BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 100A
NIPSCO 2024 IRP
Part 1

150 West Market Street, Suite 600
Indianapolis, IN 46204

December 9, 2024

Via Email Delivery – bborum@urc.in.gov

Dr. Brad Borum, Director
Research, Policy and Planning Division
Indiana Utility Regulatory Commission
PNC Center
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204

Re: Northern Indiana Public Service Company LLC
2024 Integrated Resource Plan

Dear Dr. Borum:

In accordance with 170 IAC 4-7 ("IRP Rules"), Northern Indiana Public Service Company LLC ("NIPSCO") is submitting via email transmission its redacted Integrated Resource Plan ("IRP") (Volume 1). NIPSCO's IRP reflects the assessment of supply- side and demand-side resources to meet NIPSCO's customers' electric service needs.

The nonredacted version of NIPSCO's IRP is the subject of a petition being filed contemporaneous with this email transmission of the redacted version of its IRP. Once NIPSCO has received approval for confidential treatment of its IRP, a nonredacted version will be submitted under seal. This procedure is at the request of the Commission staff.

By copy of this letter, NIPSCO is providing to the Commission the information required by 170 IAC 4-7-2(c). The organizations or individuals NIPSCO considered to be interested parties are included on an enclosure included with this letter. This list was determined based on organizations or individuals that participated in NIPSCO's IRP process.

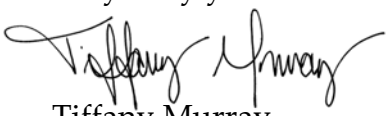
By copy of this letter, which NIPSCO is sending via electronic mail, NIPSCO notifies the interested parties that it has submitted an IRP to the Commission that is generally described above and the redacted copy of NIPSCO's IRP can be viewed / downloaded at https://www.nipsco.com/irp. The Commission invites an interested party

to submit written comments on NIPSCO's submitted IRP. The Commission will provide notice of the IRP and the due date for the submission of written comments pursuant to the publication requirements of Ind. Code § 8-1-1-8. 170 IAC 4-7-2.2 provides for a ninety (90) day period, or longer as determined by the Commission, to submit written comments.

In accordance with 170 IAC 4-7-2(d)(3), NIPSCO is serving via email transmission its redacted IRP (Volume 1) on the Indiana Office of Utility Consumer Counselor ("OUCC"). A nonredacted copy of NIPSCO's IRP (Volume 2) is also being provided to the OUCC pursuant to the Standard Form Nondisclosure Agreement between NIPSCO and the OUCC dated August 6, 2006.

NIPSCO has submitted an IRP that is intended to contain the information required by the Commission's IRP Rules. If the Commission, its Staff, or any interested party believes that NIPSCO's IRP needs clarification in some respect, please contact Erin Whitehead at (317) 965-8334 or via email at ewhitehead@nisource.com

Very truly yours



Tiffany Murray

Enclosures

Contact First Name	Contact Last Name	Contact Email Address	Company
Denise	Abdul-Rahman	darahman17@gmail.com	Indiana State Conference of the NAACP
Denise	Abdul-Rahman	denise@blacksunlight.org	Black Sun Light Sustainability
Denise	Abdul-Rahman	darahman17@gmail.com	Indiana NAACP
Levy	Agaronnik	Levy.agaronnik@blackstone.com	Blackstone
Shannon	Anderson	shannon@earthcharterindiana.org	Earth Charter Indiana
Cynthia	Armstrong	carmstrong@oucc.in.gov	Indiana OUCC
Laura	Arnold	Laura.Arnold@IndianaDG.net	Indiana Distributed Energy Alliance
Pat	Augustine	paugustine@crai.com	Charles River Associates
Ryan	Baker	Ryanbaker@usw12775.org	
Quinn	Beckham	quinn.beckham@keycaptureenergy.com	Key Capture Energy
Michael	Beeler	mbeeler@urc.in.gov	IURC
Amanda	Bersing	amanda.bersing@wellsfargo.com	Wells Fargo Securities
Geraldine	Black	babygirlhosea@gmail.com	
Marc	Blanchard	marc.blanchard@bp.com	BP
Alexandra	Boillot Navin	alexandra@rangerpower.com	Ranger Power
Jean	Boling	jboling1@urc.IN.gov	Indiana Utility Regulatory Commission
Bradley	Borum	bborum@urc.in.gov	IURC
Drew	Burczyk	dcburczyk@burnsmcd.com	Burns and McDonnell
Jonathan	Burke	jburke@tac.nrg.com	Tactical Energy Group, Inc.
Taylor	Carpenter	tcarpenter@calfee.com	Calfee
Gilles	Charriere	Gillescharriere@yahoo.com	
Chris	Chyung	chris@inconservationvoters.org	ICV
Richie	Ciciarelli	rciciarelli@veritionfund.com	Verition
Christine	Colon	colongar@aol.com	
Jordan	Covely	jordan.covely@inovateus.com	Inovateus Solar LLC
Joan	Crist	cristjoan1@gmail.com	
Anaelle	Croteau	acroteau@advantagecap.com	AdvantageCapital
Garrett	Culp	gculp@indianaenergy.org	Indiana Energy Association
Bruna	da Silva	bruna.dasilva@keycaptureenergy.com	Key Capture Energy
Roy	Dell'Aquila	ROYDELLAQUILA@YAHOO.COM	
Lou	Donkle	donkle3@gmail.com	none
Paul	Dort	paul.dort@edp.com	EDP Renewables North America
Sameer	Doshi	sdoshi@earthjustice.org	Earthjustice
Carol Sparks	Drake	CaDrake@oucc.IN.gov	Indiana Office of Utility Consumer Counselor
Cory	Dutcher	cory.dutcher@ge.com	GE Vernova / GE Gas Power
Stephen	Dynako	dynako@gmail.com	Stephen Dynako
Michael	Eckert	meckert@oucc.in.gov	OUCC
Suzanne	Escudier	suzanne.escudier@origisenergy.com	Origis Energy
Hadiza	Felicien	hfelicien@formenergy.com	Form Energy
Brian	Flory	bflory@solarunitedneighbors.org	Solar United Neighbors
McKenzie	Fowler	mfowler@crai.com	CRA
Steve	Francis	Sierrasteve@comcast.net	SEED - Sustainable Energy and Economic Development
Ray	Fu	rfu@bamfunds.com	Balyasny
Erik	Gage	egage@nationalgridrenewables.com	National Grid Renewables
Aditya	Gandhi	agandhi@wolferesearch.com	Wolfe Research
Eliza	Gedney	elizagedney@gmail.com	CRA
Aidan	Gibbons	agibbons@crai.com	Charles River Associates
Lucas	Giese	lugiese@iu.edu	
Richard	Gillingham	rgillingham@hepn.com	Hoosier Energy
Elena	Gomez	elena.gomezescalonilla@x-elio.com	X-ELIO
Elena	Gomez	elena.gomezescalonilla@x-elio.com	X-ELIO
Emma	Goodnow	emma.goodnow@duke-energy.com	Duke Energy
Doug	Gotham	gotham@purdue.edu	State Utility Forecasting Group
Kimberly	Graham	akgraham7@comcast.net	
Donald JACK	Groves	poweresi@comcast.net	ENERGY SOUTHWEST INC.
Karen S	Hall	Karen.Hall2@duke-energy.com	Duke Energy
Leslie	Hamby	leslie.hamby@centerpointenergy.com	CenterPoint Energy
John	Hanks	Jhanks@oucc.in.gov	OUCC
Michael	Hardie	michael.hardie@aes.com	AES Indiana
Frank	He	fhe@orionrenewables.com	

Contact First Name	Contact Last Name	Contact Email Address	Company
Steph	Hodgin	stehodgin@urc.in.gov	IURC
Chelsea	Hotaling	chotaling@energyfuturesgroup.com	Energy Futures Group
James	Huston	jhuston1@urc.in.gov	IURC
Ben	Inskeep	binskeep@citact.org	Citizens Action Coalition
John	Isaac	john.isaac@leewardenergy.com	2/2/2024
Evan	Iskenderian	evan@rangerpower.com	Ranger Power
David	Jackson	djackson@flexgen.com	Flexgen, Inc.
Jeff	James	jjames@savionenergy.com	Savion, LLC
Christopher	Jeffrey	christopher.jeffrey@mizuhogroup.com	Mizuho Securities
Alexandra	Jones	ajones@boselaw.com	Bose, McKinney, & Evans LLP
Michelle	Kang	michelle.kang@earthriseenergy.com	Earthrise Energy, PBC
Kelley	Karn	kelley.karn@duke-energy.com	Duke Energy
Tony	Kazakevicius	tkaz@anacostia.com	Chicago South Shore & South Bend Railroad
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Patrick	Kelley	PKelley@oucc.in.gov	OUCC
Genevieve	Kennedy	genevieve.kennedy@leewardenergy.com	Leeward Renewable Energy
Will	Kenworthy	will@votesolar.org	Vote Solar
Nick	Kile	Nicholas.kile@btlaw.com	Barnes & Thornburg
Mo	Klefeker	mklefeker@primaryenergy.com	Primary Energy
Tim	Koenning	tkoenning@npca.org	
Gregory	Krieger	gkrieger@oucc.in.gov	Indiana OUCC
Nikhil	Kumar	nikhil@gridlab.org	GridLab
Reagan	Kurtz	rkurtz@citact.org	Citizens Action Coalition of Indiana, Inc.
Brian	Latham	blatham@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Derek	Leader	dleader@oucc.in.gov	OUCC
Robert	Leah	bleah@nationalgridrenewables.com	National Grid Renewables
Robert	Lee	rlee@crai.com	Charles River Associates
Max	Lee	max.lee@edp.com	EDP Renewables
Sally	Lei	sally.lei@nexteraenergy.com	Nexetra Energy Resources
Michael	Leikin	mike.leikin@electrotempo.com	ElectroTempo
Spark	Li	sli8@jefferies.com	Jefferies
Jeff	Lichy	jlichy@bluegrottocapital.com	blue grotto
Edward	Locigno	ejlocigno@aep.com	Indiana Michigan Power Company
Arthur	Longthorne	Alongthorne@solscient.com	Solscient Energy
Earl	M Miller	emiller@hilerindustries.com	Accurate Castings, Inc.(Hiler Ind.)
Sunil	Maheshwari	mahesh67@purdue.edu	Purdue University
Bill	Malcolm	wmalcolm@aarp.org	AARP
Jeremy	Martin	jeremy.martin@centerpointenergy.com	CenterPoint Energy
Davis	McCourt	davis@rangerpower.com	Ranger Power
Emily	Medine	emedine@evainc.com	Energy Ventures Analysis, Inc.
Zachary	Melda	zachary.melda@nexteraenergy.com	NextEra energy
Dan	Mellinger	dmellinger@energyfuturesgroup.com	Energy Futures Group
Tony	Mendoza	tony.mendoza@sierraclub.org	Sierra Club
Erik	Miller	erik.miller@aes.com	AES
Bryan	Mills	bryan.mills@nexteraenergy.com	NextEra Energy Resources
Alan	Mok	alan.mok@duke-energy.com	Duke Energy
Mike	Mooney	mmooney@hepn.com	Hoosier Energy
Joe	Motuliak	joe.motuliak@nee.com	NextEra Energy Resources
Edwin	Moyo	emoyo@crai.com	CRA International
David	Nderitu	nderitu@purdue.edu	State Utility Forecasting Group
Kay	Nelson	knelson@nwiforum.org	Northwest Indiana Forum
Ren	Norman	rnorman@urc.in.gov	Indiana Utility Regulatory Commission
Christopher	Norrick	cnorrick@solarunitedneighbors.org	Solar United Neighbors
Jessica	Nyquist	jnyquist@formenergy.com	Form Energy
Kerwin	Olson	kolson@citact.org	Citizens Action Coalition
lois	osborn	bornsoil@gmail.com	
Nadia	Pabst	NPabst@aypa.com	Aypa Power
April	Paronish	aparonish@oucc.in.gov	Indiana Office of Utility Consumer Counselor
Richard	Pate	rgpate@pateassociates.com	Pate & Associates
Harshil	Patel	harshil.patel@leewardenergy.com	Leeward Renewable Energy

Contact First Name	Contact Last Name	Contact Email Address	Company
Mary	Perren	mary.perren@gmail.com	Hoosier Solar
Matthew	Peterson	Matthew.Peterson@duke-energy.com	Duke Energy
Ryan	Pfefferle	rypfefferle@microsoft.com	Microsoft
Tim	Phillips	timphillips@purdue.edu	State Utility Forecasting Group
Timothy	Powers	tim.powers@inovateus.com	Inovateus Solar LLC
Govind	Ramakrishnan	govind.ramakrishnan@blackstone.com	Blackstone
Tolaver	Rapp	tolaver.rapp@clevelandcliffs.com	Cleveland-Cliffs
Greg	Reiss	greiss@veritionfund.com	
Matt	Rice	matt.rice@centerpointenergy.com	CenterPoint Energy
Thomas	Rickabaugh	thomas.rickabaugh@edf-re.com	EDF Renewables
Chad	Ritchie	chad.ritchie@oracle.com	Oracle
Stephen	Rodocanachi	srodo@hartreepartners.com	Hartree Partners, LP
Colleen	Rosales	cmfrosales@gmail.com	OpenAQ / University of California in Davis
Roopali	Sanka	rsanka@oucc.in.gov	OUCC
Maxwell	Santiago	maxsanti@iu.edu	
David	Savage	dsavage@urc.in.gov	Indiana Utility Regulatory Commission
Zach	Schalk	Zach@solarunitedneighbors.org	Solar United Neighbors
Andrea	Schroeder	andrea.schroeder@engie.com	ENGIE
Carter	Scott	carter@rangerpower.com	Ranger Power LLC
Donnita	Scully	donnita4sfhs@hotmail.com	NAACP LaPorte County Branch
Zico	Shaker	zico.shaker@leewardenergy.com	Leeward Renewable Energy
Sebastien	Sherman	Sebastien.Sherman@Blackstone.com	Blackstone
Joshua	Siegel	joshua.siegel@bp.com	BP
Mark	Simons	mcsimons803@gmail.com	MCSimons Inc
Regiana	Sistevaris	rsistevaris@aep.com	I&M
Steven	Smith	smiste@mac.com	Franklin Covey
Jesse	Smith	jsmith@demandsideanalytics.com	Demand Side Analytics, LLC
Jeffrey	Solomon	jsolomon@savionenergy.com	Savion LLC
Anna	Sommer	asommer@energyfuturesgroup.com	Energy Futures Group
Oliver	Stover	ostover@crai.com	CRA
Spencer	Summers	ssummers@nwiforum.org	Northwest Indiana Forum
Joshua	Swanson	joshua.swanson@centerpointenergy.com	CenterPoint Energy
Will	Talbott	wtalbott@aypa.com	Aypa Power
Dale	Thomas	dthomas@urc.in.gov	IURC
Susan	Thomas	Susan@jtnwi.org	Just Transition NWI
Quintin	Thompson	quintin.thompson@aes.com	AES IN
Edward	Twarok	ehtwarok@comcast.net	Retired
Gregory	Va Horssen	gvhorssen@vanhorssenlaw.com	Van Horssen Law & Government, PLLC
Marco	Velastegui	mvelaste@purdue.edu	Purdue
Nathan	Vogel	nathan.vogel@inovateus.com	Inovateus Solar LLC
Connor	Ward	cward@advantagecap.com	Advantage Capital
Jennifer	Washburn	jwashburn@citact.org	Citizens Action Coalition of Indiana
Doug	Wester	doug@nationalgridrenewables.com	National Grid Renewables
Kristina	Wheeler	kwheeler@boselaw.com	Bose McKinney & Evans LLP
Andy	White	andrew.white@leewardenergy.com	LRE
Theodore	Why	twhy@crai.com	Charles River Associates
Ryan	Wilhelmus	ryan.wilhelmus@bigrivers.com	Big Rivers Electric Corporation
Rachel	Wilson	rwilson@formenergy.com	Form Energy
Luke	Wilson	LuWilson@urc.IN.gov	Indiana Utility Regulatory Commission
Brian	Wright	brwright@oucc.in.gov	OUCC
J. Scott	Yaeger	scott.yaeger@rocklandcapital.com	Rockland Capital
Gilbert	Zelaya	gzelaya@earthjustice.org	Earthjustice
Micheal	Zhang	micheal.zhang@blackstone.com	Blackstone

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.

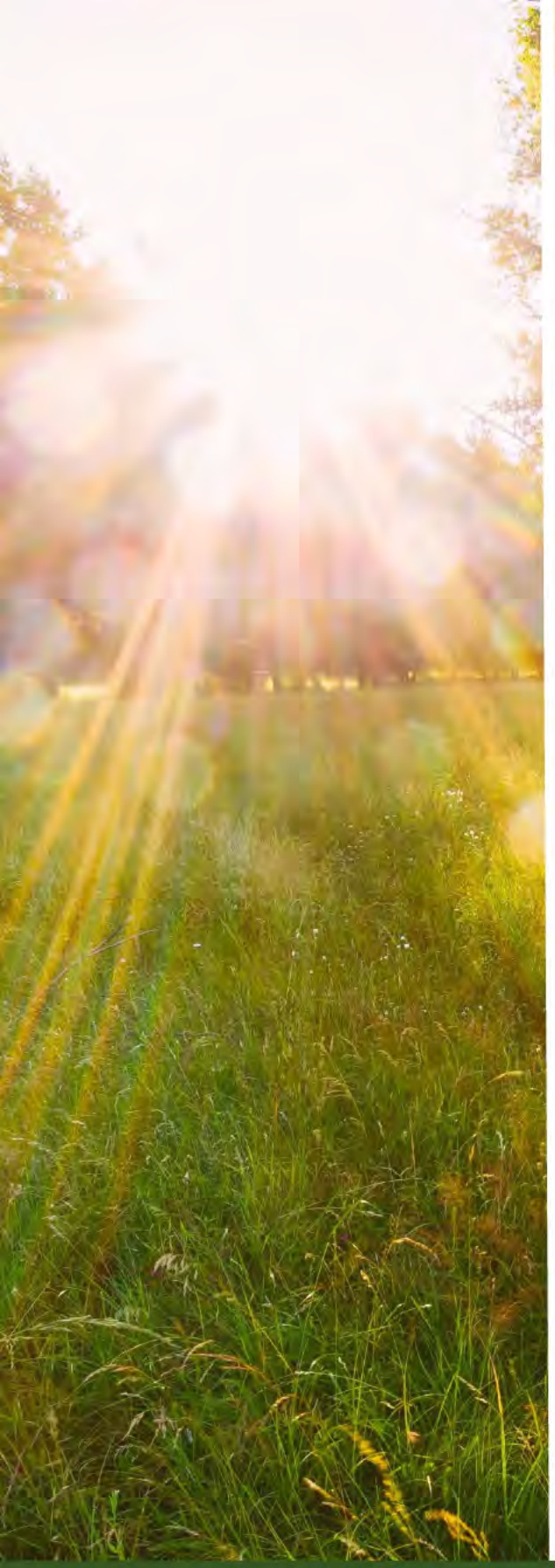
Since NIPSCO introduced our last plan in 2021, we've continued to build out our electric generation portfolio with the completion of wind, solar, and storage projects and gained regulatory approval for our natural gas peaking resource that will be located at the R.M. Schahfer Generating Station property. 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 me hodology for calculating and awarding capacity value to generating facilities. This new me hod 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 wi hout 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 wi hout new data center load

Northern Indiana Public Service Company LLC

2024
Integrated Resource Plan

December 9, 2024

Table of Contents

Section 1. Integrated Resource Plan Summary 1
1.1 Short-Term Action Plan 1
1.2 Plan Summary 4
1.3 Emerging Issues 5
1.3.1 Market Rules Uncertainty 5
1.3.2 Policy Uncertainty 6
1.3.3 Technology Uncertainty 6
Section 2. Planning for the Future 8
2.1 IRP Public Advisory Process 8
2.1.1 Stakeholder Meeting 1 8
2.1.2 Stakeholder Meeting 2 9
2.1.3 Stakeholder Meeting 3 10
2.1.4 Stakeholder Meeting 4 10
2.1.5 Stakeholder Meeting 5 10
2.2 Other Stakeholder Input Since NIPSCO's Last IRP 11
2.2.1 IURC Contemporary Issues 11
2.2.2 2021 IRP Feedback and 2024 Process Improvement Efforts 12
2.2.3 Equitable Transition 13
2.3 Overall IRP Approach 13
2.3.1 Step 1: Identify Planning Objectives and Key Questions 16
2.3.2 Step 2: Develop Market Perspectives 21
2.3.3 Step 3: Develop Integrated Resource Strategies 25
2.3.4 Step 4: Portfolio Modeling 27
2.3.5 Step 5: Evaluate Tradeoffs and Produce Recommendations 27
Section 3. Energy and Demand Forecast 28
3.1 Introduction and Major Highlights of the Forecast 28
3.2 Forecasting Methodology Overview 29
3.3 Base Customer Count, Electric Energy, and Peak Demand Forecast 30
3.3.1 Data Gathering, Weather Normalization, and Econometric Modeling 30

3.3.2 Industrial Service Structure....34
3.3.3 Customer Count Forecast....34
3.3.4 Sales per Customer and Total Electric Sales Forecast....36
3.3.5 Peak Load Forecast Development....37
3.4 Electric Vehicles....39
3.4.1 Methodology Overview....39
3.4.2 Core Data Source Inputs....39
3.4.3 Light Duty Vehicles....40
3.4.4 MDV and Transit Vehicles....50
3.4.5 Heavy-Duty Vehicles....57
3.4.6 Corridor Charging....57
3.4.7 Electric Vehicle Forecast Results....65
3.5 Customer-Owned DERs....67
3.5.1 Existing Solar Distributed Energy Resources....67
3.5.2 Customer-Owned Distributed Energy Resource Projections....71
3.5.3 Key Input Assumptions....72
3.6 Large Economic Development Loads....79
3.7 All-in Load Summary....81
3.8 Scenario Analysis....83
3.8.1 Economic Variables....84
3.8.2 Electric Vehicles....84
3.8.3 Distributed Energy Resources....84
3.8.4 Other Electrification....84
3.8.5 Industrial Load Risk....85
3.8.6 Conversion from Sales to Peak....86
3.8.7 Scenario Results....87
3.9 Detailed Forecast Results....89
Section 4. Supply-Side Resources....102
4.1 Existing Resources....102
4.1.1 Michigan City....103
4.1.2 Schahfer....103
4.1.3 Sugar Creek....104

4.1.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources) 105
4.1.5 NIPSCO Wind and Solar Purchase Power Agreements and Joint Venture 106
4.1.6 Total Resource Summary 109
4.2 Fuel, Energy, and Capacity Procurement Strategy for Existing Resources 110
4.2.1 Coal Procurement and Inventory Management Practices 110
4.2.2 Natural Gas Procurement and Management 114
4.2.3 Electric Generation Gas Supply Request for Proposal Process 115
4.3 Planned Resource Summary 115
4.3.1 Planned Wind Resources 115
4.3.2 Planned Solar and Solar + Storage Resources 116
4.4 MISO Wholesale Electricity Market 119
4.4.1 Operations Management and Dispatch Implications 119
4.5 Resource Adequacy and Current Supply-Demand Balance 119
4.6 Future Resource Options 120
4.6.1 Request for Proposal 121
4.6.2 Incorporation of the RFP Results into the IRP 125
4.6.3 Longer-Term New Resource Assumptions – Mature Technologies 128
4.6.4 Emerging Technologies – Hydrogen 131
4.6.5 Emerging Technologies – Renewable Natural Gas 136
4.6.6 Emerging Technologies – Carbon Capture, Utilization, and Storage 136
4.6.7 Emerging Technologies – Long-Duration Energy Storage 142
4.6.8 Emerging Technologies – Small Modular Reactors 147
4.6.9 Long-Term Uncertainties with Emerging Technologies 152
4.6.10 Federal Tax Incentives for Clean Energy Resources 152
Section 5. Demand-Side Resources 155
5.1 Existing Resources 155
5.1.1 Existing Energy Efficiency Resources 155
5.1.2 Existing Demand Response Resources 165
5.2 DSM MPS 165

