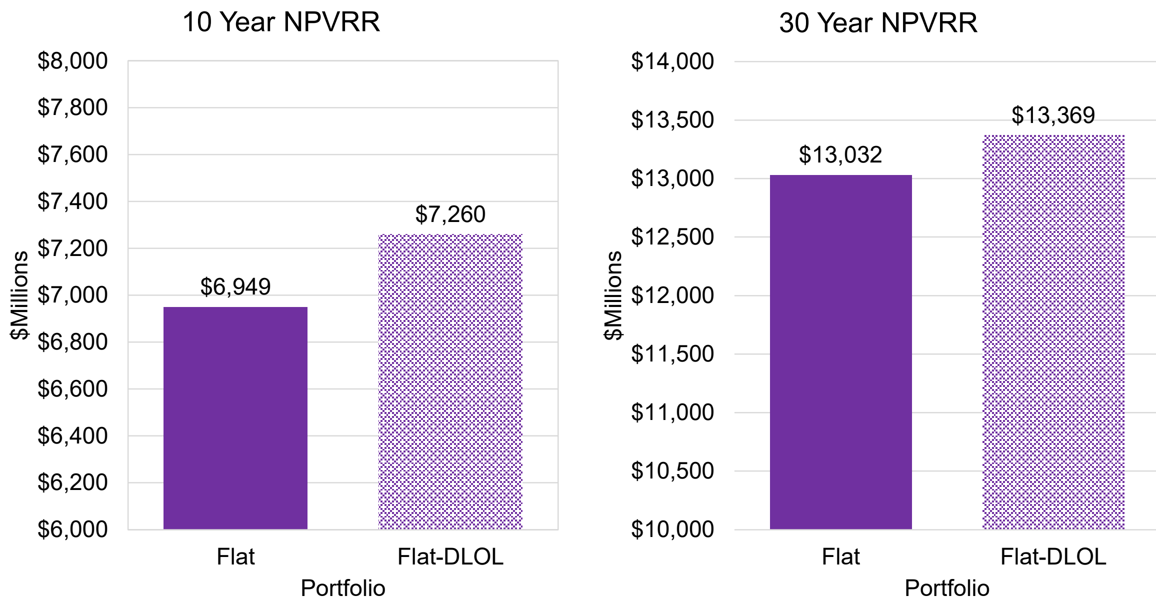
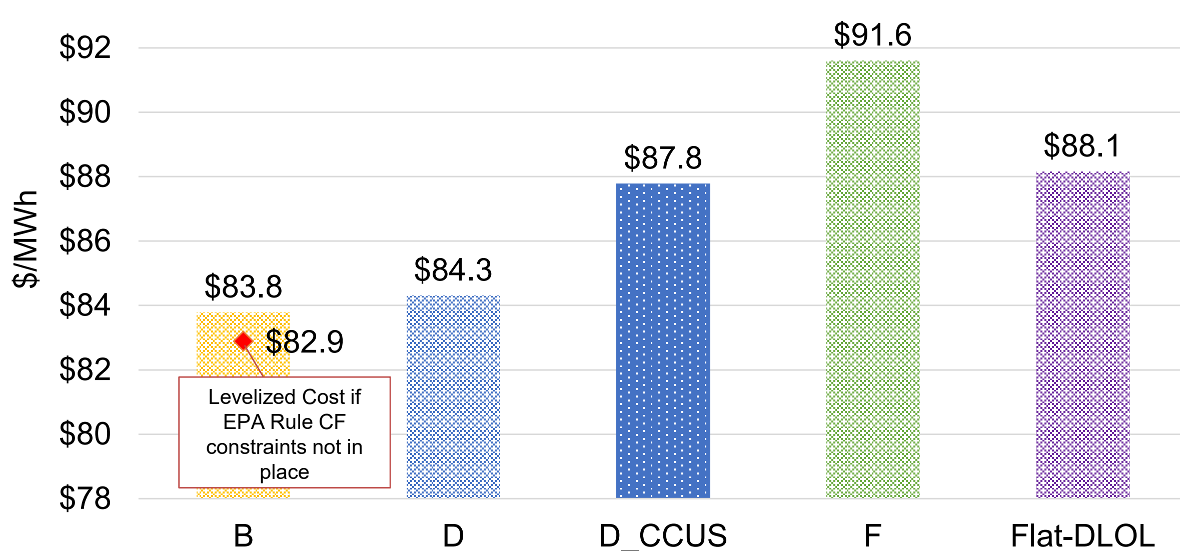


Figure 9-34: Levelized Portfolio Costs for Reference Case and Flat Load Portfolios under D-LOL market Rules



9.3.6 Sensitivity Analysis – Emerging High Load Growth

In addition to the flat load sensitivity, NIPSCO also developed an alternative portfolio construct under an emerging high load sensitivity case, premised on significant new data center load additions to the system based on input from NIPSCO's Economic Development team. As shown in Figure 9-35, relative to the Reference Case, the emerging high load sensitivity incorporates 2,600 MW of additional load by 2028, 4,500 MW by 2030, and 6,000 MW by 2035. As discussed in the next section, a single portfolio was developed under the emerging high load sensitivity under the EPA Rules and D-LOL assumptions (the "Portfolio D" concept).

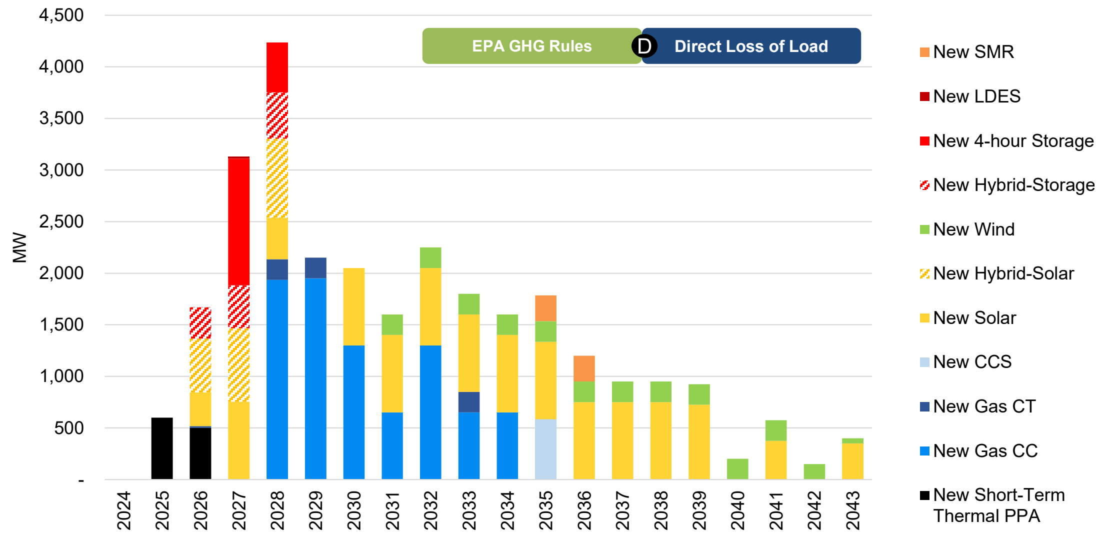
Figure 9-35: Emerging High Load Sensitivity

		2028	2030	2035
	IRP Peak Load – Flat Load*	~2,300 MW	~2,300 MW	~2,500 MW
	+New Load Added for Reference Case	*+600 MW*	*+1,600 MW*	*+2,600 MW*
	IRP Peak Load – New Reference Case	**~2,900 MW**	**3,900 MW**	**5,100 MW**
Incremental to Reference Case	*+Emerging Load Sensitivity*	*+2,600 MW*	*+4,500 MW*	*+6,000 MW*
	Total IRP Peak Load With Emerging Load Sensitivity	**5,500 MW**	**8,400 MW**	**11,100 MW**

9.3.6.1 Emerging High Load Portfolio – EPA GHG Rules and D-LOL

The Emerging High Load Portfolio included a total of 1,100 MW of short-term thermal PPAs and ZRCs, 8,435 MW of combined cycle capacity (3,885 MW through 2029), 620 MW of natural gas peaking capacity (420 MW through 2029), 2,886 MW of new storage capacity (all through 2029), 2,400 MW of wind, 11,694 MW of solar (3,494 MW through 2029), 585 MW of combined cycle capacity with CCUS, and 500 MW of SMR nuclear capacity over the twenty-year study period. In addition, the portfolio included all EE programs except for the final tranches of C&I, Residential High, and Residential Low-Medium (2033-2046). All DR programs were selected except for Dynamic Rates. Figure 9-36 provides a summary of the annual nameplate capacity resource additions for the Emerging High Load Portfolio.

Figure 9-36: Emerging High Load Portfolio – Annual Resource Additions (Nameplate MW)



Note: The short-term PPAs have various durations through 2030.

Overall, the emerging high load analysis highlighted that NIPSCO would require significant capacity additions from a diverse set of new resource types to meet both future capacity and energy requirements, particularly over the next ten years. Major observations and findings from the sensitivity analysis included:

- Significant near-term load growth would require large capacity additions through 2029, including:
  - Over 1,000 MW of Thermal PPAs and ZRCs
  - Nearly 3,500 MW of solar and nearly 3,000 MW of storage
  - Over 4,000 MW of natural gas capacity
- New combined cycle capacity is needed for near-term energy requirements, although the portfolio could be short energy for periods of time depending on the pace of new CCGT additions. Importantly, flexibility to operate CCGTs above 40% prior to the implementation of the GHG Rules in 2032 could allow for most energy needs to be met, but EPA Rules on capacity factor constraints thereafter could result in higher levels of energy market purchases.
- A diverse mix of long-term resource additions would be required, contingent upon resource availability constraints and technological advancement. These long-term resource additions would include:
  - Additional CCGT and gas peaking capacity;

- Significant amounts of post-2030 solar (8,200 MW) and wind (2,400 MW);
- CCUS and SMR capacity as it becomes available, showcasing the potential for clean form resource additions to provide potentially carbon-free capacity that could run at high capacity factors.

- Significant energy efficiency and demand response additions would be expected to support portfolio requirements.

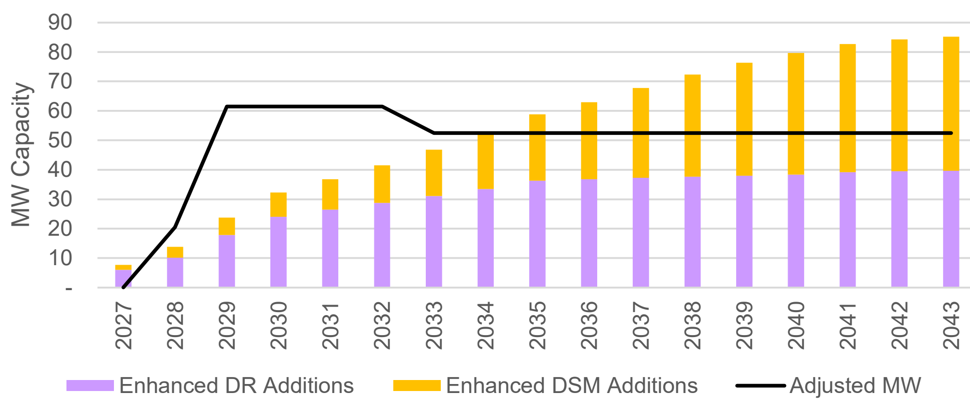
9.3.1 Sensitivity Analysis – Additional DSM

NIPSCO also performed a sensitivity analysis to evaluate the impact of moving from the RAP DSM levels to the Enhanced RAP and MAP savings trajectories for energy efficiency and demand response programs, respectively. As documented in Section 5, moving from RAP to Enhanced RAP and MAP results in larger savings, but also higher program costs.

NIPSCO evaluated the impact of moving to the MAP DR bundles and the Enhanced RAP EE bundles under Portfolio D. This was done by effectively "forcing in" the same DR and EE bundles as identified in the portfolio optimization analysis, but at the MAP or Enhanced RAP level instead of at the RAP level. This has the impact of both reducing energy requirements and mitigating the need for some capacity additions. NIPSCO identified approximately 85 MW of additional peak load reduction potential over time. This additional DSM was able to displace 75 MW of incremental natural gas peaking capacity additions, as summarized in Figure 9-37.

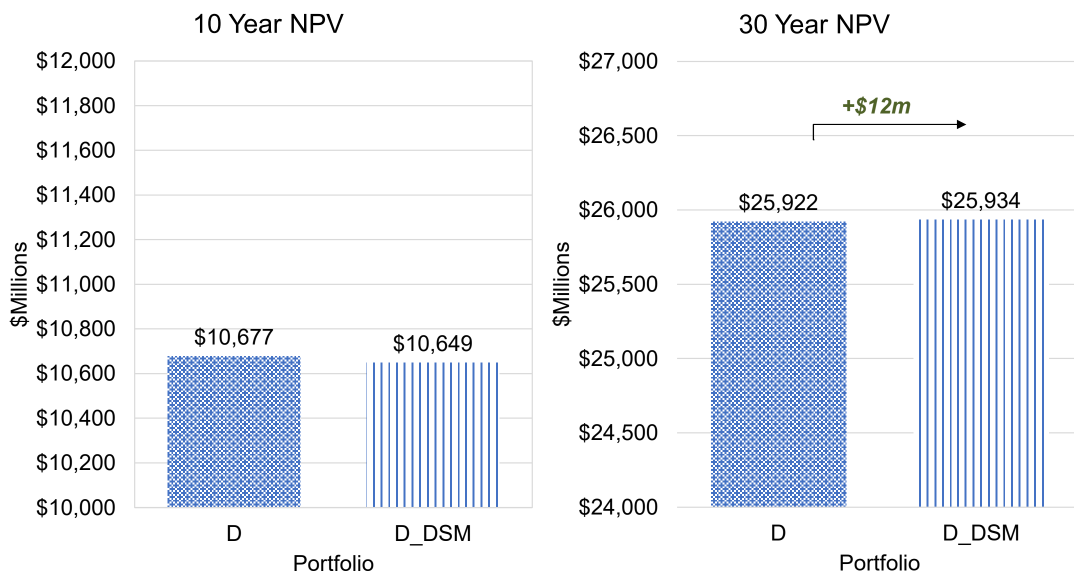
The impact of reduced energy requirements was evaluated through a re-dispatch of the portfolios in the Aurora portfolio model, while 75 MW of future natural gas peaking capacity additions around 2030 were removed to reflect the reduced capacity obligation.

Figure 9-37: Additional DSM versus Avoided Peaking Capacity Additions



Under Reference Case conditions, NIPSCO's analysis found that moving from the RAP to the Enhanced RAP and MAP DSM bundles would increase the 30-year NPVRR by $12 million for Portfolio D, but result in a lower NPVRR on a ten-year basis. As illustrated in Figure 9-38, over the first ten years, the total revenue requirement for the D_DSM portfolio is lower than Portfolio D due to avoided capital and O&M costs from reduced natural gas peaking capacity additions. However, over 30 years, the D_DSM portfolio costs are higher than Portfolio D's, as higher DSM program costs outweigh capital cost savings.

Figure 9-38: NPV Impact of Shifting from RAP to Enhanced RAP or MAP – Portfolio D Example



9.3.2 Scorecard Summary

Figure 9-39 presents a summary of all scorecard metrics for each of the eight portfolios that were evaluated under Reference Case load conditions. 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 metrics, and impacts on the local economy, as described above. The following key observations were made:

- Customer costs in the Reference Case generally increase as additional constraints are placed on the portfolios, including D-LOL accreditation rules, EPA GHG rules, and limits on new fossil additions without emission controls.
- Across the five market scenarios, the Portfolio D variants and Portfolios E and F have the lowest range of cost outcomes. The Portfolio D variants provide optionality for the portfolio in the face of uncertainty associated with future environmental policy.
- Across the stochastic cost distribution, portfolios with more natural gas-fired capacity (Portfolios A through D) exhibit higher cost risk than those with less natural gas capacity (Portfolios E and F). This results in a wider range of cost outcomes, with higher 95th percentile cost risk and lower 5th percentile cost opportunity.

- Portfolios that include more natural gas capacity and do not retrofit that capacity to control for carbon emissions result in higher overall emissions intensity over the 2024-2040 period. The Portfolio D variants reduce emission intensity over time, and Portfolios E and F have the lowest overall.

- Portfolio D performs best on the reliability and flexibility metrics, given larger amounts of flexible, long-duration dispatchable capacity. Portfolios E and F are most exposed to forced market risk exposure, given higher levels of intermittent capacity and lower amounts of long-duration dispatchable capacity.

- Portfolios E and F have the highest investment in the local economy due to higher-cost resource additions. The Portfolio D variants follow, as a result of investment in emission control retrofits in the mid-to-late 2030s, while Portfolios A through D have slightly less local investment overall.

Figure 9-39: Portfolio Scorecard

	A	B	C	D	D-CCUS	D-H2	E	F
Carbon Emissions Constraint	No EPA GHG Constraints		EPA GHG Rules				Emissions Controls At Start-Up	
MISO Market Rules	Current Market Rules	Direct Loss of Load	Current Market Rules	Direct Loss of Load			Current Market Rules	Direct Loss of Load
Cost To Customer – 10-year NPVRR (Ref Case) $M	$10,307 +$62	$10,735 +$491	$10,244 -	$10,677 +$433	$10,993 +$749	$10,993 +$749	$10,951 +$705	$11,309 +$1,065
Cost To Customer – 30-year NPVRR (Ref Case) $M	$25,142 -	$25,626 +$484	$25,471 +$329	$25,922 +$780	$27,236 +$2,094	$27,999 +$2,857	$27,984 +$2,842	$28,756 +$3,614
Cost Certainty 30-year Scenario Range NPVRR $M	$9,669 +$4,952	$10,245 +$5,529	$7,815 $3,098	$9,286 $4,569	$5,414 $697	$4,717 -	$5,232 $516	$5,451 +$735
Cost Risk 95th % Cost Risk	$53.1 +$8.1	$53.3 +$8.4	$54.2 +$9.2	$56.8 +$11.9	$54.1 +9.2	$54.1 +9.2	$45.1 +$0.2	$45.0 -
Lower Cost Opp. 5th % Cost Risk	-$37.4 +$1.8	-$37.3 +$1.9	-$37.4 +$1.8	-$39.2 -	-$38.9 +$0.3	-$38.9 +$0.3	-$35.4 +$3.8	-$36.3 +$2.9
Carbon Emissions M of tons/MWh 2024-40 Cum.	0.23 +0.14	0.24 +0.15	0.19 +0.10	0.22 +0.13	0.18 +0.09	0.20 +0.11	0.09 -	0.09 -
Reliability Forced Market Exposure (GWh)	235 +231	86 +82	89 +85	4 -	4 -	4 -	793 +789	515 +511
Flexibility New capacity able to respond within 30 mins (MW)	3,849 -963	4,482 -330	4,121 -691	4,812 -	4,632 -180	4,812 -	3,905 -907	4,456 -356
Local Economy NPV of property taxes	$1,849 -$849	$1,853 -$845	$1,938 -$760	$1,840 -$858	$2,229 -$484	$2,097 -$609	$2,619 -$79	$2,698 -

Note that carbon emissions for Portfolios A and B are summarized from the analysis performed with Portfolios A and B not complying with EPA GHG rules even though scenario analysis was performed with the prevailing scenario environmental policy drivers in place.

9.4 Preferred Portfolio

NIPSCO has identified Portfolio D_CCUS as its preferred portfolio based on the following key considerations:

- Given the need for dispatchable capacity in MISO and FERC's approval of the D-LOL market reforms on October 25, 2024, NIPSCO should plan for compliance, focusing on Portfolios B, D, and F.
- Portfolio B does not prepare to comply with EPA rule constraints, as it would likely need additional peaking capacity or additional solar + storage to make up for the capacity factor limitations on new combined cycles, which are accounted for in the Portfolio D variants.
- The Portfolio D variants all have the same resource mix through 2030, but Portfolio D (without CCUS or Hydrogen retrofits) does not reduce emissions over time. Given that future hydrogen supply is more uncertain than future CCUS deployment, NIPSCO is left with Portfolio D_CCUS or Portfolio F as options to meet its long-term emissions reduction goals.
- Overall, Portfolio D_CCUS provides more optionality for NIPSCO around future decarbonization actions and performs well relative to Portfolio F:
    - Portfolio D_CCUS has lower customer cost due to lower storage needs through 2030 and due to delaying decarbonization retrofits until they are more feasible in the 2030s.
    - Portfolio D_CCUS has comparable and slightly better cost certainty compared to Portfolio F, particularly associated with optionality around future decarbonization actions in the face of external market uncertainty.
    - Portfolio D_CCUS has marginally higher annual cost risk than Portfolio F due to higher commodity price risk.
    - Portfolio D_CCUS has higher emission intensity than Portfolio F due to additional natural gas generation, but still decarbonizes by end of 2030s.
    - Portfolio D_CCUS has significantly higher reliability due to more long-duration dispatchable capacity, including from natural gas resources. Portfolio D_CCUS also has better resource flexibility due to more dispatchable natural gas-fired capacity.
    - Portfolio D_CCUS has lower local economy benefits than Portfolio F due to lower capital spend.

Figure 9-40 summarizes the elements of NIPSCO's preferred plan, including the expected ranges of capacity additions by resource type through the 2029 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 9-40: Preferred Portfolio Capacity Additions

Timing	Near Term 2025-2029	Mid Term 2030-2034	Long Term 2035 & Beyond
Retirements	• Schahfer Units 17, 18 (by 2025) • Schahfer Units 16A/B (by 2027) • Michigan City Unit 12 (by 2028)	• N/A	• N/A
Preferred Plan – Capacity Additions	• *Storage (900+MW)** • *Thermal Contracts (150-350 MW)* • *DSM Resources* (up to 440 MW over 20-yr period)* • Gas CCGT (1,285 MW) • Gas Peaking (420 MW) ***2600 MW Data Center Load***	• *Storage (125 MW)** • *Wind (150-650MW)** • Solar (750 MW) • Gas CCGT (1,950 MW) • Gas Peaking (200 MW) ***2600 MW Data Center Load***	• *Storage (25 MW)** • *Wind (250-900 MW)** • *Sugar Creek Retrofit Hydrogen** • Solar (525 MW) • CCGT Retrofits – CCUS ***2600 MW Data Center Load***

Other Activities	• Monitor changing regulatory policy (MISO, EPA, local) and technology advancements
	• Previously planned additions:
	  • 1,700 MW renewables
	  • 400 MW gas peaker
		• Reevaluate decarbonization options including CCUS, H2 and other emerging technologies for best fit
		• Add additional renewables as needed to support higher energy needs
			• Implement most cost-effective retrofits
			• Determine final steps to achieve Net Zero

Storage Investment	CCGT / Gas Peaking Investment	Monitor / Respond To Changes	Execute Previously Planned Activities
~900 MW of storage dependent on file MISO capacity accreditation	CCGT additions to support data center load and gas peaking investment as needed for additional capacity	MISO rules; EPA rules; Long-duration energy storage; Hydrogen; Carbon capture; Nuclear	Schahfer & Michigan City retirements; Renewable Projects ~1,700 MW, ~400 MW Gas Peaker

**Italicized resources listed above would be needed under all portfolios (including those without data center load).*

Regardless of future data center growth, this preferred portfolio includes near-term thermal contracts to firm up NIPSCO's capacity position as a result of D-LOL market reforms and over 900 MW of storage capacity through the end of the decade. If data center load materializes in line with the Reference Case load forecast, NIPSCO's preferred portfolio would also include up to 1,300 MW of combined cycle capacity and around 420 MW of natural gas peaking capacity. Over the 2030-2034 time period, the preferred portfolio includes additional storage and wind, with additional solar, combined cycle, and peaking capacity depending on the magnitude of NIPSCO's load growth. Over the long-term (2035 and beyond), the preferred portfolio includes additional storage, wind, and solar capacity, along with retrofits of combined cycle capacity (existing and new) to reduce CO2 emissions via CCUS or hydrogen.

Figure 9-41, Figure 9-42, Figure 9-43, and Figure 9-44[171] show NIPSCO's projected supply-demand balance under the preferred portfolio for the summer, winter, fall, and spring

[171] Note that the figures display the DSM selection for Portfolio D, as documented in Figure 9-10 and Figure 9-11. However, NIPSCO plans to pursue a DSM plan consistent with the incremental DSM selections identified in the Flat Load sensitivity, as documented in Section 9.3.5.2 and shown in the Preferred Portfolio summary in Figure 9-40, This would result in slightly more DSM than summarized in the supply-demand figures.

seasons, respectively.[172] As shown, natural gas and storage resources contribute most to the growing supply need across all seasons, particularly as the D-LOL construct reduces the expected accreditation of solar and wind capacity in 2028 and beyond.

Figure 9-41: Preferred Portfolio Supply-Demand Balance - Summer

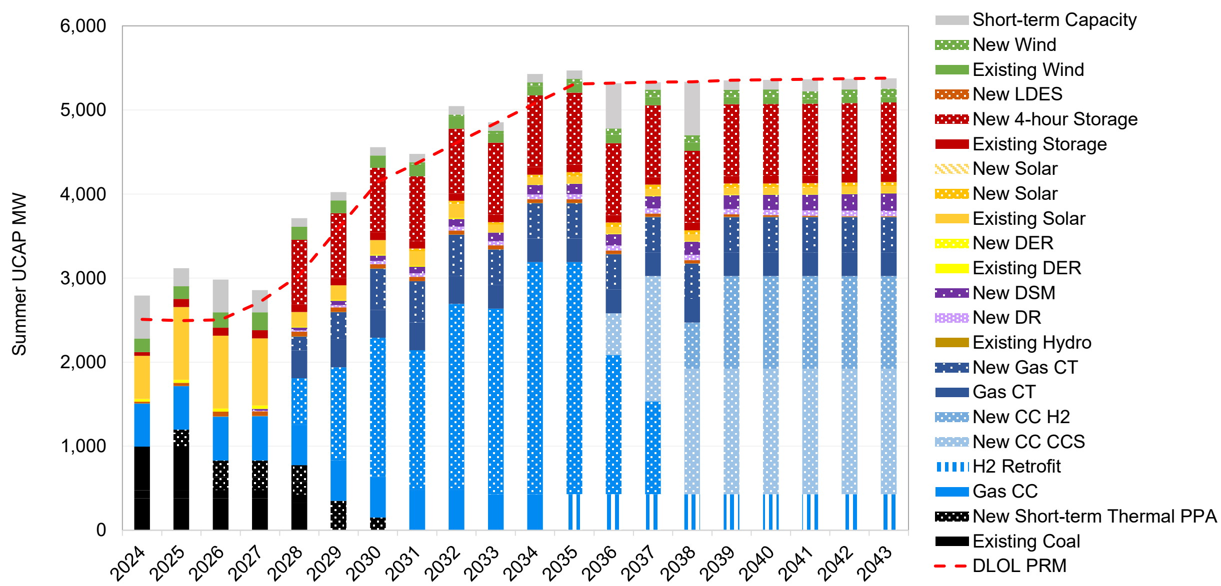
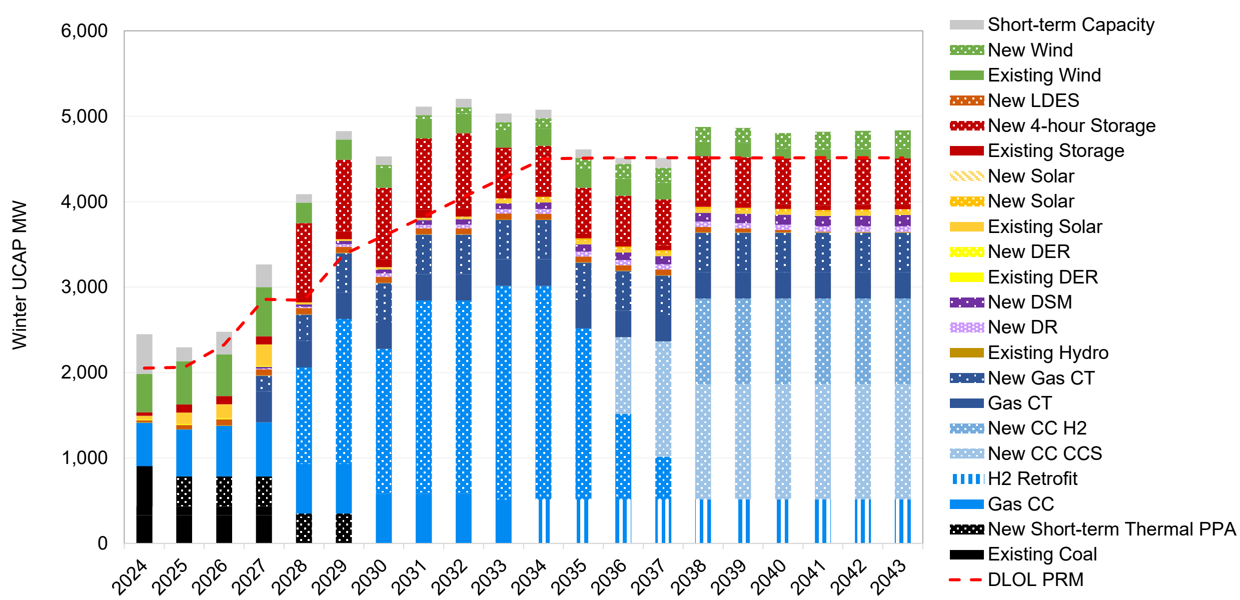


Figure 9-42: Preferred Portfolio Supply-Demand Balance - Winter



172 Note that through the mid-to-late 2030s, the supply-demand balance reflects potential outage periods as combined cycle resources convert to CCUS or retrofit with hydrogen blending capabilities. Market purchases were assumed to cover short-term capacity needs in line with potential plant outages.