5.2.1 DSM MPS – Purpose and Key Objectives 165
5.2.2 Impact of Opt-out Customers.....166
5.2.3 Modeling Framework.....166
5.2.4 Key Assumptions That Impact Energy Efficiency Potential 166
5.2.5 Energy Efficiency Measures & Potential.....168
5.2.6 DR Potential.....175
5.3 Future Resource Options.....178
5.3.1 Energy Efficiency Bundles 178
5.3.2 DR Programs.....192
5.4 Consistency between IRP and Energy Efficiency Plans.....194
Section 6. Transmission and Distribution System.....196
6.1 Transmission System Planning.....196
6.1.1 Transmission System Planning Criteria and Guidelines.....196
6.1.2 North American Electric Reliability Corporation.....196
6.1.3 Midcontinent Independent System Operator, Inc. 197
6.1.4 Market Participants 198
6.1.5 Customer Driven Development Projects 198
6.1.6 NIPSCO Transmission System Capital Projects.....198
6.1.7 Electric Infrastructure Modernization Plan.....199
6.2 Distribution System Planning 199
6.2.1 Evolving Technologies and System Capabilities.....201
Section 7. Environmental Considerations 203
7.1 Environmental Sustainability.....203
203
7.2 Environmental Compliance Plan Development.....203
7.3 Environmental Regulations.....204
7.3.1 Solid Waste Management 204
7.3.2 Clean Water Act and Effluent Limitations Guidelines (ELG).....204
7.3.3 Clean Air Act 204
7.4 Climate-Related Considerations 205
Section 8. Managing Risk and Uncertainty.....206
8.1 Introduction & Process Overview.....206

8.2 Reference Case Market Drivers and Assumptions 207
8.2.1 Natural Gas Prices 207
8.2.2 Coal Prices 213
8.2.3 Carbon Emission Regulation 215
8.2.4 MISO Energy and Capacity Prices 216
8.3 Defining Risk and Uncertainty Drivers and Scenario and Stochastic Treatment 221
8.4 IRP Scenarios 223
8.4.1 Scenario Overview 223
8.4.2 Slower Transition Scenario 224
8.4.3 Domestic Resiliency Scenario 226
8.4.4 Aggressive Environmental Regulation Scenario 228
8.4.5 Accelerated Innovation Scenario 231
8.4.6 Scenario Comparisons 233
8.5 Stochastic Modeling and Analysis 241
8.5.1 Stochastic Analysis Motivation and Key Metrics 241
8.5.2 Stochastic Modeling Approach 242
8.5.3 Input Data Development 242
8.5.4 Statistical and Fundamental Analysis 244
Section 9. Portfolio Analysis 250
9.1 Portfolio Development 250
9.1.1 Process Overview 250
9.1.2 Portfolio Concepts 250
9.1.3 Portfolio Optimization Analysis 251
9.1.4 Additional Portfolio Variants 256
9.1.5 DSM Program Selection 258
9.2 Portfolio Evaluation – Scorecard Metrics 260
9.3 Portfolio Evaluation – Analysis Results 261
9.3.1 Reference Case Customer Cost Results 261
9.3.2 Scenario Customer Cost Results 262
9.3.3 Stochastic Analysis Results 267
9.3.4 CO2 Emissions 272
9.3.5 Sensitivity Analysis – Flat Load Growth 275

9.3.6 Sensitivity Analysis – Emerging High Load Growth 279
9.3.1 Sensitivity Analysis – Additional DSM.....281
9.3.2 Scorecard Summary 282
9.4 Preferred Portfolio 284
9.4.1 Preferred Portfolio Summary.....288
9.4.2 Financial Impact.....289
9.4.3 Developments That Will Shape NIPSCO's Preferred Portfolio Implementation 290
9.5 Short-Term Action Plan.....292
9.6 Conclusion 292
Section 10. Customer Engagement 294
10.1 Enhancing Customer Engagement.....294
10.1.1 Leveraging Customer and Stakeholder Feedback.....294
10.1.2 Customer Education – Generation Transition, Energy Efficiency and Assistance 296
10.2 Community Partnerships.....298
10.2.1 Community Advisory Panels 298
10.3 Customer Programs.....298
10.3.1 Feed-in Tariff (FIT) 298
10.3.2 Excess Distributed Generation Tariff 300
10.3.3 Green Power Rider (GPR) Program 301
10.3.4 Green Path Rider Program.....303
10.3.5 Transportation Decarbonization: DC Fast charging stations & IDEM Grant 304
10.3.6 Advanced Metering Infrastructure (AMI) 304
10.3.7 Supporting Economic Growth 305
10.3.8 Supplier Diversity 305
10.3.9 Workforce Development.....305
10.3.10 Corporate Citizenship 308
10.3.11 Targeted Grants.....308
10.3.12 Charitable Giving.....309
Section 11. Compliance with IRP Rule.....311

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

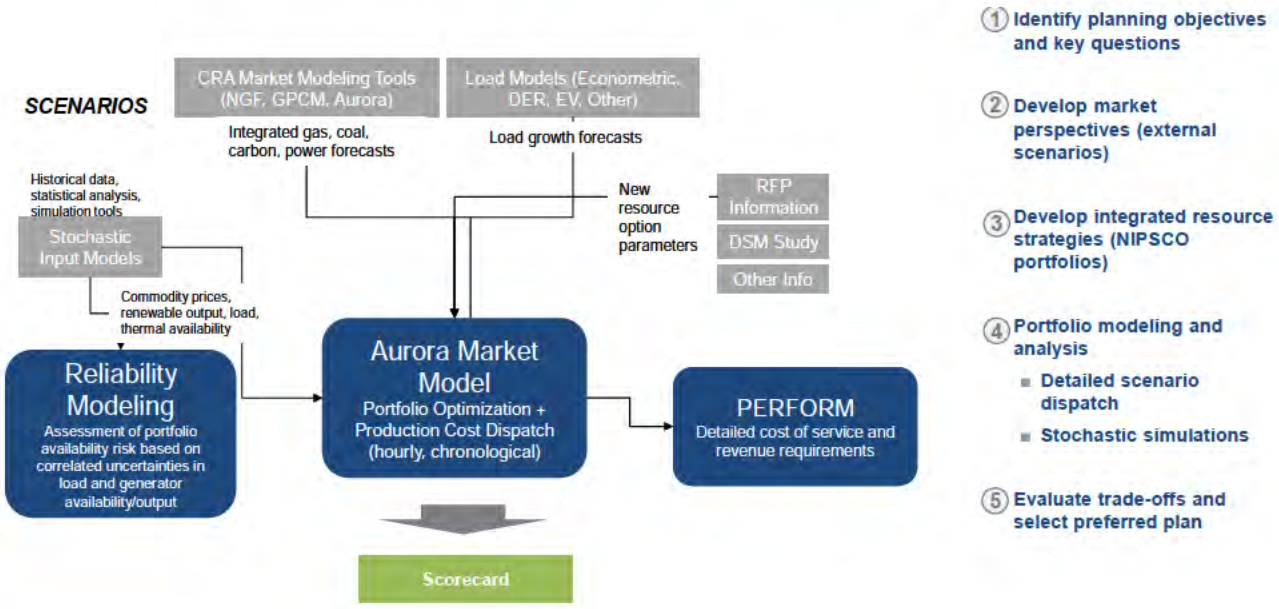
The long-term strategic plan identifies expected energy and demand needs over a 20-year horizon and recommends a potential resource portfolio to meet those needs. The short-term action plan identifies the steps NIPSCO will take over the next three to five years to implement the long-term strategic plan.

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,

---

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

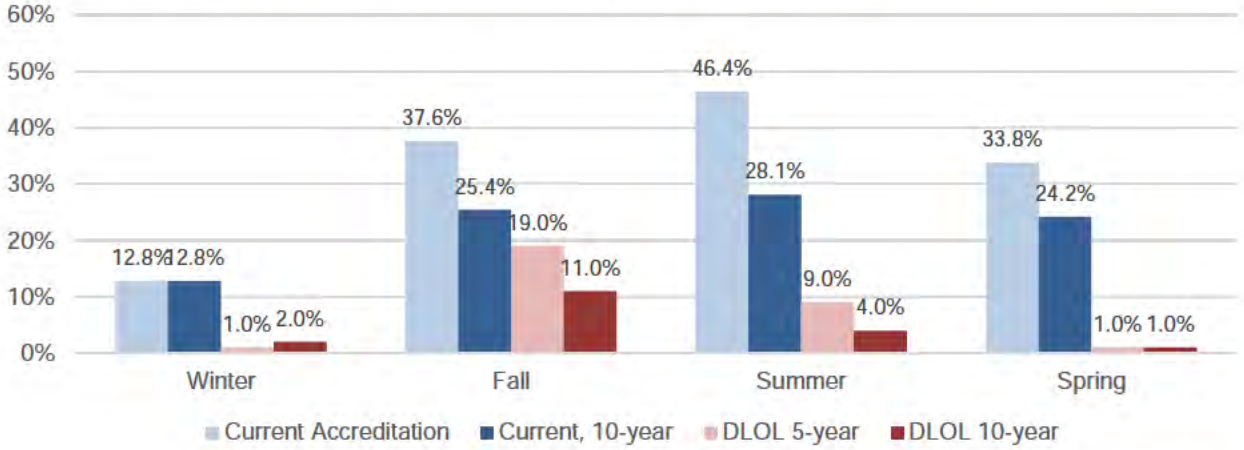
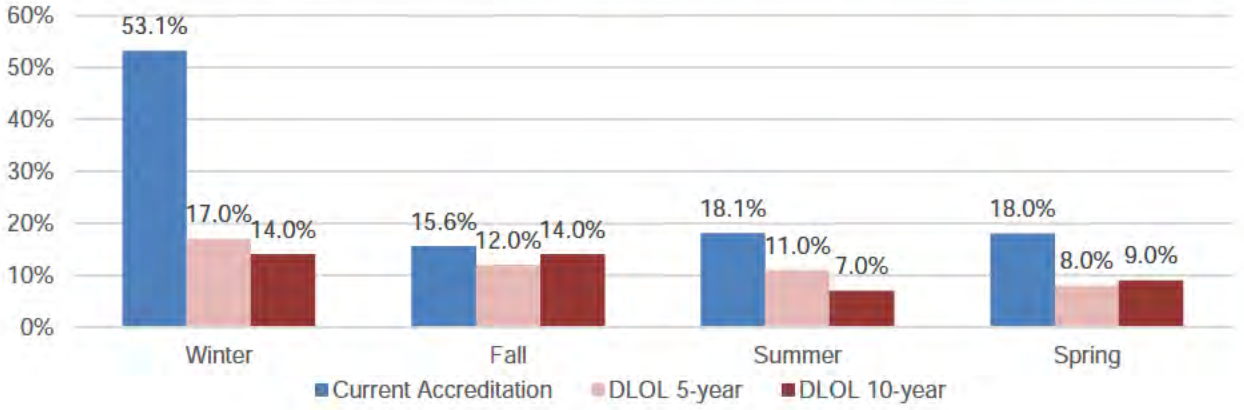


Figure 2-4: Accreditation Expectations under Different Constructs – Wind



[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

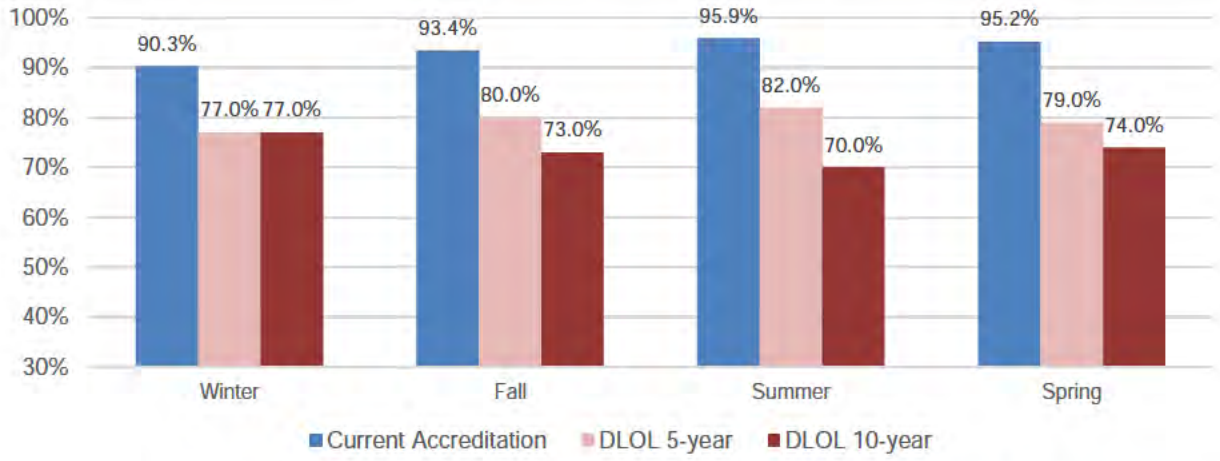
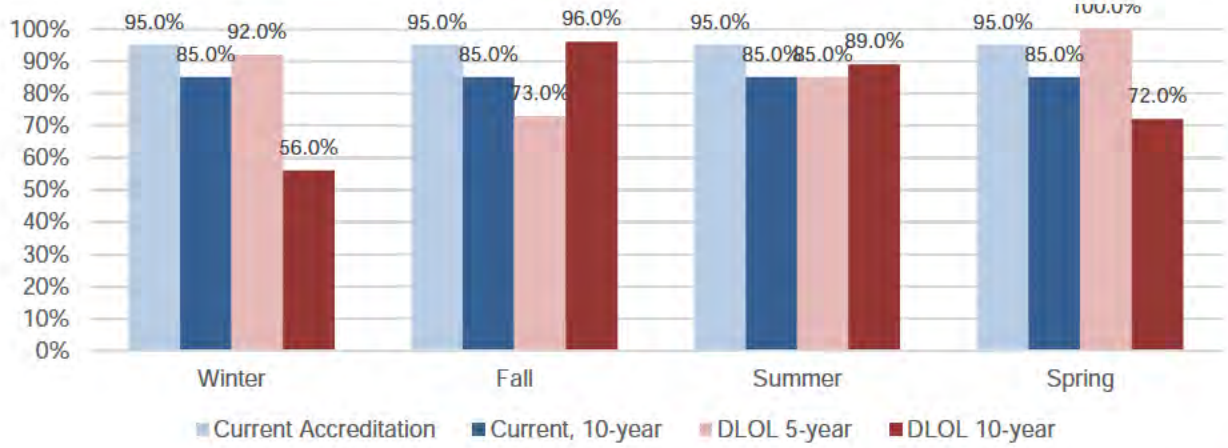


Figure 2-6: Accreditation Expectations under Different Constructs – 4-Hour Storage



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 not 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

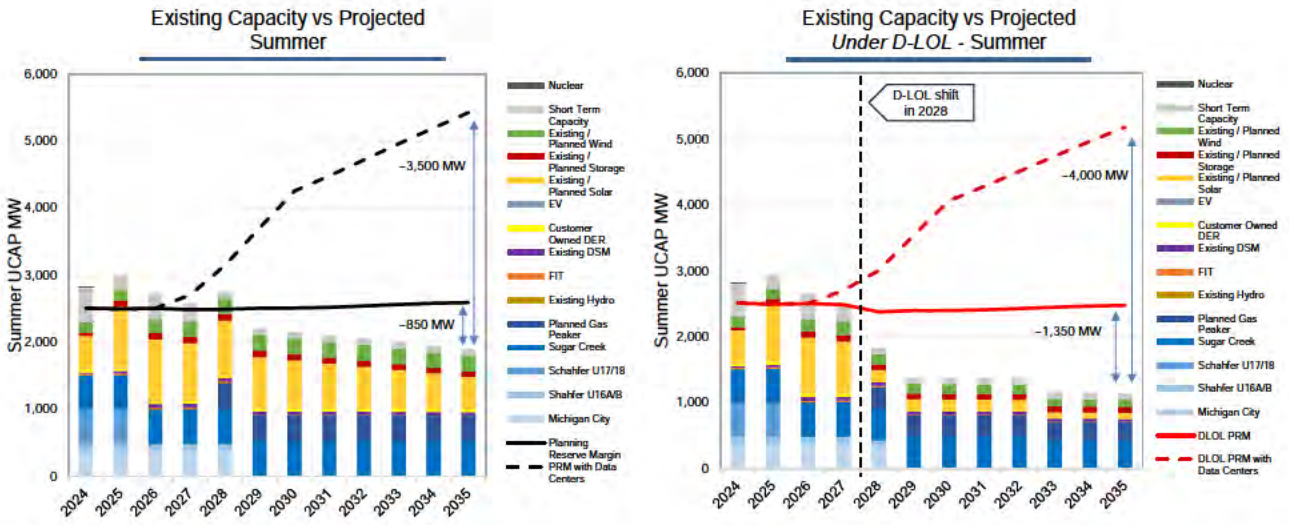
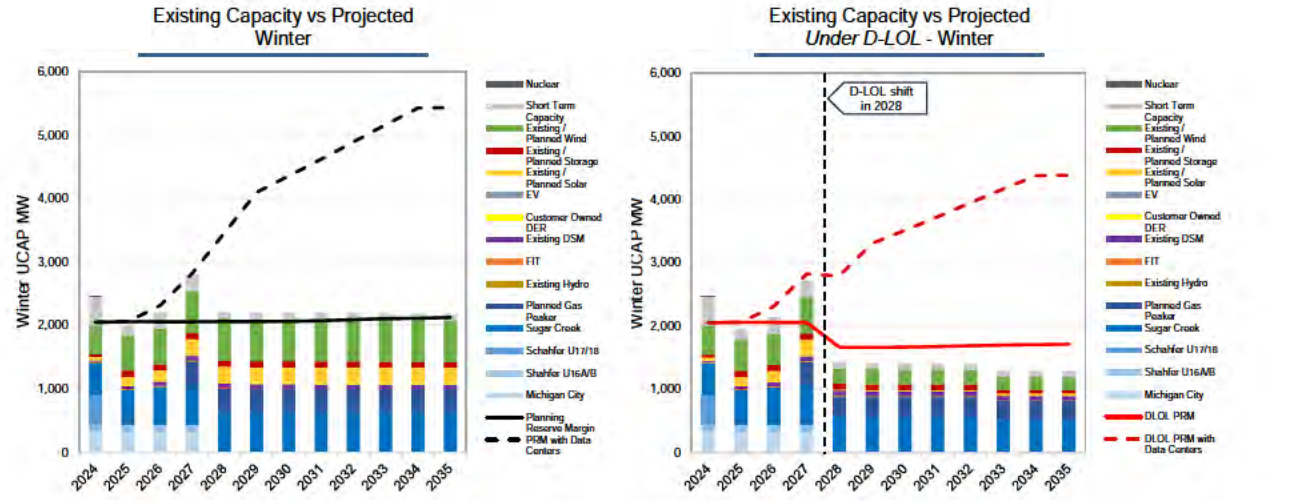


Figure 2-11: Starting Supply-Demand Balance – Winter with and without D-LOL



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.

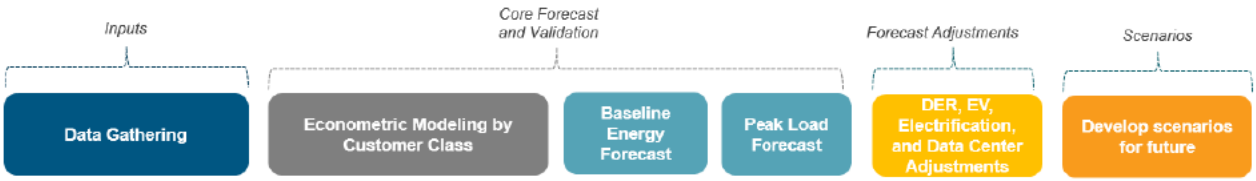
- **Econometric Modeling by Customer Class:** Testing of all economic and demographic "driver" variables in a dynamic regression system and performance of post-estimation tests on econometric models' specification and forecasting performance (for example, Systemic Mean Absolute Percentage Errors).

- **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

$$C_{it} = b_o + b_1 X_{it} + b_{jt}\theta_t + \pi_{it}$$

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

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

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

$a_1, a_2, a_3, \ldots a_j$ = 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

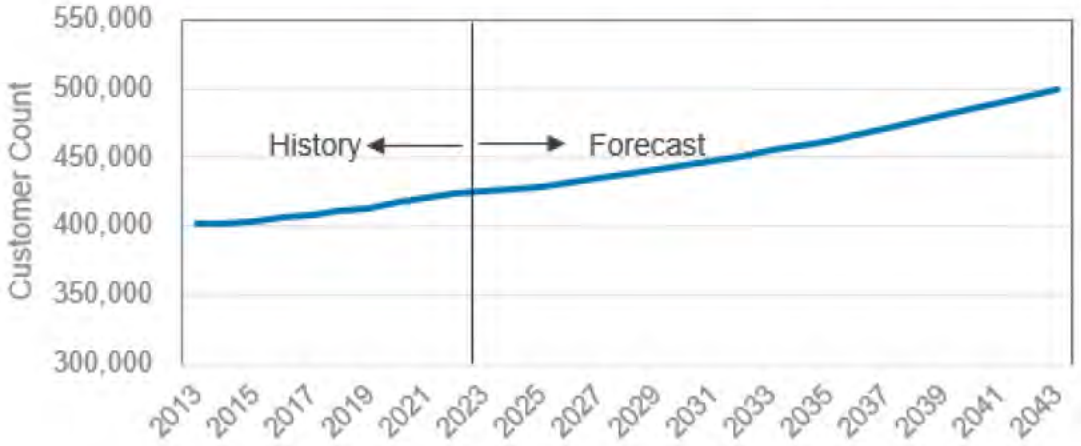


Figure 3-4: NIPSCO Commercial Customer Count Forecast

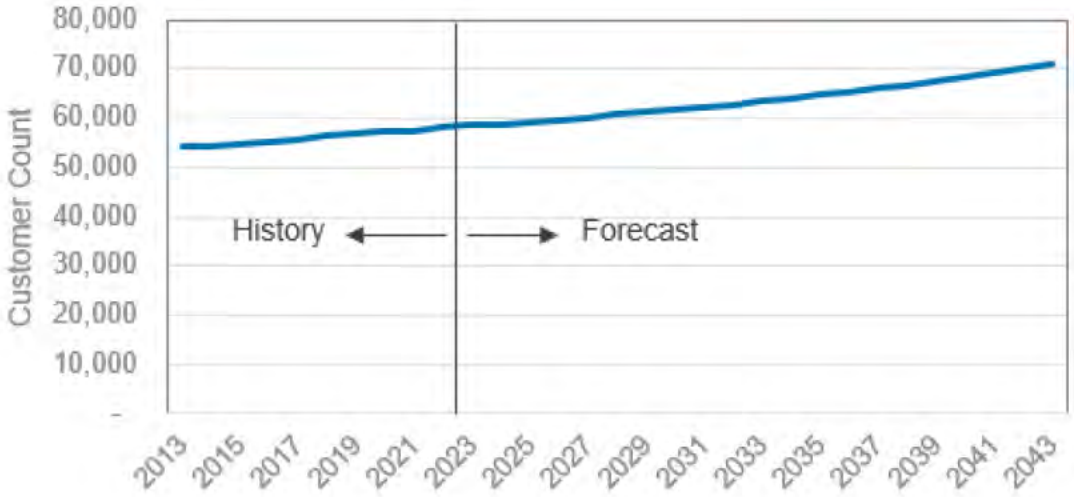
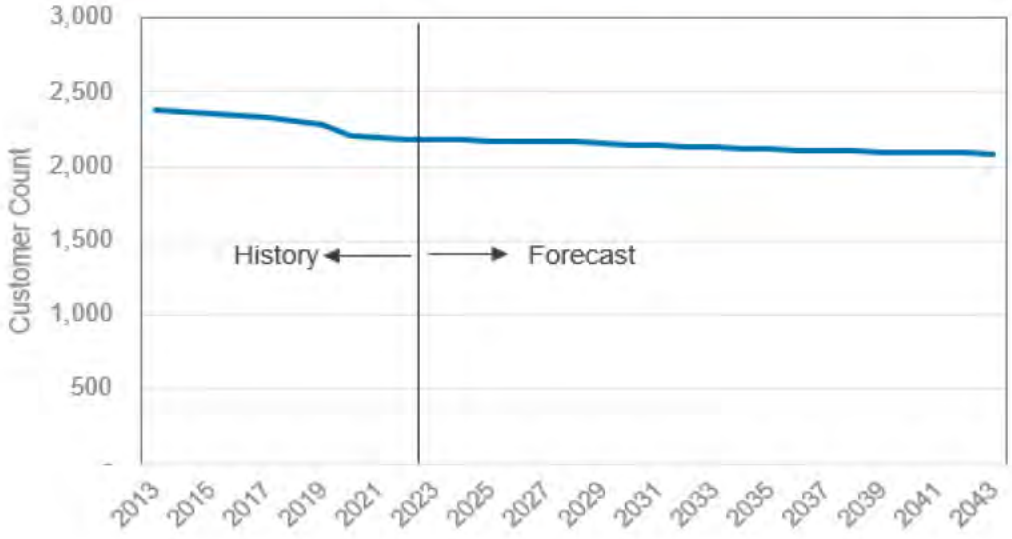


Figure 3-5: NIPSCO Industrial Customer Count Forecast



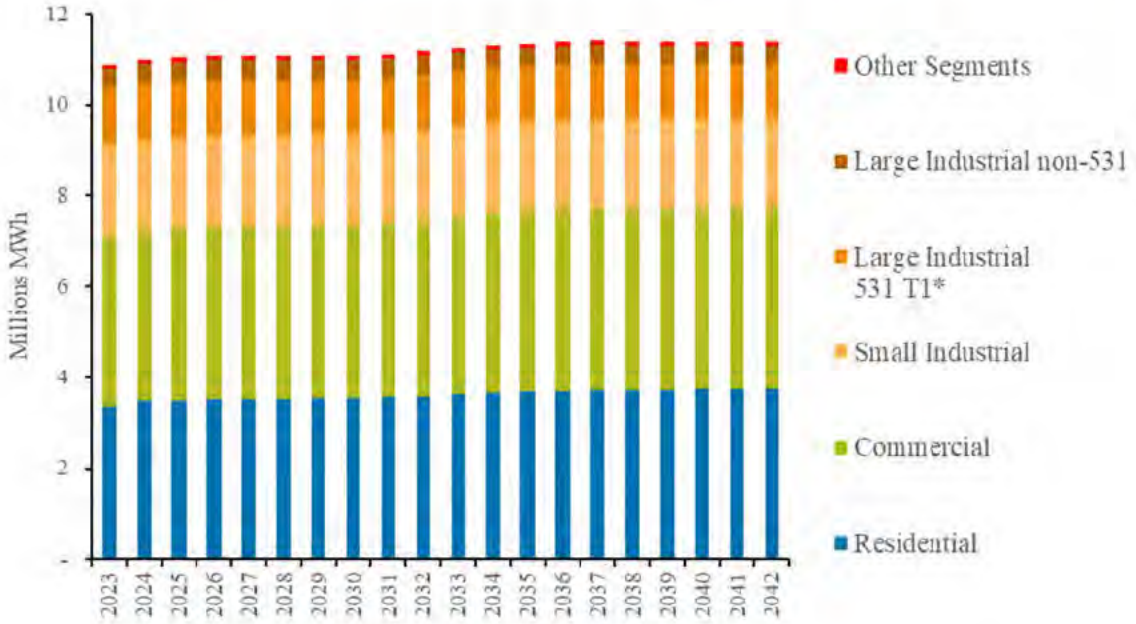
3.3.4 Sales per Customer and Total Electric Sales Forecast

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 .