Figure 9-43: Preferred Portfolio Supply-Demand Balance - Fall

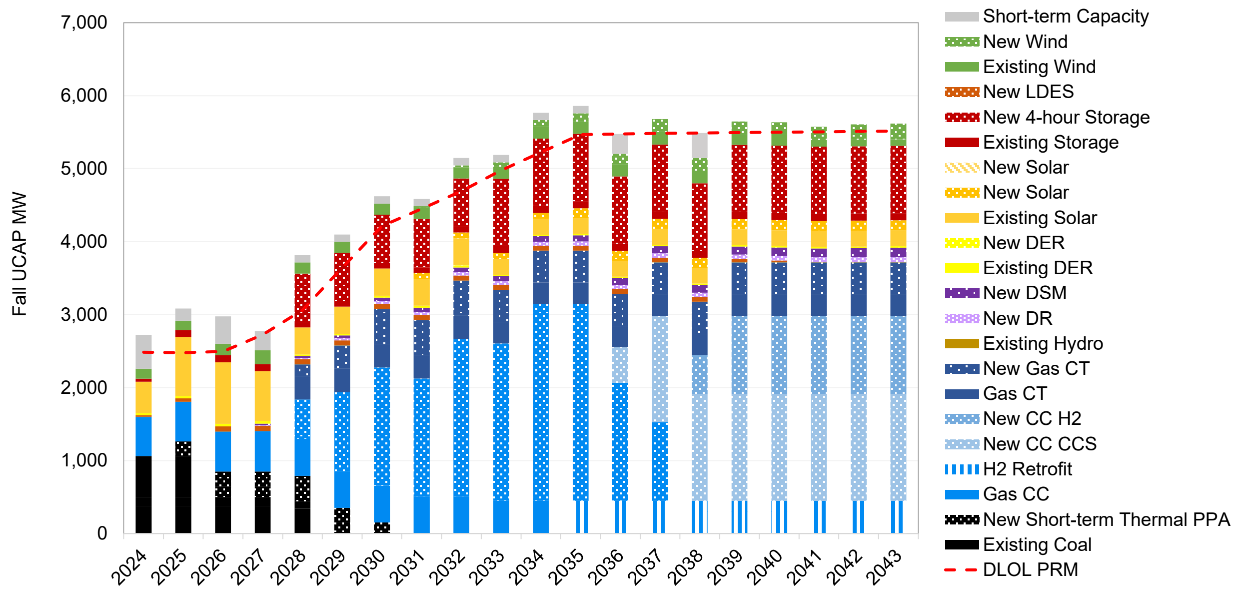


Figure 9-44: Preferred Portfolio Supply-Demand Balance - Spring

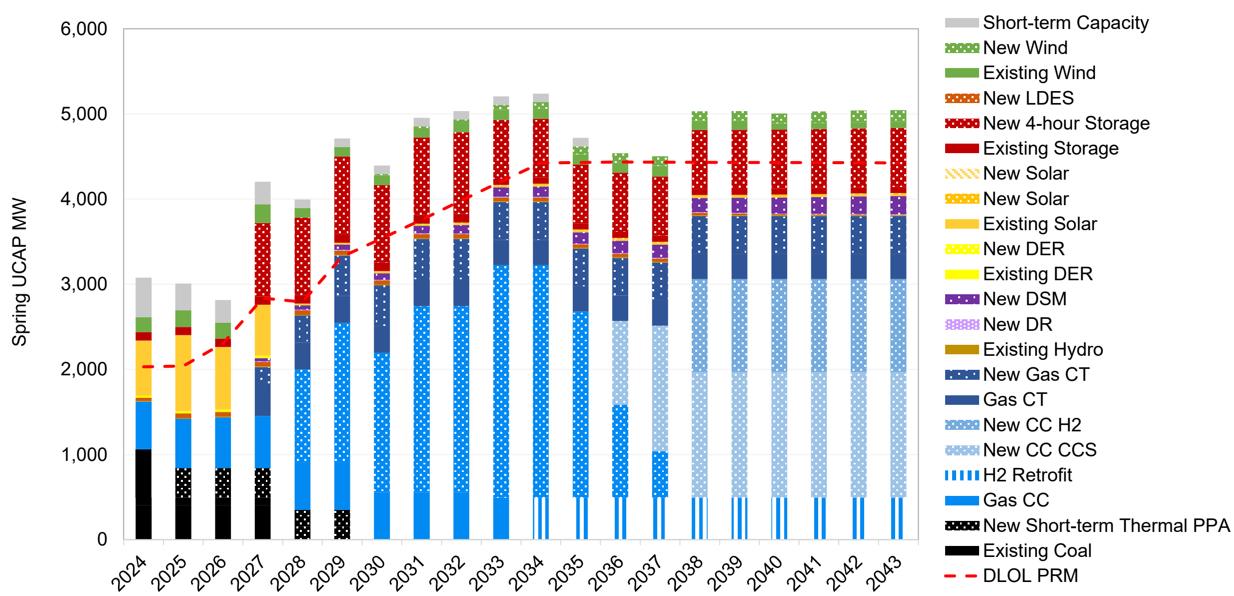
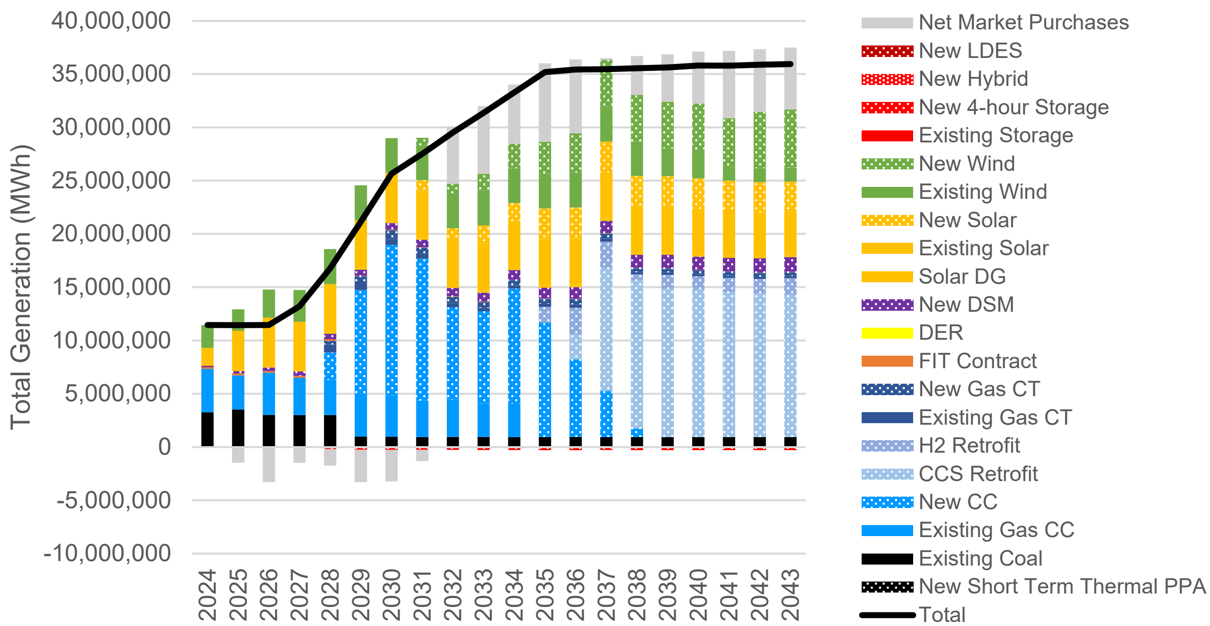


Figure 9-45 summarizes the expected energy balance for the preferred portfolio over time. As shown, new energy from combined cycle capacity additions is projected to meet growing load into the early 2030s. Under Reference Case conditions, the enforcement of a 40% capacity factor limit on new combined cycles as a result of the EPA GHG rules would result in a decline in natural gas generation after 2031. Over the mid-to-long term, NIPSCO's preferred portfolio adds new wind and solar energy and realizes increased energy savings from DSM programs.[173] In addition, in the mid-2030s, combined cycles are expected to covert to CCUS or blend hydrogen, with the largest energy contribution expected to come from CCUS facilities, given high projected capacity factors as a result of federal tax credit incentives.

Figure 9-45: Preferred Portfolio Energy Mix



9.4.1 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. NIPSCO's resource strategy is expected to:

- Continue to implement the Company's portfolio transition by integrating new renewable projects currently under development and taking the necessary steps to retire Units 17 and 18 at the Schahfer coal plant by the end of 2025 and Unit 12 at the Michigan City coal plant by the end of 2028;

173 For modeling purposes, newly selected DSM programs are evaluated on the "supply side" and are shown accordingly.

- Continue the Company's commitment to EE and DR by executing the current filed DSM plan and continuing to plan for the most expansive economic residential and commercial DSM programs identified in NIPSCO's portfolio optimization analysis, as well as potential emerging energy savings and demand response opportunities with new large loads;

- Integrate new resources to meet the energy and capacity needs of potential large new customers;

- Ensure that system reliability is preserved as NIPSCO and the broader MISO market increase the amount of intermittent resource capacity and operate within the new D-LOL construct;

- Provide a cost-effective portfolio for customers while also balancing other objectives associated with rate stability, environmental sustainability, and positive social and economic impacts;

- Preserve flexibility in resource procurement and future resource optionality, particularly associated with long-term decarbonization initiatives;

- 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 2024 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.

9.4.2 Financial Impact

Figure **9-46** shows NIPSCO's financial impact of Portfolio D_CCUS over the planning period. While NIPSCO's preferred portfolio intentionally retains flexibility, this summary is being provided as a baseline benchmark.

The 30-year NPVRR is broken down into operating and capital costs. The operating costs are split into 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.[174] 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[175]

Financial Impact Summary	
Operating Costs ($000)	$14,256,270
Capital Costs ($000)	$12,979,627
Total Revenue Requirement ($000)	$27,235,897
Total Energy Requirement (GWh)	310,807
Cents/kWh	8.76

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.

9.4.3 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 2024 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 and future portfolio actions. These can broadly be categorized into factors associated with new large load additions; the implementation of MISO market rules changes;

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174 Note that the value of federal tax credits are rolled into the net taxes line item.

175 The information is based on Portfolio D_CCUS under the Reference Case market assumptions. As discussed throughout this section, to preserve flexibility, NIPSCO's ultimate preferred portfolio may incorporate other long-term strategies around the D Portfolio concepts.

federal environmental policy, particularly associated with the future implementation of EPA GHG rules; and technology change.

9.4.3.1 Large Load Growth

NIPSCO's Reference Case load forecast incorporates 2,600 MW of new large load growth by 2035. Such load growth will require significant new resource additions to serve both energy and capacity requirements. The magnitude and pace of NIPSCO's load growth, however, is not certain, and NIPSCO will need to refine its resource acquisition strategy as specific customer requirements are defined. Within the 2024 IRP, NIPSCO evaluated a Flat Load portfolio and an Emerging High Load sensitivity with up to 8,600 MW of new load by 2035. These analyses provide a framework within which NIPSCO can implement its short-term action plan.

9.4.3.2 MISO Market Rules Changes

FERC approved MISO's D-LOL filing on October 25, 2024, so NIPSCO must now be prepared to operate under a revised capacity accreditation methodology. The portfolios developed in this 2024 IRP were evaluated based on the best accreditation information available as of the report's submission date, but NIPSCO expects MISO to continue to refine its modeling methodologies and provide additional guidance on future capacity accreditation levels between now and the 2028/29 planning period. Regional changes in load growth, load shapes, and the penetration of wind, solar, and storage resources will all impact future accreditation values for NIPSCO's resources (both existing and new), and NIPSCO will need to track updates accordingly. This 2024 IRP has concluded that new storage resources will likely play a role as the near-term "swing" resource type, meaning that NIPSCO will need to be flexible in its resource acquisition strategy to adapt its procurement activities to an evolving capacity need.

9.4.3.3 Federal Environmental Policy

Federal environmental policy is likely to remain dynamic. Most notably, the EPA GHG rules face both political and legal uncertainty that NIPSCO will continue to track, and these rules will dictate how NIPSCO can operate new natural gas-fired additions. While the Company's preferred portfolio was evaluated with the rules in force, NIPSCO's preferred portfolio is flexible enough to operate effectively even if challenges to the rules are successful or if they are revised in the future. In addition, the long-term decarbonization initiatives embedded in NIPSCO's preferred portfolio are contingent on the availability of federal tax credits for renewable, storage, and CCUS projects. NIPSCO will continue to monitor federal policy as it positions long-term portfolio actions and evaluates the timing of certain resource additions or retrofits.

9.4.3.4 Technology Change

The implementation of NIPSCO's preferred portfolio over the long-term is highly dependent on the evolution of emerging power sector technologies. Most notably, NIPSCO expects to continue to study CCUS and hydrogen in more detail over the next several months and years to understand the costs, challenges, and opportunities associated with such technologies. In addition, NIPSCO expects to further diligence its options associated with LDES technology, particularly since several portfolios identified LDES as a potential near-to-mid-term resource that provides strong capacity accreditation and hedges against load and intermittent resource output uncertainty. Finally, NIPSCO will continue to assess other emerging technologies that may play a role in its future portfolio, including nuclear.

9.4.3.5 Other Factors

NIPSCO will again continue to perform project-specific analyses for any new loads and 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.

9.5 Short-Term Action Plan

NIPSCO's short-term action plan covers the period 2025 to 2029 and includes several elements, as summarized in Figure 9-47.

9.6 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 2024 IRP incorporated several emerging trends and 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 manage customer costs, minimize future environmental impacts, ensure reliability, maximize resource diversification, and preserve optionality over the long-term.

Figure 9-47: Short-Term Action Plan Summary

Complete and place in service the remaining renewable facilities and gas peaker project approved by the IURC but not yet operational
Complete retirement and shutdown remainder of Schahfer coal units (17,18) by the end of 2025
Complete the retirement of Michigan City 12 by the end of 2028.
Implement required reliability and transmission upgrades necessitated by retirement of the Michigan City 12 and Schahfer 16A/B
Continue implementation of filed DSM Plan for 2025 through 2026
Select the best storage projects from the 2024 RFP, optimizing existing interconnection rights and federal tax credit opportunities
Procure short-term capacity as needed from the 2024 RFP, the MISO market, or through short-term bilateral capacity transactions
Continue discussions with new data center customers and refine the near-to-mid-term load outlook as contracts are signed and expected loads are firmed
Perform additional diligence on the costs, feasible locations, and operational characteristics of new natural gas combined cycle and peaking additions necessary to meet new data center load.
Study potential future decarbonization pathways for gas-fired generation further, particularly CCUS and hydrogen blending
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 energy storage and hydrogen
File CPCN(s) and other necessary approvals for selected replacement projects
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

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.

NIPSCO was named among the most trusted utility brands by Escalent, following its 2024 Cogent Syndicated Utility Trusted Brand & Customer Engagement: Residential study. The ranking recognized only 33 brands nationwide, with NIPSCO scoring in the top three of their Midwest Region combination gas/electric peers. Escalent measured factors including customer advocacy, safety and reliability and environmental focus, among others. Their findings were based on a survey of more than 61,000 residential electric and natural gas customers, which included 142 electric, natural gas and combination utilities.

That trust is built through a variety of ways including our work to continually enhance our customer engagement, ensuring the services we provide are bringing customers value.

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, MSR Group surveys, 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, interactions with field personnel, and with other interactions, such as mobile, integrated voice responses and the website. The company also researches best practices demonstrated by those within the utility sector and those outside the industry. Customer feedback is the primary driver behind many of the changes to operations, improvements to customer communications, enhancements to services and added programs, and other offerings that have been instituted in recent years.

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 and engagement data from February 2022 through June 2024, NIPSCO has significantly enhanced its customer service capabilities through various digital initiatives:

1. **Chatbot and Live Chat**: The chatbot has handled a substantial number of conversations, facilitating transactions such as account balance inquiries, payment status checks, and bill retrieval. Live chat availability has been expanded to improve accessibility, demonstrating NIPSCO's commitment to responsive customer support.

2. **Mobile App Enhancements**: NIPSCO has made 34 enhancements to its mobile app, including intuitive shortcut tiles for functions like payments, account registration, and service requests. The addition of three new payment plan options via the app has empowered customers to manage their finances conveniently.

3. **Website Improvements**: Over 90 enhancements on the NIPSCO website have enhanced user experience, featuring an interactive bill tool, a streamlined navigation menu, and improved accessibility for users with disabilities. Real-time email validation ensures accurate communications, while enhanced payment management capabilities cater to diverse customer needs.

4. **Digital Self-Service Adoption**: The adoption rate of digital self-service options has increased, with 82.7% of transactions completed through web, mobile app, IVR, and chatbot channels by June 2024. This growth highlights the effectiveness of NIPSCO's digital strategy in empowering customers to manage their accounts independently.

5. **Mobile App Usage**: The NIPSCO mobile app has been downloaded over 218,000 times since 2022, supporting more than 74,000 transactions related to service requests such as starting, stopping, or moving services.

Notably, NIPSCO.com was ranked the #1 Utility Website by E Source in 2023. NIPSCO participated in a Website Benchmark assessment through E Source, a company with 30+ years of industry expertise. The biennial list assesses utility websites in the US and Canada for findability, functionality, content and appearance. The report cited that utility websites must offer digital tools that support customers equitably, regardless of their background, abilities, language or level of access to technology. By doing so, utility companies promote self-service offerings that increase customer satisfaction and reduce operating costs, among other benefits.

These initiatives collectively underscore NIPSCO's efforts to enhance customer convenience, improve service accessibility and empower customers through efficient digital solutions. 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 we can continue to improve across technologies, processes and experiences.

It is important for customers to understand what they are paying for and that they are getting good value. Along with working to improve these direct customer channels, NIPSCO has also made service improvements in recent years that directly benefit customers, including:

- Modernizing the electric system to improve system reliability, reduce outage time, and harden it against severe weather

- Replacing over 300 miles of a specific vintage of underground cable that was causing up to 90% of the outages on its underground system

- Modernizing electric distribution and transmission substations with equipment that helps monitor asset and system health, ensuring these technologies achieve their maximum life

- Inspecting and treating over 300,000 wood poles helping to harden its distribution system and improve reliability

- Maintaining reliability by coating and extending the life of more than 3,227 steel transmission structures since 2016 to protect against physical damage and weather conditions

- Continuing investments to thwart and protect against cybersecurity threats

- Reducing power outage durations by 40%

- Providing customers with 100% of the revenues when NIPSCO sells the excess power it generates back to the grid – including sales from the newly added renewable energy

- $70 million in savings for customers through eliminating fuel, purchase power, and operating and maintenance costs by retiring NIPSCO's coal-fired generating units

10.1.2 Customer Education – Generation Transition, Energy Efficiency and Assistance

NIPSCO's 2024 Integrated Resource Plan continues to demonstrate that a more balanced electric generation portfolio is the best option for customers in terms of long-term affordability and reliability in terms of long-term affordability and reliability. As NIPSCO continues this generation transition, it is important for customers to understand why and how this transition will occur to maintain customer trust and confidence in the essential, reliable energy this balanced portfolio provides.

Along with making this cost-effective electric generation transition, NIPSCO remains committed to supporting its customers through a variety of assistance programs. For those facing financial difficulties, NIPSCO offers comprehensive bill payment assistance initiatives. These include payment agreements tailored to provide flexibility during times of financial strain, such as three-month, six-month, and twelve-month options designed to ease the burden of overdue balances. Introduced in 2020, these plans continue to be available to eligible customers, ensuring manageable payment schedules that align with their financial circumstances.

In addition to its in-house payment plans, NIPSCO collaborates with federal, state, and local agencies to extend support through programs like LIHEAP. LIHEAP provides vital financial aid to households with incomes at or below 60% of the State Median Income, helping them manage their energy bills during critical times. Applications for heating assistance under EAP are accepted annually from Oct. 1 through April 14 ensuring timely support for eligible families across Indiana.

Furthermore, NIPSCO's CARE Program offers additional discounts on energy bills for qualifying customers using natural gas for heating, supplementing the benefits provided by LIHEAP. This program runs during the colder months of the year when bills can be at their steepest, providing significant savings depending on household income levels. For customers facing specific financial hardships related to energy costs, NIPSCO's Hardship Program offers targeted assistance through local Community Action Agencies, providing much-needed relief for natural gas customers falling between 151-250% of the Federal Poverty Level.

Since NIPSCO’s last Integrated Resource Plan in 2021, two additional hardship programs have been introduced to assist NIPSCO customers:

- **SERV:** The Supply Energy Resources to Veterans (SERV) program is an income-eligible assistance program that offers a one-time benefit to our active military and eligible veteran customers that fall between 0-250 percent of the federal poverty level and is in need of financial assistance with gas residential utility charges. Learn more at https://www.nipsco.com/bills-and-payments/financial-support/income-eligible-assistance-programs

- **SILVER:** The Seniors in Indiana Low-income & Vulnerable Energy Resource (SILVER) program is an income-eligible assistance program that offers a one-time benefit to our senior citizen customers 60 years of age or older that fall between 0-250 percent of the federal poverty level and is in need of financial assistance with gas residential utility charges. Learn more at https://www.nipsco.com/bills-and-payments/financial-support/income-eligible-assistance-programs

Recognizing the diverse needs of its customers, NIPSCO also facilitates access to local resources such as Township Trustees, who administer limited energy assistance funds. These trustees can offer individualized support to eligible residents, further enhancing the reach and effectiveness of NIPSCO's assistance efforts. Additionally, renters in need of support can avail themselves of the Indiana Emergency Rental Assistance (IERA) Program, which provides comprehensive rental and utility assistance for up to 18 months.

In addition to helping customers to manage their bill NIPSCO also promotes energy efficiency. This is not only good for customers, but it can also 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 provide education and identify opportunities to ensure energy savings. Since 2010, NIPSCO customers have saved more than 1.7 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 program and measure offerings. We regularly track and report on program performance, which helps to inform and improve future program filings and customer offerings.

By proactively engaging with customers and offering tailored assistance programs, NIPSCO continues to demonstrate its commitment to supporting community well-being and ensuring energy affordability during challenging times. Through dedicated website landing pages, informative fact sheets, timely bill inserts, strategic media placements, and more, NIPSCO ensures that customers are well-informed and empowered to access the full range of assistance programs available to them, supporting their energy needs with clarity and transparency.

10.2 Community Partnerships

10.2.1 Community Advisory Panels

Another NIPSCO engagement avenue with customers and stakeholders is the use of 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 and local government and community leaders representing a diverse, broad cross-section of NIPSCO customers. Meetings are held three times a year featuring internal and external presenters to help the company identify communication improvements, highlight information about helpful customer programs and outreach efforts, and create a channel for ongoing dialogue and feedback. NIPSCO senior management meets with each of the regional CAPs once a year to share the Company's strategic direction and to ask members of the CAPs for insight on emerging issues.

10.3 Customer Programs

10.3.1 Feed-in Tariff (FIT)

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 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 Interconnection Agreement and Renewable Power Purchase Agreement 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 Interconnection Agreement.

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 10-2 shows the subscription for Phase II as of July 2024.

Table 10-2: FIT Phase II Project Totals

Technology	In-Service (kW)	Queue (kW)	Total FIT (kW)
Micro Solar	436	43	479
Intermediate Solar	6,370	200	6,570
Micro Wind	20	0	20
Intermediate Wind	0	0	0
Biomass	0	0	0
Total	6,826	243	7,069

With over 36 MW of capacity currently interconnected in the FIT program, as of Dec. 31, 2023, NIPSCO had a total metered generation from customers selling electricity of 1,188,625 MWh. Despite continued interest in the FIT program, 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)

Year	Biomass	Intermediate Solar	Micro Solar	Intermediate Wind	Micro Wind	Total
2011	6,219,791	0	0	0	0	6,219,791
2012	19,152,432	433,758	118,895	0	3,588	19,708,673
2013	31,602,728	15,789,457	471,806	90,113	15,721	47,969,825
2014	49,916,700	21,665,115	718,758	165,880	12,051	72,478,504
2015	81,369,723	22,436,103	818,332	217,949	9,462	104,851,569
2016	83,552,339	22,696,839	825,066	165,593	8,019	107,247,856
2017	89,486,440	24,391,349	848,789	167,807	8,487	114,902,872
2018	94,942,135	27,450,274	848,789	179,797	8,487	123,429,482
2019	94,551,873	26,707,084	857,037	142,631	8,381	122,267,006
2020	96,144,048	30,345,387	899,064	115,177	7,880	127,511,556
2021	96,195,974	30,761,852	1,047,838	88,207	4,333	128,098,205
2022	77,891,838	27,893,285	1,109,705	118,714	4,924	107,018,466
2023	79,614,091	26,016,366	1,192,461	95,105	3,515	106,921,537
Total	900,640,112	276,586,868	9,756,540	1,546,973	94,848	1,188,625,342

10.3.2 Excess Distributed Generation Tariff

The Net Metering program ended for new customer applications for non-residential customers on Oct. 1, 2021, and for residential customers on June 20, 2022. The EDG Tariff replaced Net Metering. NIPSCO's EDG Tariff allows customers to install renewable energy generation to offset all or part of their own electricity requirements. An EDG credit is applied to a customer's bill if a customer generates more energy than they consume. If a customer produces more than they need, they receive a utility bill credit that can be applied to reduce their bill in the amount of 125% of market priced power for all excess distributed generation. Production is measured on a per 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 in the Indiana Administrative Code regarding EDG and the interconnection process. Customers with a fully executed EDG Agreement and Interconnection Agreement receive credit for generation provided to NIPSCO above their own usage requirements. The current number of EDG customers as of Dec. 31, 2023, is shown in Figure 10-1.

Figure 10-1: Classification of EDG

Non-Residential				Residential			
Number Customers	Total Capacity	Battery Storage		Number Customers	Total Capacity	Battery Storage	
		kW	kWh			kW	kWh
23	2583.63	4.5	9	83	856.86	99.8	200.8

10.3.3 Green Power Rider (GPR) Program

NIPSCO's GPR program was approved on Dec. 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 Dec. 30, 2014, in Cause No. 44520. The GPR Program is a voluntary program that allows customers to designate a portion or all 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 or 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 Dec. 31, 2024, 1,600 customers were participating in the GPR Program. Figure 10-2 shows the breakdown among residential customers as of Dec. 31, 2023.