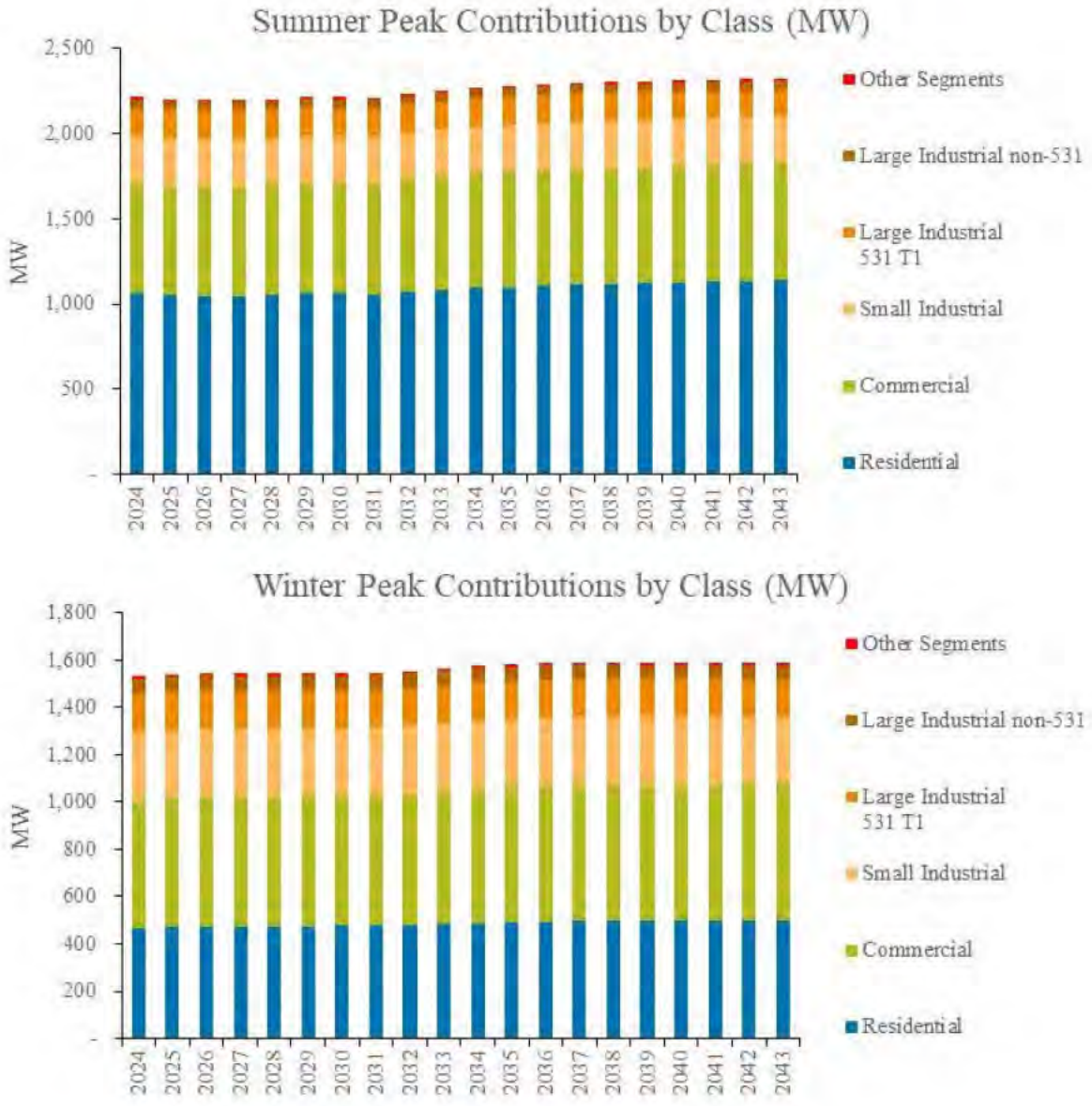
Equation 3-3: Load Factor Calculation

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

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

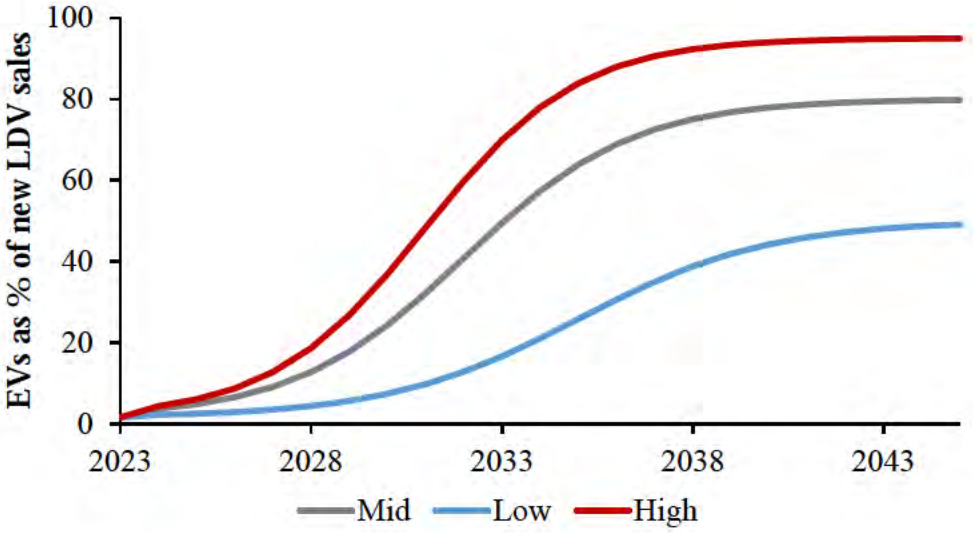
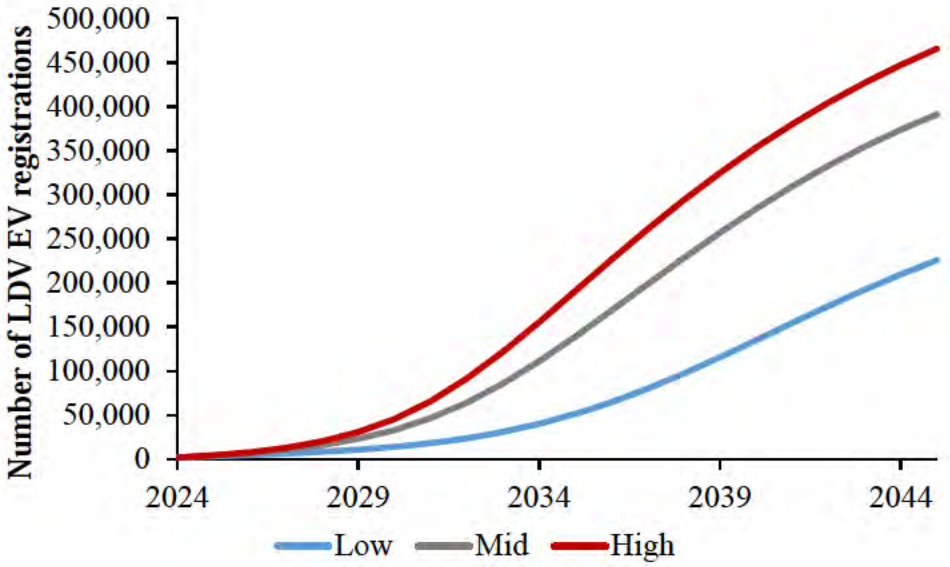


Figure 3-10: LDV EV Adoption: Number of EVs registered in NIPSCO service territory[25]



[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

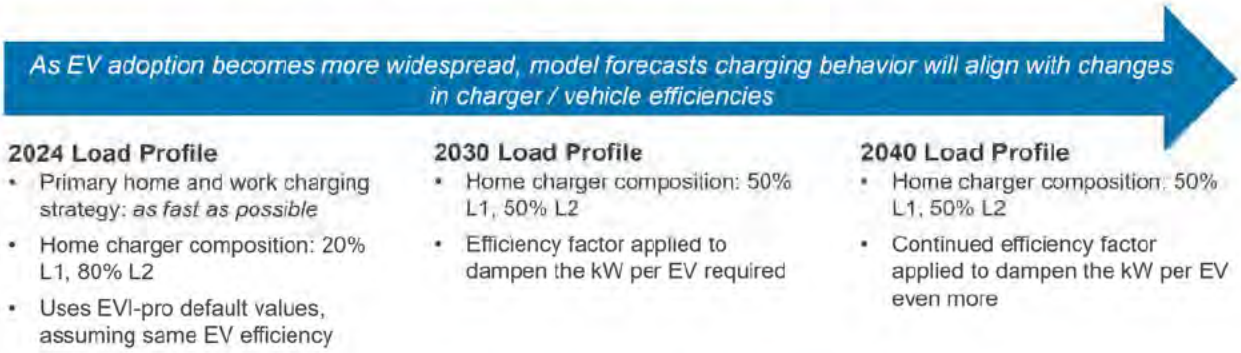


Table 3-6: Assumed efficiency of LDV vehicle types (miles/kWh)[27]

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)

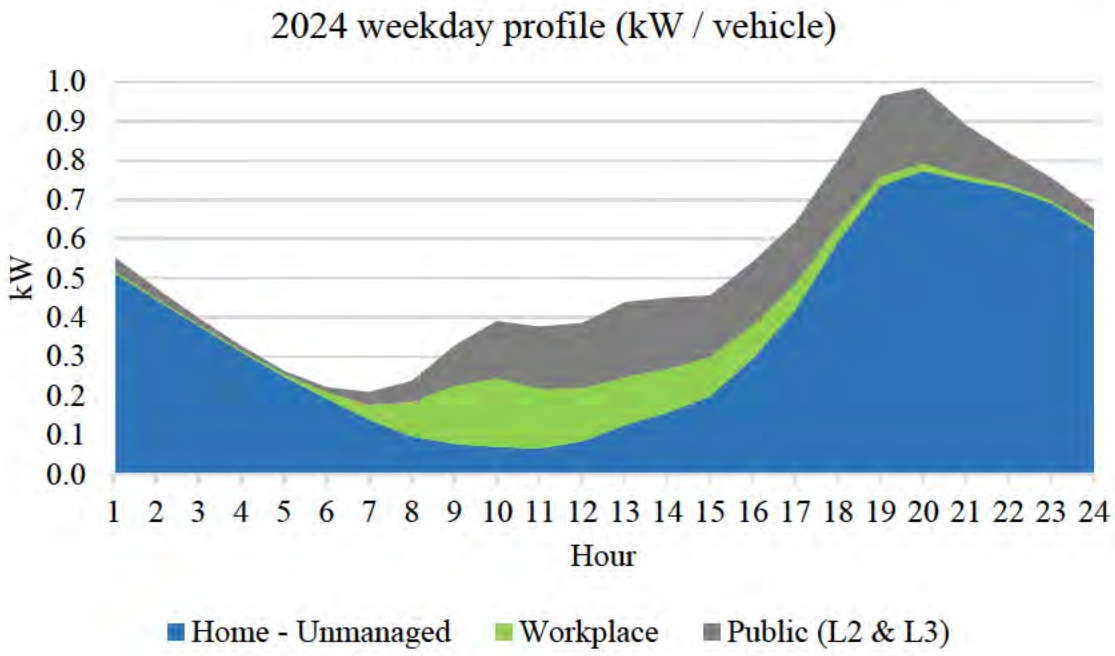


Figure 3-13: LDV EV 2024 Weekend Charging Profile (kW/vehicle)

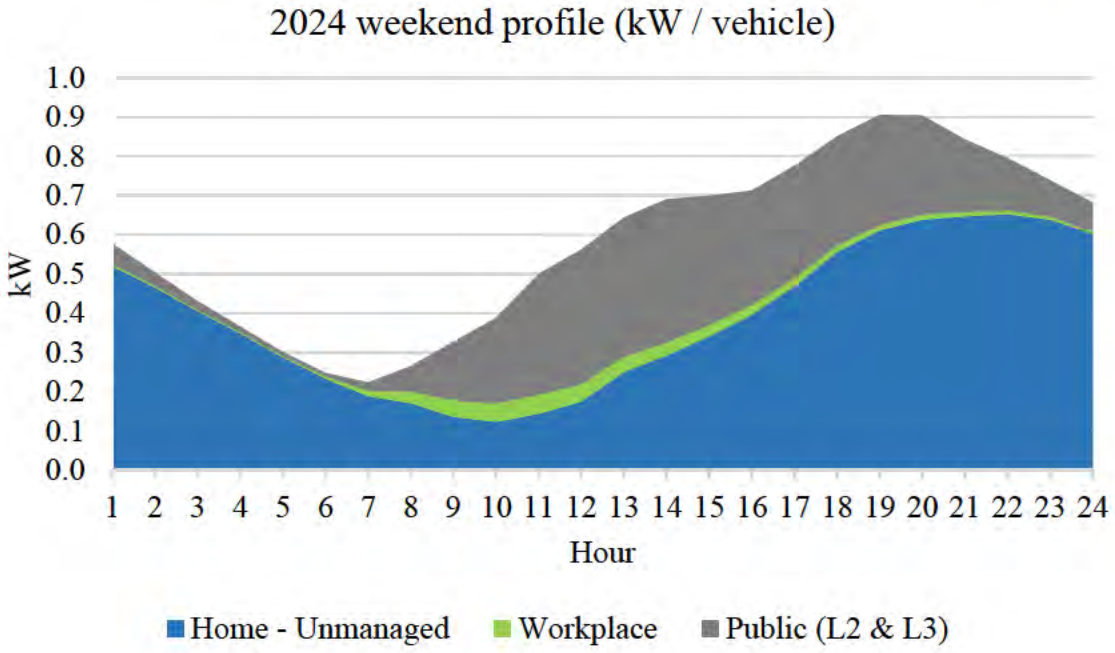


Figure 3-14: LDV EV 2030 Weekday Charging Profile (kW/vehicle)

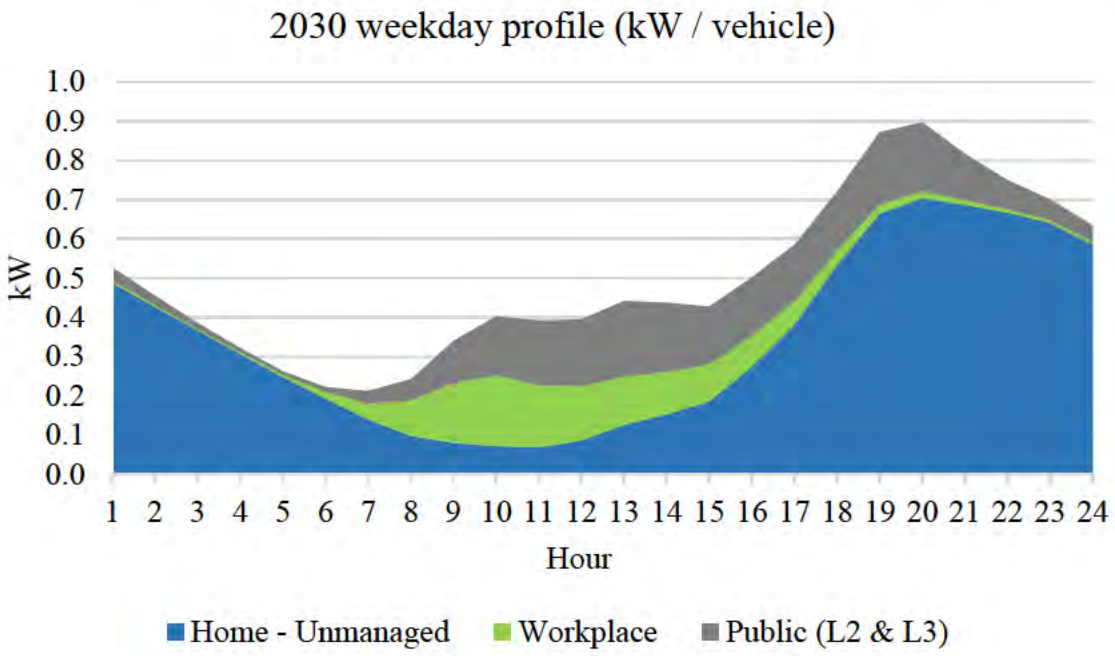


Figure 3-15: LDV EV 2030 Weekend Charging Profile (kW/vehicle)

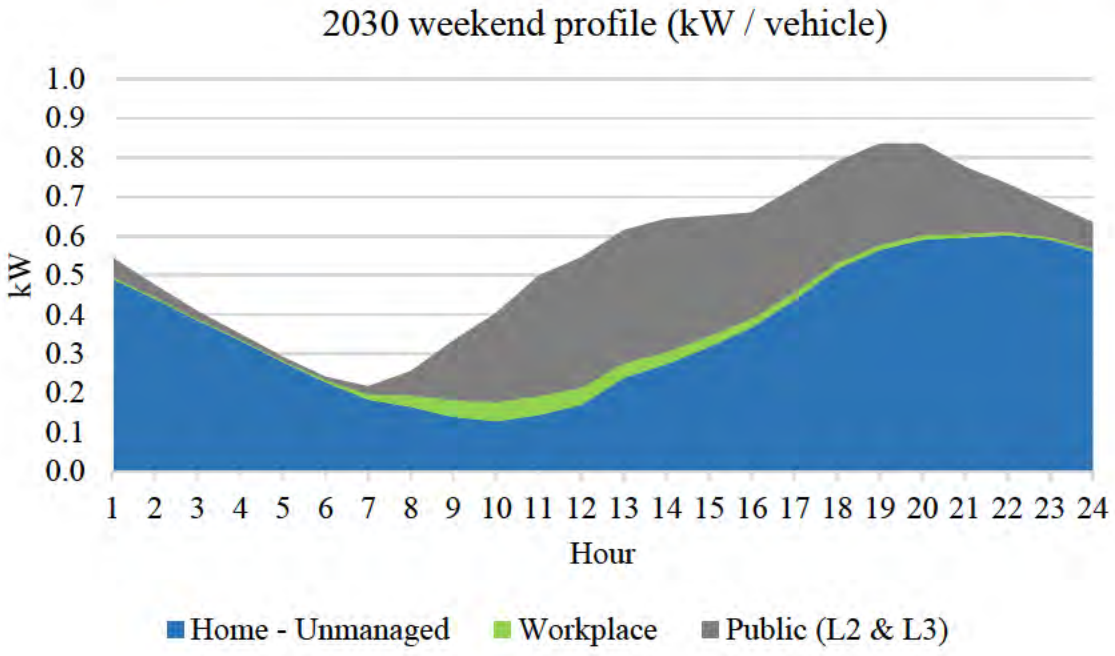


Figure 3-16: LDV EV 2040 Weekday Charging Profile (kW/vehicle)

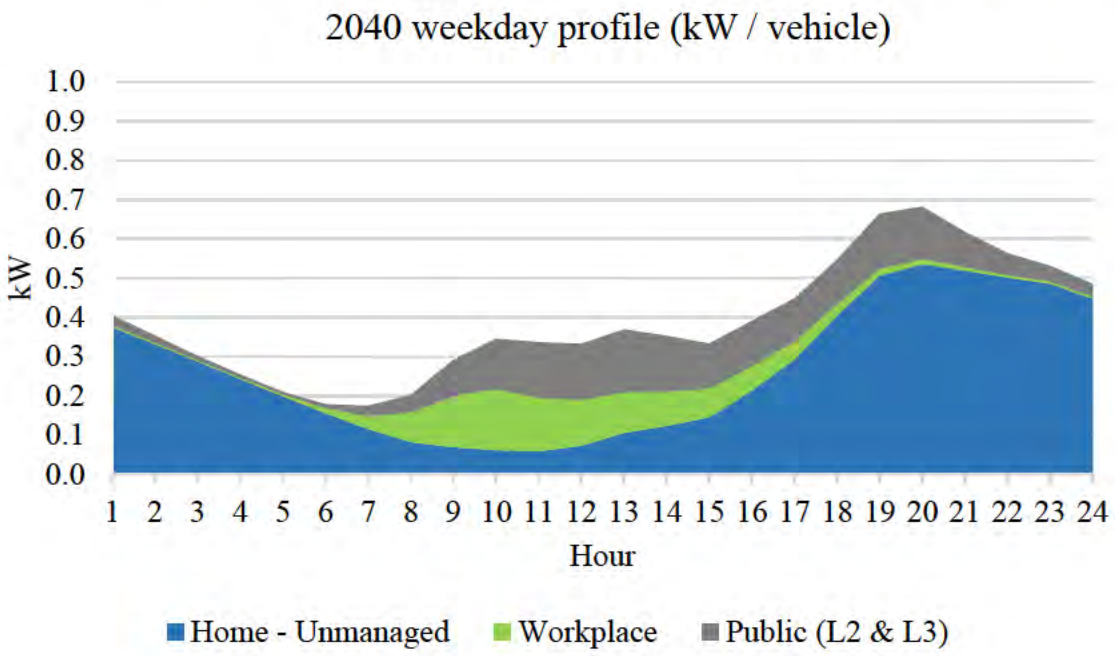
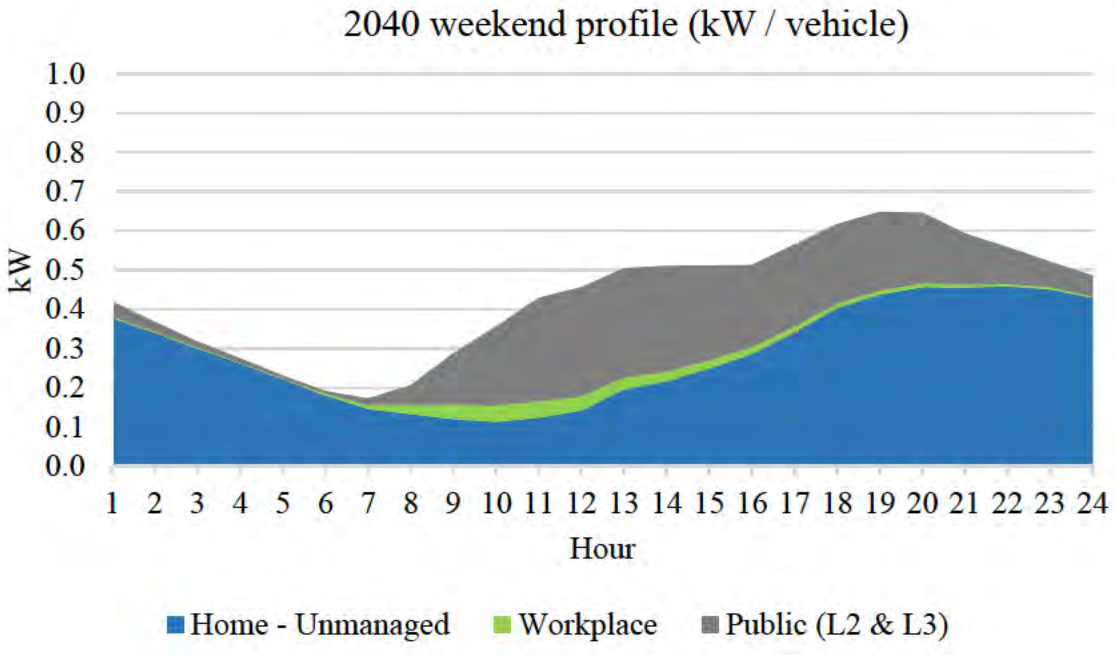