Figure 10-2 GPR Program Residential Customer Count

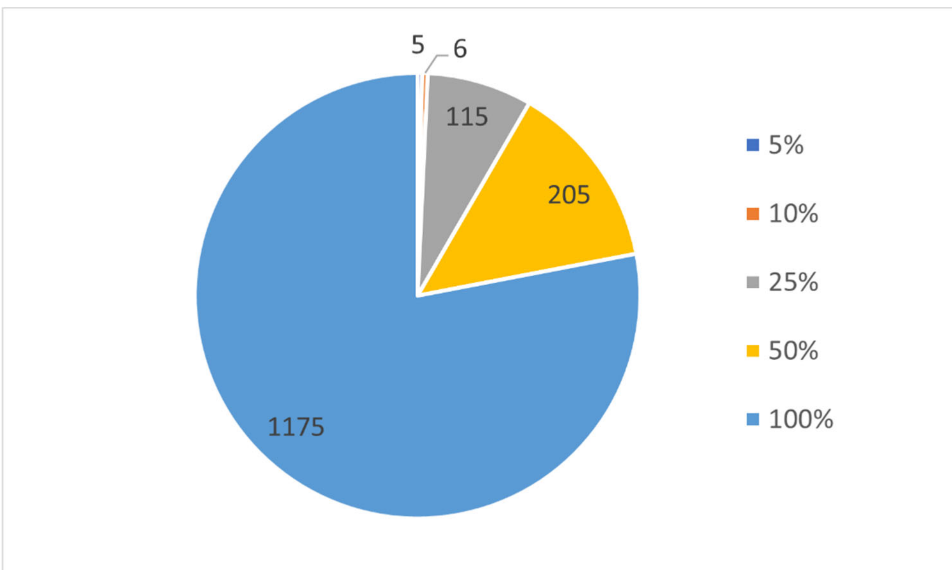
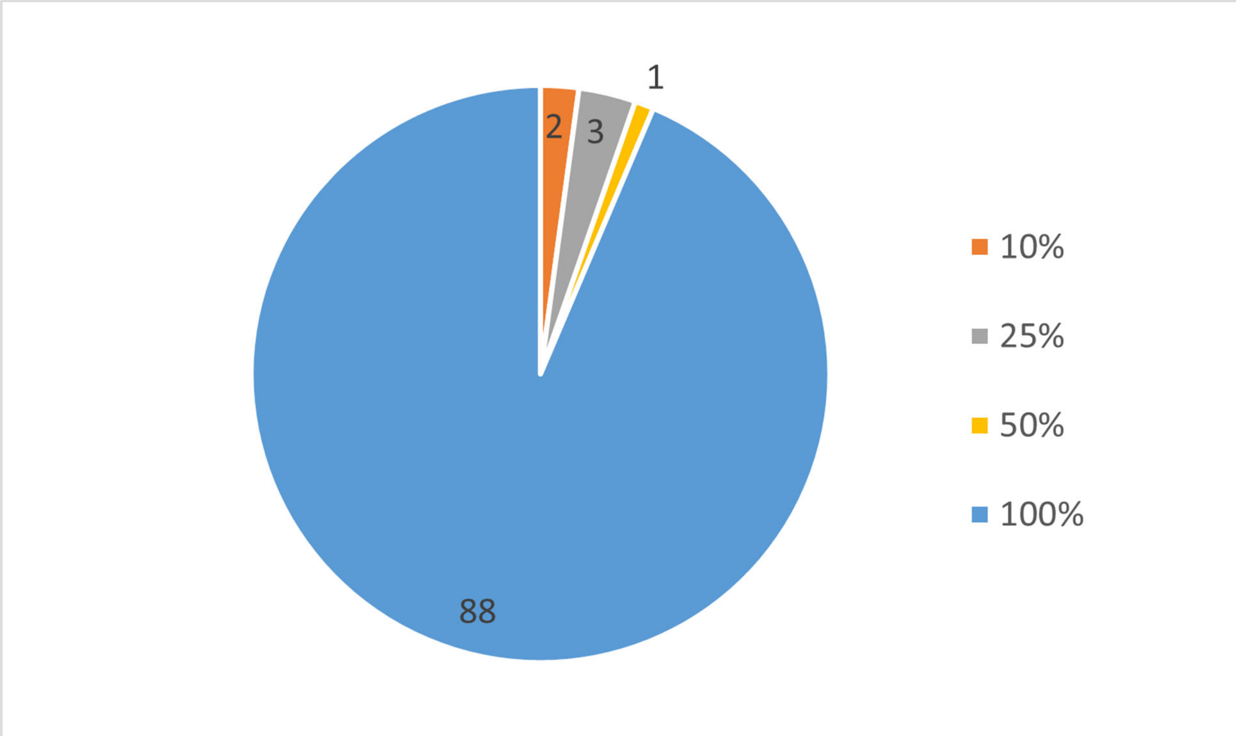


Figure 10-3 shows the breakdown of commercial and industrial customers as of December 31, 2023.

Figure 10-3: GPR Program Commercial Customer Count



NIPSCO's GPR program from Jan. 1 through Dec. 31, 2023, accounted for 376,983,386 kWh of energy consumption designated as green power. Residential customers accounted for 10,119,490 kWh of energy consumption, and nonresidential customers accounted for 366,869,896 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 Jan. 1 through Dec. 31, 2023.

Table 10-4: Green Power Customers by Rate Type (kWh)

2023	Residential	Nonresidential
January	955,852	35,769,593
February	785,049	28,138,645
March	755,862	39,428,393
April	693,840	27,357,435
May	648,145	41,867,313
June	792,617	40,902,897
July	1,077,787	33,823,421
August	1,133,238	36,111,684
September	1,041,851	35,284,240
October	707,356	20,234,459
November	692,436	10,722,534
December	835,459	17,223,285
Total	10,119,490	366,863,896

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 July 1, 2021, through June 30, 2025.

Table 10-5: Green Power Rates

July 2021 to June 2022	July 2022 to June 2023	July 2023 to June 2024	July 2024 to June 2025
$0.005439	$0.003092	$0.001992	$0.000932

10.3.4 Green Path Rider Program

NIPSCO's Green Path Rider Program was approved on Nov. 23, 2022, in Cause No. 45730. Green Path is a voluntary program which allows customers to designate a portion or all their monthly natural gas usage to be supplemented by a combination of RNG and carbon offsets to allow them to offset emissions from their natural gas usage. Customers can enroll online or by calling NIPSCO.

Carbon offsets purchased for NIPSCO are on a global scale and are registered, recognized, and retired by such registries as Verra; Climate Action Reserve; American Carbon Registry; UN CDP; or The Gold Standard. M-RETS®, a non-profit organization that utilizes a web-based system, tracks and confirms the RNG attributes NIPSCO acquires. Both NIPSCO residential and non-residential customers can elect to designate 25%, 50%, or 100% of their monthly natural gas therm usage to participate in the Green Path program.

Customers shall pay a fixed volumetric charge reflecting the cost of the RNG environmental attributes and carbon offsets needed to reflect the selected 25%, 50% or 100% reduction in emissions. The fixed volumetric charge shall be reviewed and may be adjusted annually by the Company and approved by the Commission. The fixed volumetric charges set forth below are effective for bills rendered for the billing month of January 2024, and will remain in place until new fixed volumetric charges are approved by the Commission in a subsequent proceeding:

- 25% Emissions Reduction $0.05625 per Therm for all Therms used per month
- 50% Emissions Reduction $0.1125 per Therm for all Therms used per month
- 100% Emissions Reduction (Net Zero) $0.225 per Therm for all Therms used per month

As of July 2024, NIPSCO has 415 residential customers participating in Green Path and 5 non-residential customers for a combined total of 420 customers.

Count of CUSTOMER ACCOUNT	**Column Labels**			
Row Labels	**25**	**50**	**100**	**Grand Total**
311 - Res	140	99	176	415
321 - Com		1	4	5
Grand Total	**140**	**100**	**180**	**420**

10.3.5 Transportation Decarbonization: DC Fast charging stations & IDEM Grant

NIPSCO has completed installation of 8 EV Fast Charging Stations as part of two grant awards: (1) an IDEM grant award being managed as part of the Indiana Volkswagen Environmental Mitigation Trust Fund Committee and (2) a grant award from the White County Economic Development Committee. In addition, NIPSCO was selected as an award winner for two NEVI site grants being managed by INDOT. These two NEVI grants will be used to expand one of the currently existing DC Fast Charging Stations in Merrillville, Indiana and the other will be used to install a new station in Gary, Indiana, which will bring the total NIPSCO owned EV Fast Charging Stations to nine once completed. In addition, NIPSCO continues to seek and explore additional funding opportunities to assist with transportation electrification efforts for our customers.

10.3.6 Advanced Metering Infrastructure (AMI)

In 2024, NIPSCO announced plans to enhance electric and gas metering systems by deploying AMI technology. The initiative aims to upgrade services for customers across the region. The deployment will cover 490,000 electric customers over the next three years and 870,000 gas customers throughout NIPSCO's service area.

Installation of electric AMI meters and gas AMI communications devices has already begun. As of November 2024, approximately 78,000 electric AMI meters and approximately 61,000 gas AMI communications devices have already been installed in NIPSCO's service area, marking a significant step forward in the modernization effort. Installation of gas AMI communications devices is expected to be completed by the end of 2026 and the rollout of electric AMI meters is expected to be completed by the end of 2027.

Integration of AMI technology will allow NIPSCO to provide improved responses for outages and emergencies and lay the foundation for greater energy efficiency offerings, cost savings, and more granular billing information for customers. NIPSCO will also be able to read and access customer meters remotely.

10.3.7 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 invests $1.1 million in economic development efforts each year, which has resulted in 88 new businesses or expansions and 11,000 local jobs in the past 10 years. The NIPSCO Economic Development team participates in local and regional economic development boards and helps promote and market our service territory for new investment. NIPSCO's Economic Development team works closely with the state of Indiana, local government, economic development professionals, and the real estate/developer community to help attract and land key investments that create jobs and increase local tax revenue in the communities we serve.

NIPSCO's Economic Development Rider 577 allows NIPSCO to offer an incentive for new investment within our service territory. This rate can be offered 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.

10.3.8 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 2023, NIPSCO's direct supplier spending in Indiana was $1.5 billion. Of that, $204.6 million was spent on diverse businesses and $57.5 million was spent with diverse subcontractors.

10.3.9 Workforce Development

NIPSCO continues to lead efforts and partnerships focused on workforce development – both for the current and future workforce generations. Some recent highlights include:

- **Ivy Tech Power Your Future Program & FLEX Lab:** NIPSCO has partnered closely with Ivy Tech Community College to drive workforce innovation, notably through initiatives such as the "Power Your Future" program. This collaborative effort was bolstered by a $50,000 grant from the NISOURCE Foundation to Ivy Tech - Lake County Campus, aimed at inspiring diverse students in grades 7 to 12 to pursue careers in the energy and industrial technology fields. This initiative complements NIPSCO's sponsorship of the FLEX Lab within Ivy Tech's Energy Technology Program in Valparaiso, where students gain hands-on training in essential skills like climbing techniques and industrial wiring. Upon completion, graduates earn an associate degree in Energy Technology and a technical certificate in Electric Line Technology, directly preparing them for roles at NIPSCO. Beyond financial support, NIPSCO encourages its employees to engage directly with local classrooms across Lake County, sharing personal career journeys and insights. This volunteer effort not only enriches educational experiences but also fosters a future workforce well-equipped for the utility industry's demands. By investing in education and community involvement, NIPSCO and Ivy Tech are collaboratively shaping a promising future for aspiring professionals in Indiana's energy sector, addressing critical workforce needs and highlighting the diverse and rewarding career opportunities available.

- **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.

- **IN-POWER Youth Mentoring Program:** In its 14th year, NIPSCO's IN-POWER Youth Mentoring Program has been 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 of Northwest Indiana, Inc., is a college- and career- readiness program that has been going strong for seven years. This opportunity invites 11th and 12th grade students throughout northwest Indiana to participate in virtual workshops, field trips, meetups, community engagement and activities designed to educate students about NIPSCO's operations and encourage STEM learning.

- **Free Gas Training Safety Event for Local Fire Departments:** NIPSCO plays a vital role in community safety by offering comprehensive natural gas safety training to fire departments across NIPSCO's service area. Since 2018, nearly all fire departments—approximately 99%—have participated in this initiative, benefiting around 8,000 first responders. This training equips firefighters with essential skills and knowledge to effectively handle natural gas emergencies, covering topics such as the gas distribution system, characteristics of natural gas, and safe response tactics. Led by experienced trainers who are former firefighters themselves, the program includes live demonstrations to illustrate potential hazards like ignitions and explosions. NIPSCO's commitment to continuous education and preparedness not only ensures compliance with safety standards but also fosters strong community partnerships, enhancing overall safety and response capabilities in the region.

- **OJT Coach Program for Power Delivery:** Launched in 2021, NIPSCO's On the Job Training (OJT) coach program for Power Delivery enhances workforce development by providing rigorous training and support for field employees. This program builds on an existing structured OJT model and includes collaboration with Northwest Lineman College. The training combines 70% hands-on field learning with structured instructor-led sessions, facilitated through iPads for easy access to training materials. OJT coaches reinforce formal instruction and ensure safety and standards compliance through regular knowledge checks and performance evaluations. This program aims to develop critical competencies in apprentices, contributing to their safe and effective performance in the field.

- **Mobile Unit Partnership with Workforce Innovations:** The launch of a new mobile unit, made possible by a $100,000 grant from the NIPSCO/NiSource Charitable Foundation, is a significant development by the United Way of Northwest Indiana in partnership with the Center of Workforce Innovations (CWI). This mobile unit is part of the Level Up program, which aims to assist struggling working individuals in developing new skills, stabilizing their finances, and finding better-paying jobs. The unit addresses barriers such as lack of transportation and limited free time by bringing resources directly to communities in need. The mobile unit visits libraries, career events, community gatherings, and client-serving organizations across Northwest Indiana. Other goals of the program include reducing social-emotional barriers for students, increasing students' interest in STEM careers, boosting self-esteem and supporting educational goals.

- **Junior Achievement Support:** NIPSCO provides annual support for classroom business education programs through both contributions and volunteer instructors across NIPSCO's service area. NIPSCO has supported a "JA Day" in a local Hammond and East Chicago school systems where NIPSCO employees go into a local school and deliver JA curriculum. NIPSCO employees also participate in local career fairs through JA, showing local students what kind of job opportunities there are throughout the region. In 2024, NIPSCO partnered with JA to support the launch of virtual platform called Metaversity that will allow students to learn about different careers in a virtual interactive environment.

- **Girl Scouts Engineering Day:** For more than ten years, NIPSCO has hosted more than area girls from kindergarten to 5th grade for the annual Introduce a Girl to Engineering Day. The girls come from local Girl Scout troops, community members along with some young relatives of NIPSCO and NiSource employees. The five-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 at NiSource.

10.3.10 Corporate Citizenship

At NIPSCO, being a responsible corporate citizen is at the core of who we are. We are committed to building a better future, fueled by the belief that by coming together, we can improve the lives of those who need it most. Each year, NIPSCO donates time, money and other resources to hundreds of local philanthropic programs and organizations across its 32-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.

10.3.11 Targeted Grants

NIPSCO helps fund environmental projects and programs through its annual Environmental Action Grant. To date, NIPSCO has helped 124 projects come to fruition across northern Indiana. The 15 projects funded in 2023 by the NiSource Charitable Foundation provided funds to projects focused on Monarch butterflies, habitat restoration, youth outdoor nature education and sustainability programming. Many funded projects and programs included a significant volunteer and community engagement component, encouraging community members to give back through environmental stewardship projects.

In its sixth year, NIPSCO's Public Safety Education and Training Action Grant provided funding to 16 local nonprofit organizations and first responders with their public safety education and training across northern Indiana. Some of the projects included distribution of carbon monoxide detectors to residents, carbon monoxide educational training and lithium-ion battery response training.

In 2023, together with the NiSource Charitable Foundation and direct employee contributions, NIPSCO donated over $2.4 million to more than 250 local non-profits and community organizations and volunteered more than 2,700 service hours throughout the NIPSCO service territory.

A highlight of that effort includes NIPSCO’s annual Charity of Choice campaign, a collaborative initiative led by employees, aiming to make a meaningful impact through volunteer work in diverse community projects throughout NIPSCO's service area. NIPSCO employees accumulated 800 volunteer hours for local organizations. Recent benefactors and causes selected by employees have included local food banks, a domestic violence shelter, Humane Indiana, a United Way chapter, Boys & Girls Clubs, to name a few.

10.3.12 Charitable Giving

In 2023, NIPSCO and the NiSource Charitable Foundation provided funding to organizations focused on making positive contributions to the communities we are privileged to serve.

- $100,000 to United Way of Northwest Indiana: This donation provided collaborative partnership with the Center of Workforce Innovations to develop two handicap-accessible mobile resource centers. This project combines resources from both agencies to make a strong impact in our communities.

- $50,000 to Believe in a Dream: Believe in a Dream received funds to scale up its Pave The Path program. The program focuses on youth development, empowering high school students across Northeast Indiana to discover their strengths, and personal brand, and explore leadership experiences through community connections.

- $50,000 to Hilltop Neighborhood House: Funds will be used to build the Hilltop Mission Kitchen, a community soup kitchen to serve meals to food-insecure people living in Valparaiso and provide cooking and life skills classes for clients. NIPSCO manager and Hilltop board member, Ryan Hutnick, leveraged this donation with a volunteer event to install board siding on the facility.

- $35,000 to Purdue Northwest University: Purdue Northwest University used the funds to host the Summer Innovation Makers STEM Camp in July 2023. This week-long camp introduced Northwest Indiana high school sophomores and juniors to entrepreneurship and experiential learning through inventing, building a business and pitching investors with access to the maker lab's cutting-edge technology.

- $25,000 to the Nature Conservancy: Funds were used to create an outdoor pavilion and two public viewing platforms to support Kankakee Sand's Welcome Center and bison viewing initiative. There are over 100 bison grazing and roaming in the Kankakee Sands Reserve, supporting biodiversity and restoring northwest Indiana's prairie.

Section 11. Compliance with IRP Rule

Rule	Section(s)
170 IAC 4-7-2: Integrated Resource Plan Submission	
(c) 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 December 9, 2024
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP. (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If the utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.	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.	Executive Summary

Rule	Section(s)
(B) A simplified discussion of resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	
(d) Contemporaneously with the submission of an IRP, a utility shall provide to the director the following information: (1) The name and addresses of known entities considered by the utility to be interested parties. (2) A statement that the utility has sent known interested parties, 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. An interested party includes a business, organization, or particular customer that participated in the utility's previous public advisory process or submitted comments on the utility's previous IRP. A utility is not required to separately notify other customers. (3) A statement that the utility served a copy of the documents submitted under subsection (c) on the OUCC.	Transmittal Letter
170 IAC 4-7-2.6: Public Advisory Process	
(a) The following utilities are exempt from this section: (1) Indiana Municipal Power Agency; (2) Hoosier Energy Rural Electric Cooperative; (3) Wabash Valley Power Association. (b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within fifteen (15) business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information. (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission 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 (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in	Section 2.1 Appendix A

Rule	Section(s)
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-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable 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 the utility's rationale for its selection. (2) The utility may hold additional meetings. (3) The schedule for meetings shall: (A) be determined by the utility (B) be consistent with its internal IRP development schedule; and (C) 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; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and (D) develop and publish to its website minutes within fifteen (15) 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: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC; of its public advisory process.	
170 IAC 4-7-2.7: Contemporary Issues	

Rule	Section(s)
(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. (c) Utilities, the OUCC, and interested parties may request commission staff include specific contemporary issues and presenters. (d) 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.	N/A
(e) Utilities shall address the designated contemporary issues in the next IRP if the contemporary issues were designated by the director at least one (1) year prior to the submittal date of the utility's IRP.	Section 2.2.1
170 IAC 4-7-4: Integrated Resource Plan Contents	
An IRP must include the following:	
(1) At least a twenty (20) year future period for predicted or forecasted analyses.	Used throughout
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Section 3.3 Section 3.4 Section 3.4 Section 3.5 Section 3.6 Section 3.7 Section 3.9
(3) At least three (3) alternative forecast scenarios of peak demand and energy usage in compliance with section 5(b) of this rule.	Section 8.4
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	Section 4.1 Section 4.2 Section 5.1 Section 6 Section 7.3 Confidential Appendix C
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Section 5

Rule	Section(s)
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	
(7) The resource screening analysis and resource summary table required in section 7 of this rule.	Section 4.6
(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 9.1 Section 9.2 Section 9.3 Confidential Appendix D
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Section 9.2 Section 9.3 Section 9.4
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Section 1.1 Section 9.5
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Section 2 Section 3.3 Section 3.4 Section 3.5 Section 3.6 Section 4.1 Section 4.2 Section 4.3 Section 4.6 Section 5.1 Section 5.2 Section 5.3 Section 7.3 Section 8.2 Section 8.5 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 section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data.	Confidential Appendix D

Rule	Section(s)
The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as comma separated value or excel spreadsheet file.	
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (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: (A) end-use penetration, (B) end-use saturation rates, and (C) end-use electricity consumption patterns.	See Note 2
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Section 3 Section 10
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e) of this rule.	Section 2.2
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	Section 3.5 Section 3.8 Section 10
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Appendix A
(20) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Section 2
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	Section 7

Rule	Section(s)
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 2.3
(23) 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 7.4 Section 8.2.3
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness, (B) rate impacts, (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	Section 9.2
(25) 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: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 solicits stakeholder input regarding the inclusion and describes the input received; (ii) Future resources have obtained the necessary regulatory approvals; (iii) Future laws and policies have a high probability of being enacted. A base case need not align with the utility's preferred resource portfolio.	Section 8.2 Section 9.3
(26) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 8.4 Section 9.3

Rule	Section(s)
(27) A brief description of the models, 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. The 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. (iii) Operating restrictions and limitations particular to the utility.	Confidential Appendix C
(28) A list and description of the methods used 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 5.2 Section 8.1 Section 9.3 Appendix B
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. 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.	Section 5.2 Appendix B

Rule	Section(s)
(D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.	
(30) A summary of the utility's most recent public advisory process, including the following: (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 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.	0 Confidential Appendix D
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) 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 3.2 Section 3.3
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Section 3.2 Section 3.3
(8) Justification for the selected forecasting methodology.	0

Rule	Section(s)
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	Section 2.2
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	No Response Needed
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts. (c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (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 3.8
(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 Section 2.2.2
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 relevant to the twenty (20) year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	Section 4.1
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Section 4.1

Rule	Section(s)
(3) A fuel price forecast by generating unit.	Section 8.2 Confidential Appendix D
(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: (i) transmission losses, (ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	Section 5.2 Section 6.1
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivisions (1) through (4) and in subdivision (6) shall be provided for each year of the future planning period.	Section 3.2 Section 5 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) Rate design as a resource in meeting future electric service requirements.	Section 3.1 Section 3.5.3 Section 3.8 Section 5.2
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics, and parameters. (B) The method by which the costs, characteristics, and other parameters of the demand-side resource are determined. (C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings.	Section 5 Appendix B See Note 3

Rule	Section(s)
(E) The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (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. (C) A description of significant environmental effects, including the following: (i) air emissions. (ii) solid waste disposal. (iii) hazardous waste and subsequent disposal. (iv) water consumption and discharge.	Section 4.1 Section 4.3 Section 4.5 Section 4.6
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following: (A) The type of transmission resource, including whether the resource consists of one (1) of the following: (i) new projects. (ii) upgrades to transmission facilities. (iii) efficiency improvements. (iv) smart grid technology. (B) A description of the timing, types of expansion, and alternative options considered.	Section 6.1 Section 6.2
(C) The approximate cost of expected expansion and alteration of the transmission network.	Section 6.1.6
(D) 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	Section 6.1

Rule	Section(s)
(ii) RTO planning and implementation processes affect the IRP.	
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 section 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
170 IAC 4-7-8: Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from existing and future resources in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (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 9.1
(b) With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(26) of this rule. (2) The results of testing and rank ordering the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (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 Section 9.3 Confidential Appendix D
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio.	Section 9.4
(2) Identification of the standards of reliability.	Section 9.2 Section 9.3.3.1

Rule	Section(s)
(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Section 9.3
(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	Section 9.2 Section 9.3
(5) An analysis showing the preferred resource portfolio utilizes, supply-side resources and demand-side resources that safely, reliably, efficiently, and cost-effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	Section 9.3
(6) 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.	Appendix B
(7) 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 Section 9.4 Confidential Appendix D
(8) 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; (v) operating costs; (vi) construction costs;	Section 9.4

Rule	Section(s)
(vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(9) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) 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.	Executive Summary Section 9.4
170 IAC 4-7-9: Short Term Action Plan	
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule. (b) The short term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(10) of this rule, where the utility must take action or incur expenses during the three (3) year period. (c) The short term action plan must include, but is not limited to, the following: (1) A description of resources 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 goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10 and	Section 1.1 Section 9.4 Section 9.5 Confidential Appendix D

Rule	Section(s)
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 occurred.	

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 (MISO)	)))))	Order No. 202-25-7

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

Filed September 5, 2025

Exhibit 5

DOE Order No. 202-22-4

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

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

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.24 17:38:01 -05'00'

Undersecretary of Energy for Infrastructure

Generation Transition

Positive Environmental Impact • Maintaining Reliable and Affordable Service • Flexible, Balanced and Diverse Portfolio • Effective Regulatory and Legislative Partnerships

We are progressing on our Indiana energy transition plan that seeks to provide a balanced, flexible renewable energy mix to help support a cleaner environment, while responsibly managing costs for our customers.

In 2023, we unveiled the details of our latest Integrated Resource Plan for our Indiana Electric business that details our approach to providing sufficient electric generation for our customers over the next two decades. The plan was the culmination of a year-long process, including in-depth analysis and extensive input from the public. It outlines the ongoing planned transition of coal-powered thermal generation to a cleaner portfolio utilizing a mix of natural gas and renewable energy sources to produce electricity for the region.

The plan is expected to provide aggregate savings of $80 million to our customers and reduce carbon emissions by as much as 95% over the next 20 years, while striving to maintain reliable electric service. We expect to have approximately 1,000 MWs of power generation in Indiana from renewables available by 2026.

To advance this initiative, we have transitioned 635 MWs of coal-

"Our recommended mix of renewable and natural gas resources is expected to maintain the ability to turn on generating resources during times of greatest demand supporting reliability and continuing our strategy of providing cleaner electricity that meets customers' future energy needs."

— Shane Bradford, Vice President, Indiana Electric

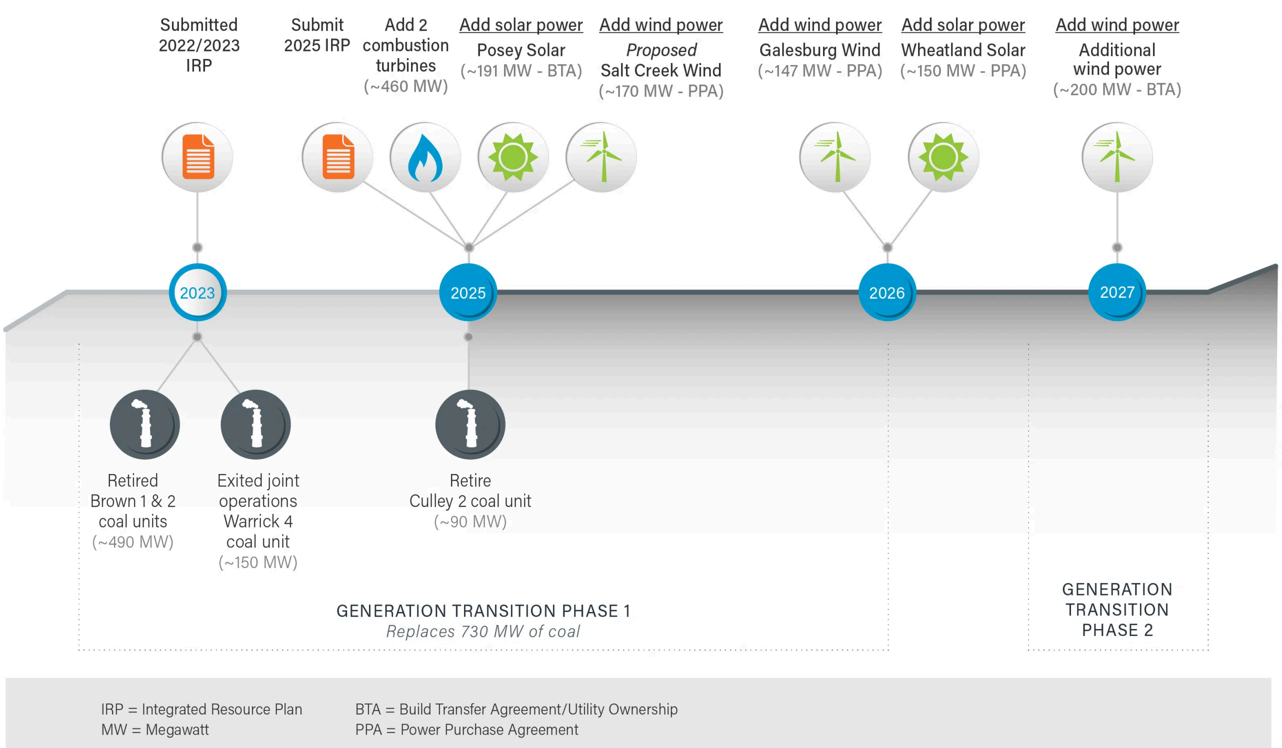
Indiana Electric

- Serves approximately 150,000 electric metered customers
- Owns and operates

County, Indiana, consisting of more than 30,000 panels.