Figure 3-17: LDV EV 2040 Weekend Charging Profile (kW/vehicle)



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

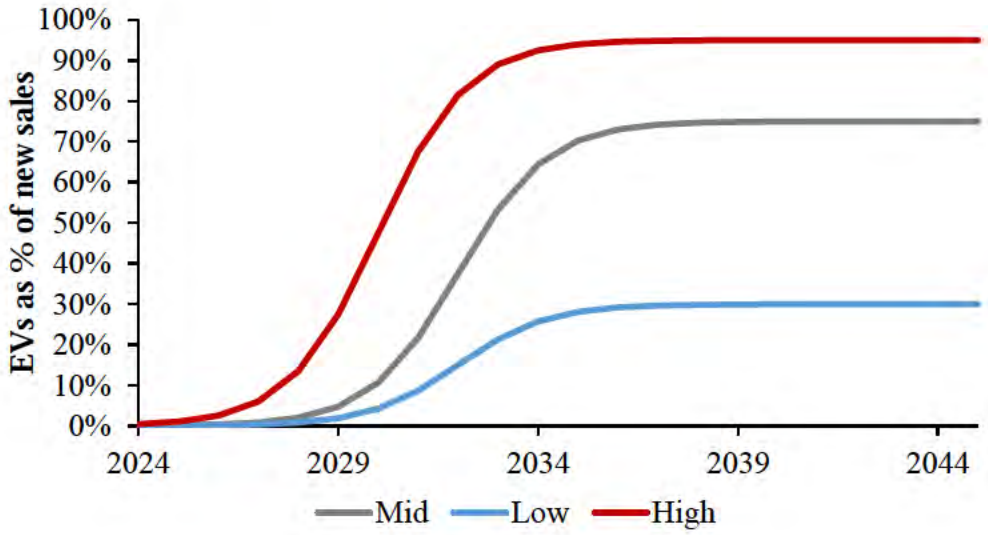
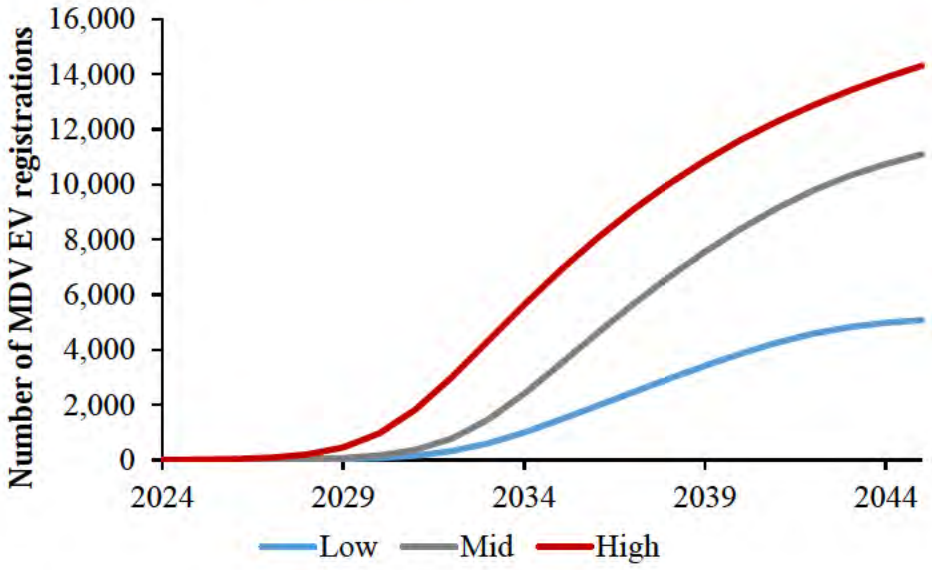
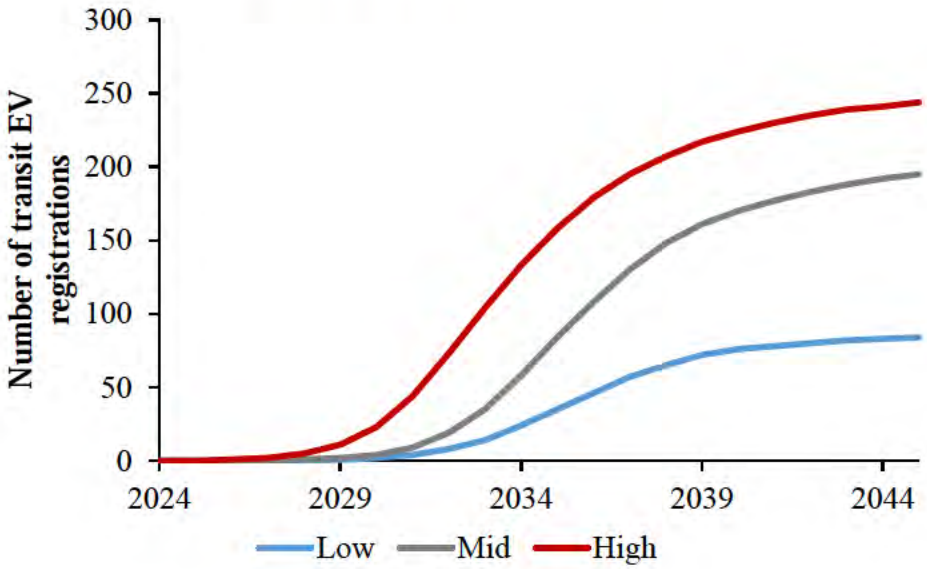


Figure 3-19: MDV EV Adoption: Number of EVs registered in NIPSCO service territory[33]



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.

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

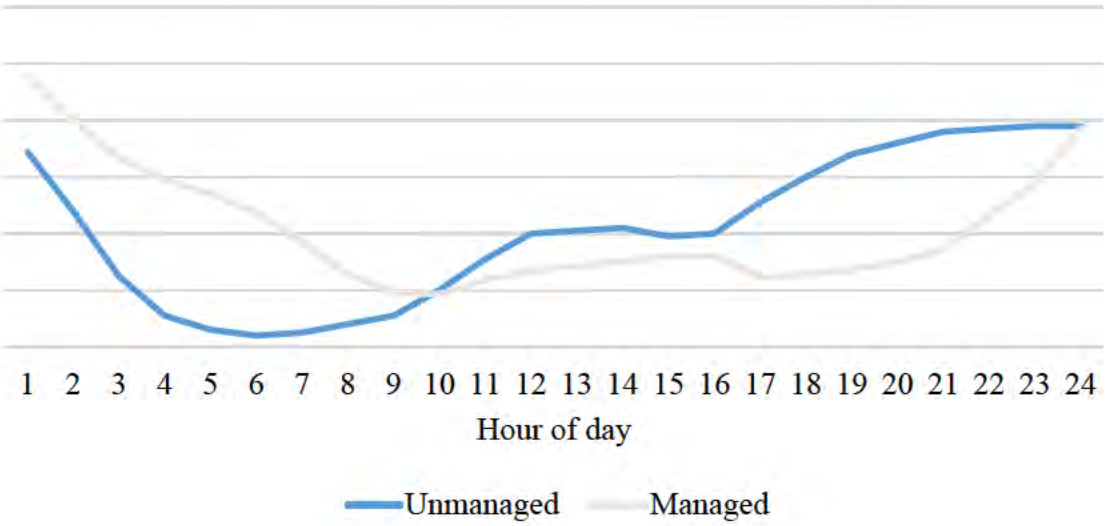


Table 3-14: Assumed Efficiency of MDV And Transit Vehicle Types (kWh/mile)[37]

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

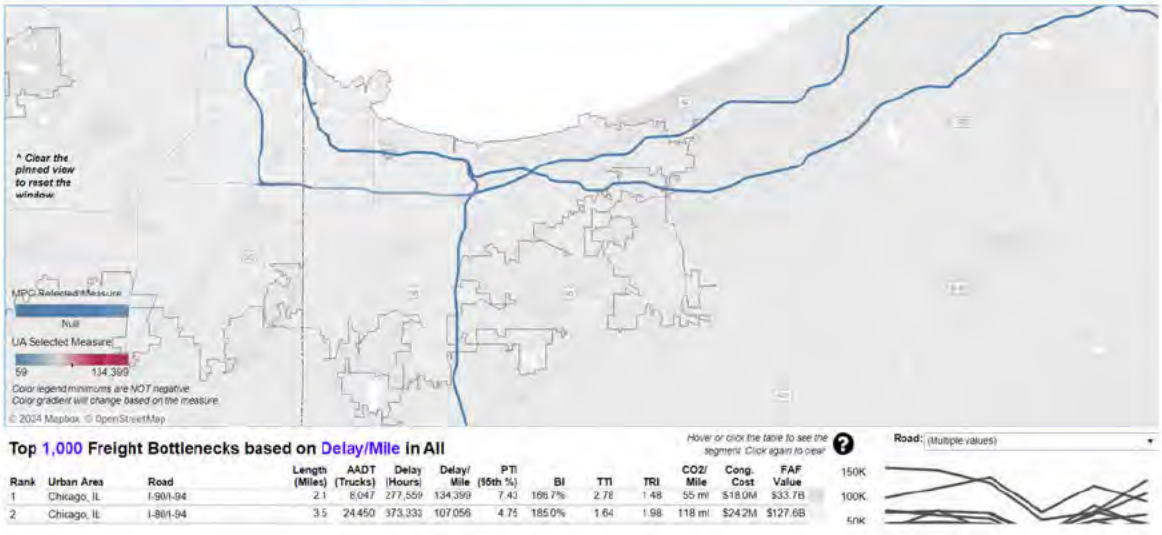
First, NIPSCO identified key traffic corridors within the service territory using Google Maps and satellite imagery. These included I-94, I-90, I-65, I-69, and other state roads (see Table 3-17). Next, NIPSCO located all highway and truck stops with current fueling stations to establish the universe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

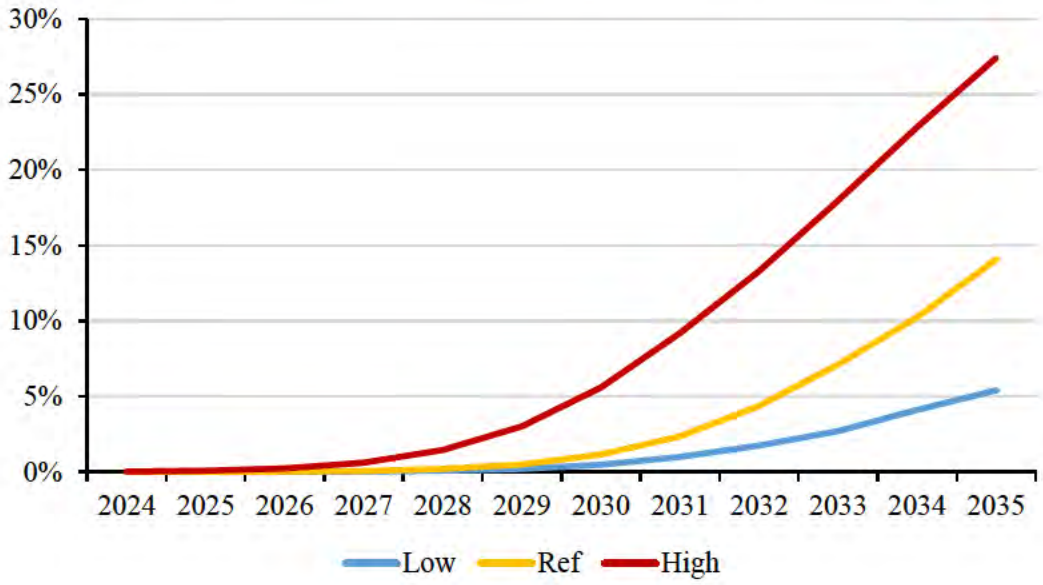
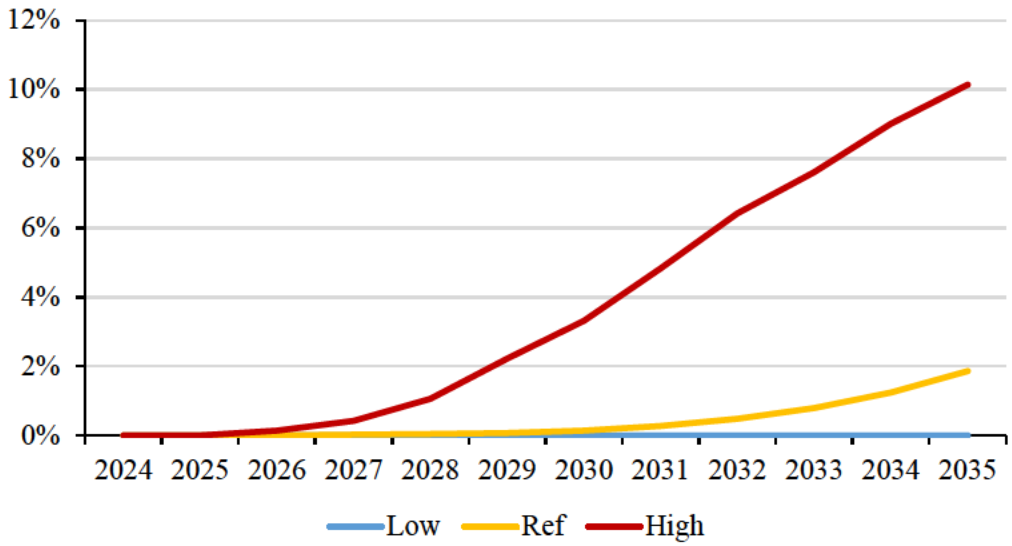


Figure 3-24: HDV EV Saturation Forecast by Scenario



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)

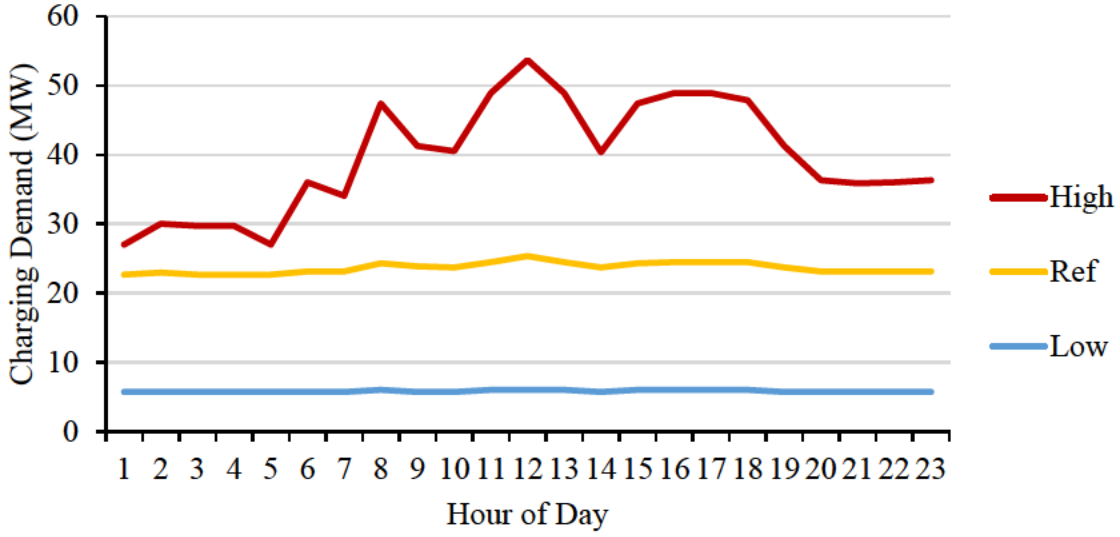
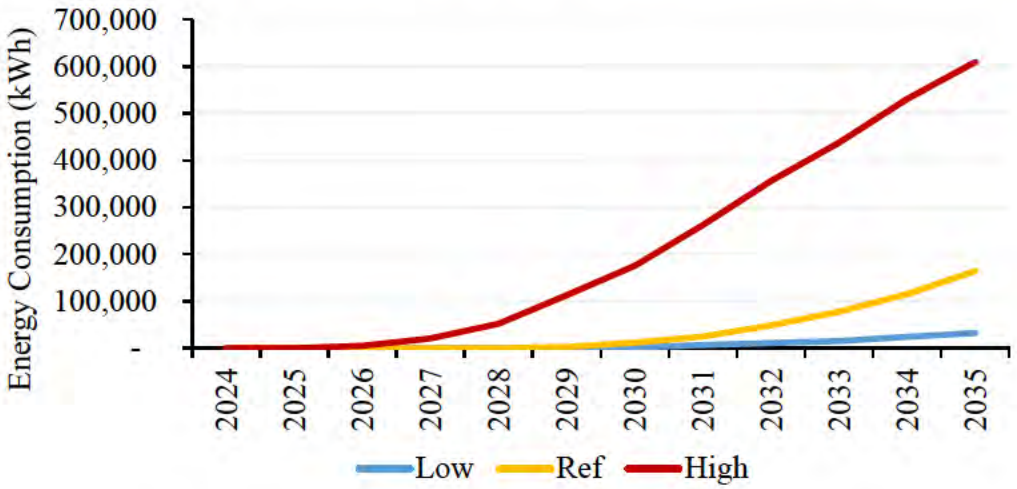


Figure 3-26: Average Daily Corridor Energy Consumption (kWh)



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)

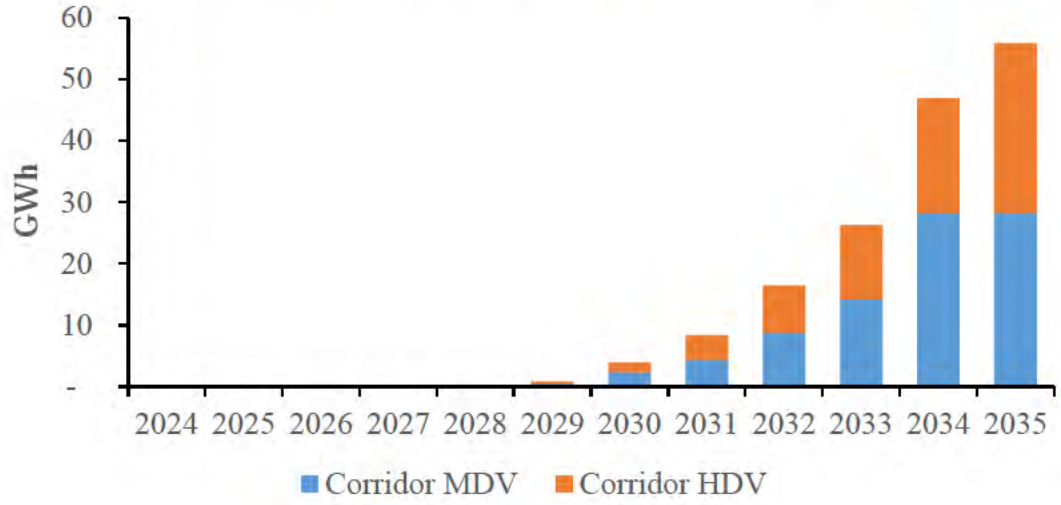


Figure 3-28: Annual Corridor EV Energy Demand – Low Case (GWh)

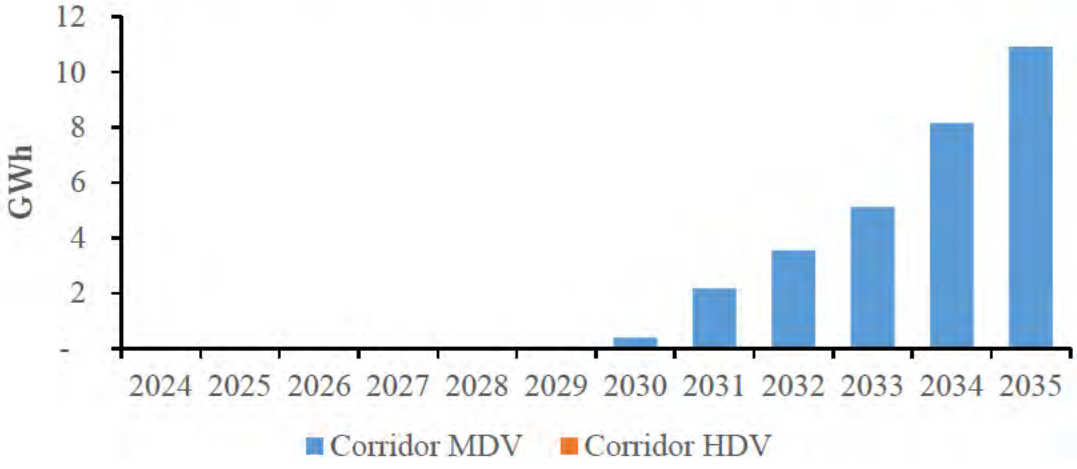
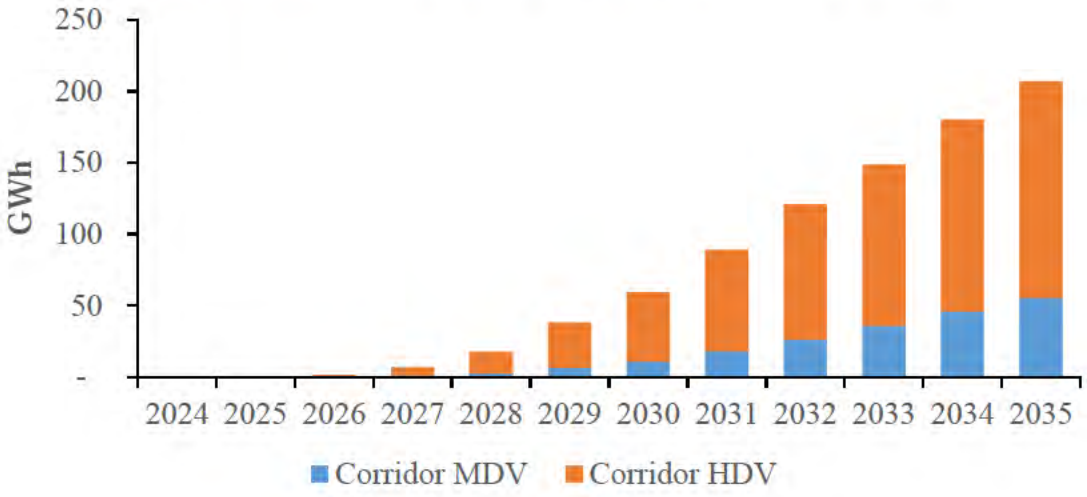


Figure 3-29: Annual Corridor EV Energy Demand – High Case (GWh)



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)

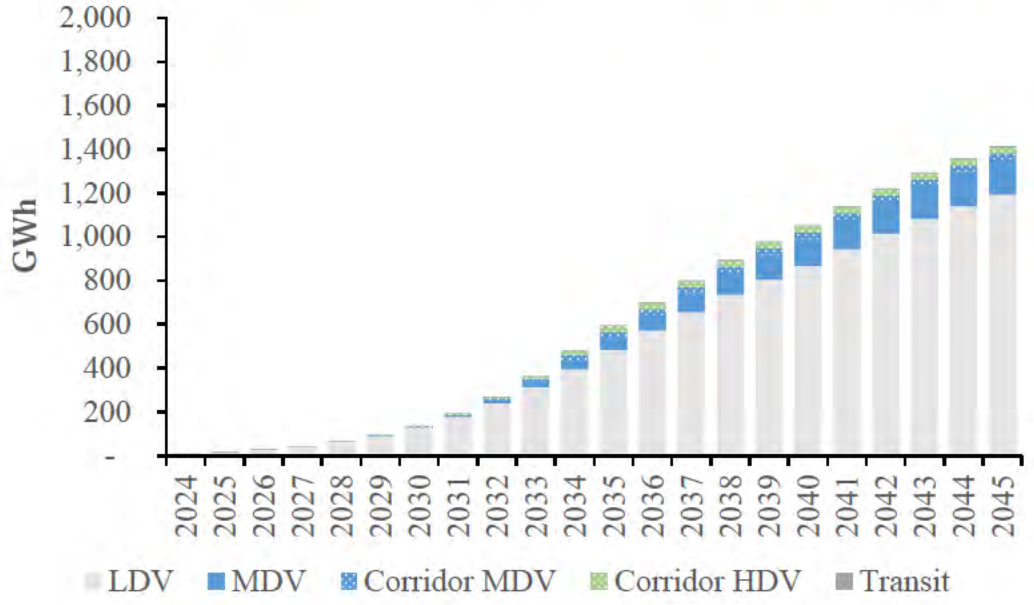


Figure 3-31: Annual EV Energy Demand – Low Case (GWh)

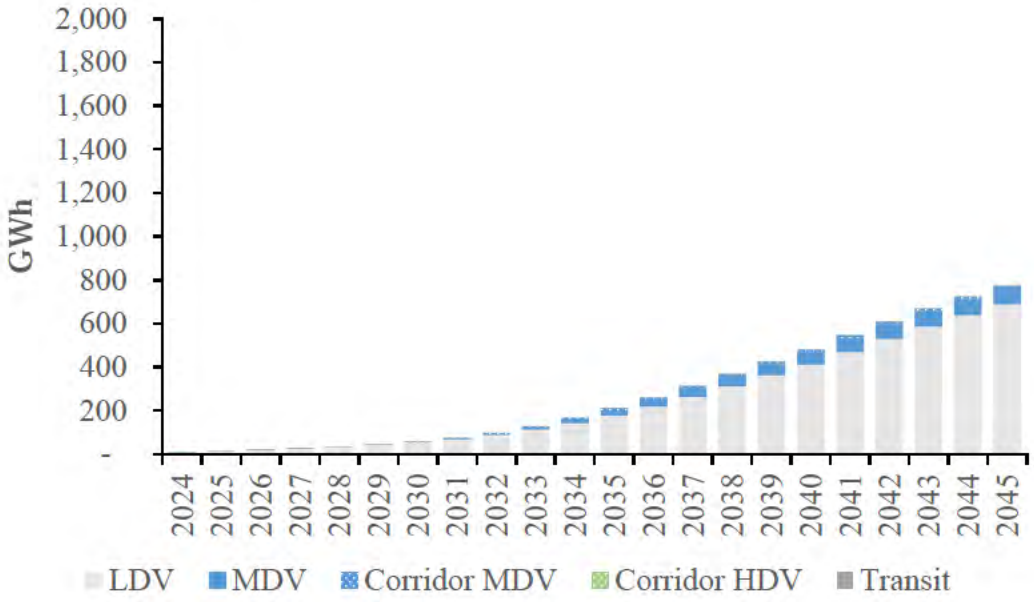
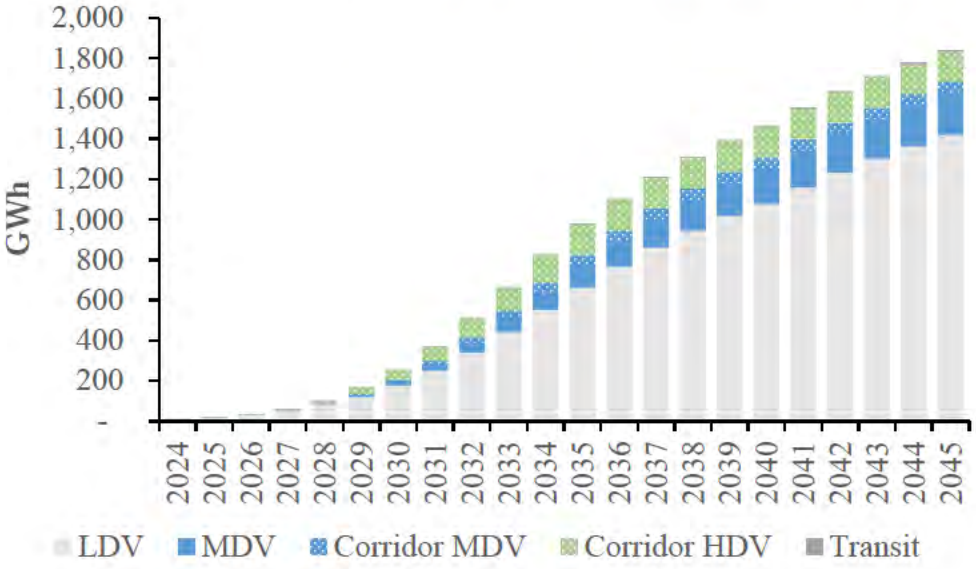


Figure 3-32: Annual EV Energy Demand – High Case (GWh)



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

[43] Note that distributed storage additions to pair with solar DERs were included as part of the Demand Side Management study.

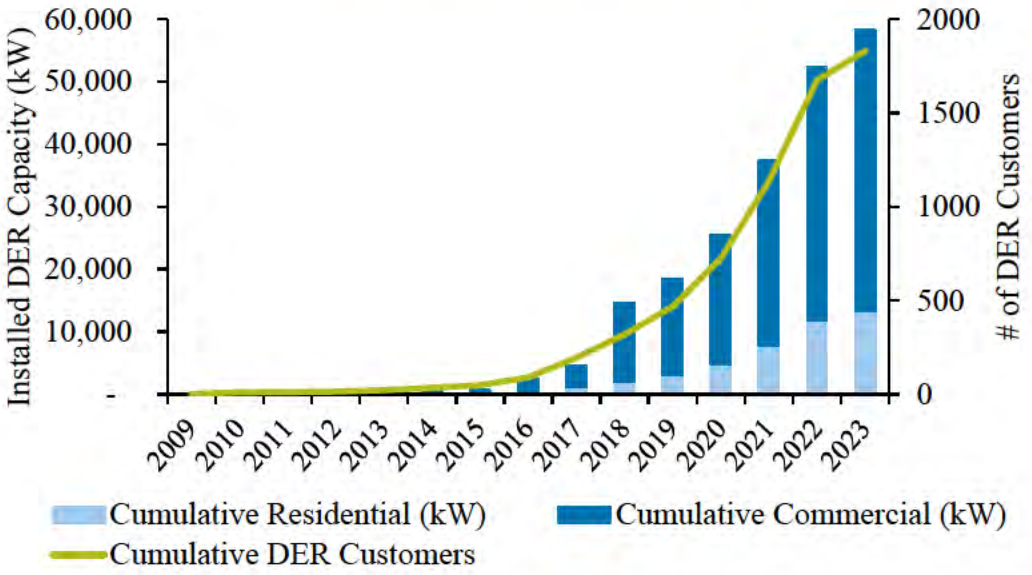
[44] Please find more detailed information on the Feed-in Tariff program here.

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

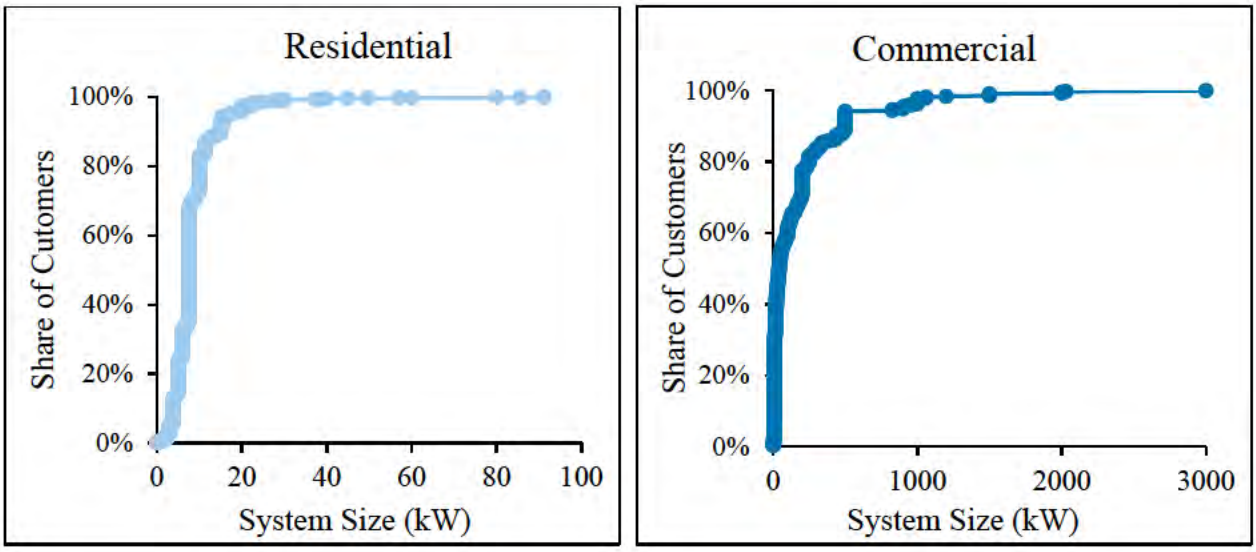
NIPSCO Counties	Total Res. Customers	Res. Solar DER Customers	% Res. Customers with Solar DER	Total Res. Solar DER (kW)
Benton	3,592	7	0.2%	60
Carroll	6,477	13	0.2%	113
DeKalb	3,035	23	0.8%	272
Elkhart	44,330	477	1.1%	4,830
Fulton	4,487	24	0.5%	248
Jasper	11,026	28	0.3%	277
Kosciusko	19,847	61	0.3%	587
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

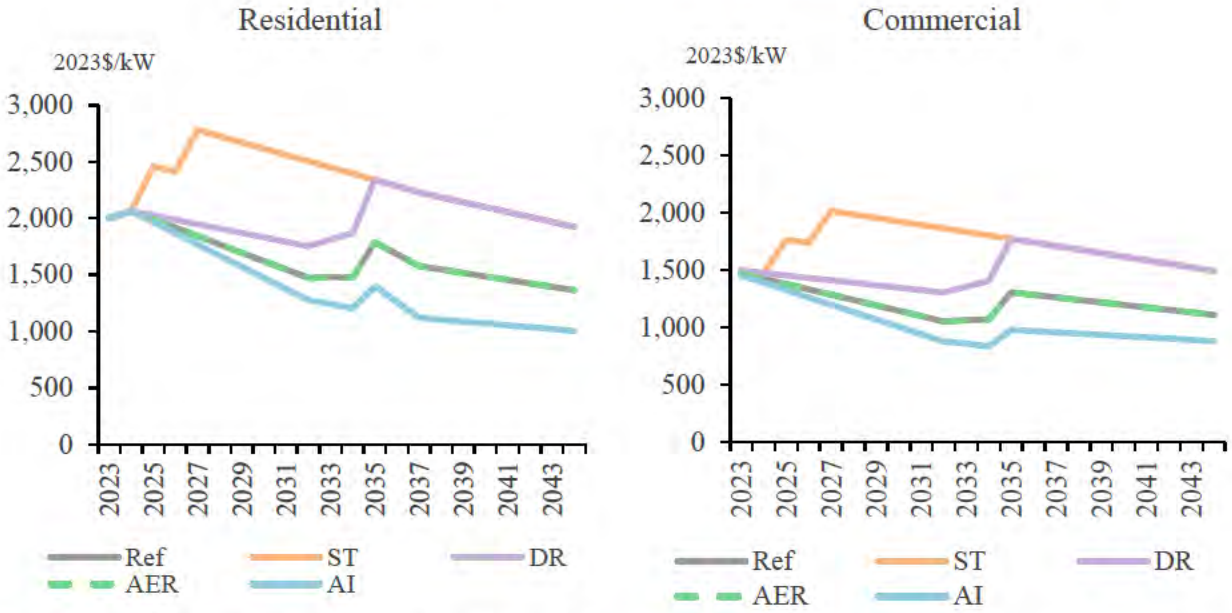
Capital Cost and Tax Credit Inputs: Assumptions regarding capital cost projections, capacity factor, and lifetime for solar PV were taken from NREL's 2023 Annual Technology Baseline for

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%

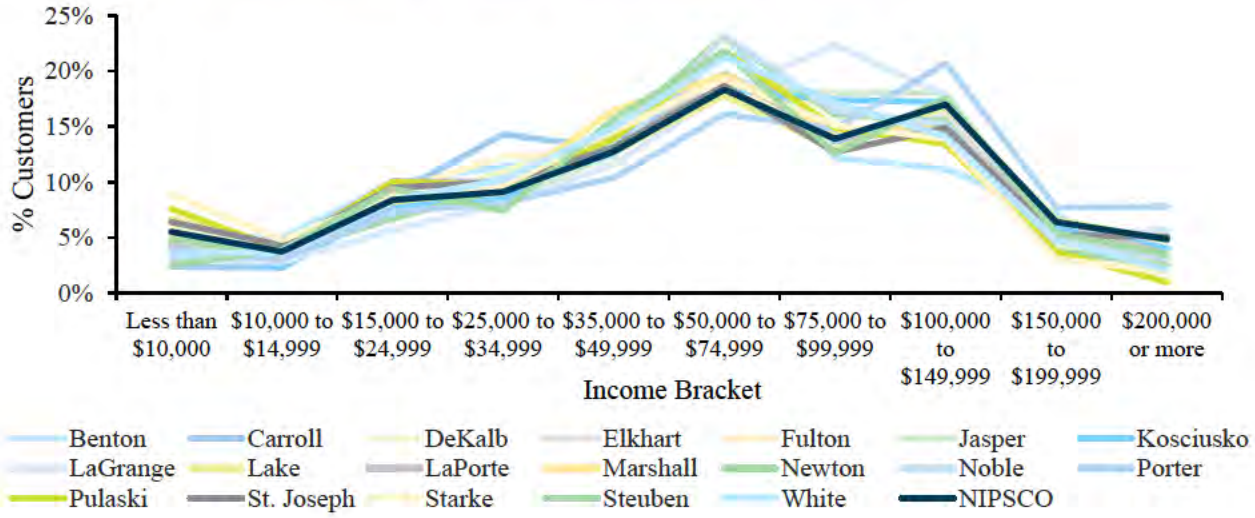
Household Income: Household income distributions by county within the NIPSCO territory were determined from the ACS. The ACS is a nationwide survey that collects and produces information on demographic, housing, economic, and social characteristics of the nation's population every year.[51] Household 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%.

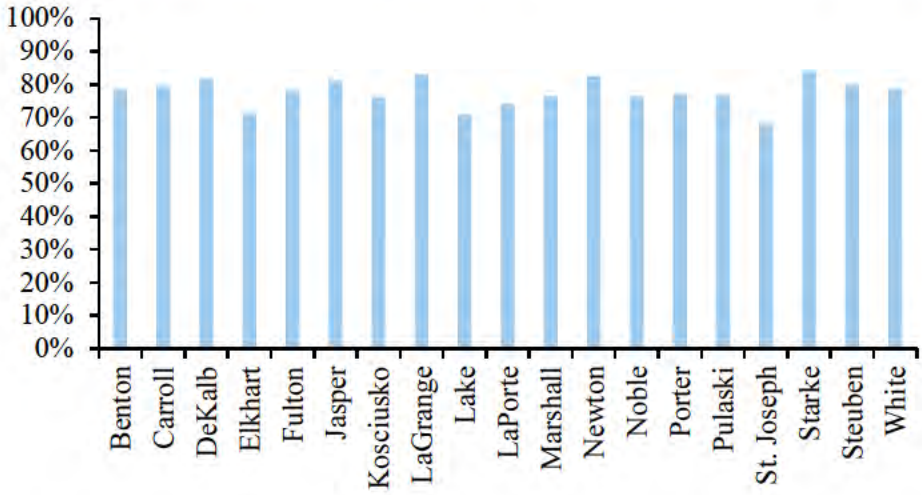
Figure 3-36: Household Income Distribution by County



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.

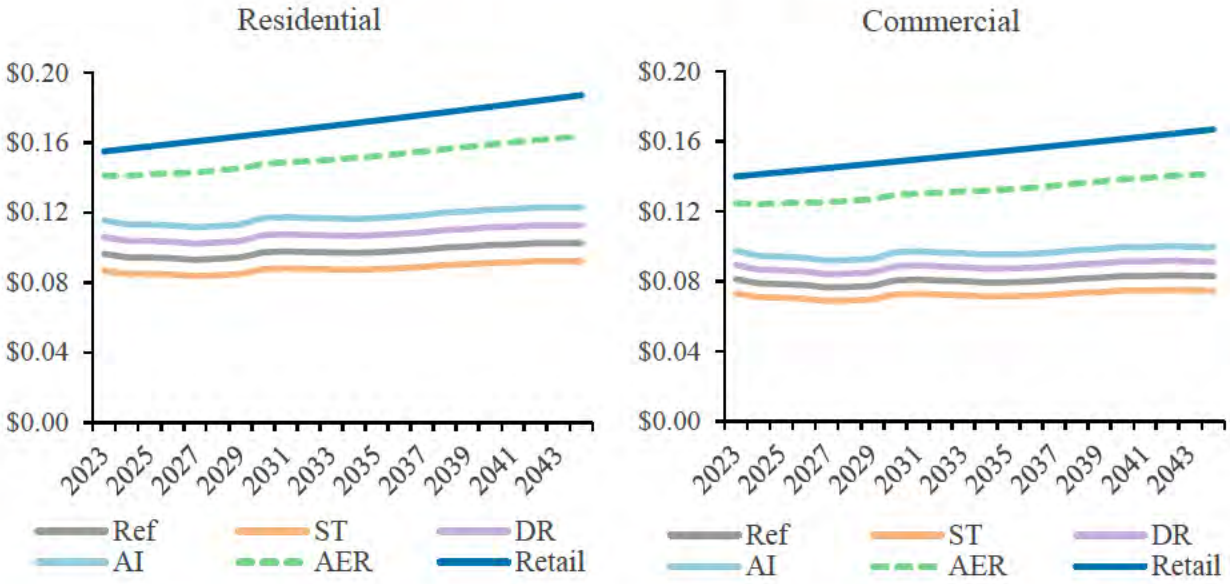
Bass Innovation Index Parameters: By using NIPSCO's customer adoption numbers from 2012 through 2023 from the Net Metering program, PenDER's bass innovation index parameters were calibrated to match historical adoption decisions (using historic retail rates and solar PV capital costs).

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.

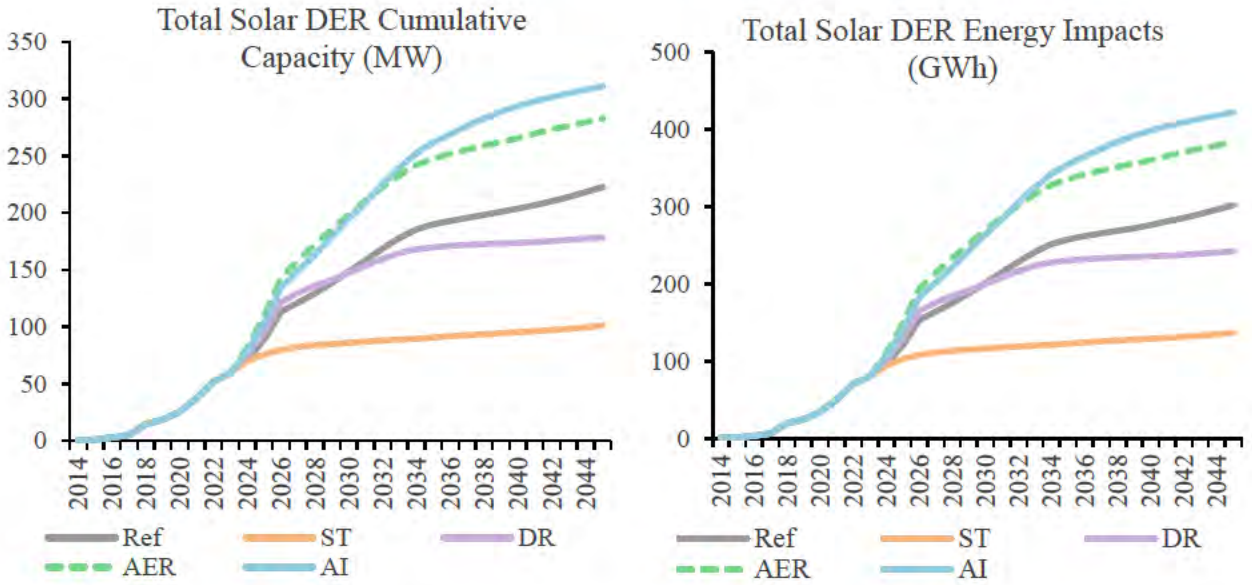
- **Payback Period**: Based on the upfront PV system capital cost, the cash flow from renewable energy incentives (i.e., EDG rates), discount rate, and solar PV lifetime, the payback period is determined by the number of years of discounted annual revenues that are required to cover the upfront PV system 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.

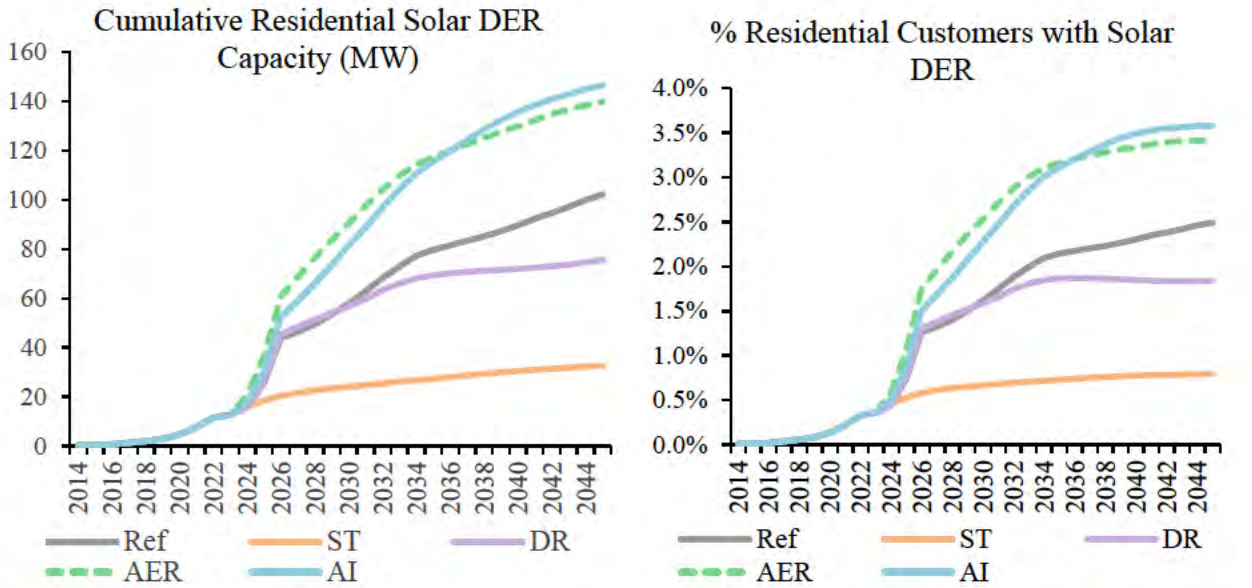
[55] Note that this graphic displays energy projections at the customer meter. For purposes of inclusion in the IRP load forecast modeling, NIPSCO grossed up the energy impact by 5% to incorporate line losses.