Just Transition

Generation Transition Timeline



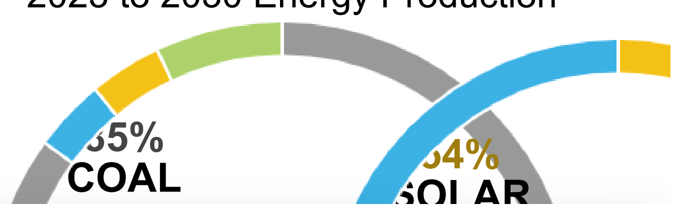
FB Culley Unit 3 conversion from coal to natural gas paused; will reassess in the 2025 resource planning process.

Renewables

Renewables represent the next component of our generation transition plan:

2026:

2023 to 2030 Energy Production



program, a customer's power is generated from locally sourced renewable generation, which can help them meet their own sustainable and renewable energy goals.

For every megawatt hour (MWh) of renewable power produced, CenterPoint Energy receives a Renewable Energy Credit (REC). Since mid-2008, we marketed these RECs to other parties including REC brokers and other utilities. The revenue received from the sale of RECs is credited to our retail electric customers to reduce their total bills.

Grid Modernization and Investment

In 2023, CenterPoint Energy completed and filed Indiana Electric's initial seven-year transmission and distribution modernization plan and received approval to extend the plan for another five years, including an additional $454 million in proposed capital investments across seven program areas addressing infrastructure in distribution, transmission and substations.

Our grid modernization plan is designed to provide future long-term electric supply needs in a safe, reliable manner. Through a combination of innovative practices, we have improved our operations and upgraded our energy delivery infrastructure to help with our transition to a cleaner energy future:

Based on 2011-2023

- Dropped average storm-related outages by 10 minutes over the last five years
- 159,000 electric smart meters installed
- 99,824 gas smart meters installed
- Trimmed trees along nearly 7,000 miles of electric distribution lines

We are thoughtful in pursuing a just transition for our coal plant employees. Our internal safety and technical training professionals are leading engagements and skills-based development programs for impacted employees to transition to other areas of the company, including our renewable operations division. With the retirement of A.B. Brown 1 and 2 coal-fired units, we hosted information sessions and small group meetings with the workforce to discuss available resources, provided reskilling opportunities and were proud to transition all employees of the units to other areas in the organization, without any job losses.

Our company supports workforce development initiatives that will help prepare our workforce and communities to respond to the energy needs of the future. In addition to developing new training centers and providing opportunities to enhance employee development, we engage with the Center for Energy Workforce Development, a nonprofit consortium of energy companies, employees and associations, to enable a skilled workforce for the energy transition.

The CenterPoint Energy Foundation also awards grants to support energy-related workforce development programs, local educational initiatives and STEM learning.

LEARN MORE Midwest Cleaner Energy Website

Generation transition plan involves forward-looking statements and risk and uncertainties. For more information, see Cautionary Statement and the risk factors included in our annual report on Form 10-K, our quarterly report on Form 10-Q and in other reports we filed with SEC.

DECLARATION OF DOUGLAS JESTER

Douglas Jester states that the following information is true and accurate to the best of my knowledge and belief:

1. I am the Managing Partner of 5 Lakes Energy, a clean-energy consulting firm. Previously, I served in various roles in Michigan state government and in the private sector. I began my career in ecosystem modeling, working for the State of Michigan from 1977 to 1999. In 2011, I cofounded 5 Lakes Energy.
2. I have a masters degree in statistics from Virginia Polytechnic Institute & State University and completed coursework for a Ph.D. in Environmental Economics from Michigan State University. I am a frequent expert witness before the Michigan Public Service Commission (MPSC).
3. I have used the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) regularly in my work, in part because the MPSC requires utilities in Michigan to use the COBRA tool to develop integrated resource plans.
4. The COBRA tool is a web-based model developed and maintained by the U.S. Environmental Protection Agency (EPA) to model the co-benefits of reductions in greenhouse gasses.[1] Those co-benefits are the benefits to public health due to reductions in co-pollutants, namely $PM_{2.5}$, NOx, SO_2, and VOCs.
5. The COBRA tool allows for the modeling of health impacts over time, based on emissions over a particular year. The model allows a user to specify particular scenarios of emission controls. It is available at: https://cobra.epa.gov/.
6. I am aware of the Department of Energy order directing the continued operation of the R. M. Schahfer Generating Station Units 17 and 18 (the "Order").
7. To estimate the health impacts of running the R. M. Schahfer Generating Station Units 17 and 18 during the period of the Order, I used the COBRA tool as follows.
8. I first selected the relevant county in Indiana—Jasper County.
9. I then identified the relevant sector—Fuel Combustion: Electric Utility—and subsector—Coal.

[1] *See* U.S. EPA, User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), Version: 5.2 (March 2025), *https://www.epa.gov/system/files/documents/2025-03/cobra-user-manual-v5.2.pdf*

10. The R. M. Schahfer Units 17 and 18 are the only coal-fueled power plants in Jasper County.
11. I then selected a 100% reduction in each of the relevant pollutants from coal-fueled power plants in Jasper County, Indiana.
12. Together, these parameters reflect the annual emissions reduction due to the closure of R. M. Schahfer Generating Units 17 and 18.
13. Finally, I selected a discount rate—2%.
14. The resulting figures provide an estimate for the health benefits over time of a year's worth of emissions reductions from the closure of the R. M. Schahfer Generating Units 17 and 18.
15. These figures also provide an estimate of the health harms resulting from the continued operation of the R. M. Schahfer Generating Units 17 and 18.
16. According to the COBRA tool, those harms in all contiguous U.S. states include 11-17 excess deaths, as well as hundreds of lost school and work days. In total, the COBRA tool estimates that the total monetized value of health effects are $180 million to $310 million in 2023 dollars.
17. I also filtered the results of the model to show health effects in Michigan only. For Michigan alone, the COBRA model estimates 1.6 – 2.7 excess deaths and monetized health effects of $24 million to $41 million in 2023 dollars.
18. I also filtered the results of the model to show health effects in Illinois. For Illinois, it estimates 2.5 to 4.8 excess deaths and monetized health effects of $38 million to $73.0 million in 2023 dollars.
19. I also filtered the results of the model to show health effects in Minnesota. For Minnesota, the COBRA model estimates 0.07 to 0.13 excess deaths and monetized health effects of $1.2 million to $2 million in 2023 dollars.
20. These estimates of public-health benefits produced by the COBRA tool are based on closing R. M. Schahfer Generating Units 17 and 18 for a year.
21. I understand that the Order prevented the R. M. Schahfer Generating Units 17 and 18 from closing from December 23, 2025, to March 23, 2026.
22. As a rough approximation, the benefits from closing the plant for the three-month period of the Order would be one quarter the benefits of a year-long closure. That would mean approximately 1.0-1.9 deaths and $15.8 million to $29 million monetized health effects across Illinois, Michigan, and Minnesota. Further, based on my experience, I believe the Department of Energy is likely to issue subsequent orders directing continued operation of R. M. Schahfer Generating Units 17 and 18 beyond the period of this initial Order. The Department of Energy has taken that approach regarding the J.H. Campbell power plant in Michigan. This means that the impact of

operating R.M. Schahfer Generating Units 17 and 18, as described herein, will likely exceed that of a quarter-year operation.

23. The exact impacts of operating R. M. Schahfer Generating Units 17 and 18 during any period of time will also depend in part on the time of the year in which it is being operated. That is because demand fluctuates throughout a calendar year. Operations during the summer or winter months (as is the case with the Order), are generally higher use cases compared to the spring and fall.
24. To precisely estimate the harm from the continued operation of the R. M. Schahfer Generating Units 17 and 18, one would need to know, or model, which generation resources are displaced by its operation. Such precision is unrealistic. But it is almost certainly true that most of the generation displaced by the continued operation of R. M. Schahfer Generating Units 17 and 18 comes from natural gas combined cycle plants.
25. The health impacts from running those plants vary depending on location, time of year, and the specific technologies employed by the plant, but they are invariably less than coal. For example, the most recent (2023) marginal emissions intensity data published by MISO indicates marginal emissions of 0.67 Lbs NO_x/MWh, 1,020 Lbs CO_2/MWh and 0.62 Lbs SO_2/MWh. These figures compare favorably to the emissions intensity of the R. M. Schahfer Units 17 and 18, which is 1.37 lbs NO_x/MWh,.2,010 Lbs CO_2/MWh, and 0.43 4 Lbs SO_2/MWh as reported in EPA's Clean Air Markets Program Data (https://campd.epa.gov/data/custom-data-download).
26. Accordingly, I can conclude that the continued operation of R. M. Schahfer Generating Units 17 and 18 will have a net harmful effect on public health in Illinois, Michigan, and Minnesota.

Pursuant to 28 U.S.C. §1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge. Executed on this day of January 22, 2026, in Leelanau Township, Michigan.

Douglas B Jester

Douglas Jester

OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER

NIPSCO
A NiSource Company

October 29, 2025

Martha Clark Mettler
Assistant Commissioner, Office of Water Quality
Indiana Department of Environment Management
100 North Senate Avenue
Indianapolis, IN 46204

Re: Northern Indiana Public Service Company
R. M. Schahfer Generating Station
NPDES Permit NO. IN0053201
Annual Progress Report under 40 CFR 423

Dear Ms. Clark Mettler:

On June 22, 2023, Northern Indiana Public Service Company, LLC (NIPSCO) submitted a Notice of Planned Participation under 40 CFR – Steam Electric Power Generating Point Source Category. Under the Reporting and Recordkeeping Requirements of 40 CFR 423.19(g), NIPSCO is providing an Annual Progress Report on the intended plan to retire Units 17 and 18 at the R. M. Schahfer Generating Station.

On January 31, 2023, NIPSCO requested a suspension date of December 31, 2025, for Units 17 and 18 from the Midcontinent Independent System Operator, Inc. (MISO). On February 2, 2023, MISO approved the suspension of Units 17 and 18.

As stated in NiSource's Third Quarter 2025 Securities and Exchange Commission (SEC) Form 10-Q Report, "We are continuing to evaluate the development of federal and state executive orders, or other regulatory actions, with respect to our generation transition plans. Absent a directive to remain open, we remain on track to retire R.M. Schahfer's remaining two coal units by the end of 2025."

If you have any questions or require additional information, please contact me at (219) 741-6742 or via email at sholcomb@nisource.com.

Sincerely,

Stephen Holcomb
Director, Environmental Policy and Sustainability

cc:
Scott Ireland, Director, U.S. EPA Region 5 Water Division
Paul Higginbotham, Deputy Assistant Commissioner, IDEM Office of Water Quality

Enclosures:
Attachment Y Suspension Notice
MISO's Approval of Attachment Y Suspension Notice

NiSource®

January 31, 2023

Andrew Witmeier
Director Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Dear Mr. Witmeier,

Pursuant to the discussions Northern Indiana Public Service Company LLC ("NIPSCO") had with MISO about moving suspension dates for Schahfer Units 17 and 18, please find enclosed new Attachment Y Notices for the suspension of Schahfer Units 17 and 18.

As shown on the Attachment Y Notices, NIPSCO is requesting a suspension date of December 31, 2025, instead of the currently approved date of May 31, 2023.

The following two individuals are the primary points of contact for NIPSCO:

Andrew S. Campbell
Director Portfolio Planning & Origination
NIPSCO
801 E. 86th Avenue
Merrillville, IN 46410
219.895.0771
andrewcampbell@nisource.com

M. Bryan Little
Assistant General Counsel
NiSource Corporate Services
150 West Market Street
Suite 600
Indianapolis, IN 46204
317.684.4903
blittle@nisource.com

Please let us know if you need any additional information.

Sincerely,

M. Bryan Little

M. Bryan Little
Assistant General Counsel

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 copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

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:
Northern Indiana Public Service Company LLC (NIPSCO)

Name of Market Participant: NIPSCO

Owner's state of organization or incorporation Indiana

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Schahfer Unit 17

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] The unit was interconnected to NIPSCO's transmission system prior to MISO

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 31 [day] of December [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: 2723 E 1500 N Wheatfield, IN 46392

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Schahfer Unit 17	7NIPS.SCHAHP18	423.5	Retire All

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: Ronald E. Talbot

Title: SVP Electric Operations

Date: 1/20/23

Contact Information

Email: rtalbot@nisource.com

Phone: 219.647.5735

STATE OF Indiana

COUNTY OF Lake

Before me, the undersigned authority, this day appeared Ronald E. Talbot, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

"I am an officer of NIPSCO, I am authorized to execute and submit the foregoing notification on behalf of NIPSCO, and the statements contained in such application are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the 31 day of January, 2023

ALEXIS M CARTER
Notary Public - Seal
Porter County - State of Indiana
Commission Number NP0735519
My Commission Expires Aug 15, 2029

Alexis M Carter

Notary Public, State of INDIANA

My Commission expires Aug 15, 2029

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 copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

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:
Northern Indiana Public Service Company LLC (NIPSCO)

Name of Market Participant: NIPSCO

Owner's state of organization or incorporation Indiana

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Schahfer Unit 18

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] The unit was interconnected to NIPSCO's transmission system prior to MISO

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 31 [day] of December [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: 2723 E 1500 N Wheatfield, IN 46392

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Schahfer Unit 18	NIPS.SCHAHP18	423.5	Retire All

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: Ronald E. Talbot

Title: SVP Electric Operations

Date: 1/20/23

Contact Information

Email: rtalbot@nisource.com

Phone: 219.647.5735

STATE OF Indiana

COUNTY OF Lake

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"I am an officer of NIPSCO, I am authorized to execute and submit the foregoing notification on behalf of NIPSCO, and the statements contained in such application are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the 31 day of January, 2023

ALEXIS M CARTER
Notary Public - Seal
Porter County - State of Indiana
Commission Number NP0735519
My Commission Expires Aug 15, 2029

Alexis M Carter

Notary Public, State of INDIANA

My Commission expires Aug 15, 2029

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA TWO-DAY-AIR DELIVERY

February 3, 2023

Ronald E. Talbot
Sr. VP Electric Operations
NIPSCO
801 E. 86th Avenue
Merrillville, IN 46410

Subject: **Approval of Schahfer Units 17 and 18 Attachment Y Suspension Notice**

Dear Mr. Talbot:

On February 1, 2023, Northern Indiana Public Service Company LLC submitted an amended Attachment Y Notice to MISO to move the suspension of Schahfer Units 17 and 18 from May 31, 2023 to December 31, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Schahfer Units 17 and 18 would not result in violations of applicable reliability criteria. Therefore, Schahfer Units 17 and 18 may suspend without the need for the generators to be designated as System Support Resource ("SSR") units as defined in the Tariff.