Figure 3-39: Projected Cumulative Customer-Owned DER Installations (MW) and Associated Energy (GWh) Impact, by Scenario



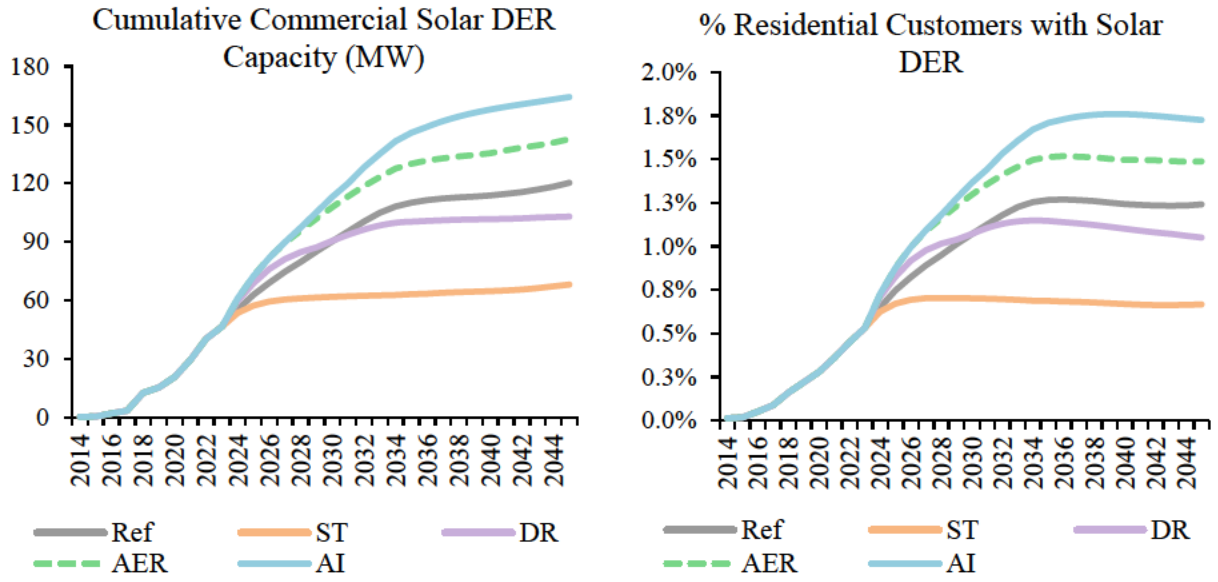
Across scenarios, it is estimated that between 0.8% and 3.6% of residential customers will install solar DER systems by 2045. There is a notable uptick in expected penetration in the early years, driven in part by the implementation of the Solar for All program among residential customers in selected 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)

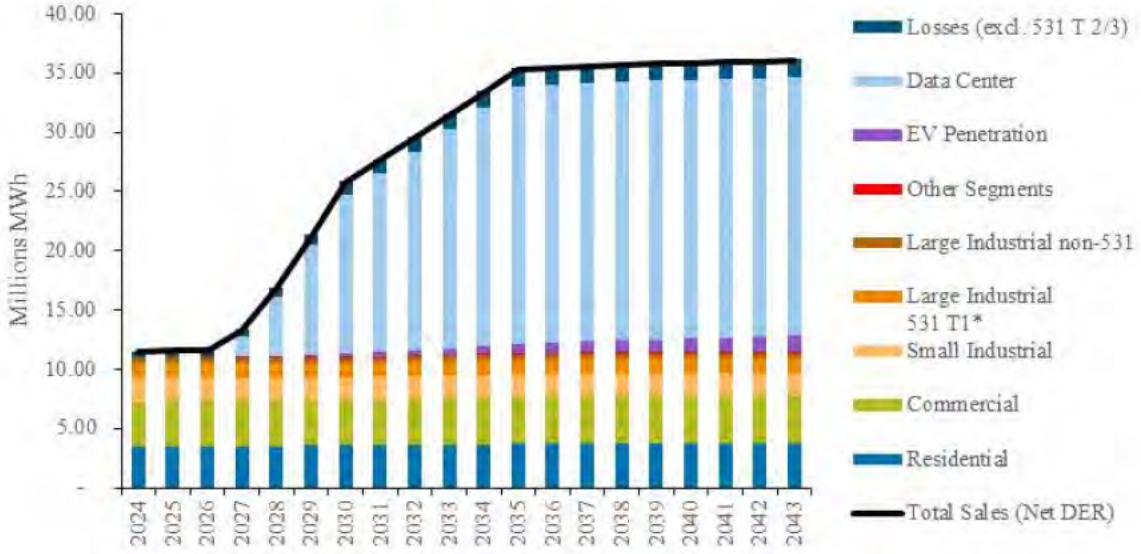
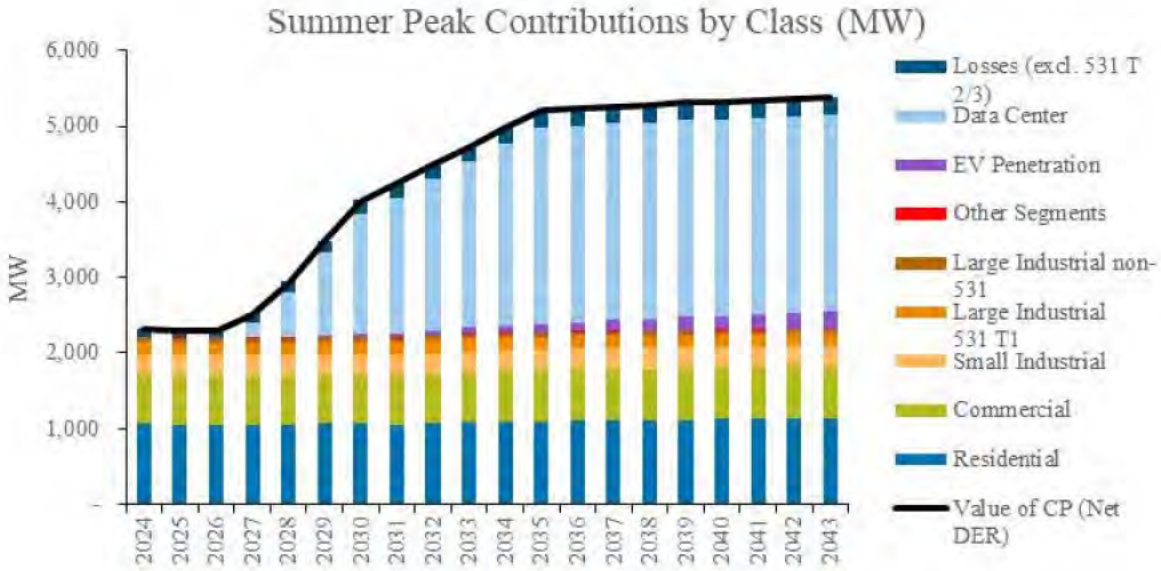
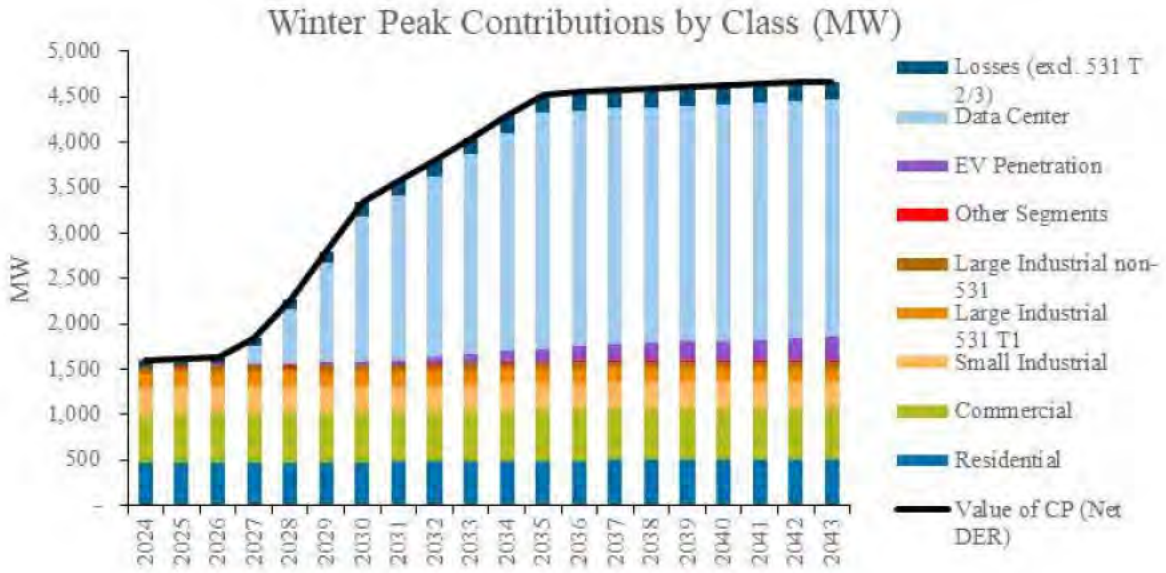


Figure 3-44: Summer and Winter Peak Contributions by Customer Class, with Adjustments (MW)





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)**	
	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)**	*Separate sensitivity with significant additional economic development load potential across all scenarios*
	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.

[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)

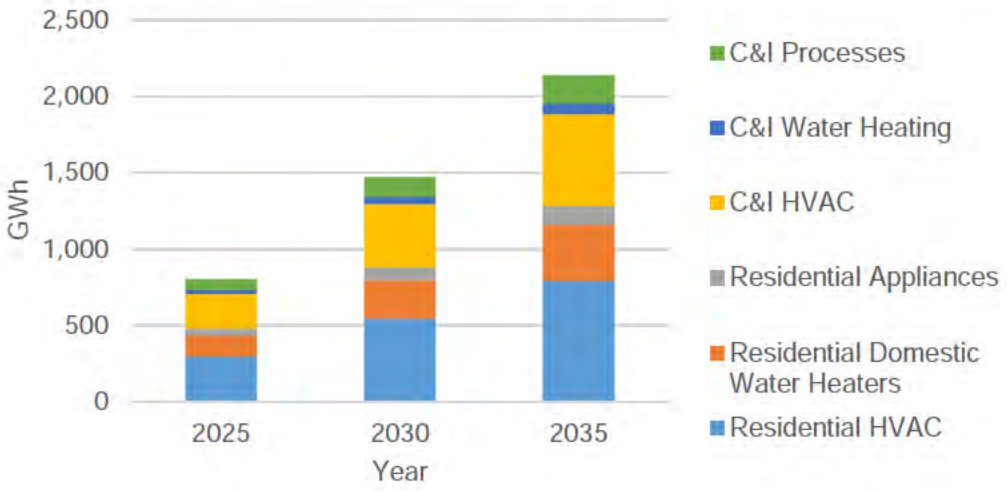
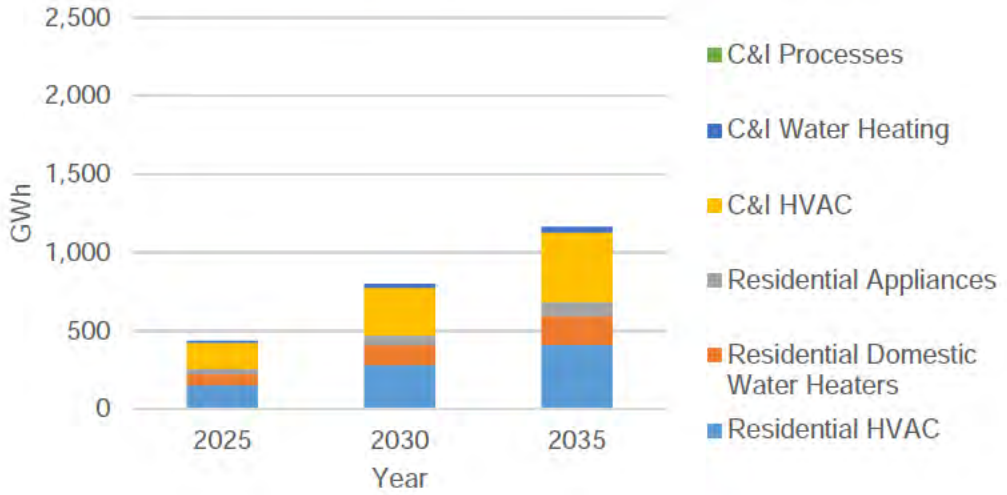


Figure 3-46: Electrification Impact on NIPSCO Energy Sales (AER Scenario)



3.8.5 Industrial Load Risk

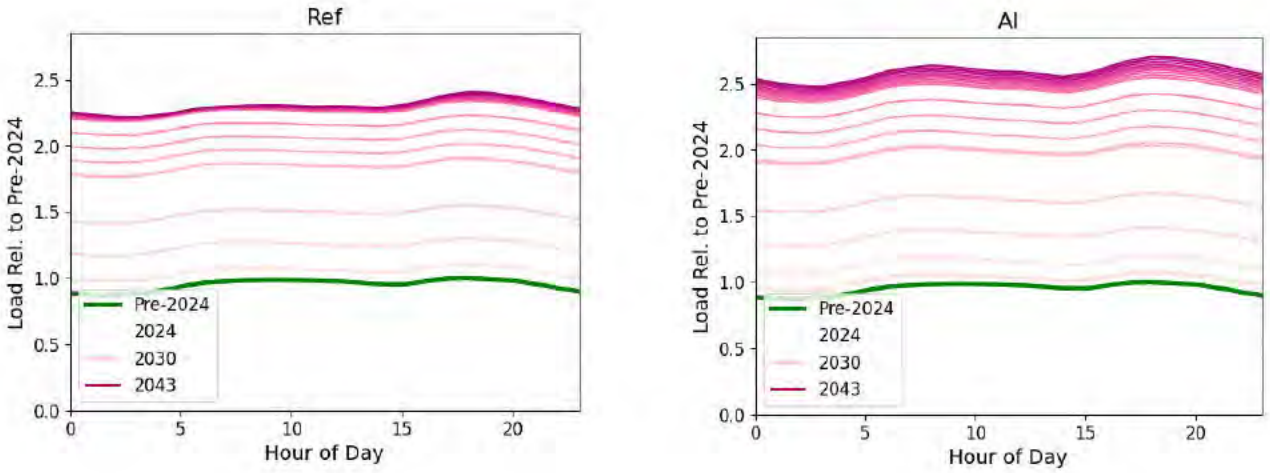
For the Slower Transition scenario, NIPSCO assumed that total industrial sales continue to decline at the pre-COVID rate (-0.12% CAGR). This scenario also incorporated the potential for additional industrial load migration, since NIPSCO recognizes that Tier 1 commitments may decline over time, particularly 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,

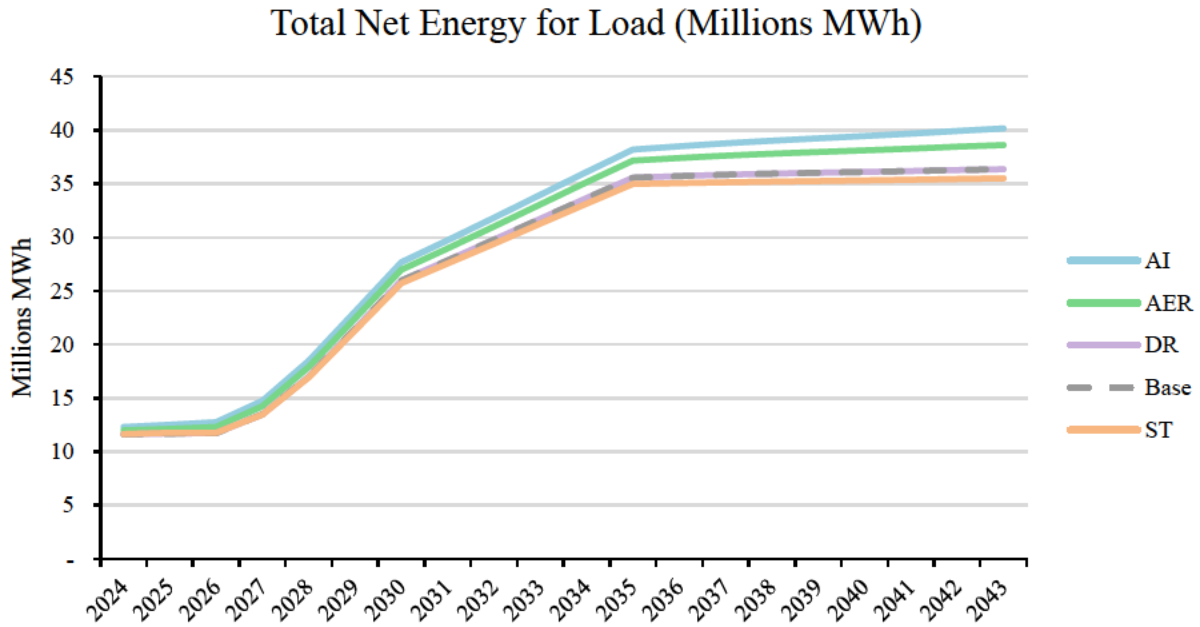
based on their expected performance in this new peak hour. For example, under current conditions, the peak may occur at 5 pm. However, with increasing DER and EV penetration, the new peak may be shifted back to 7 pm. To account for this change, the base load contribution to peak is scaled by current 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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 100B
NIPSCO 2024 IRP
Part 2

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

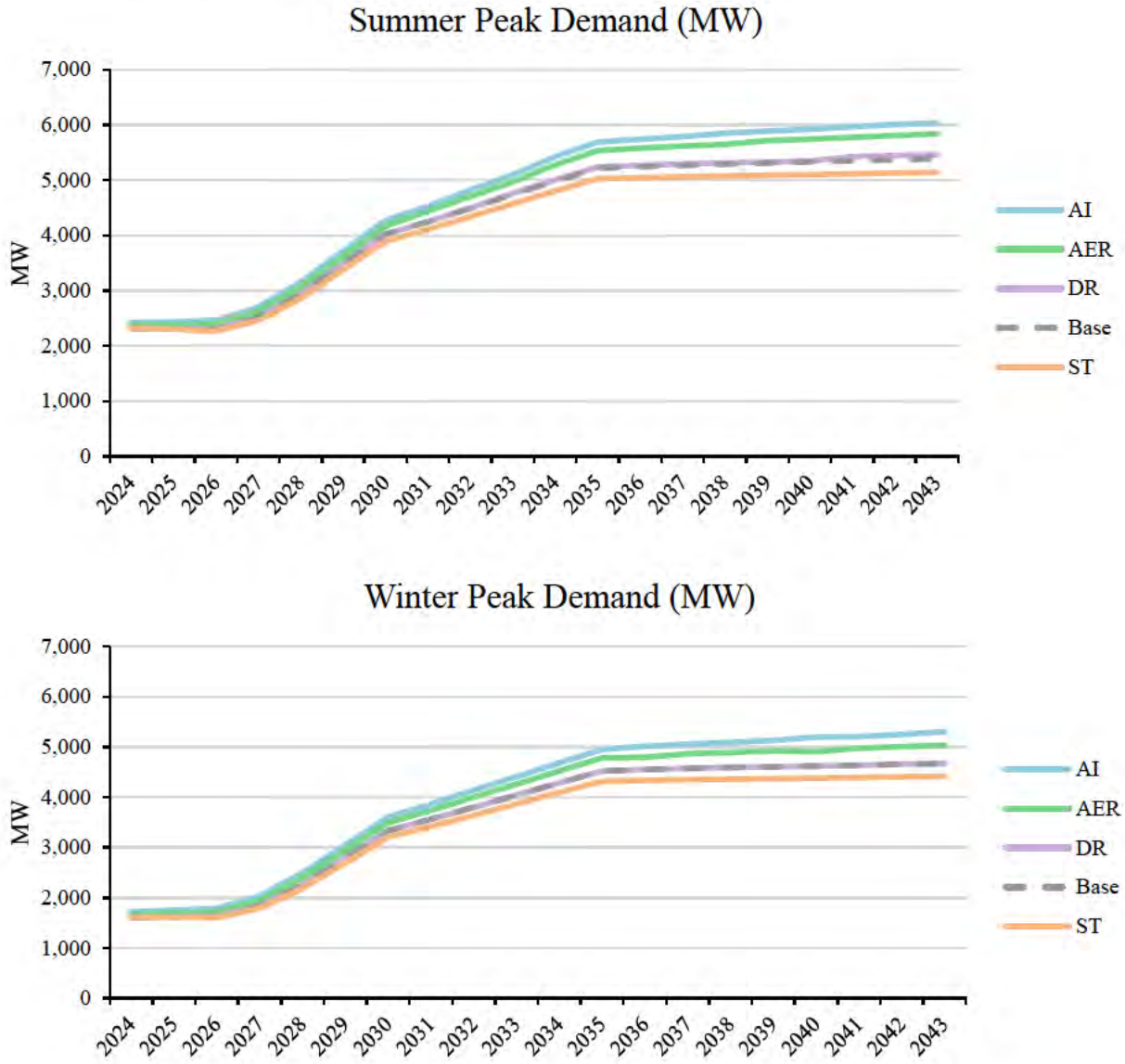
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 100
NIPSCO 2024 IRP

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

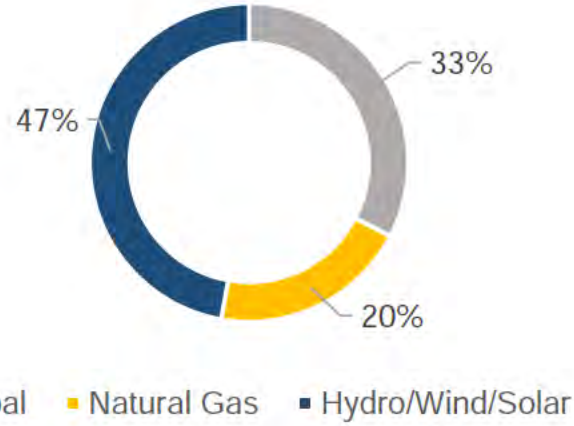
Table 4-14 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-1 illustrates NIPSCO's existing resources by fuel type.

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

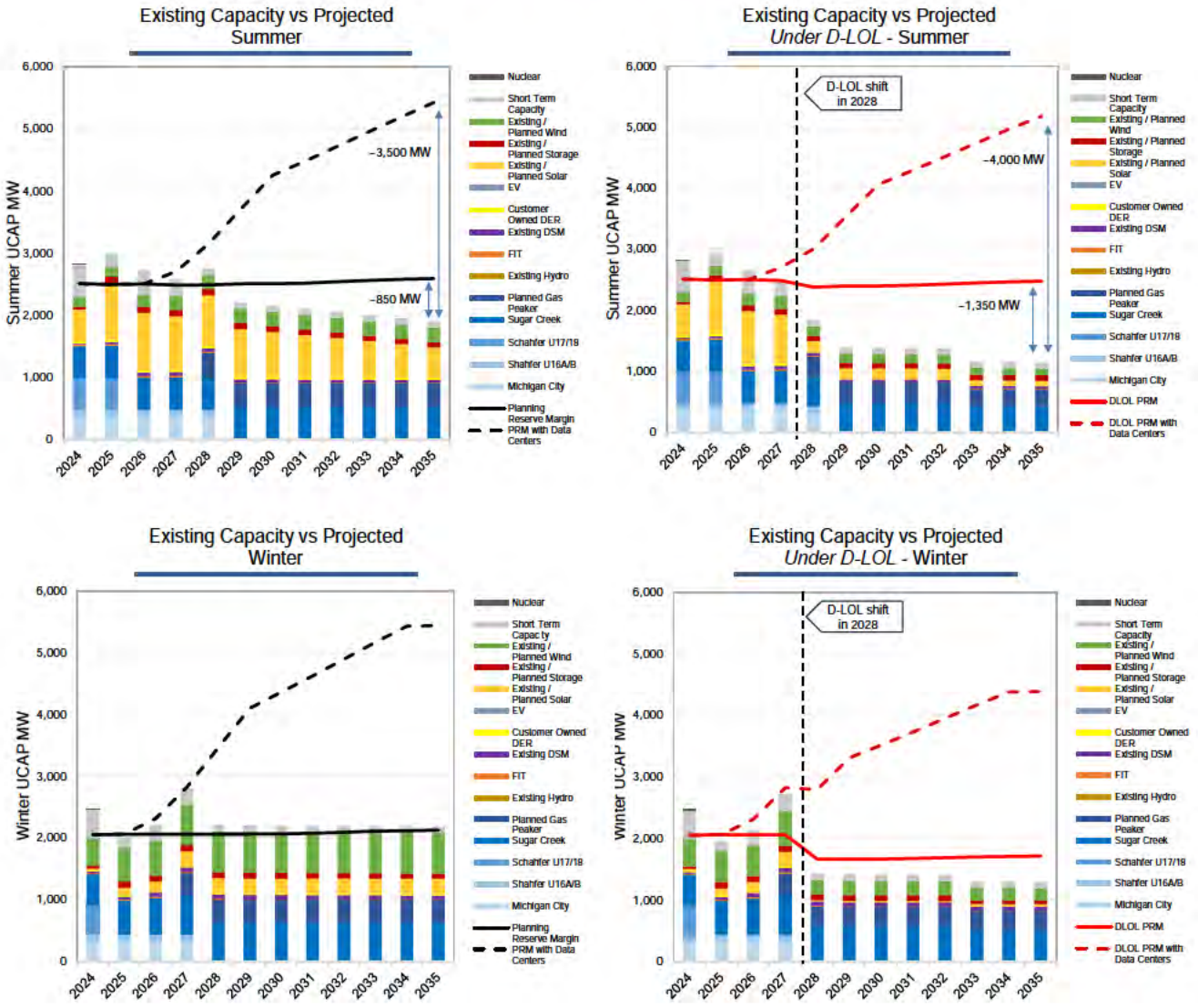
The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, 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.

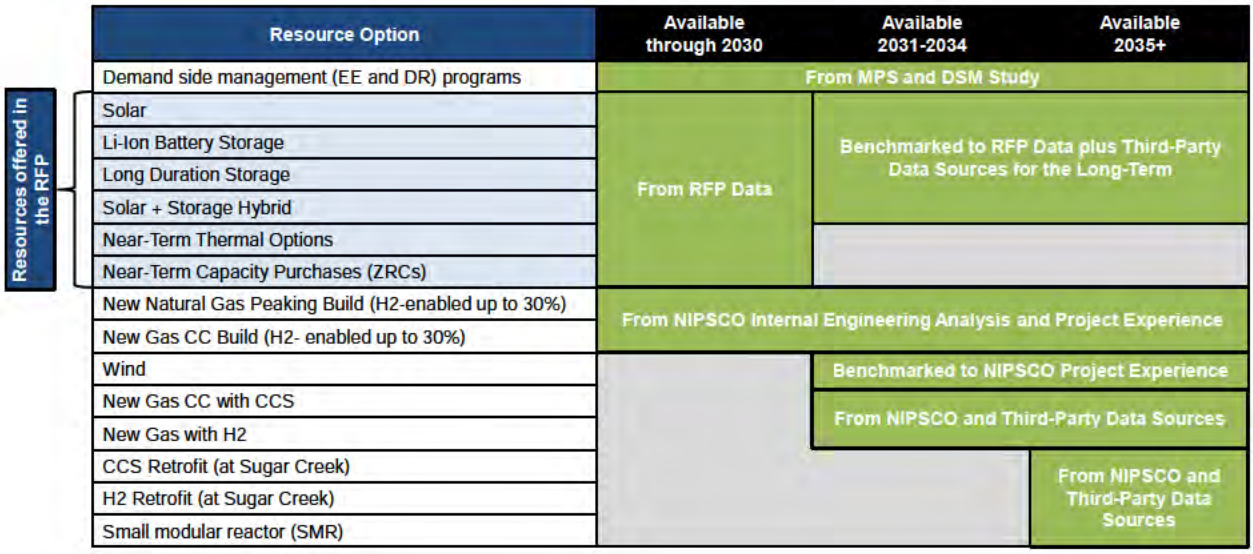
Figure 4-2: Resource Adequacy Assessment



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



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:

- Technology: 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	-	

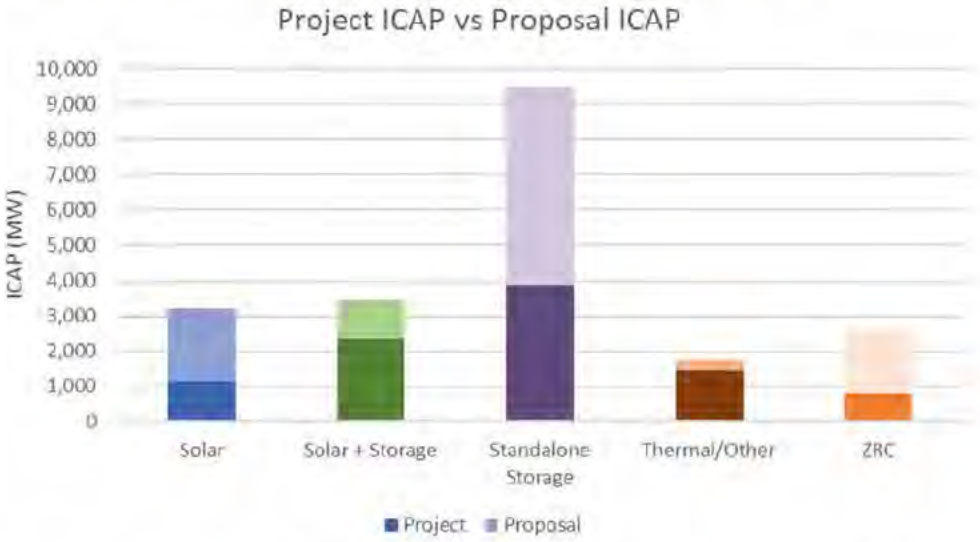
**Proposal count includes mutually exclusive projects. Projects offered as both Asset Sale and PPA/Toll are counted in the total as two proposals.*

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

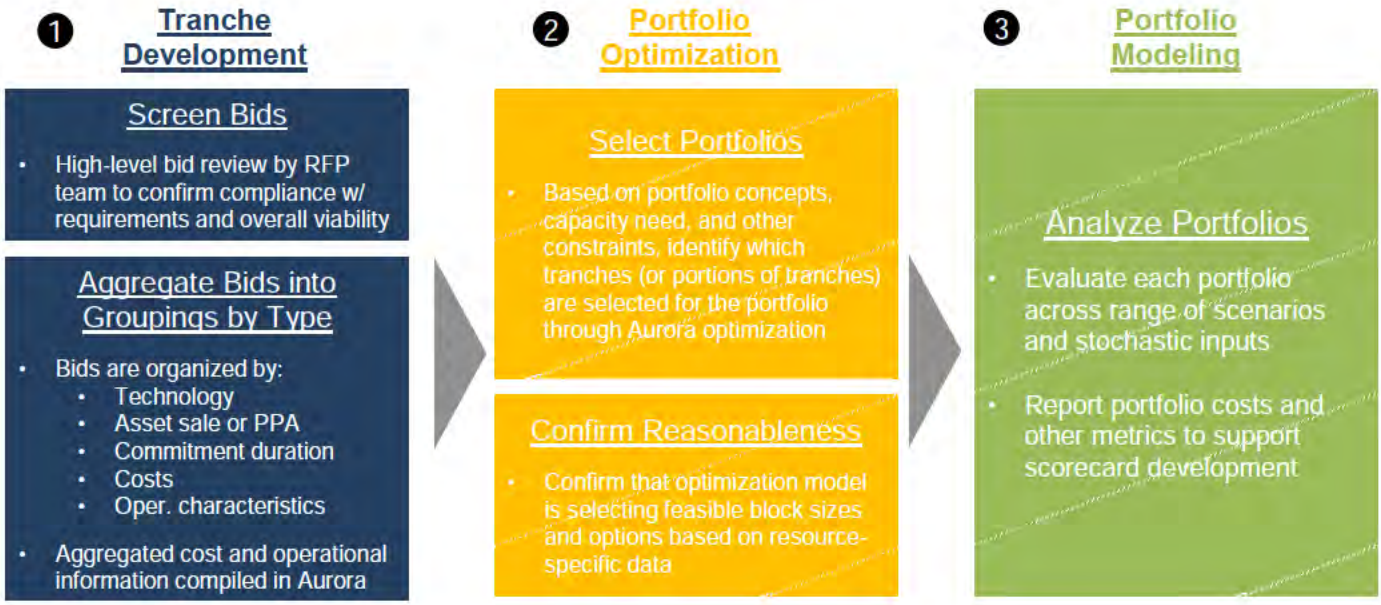
After gathering the bidder data from the RFP, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for RFP-IRP integration, which is outlined in Figure 4-7:

(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

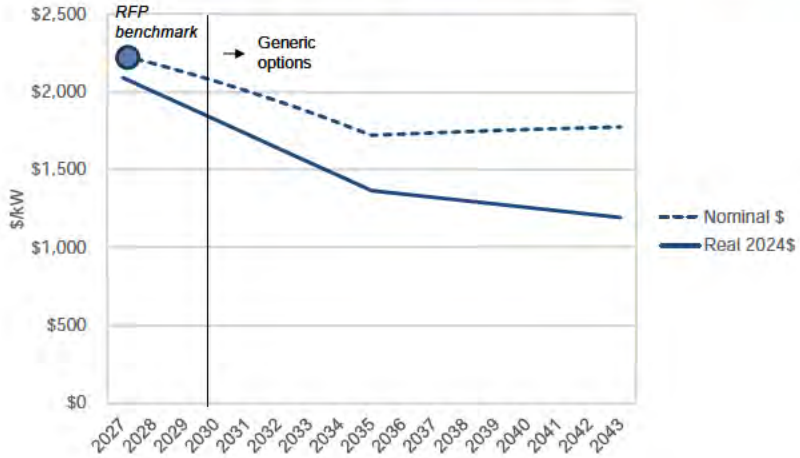
Beyond the RFP period, NIPSCO used a combination of RFP data, recent project experience, and third-party sources to develop cost and operational assumptions for well-

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.

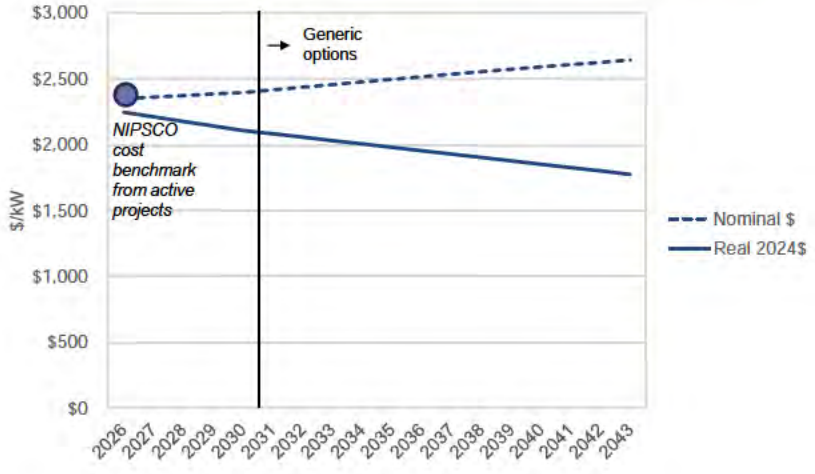
Figure 4-12: Long-Term Solar Cost Assumptions



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

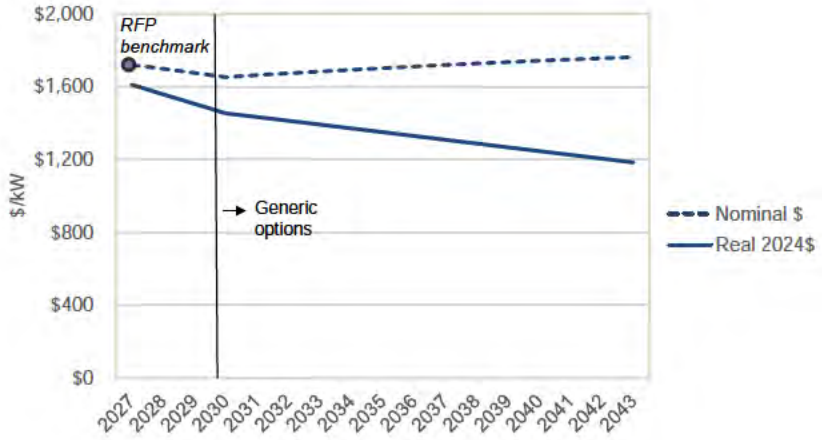


Category	Assumption
Fixed O&M (2024$/kW-yr)*	$34
Capacity Factor	39%
Tax Credit Eligibility Assumption	PTC

**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



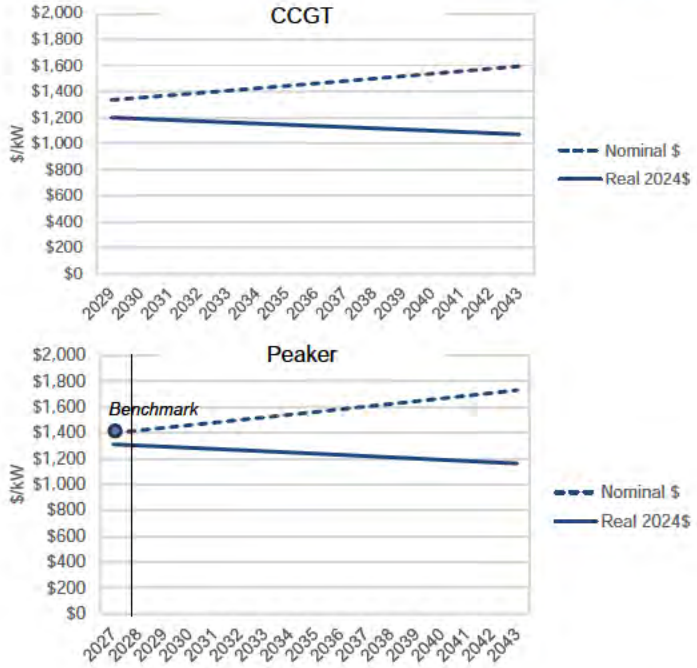
Category	Assumption
Fixed O&M (2024$/kW-yr)*	$40
Round Trip Efficiency	85%
Tax Credit Eligibility Assumption	40% ITC

**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.

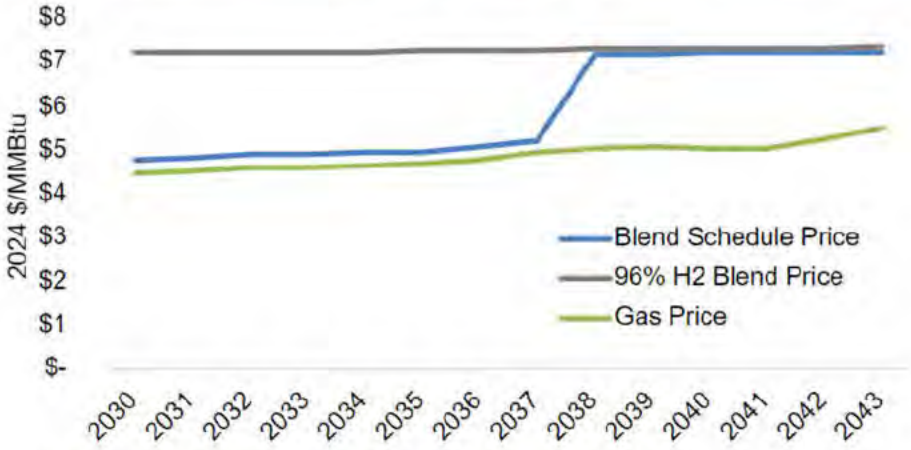
4.6.4.3 Hydrogen Modeling Input Assumptions Development

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

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.

---

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.

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

---

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"

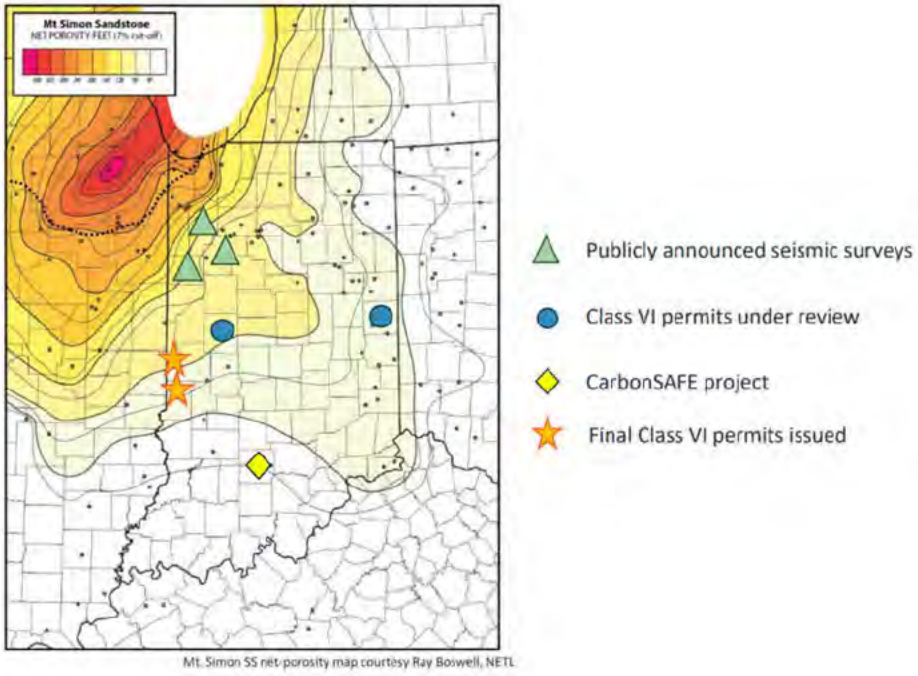
85 Clean Energy Systems – "Mendota Biomass Carbon Removal and Storage Project (BiCRS)"

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.

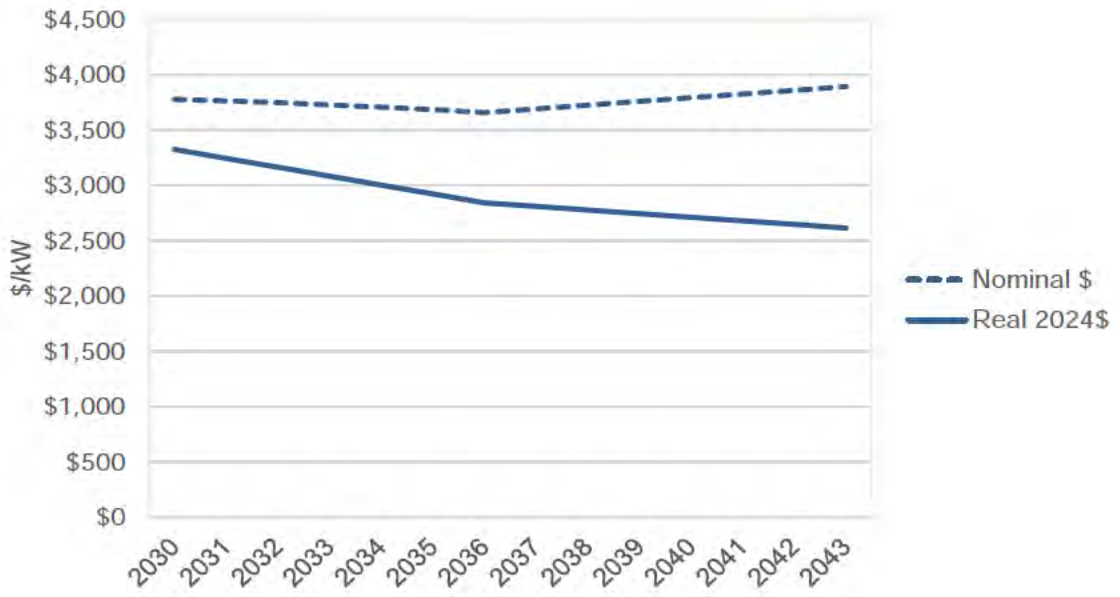
[90] See 2023 NREL Annual Technology Baseline and U.S. Environmental Protection Agency CO2 Capture, Storage, and Transport Assumptions: Chapter 6 - CO2 Capture, Storage, and Transport (epa.gov)

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

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 CO2 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 CO2 storage system, which utilizes an above-tank to achieve inter-day storage by compressing CO2. 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 CO2 to a liquid phase for storage in a dome-shaped, above-ground pressure vessel. The discharge process reverses this cycle, reheating the stored CO2 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.

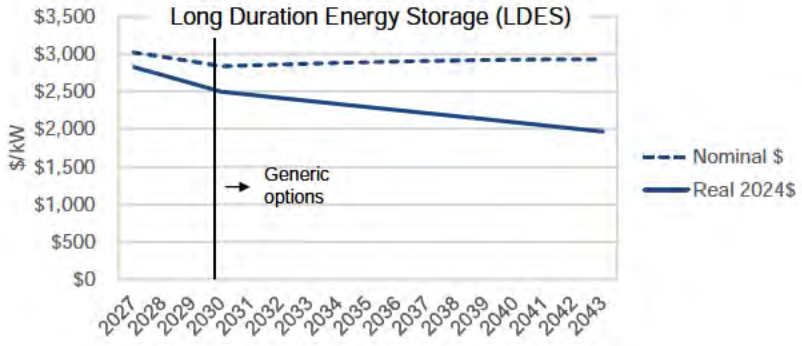
A few promising long duration technology categories identified by the U.S. Department of Energy include aqueous-electrolyte flow batteries, metal-anode batteries, and hybrid flow batteries. While this list is far from comprehensive, it helps to demonstrate some of the key characteristics of electrochemical 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

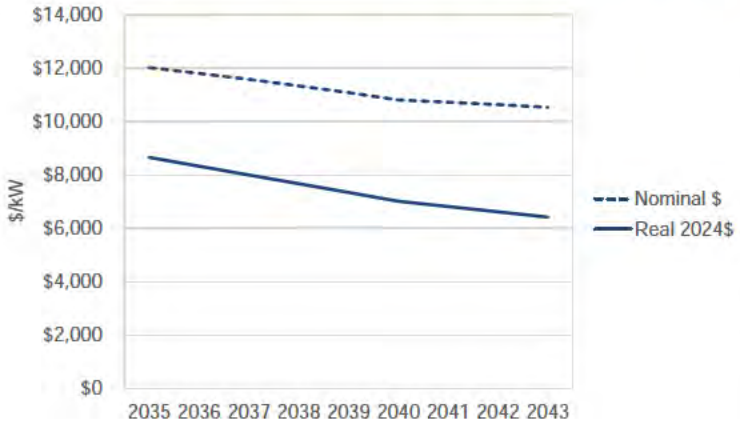
In general, SMRs are characterized by high capital costs and relatively low variable costs. Their small size and modular designs enable mass production, rapid assembly of components, and transportation of entire units, leading to significantly reduced financing and capital expenses relative to larger 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

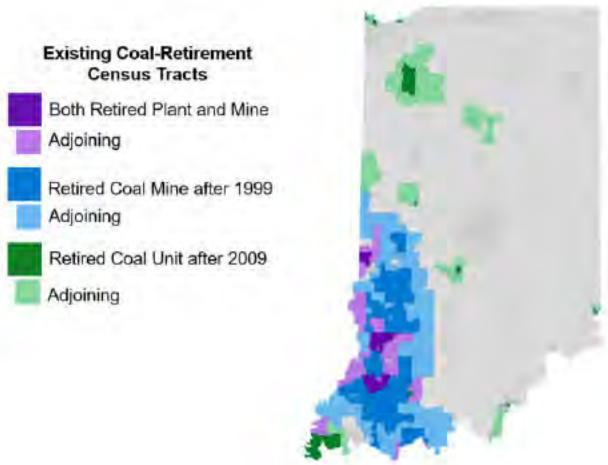
In-Service Year[6]	Production Tax Credit[1, 2]	Investment Tax Credit[1, 2]	CCS (Section 45Q)[1]	Hydrogen PTC (Section 45V)[1, 3]
	10-year $/MWh	*Up front portion of investment*	*12-year $/metric ton-CO2*	*10-year $/kg*
	$30/MWh in 2024$[5]	*%*	*$85 in 2026$[5]*	*$3/kg[4] in 2022$[5]*
2024-2035	100% of 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