This letter acknowledges that Northern Indiana Public Service Company LLC will suspend Schahfer Units 17 and 18, effective December 31, 2025. MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

DECLARATION OF DOUGLAS JESTER

Douglas Jester states that the following information is true and accurate to the best of my knowledge and belief:

1. I am the Managing Partner of 5 Lakes Energy, a clean-energy consulting firm. Previously, I served in various roles in Michigan state government and in the private sector. I began my career in ecosystem modeling, working for the State of Michigan from 1977 to 1999. In 2011, I cofounded 5 Lakes Energy.
2. I have a masters degree in statistics from Virginia Polytechnic Institute & State University and completed coursework for a Ph.D. in Environmental Economics from Michigan State University. I am a frequent expert witness before the Michigan Public Service Commission (MPSC).
3. I have used the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) regularly in my work, in part because the MPSC requires utilities in Michigan to use the COBRA tool to develop integrated resource plans.
4. The COBRA tool is a web-based model developed and maintained by the U.S. Environmental Protection Agency (EPA) to model the co-benefits of reductions in greenhouse gasses.[1] Those co-benefits are the benefits to public health due to reductions in co-pollutants, namely $PM_{2.5}$, NOx, SO_2, and VOCs.
5. The COBRA tool allows for the modeling of health impacts over time, based on emissions over a particular year. The model allows a user to specify particular scenarios of emission controls. It is available at: https://cobra.epa.gov/.
6. I am aware of the Department of Energy order directing the continued operation of the F. B. Culley Generating Station Unit 2 (the "Order").
7. To estimate the health impacts of running the F. B. Culley Generating Station Unit 2 during the period of the Order, I used the COBRA tool as follows.
8. I first selected the relevant county in Indiana—Warrick County.
9. I then identified the relevant sector—Fuel Combustion: Electric Utility—and subsector—Bituminous Coal.

[1] *See* U.S. EPA, User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), Version: 5.2 (March 2025), *https://www.epa.gov/system/files/documents/2025-03/cobra-user-manual-v5.2.pdf*

10. There are 6 coal-fueled generating units in Warrick County: F. B. Culley Units 2 and 3, and AGC's Warrick Units 1, 2, 3, and 4. COBRA does not provide for direct selection of an emissions source, necessitating external data to determine the emissions from F. B. Culley Unit 2.
11. F. B. Culley Generating Unit emissions are reported as aggregate emissions by all units in EPA's Clean Air Markets Program Data (https://campd.epa.gov/data/custom-data-download). The average annual emissions by the F. B. Culley Generating Unit in calendar years 2023, 2024, and 2025 were 1328.5 short tons SO2, 1,869,959 short tons CO2, and 1,261 short tons NOx from average annual generation of 1,548,105 MWh in the same years. EIA Form 923 data for 2023 and 2024 and for 2025 through October (https://www.eia.gov/electricity/data/eia923/) show that over that period Unit 2 generation averaging 168,409 MWh per calendar year was about 11% of total generation from the F. B. Culley Generating Unit. I therefore attribute 11% of F. B. Culley Generating Unit emissions as reported in EPA's Clean Air Markets Program Data to Unit 2, which is annual average emissions of 146 short tons SO2, 205,695 short tons CO2, and 139 short tons NOx.
12. To estimate PM2.5, NH3, and volatile organic carbon (VOC) emissions by F. B. Culley Generating Unit 2, I multiplied the annual average generation by that unit, 168,409 MWh, by its average annual heat rate of 11.79 MMBtu/MWh, and the emissions intensity factors reported by EPA eGRID documentation (https://www.epa.gov/egrid/egrid-pm25), which are 0.2405 lbs PM2.5/MMBtu, 0.0000000505973 lbs NH3/MMBtu, and 0.021254188 lbs VOC/MMBtu which yielded Unit 2 emissions per calendar year of 238.8 tons PM 2.5, 0.1 lbs NH3, and 21.1 tons VOC. I consider the NH3 emissions to be negligible and did not model its effects in COBRA.
13. Together, these parameters reflect the annual emissions reduction due to the closure of F. B. Culley Generating Unit 2..
14. Finally, I selected a discount rate—2%.
15. The resulting figures provide an estimate for the health benefits over time of a year's worth of emissions reductions from the closure of the F. B. Culley Generating Unit 2.
16. These figures also provide an estimate of the health harms resulting from the continued operation of the F. B. Culley Generating Unit 2.
17. According to the COBRA tool, those harms in all contiguous U.S. states include 3.8-7.2 excess deaths, as well as hundreds of lost school and work

days. In total, the COBRA tool estimates that the total monetized value of health effects are \$58 million to \$120 million in 2023 dollars.

18. I also filtered the results of the model to show health effects in Michigan only. For Michigan alone, the COBRA model estimates 0.19 – 0.38 excess deaths and monetized health effects of \$2.9 million to \$5.6 million in 2023 dollars.
19. I also filtered the results of the model to show health effects in Illinois. For Illinois, it estimates 0.35 to 0.72 excess deaths and monetized health effects of \$5.4 million to \$11.0 million in 2023 dollars.
20. I also filtered the results of the model to show health effects in Minnesota. For Minnesota, the COBRA model estimates 0.1 to 0.2 excess deaths and monetized health effects of \$0.17 million to \$0.32 million in 2023 dollars.
21. These estimates of public-health benefits produced by the COBRA tool are based on closing F. B. Culley Generating Unit 2 for a year.
22. I understand that the Order prevented the F. B. Culley Generating Unit 2 from closing from December 23, 2025, to March 23, 2026.
23. As a rough approximation, the benefits from closing the plant for the three-month period of the Order would be one quarter the benefits of a year-long closure. That would mean approximately 0.16-0.325 deaths and \$2.12 million to \$4.23 million monetized health effects across Illinois, Michigan, and Minnesota. Further, based on my experience, I believe the Department of Energy is likely to issue subsequent orders directing continued operation of F. B. Culley Generating Unit 2 beyond the period of this initial Order. The Department of Energy has taken that approach regarding the J.H. Campbell power plant in Michigan. This means that the impact of operating F. B. Culley Generating Unit 2, as described herein, will likely exceed that of a quarter-year operation.
24. To precisely estimate the harm from the continued operation of the F. B. Culley Generating Unit 2, one would need to know, or model, which generation resources are displaced by its operation. Such precision is unrealistic. But it is almost certainly true that most of the generation displaced by the continued operation of F. B. Culley Generating Unit 2 comes from natural gas combined cycle plants.
25. The health impacts from running those plants vary depending on location, time of year, and the specific technologies employed by the plant, but they are invariably less than coal. For example, the most recent (2023) marginal emissions intensity data published by MISO indicates marginal emissions of 0.67 Lbs NOx/MWh, 1,020 Lbs CO_2/MWh and 0.62 Lbs SO_2/MWh. These figures compare favorably to the emissions intensity of the F. B. Culley

Generating Unit 2, which is 1.65 lbs NOx/MWh,.2,443 Lbs CO2/MWh, and 1.74 Lbs SO2/MWh as reported in EPA's Clean Air Markets Program Data (https://campd.epa.gov/data/custom-data-download).

26. Accordingly, I can conclude that the continued operation of the F. B. Culley Generating Unit 2 will have a net harmful effect on public health in Illinois, Michigan, and Minnesota.

Pursuant to 28 U.S.C. §1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge. Executed on this day of January 22, 2026, in Leelanau Township, Michigan.

Douglas B Jester

____

Douglas Jester

NEWS

October 21, 2021

NIPSCO Continues Path Toward Lower-Cost, Sustainable and Reliable Energy Future

Back to News List (https://www.nipsco.com/our-company/news-room)

Chat with us

Solar panels and wind turbines in a field of grass and blue sky

Northern Indiana Public Service Company LLC (NIPSCO), a subsidiary of NiSource Inc. (NYSE: NI), today announced its refined plans for the future of its electric generation portfolio as part of the 2021 Integrated Resource Plan (IRP) public advisory process.

The company identified a Preferred Energy Resource Plan that refines the timeline to retire the Michigan City Generating Station to occur between 2026 and 2028. The Plan calls for the replacement of the retiring units with a diverse portfolio of resources including Demand Side Management resources, incremental solar, stand-alone energy storage and upgrades to existing facilities at the Sugar Creek Generating Station, among other steps. Additionally, the plan calls for a natural gas peaking unit to replace existing vintage gas peaking units at the R.M. Schahfer Generating Station to support system reliability and resiliency, as well as upgrades to the transmission system to enhance its electric generation transition.

Importantly, this plan does not alter NIPSCO's previously stated goal of a 90 percent reduction in carbon emissions (from a 2005 baseline) by 2030.

"We're on an industry-leading path to shift toward lower-cost and reliable forms of energy for our customers," said Mike Hooper, NIPSCO president. "As we continue this journey, we recognize the importance of maintaining a diverse energy portfolio that enables flexibility to adapt to evolving market rules, policy and technology advancements, while providing additional time for continued research and refinement of our long-term energy strategy. Meanwhile, careful consideration for how this transition affects our workforce and local communities is a critical focus area as the plan continues to move forward."

NIPSCO outlined the options considered for its long-term electric generation plans at a public meeting today with customers, consumer representatives, environmental organizations, regulators and other stakeholders taking part in the company's Integrated Resource Plan (IRP) – a regulatory process used in Indiana and other states to thoroughly evaluate and outline how electric utilities plan to serve customers' energy needs in the future.

NIPSCO considered a full spectrum of future scenarios as part of its analysis. Included was a request for proposals (RFP) solicitation that provided concrete data across a variety of technologies and understanding around the landscape of available projects to help inform the IRP process.

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 Generating Station unit 12 to occur between 2026 and 2028. The remaining coal units at the R.M. Schahfer Generating Station are on track to retire by 2023 as previously announced. NIPSCO operates two vintage gas peaking units – Units 16A and 16B – at the Schahfer Generating Station which were also announced to retire between 2025 and 2028.

NIPSCO plans to continue incorporating the already announced wind, solar and solar plus storage replacement resources for the scheduled 2023 retirement of the Schahfer coal generation.*

Additionally, the company may pursue potential hydrogen pilots and other emerging storage technologies identified as potential pathways toward further Decarbonization of the generation portfolio in the long term.

With enhancing reliability of the system a top priority. The Preferred Plan has identified a number of transmission upgrades to be completed in advance of the retirement of the Michigan City Generating Station. Work on those projects will begin in 2022 to align with the refined retirement timing.

During today's public meeting, NIPSCO leaders stressed the importance of stakeholder feedback in the IRP process. The company has been – and will continue – working with stakeholders and regulators to solicit input as NIPSCO finalizes the plans prior to submitting to the IURC by Nov. 15, 2021.

Current Project Profile List

NIPSCO continues to make progress on its 14 previously announced renewable energy projects* including wind, solar and solar plus battery resources, which are all expected to be completed between now and the end of 2023.

These projects were selected following a comprehensive review of bids submitted through the all-source RFP process that NIPSCO conducted in 2018 and again in late 2019 – which continues to affirm the conclusions of the 2018 NIPSCO IRP, that wind and solar resources were shown to be lower-cost options for customers compared to today's energy mix. Projects are listed with estimated in-service dates.

- Rosewater Wind Farm – 102 MW of wind, located in White County, Ind. (Complete)
- Jordan Creek Wind – 400 MW of wind, located in Benton and Warren counties, Ind. (Complete)
- Indiana Crossroads I Wind – 300 MW of wind, located in White County, Ind. (2021)
- Dunns Bridge Solar I – 265 MW of solar, located in Jasper County, Ind. (2022)
- Indiana Crossroads Solar – 200 MW of solar, located in White County, Ind. (2022)
- Brickyard Solar – 200 MW of solar, located in Boone County, Ind. (2022)
- Greensboro Solar – 100 MW of solar and 30 MW of battery storage, located in Henry County, Ind. (2022)
- Green River Solar – 200 MW of solar, located in Breckinridge and Meade counties, Ky. (2023)
- Dunns Bridge Solar II – 435 MW of solar and 75 MW of battery storage, located in Jasper County, Ind. (2023)
- Cavalry Solar – 200 MW of solar and 60 MW of battery storage, located in White County, Ind. (2023)
- Gibson Solar – 280 MW of solar, located in Gibson County, Ind. (2023)
- Fairbanks Solar – 250 MW of solar, located in Sullivan County, Ind. (2023)
- Indiana Crossroads II Wind – 204 MW of wind, located in White County, Ind. (2023)
- Elliott Solar – 200 MW of solar, located in Gibson County, Ind. (2023)

These projects have been approved by the Indiana Utility Regulatory Commission (IURC). NIPSCO has invested in these projects through a variety of commercial agreements including joint ventures and power purchase agreements that take full advantage of federal tax credits to our customers benefit.

Today's announcement is part of the company's customer-centric "Your Energy, Your Future" initiative, which includes the generation transition plan at NIPSCO. Learn about NIPSCO's "Your Energy, Your Future" plans and the latest information at NIPSCO.com/future. More information about NIPSCO's electric supply strategies and the IRP process can be found at NIPSCO.com/IRP.

**NIPSCO may sell the "Renewable Energy Credits" from this generation to a third party because this helps keep our energy more affordable for our customers.*

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