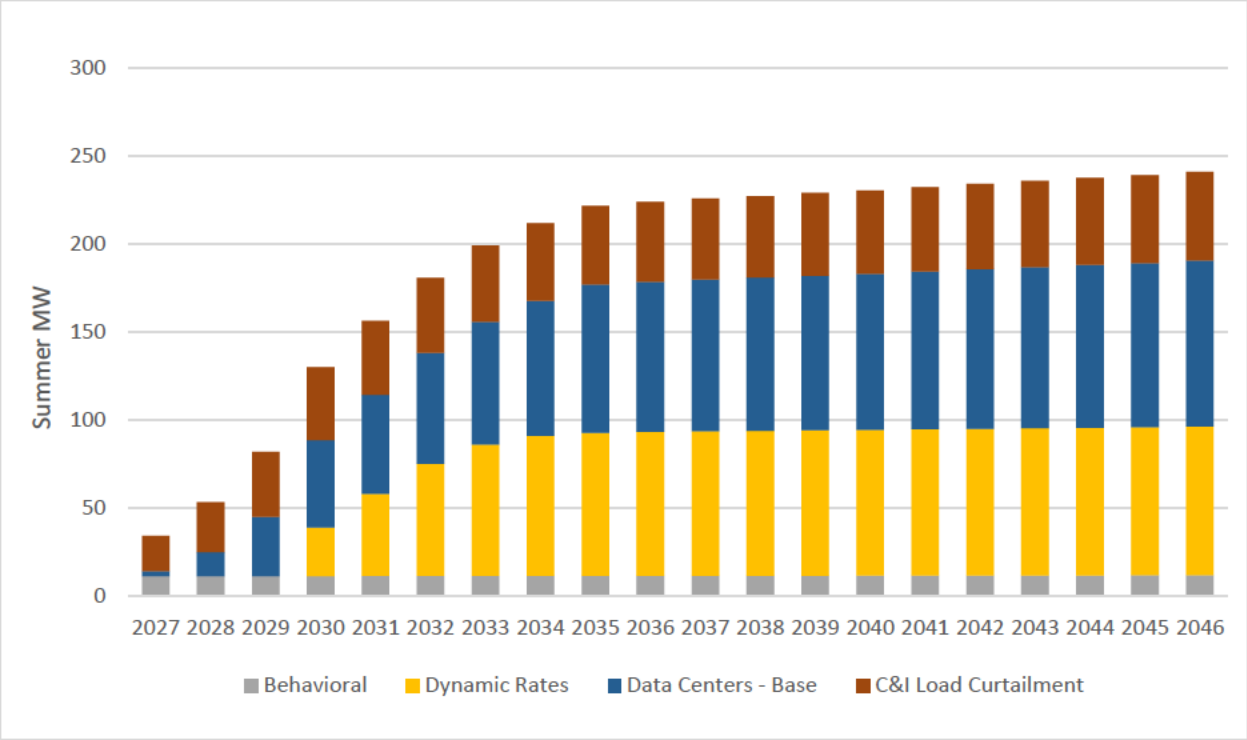
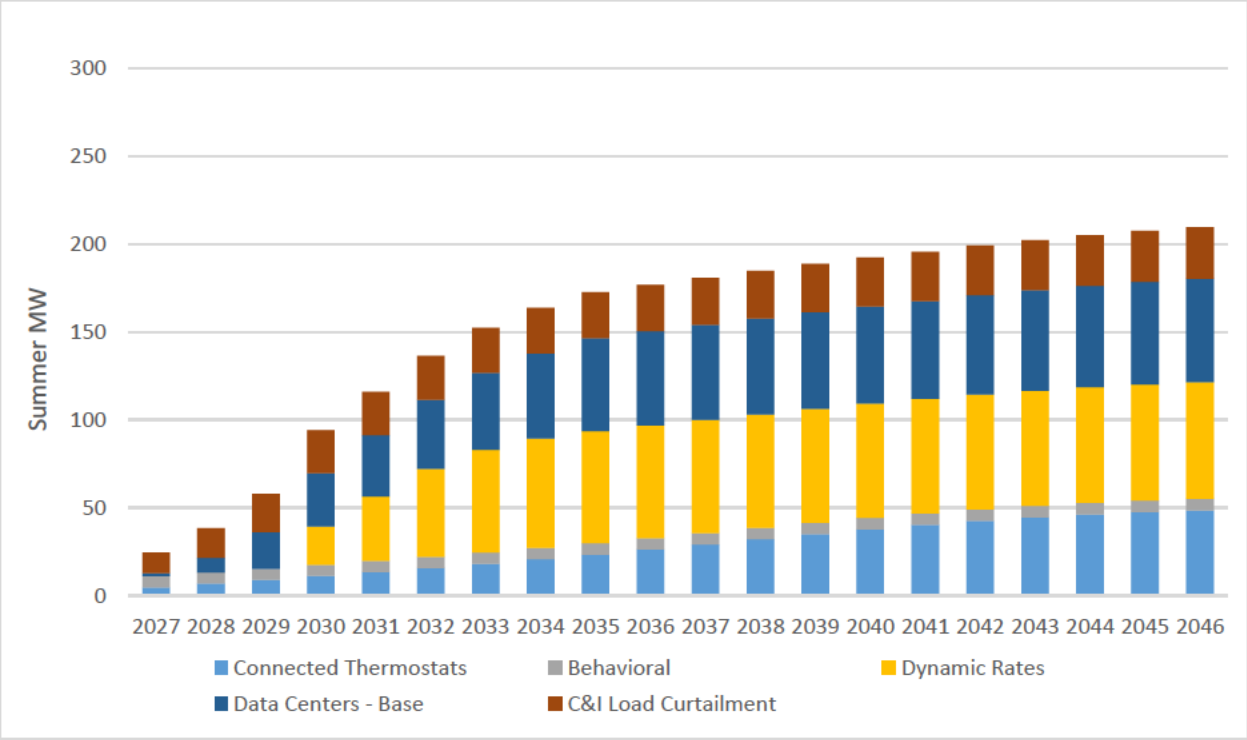


Figure 5-2: Realistic Achievable DR Potential by Program



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			

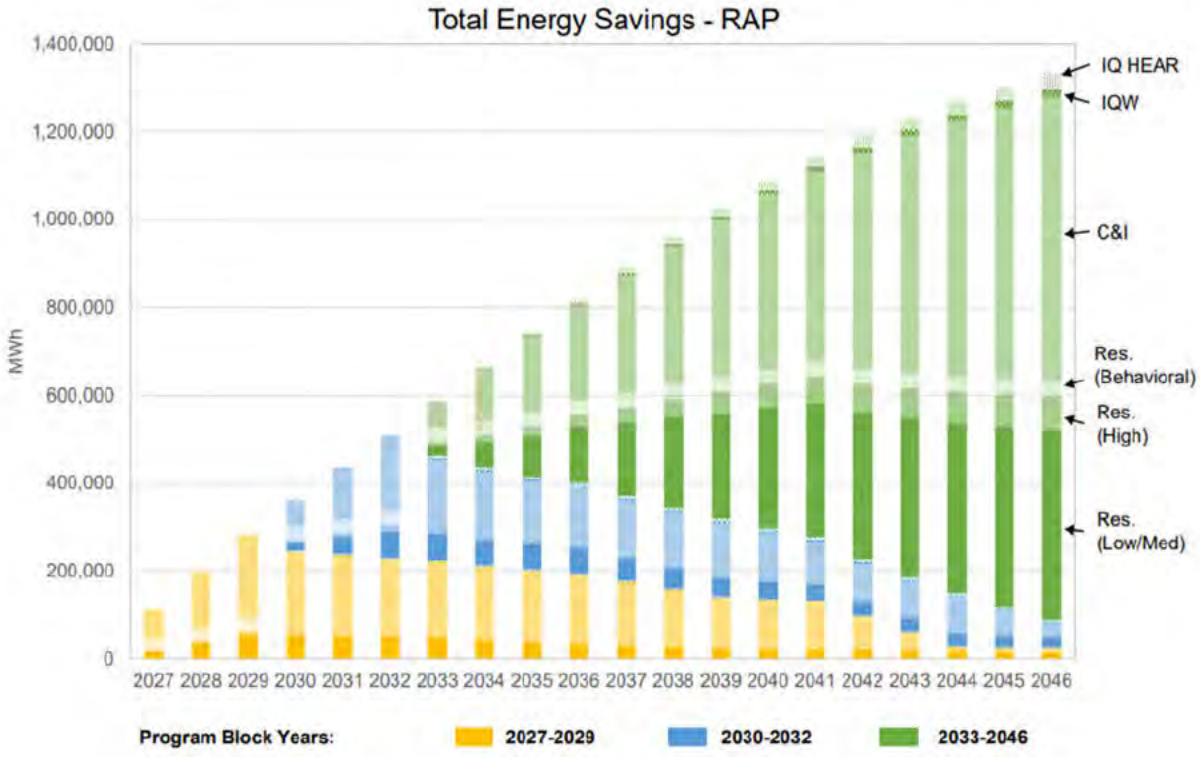
Table 5-20: 2033-2046 Energy Efficiency Base Case Bundles – Enhanced RAP

	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.

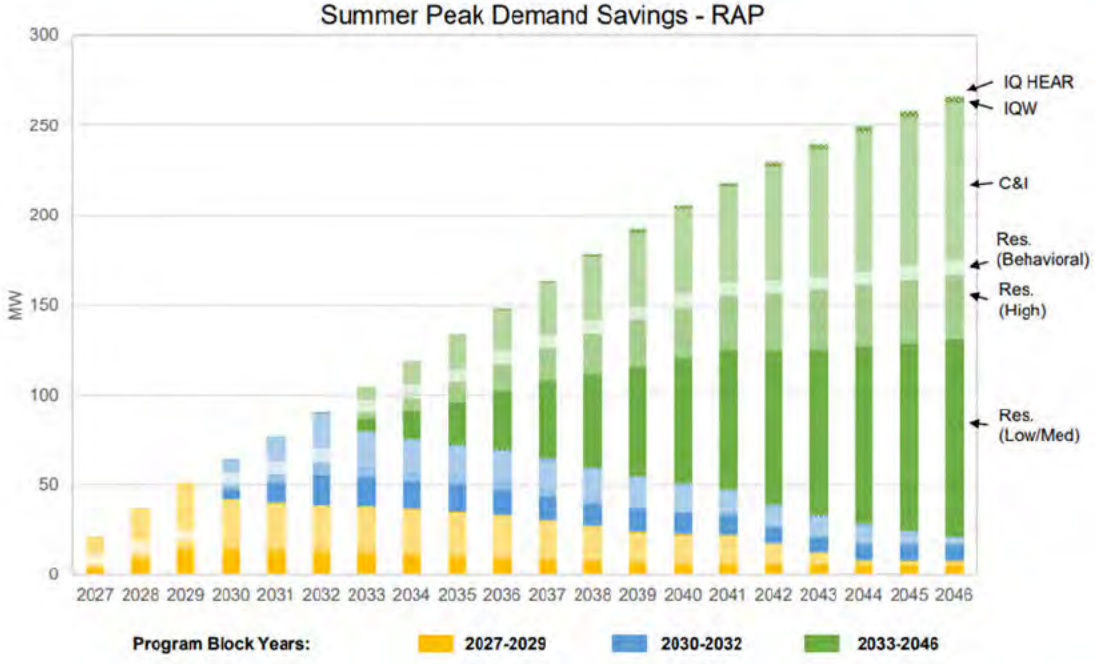
Figure 5-3: Energy Efficiency MWh Savings Bundle Illustration - RAP

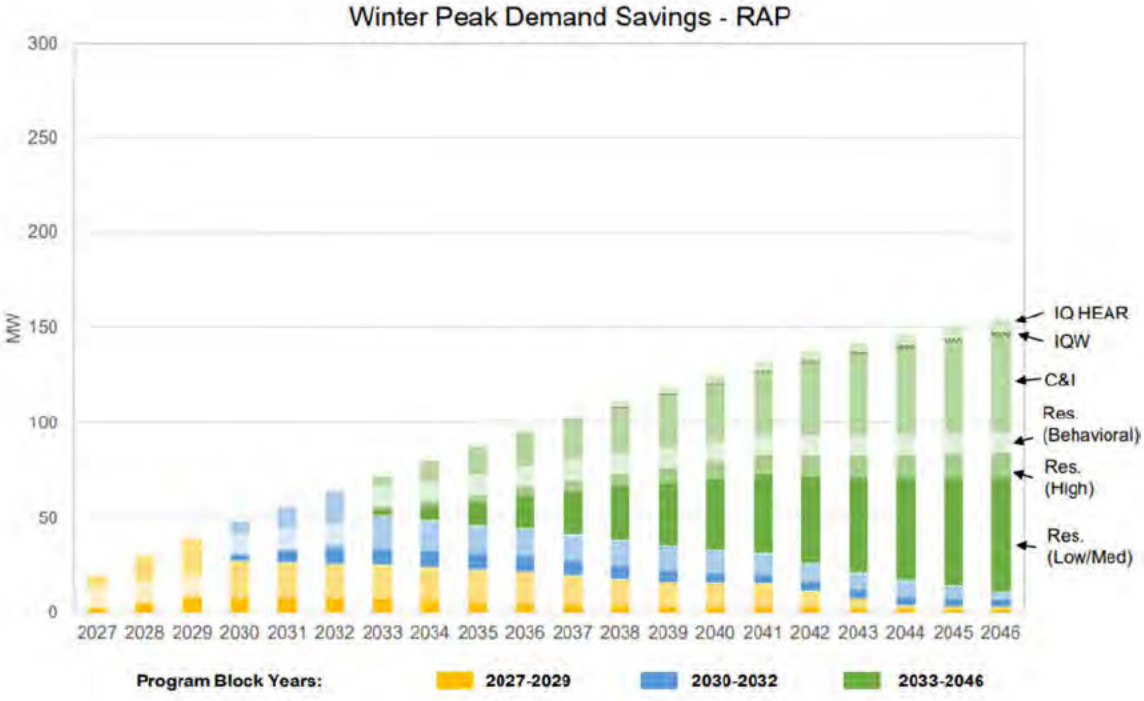


Bundle	Lifetime Levelized Cost ($/MWh) 2027-2029	2030-2032	2033-2046
IQ HEAR*	89.09	91.67	99.93
IQW*	77.50	80.02	87.62
C&I	15.81	18.69	22.35
Res. (Behavioral)	58.21	62.13	73.39
Res. (High)	101.51	102.34	106.77
Res. (Low/Med)	26.56	24.95	27.84

**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	$242.36	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	$108.06	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	$106.34
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	$169.46	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

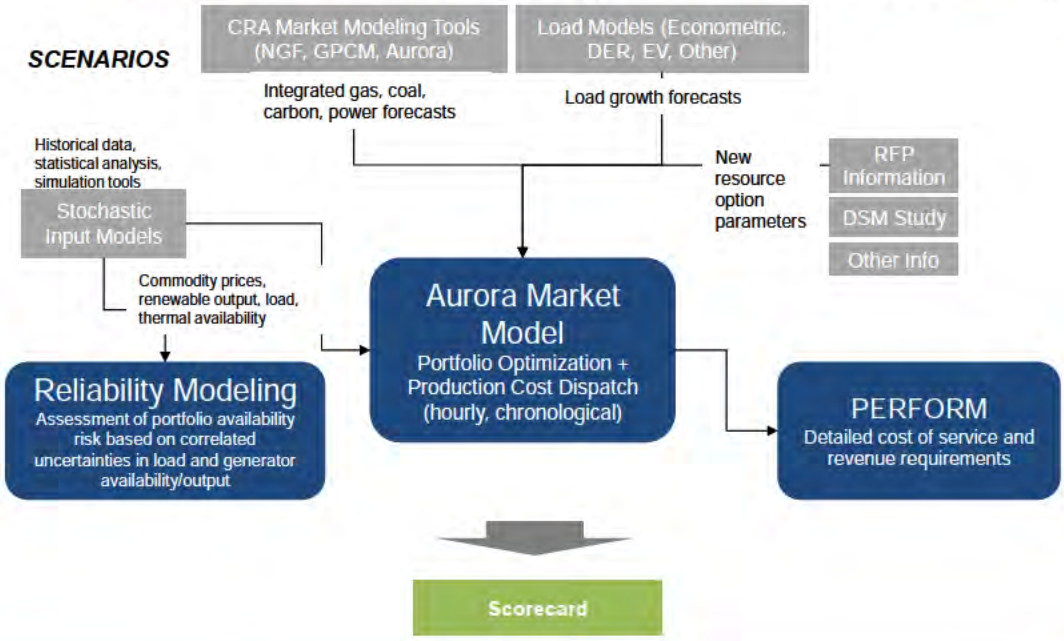
8.1 Introduction & Process Overview

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

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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 100C
NIPSCO 2024 IRP
Part 3

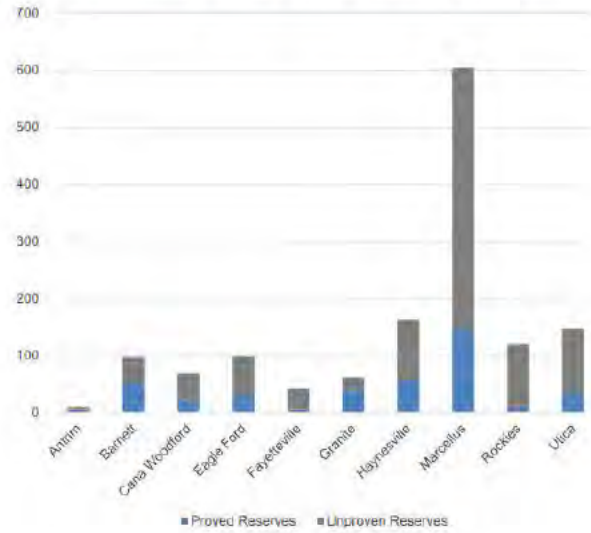
Figure 8-4: Demand Side Natural Gas Price Drivers – Reference Case

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

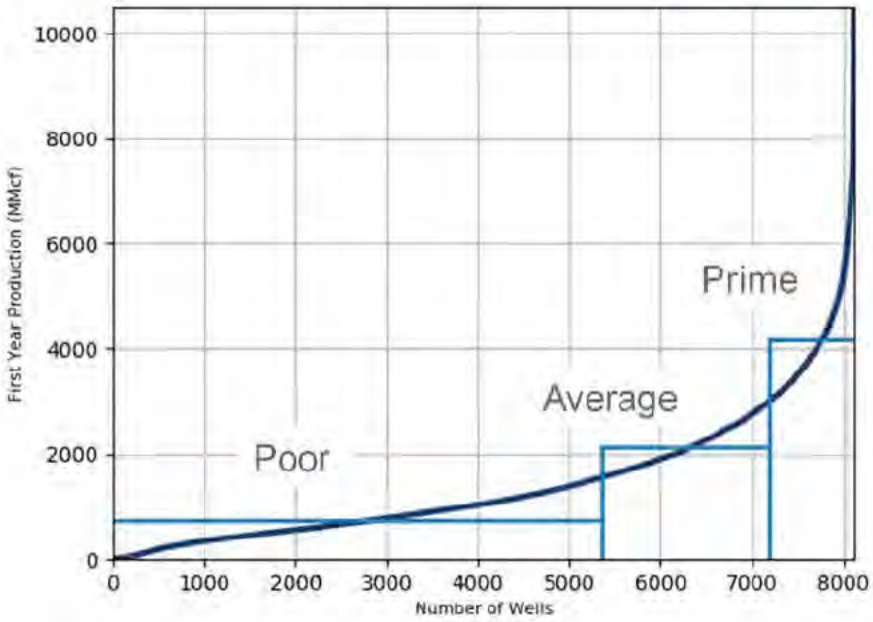


136 Note that the PGC 2022 view was released in July 2023, with PGC 2024 not available at the time of the development of NIPSCO's 2024 IRP assumptions. Scenario development (discussed further below) incorporates a range of views on the future resource base, anticipating potential ranges of resource base 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



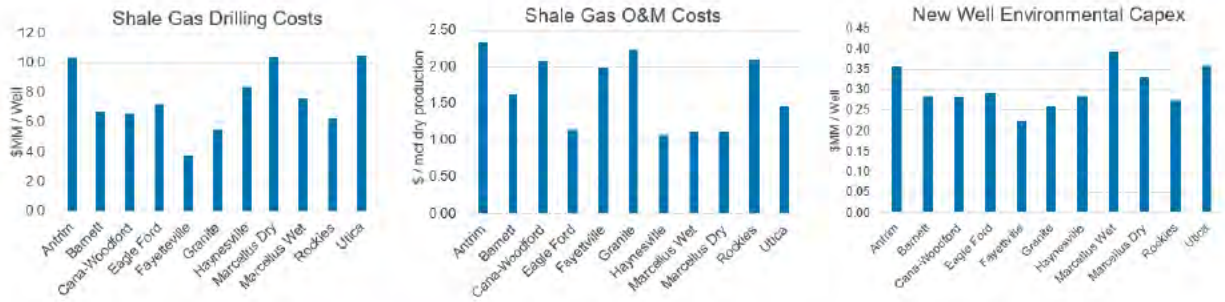
Well Costs

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.

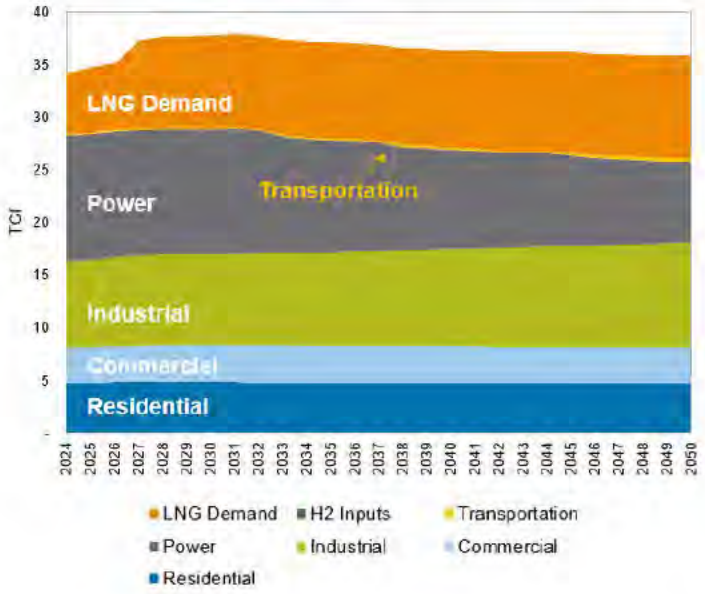
Figure 8-7: Shale Gas Drilling Costs



8.2.1.3 Demand

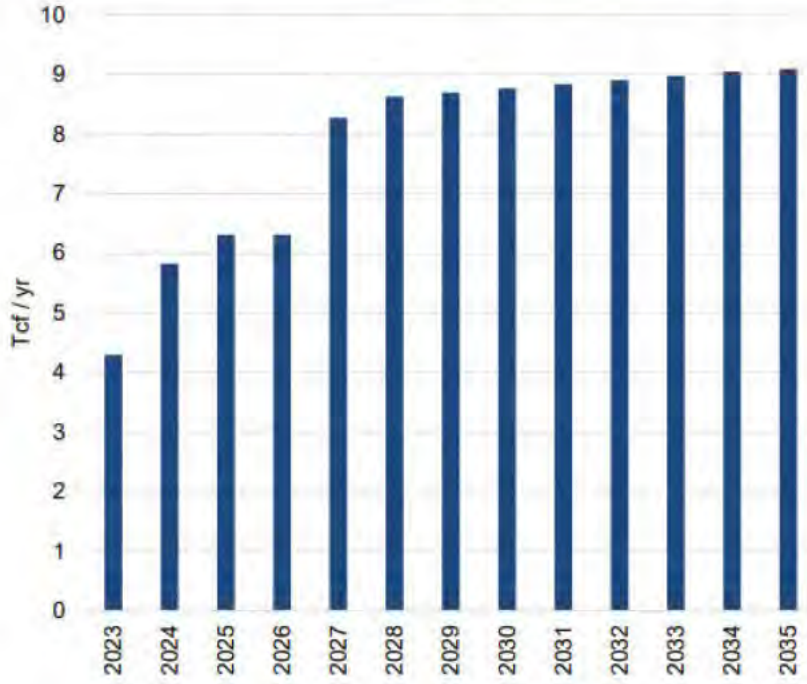
In projecting domestic natural gas demand growth, CRA relies on the AEO's projections for total demand and develops an independent electric sector demand forecast using its hourly Aurora dispatch model of the entire United States. Figure 8-8 presents the projected domestic demand assumptions through 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

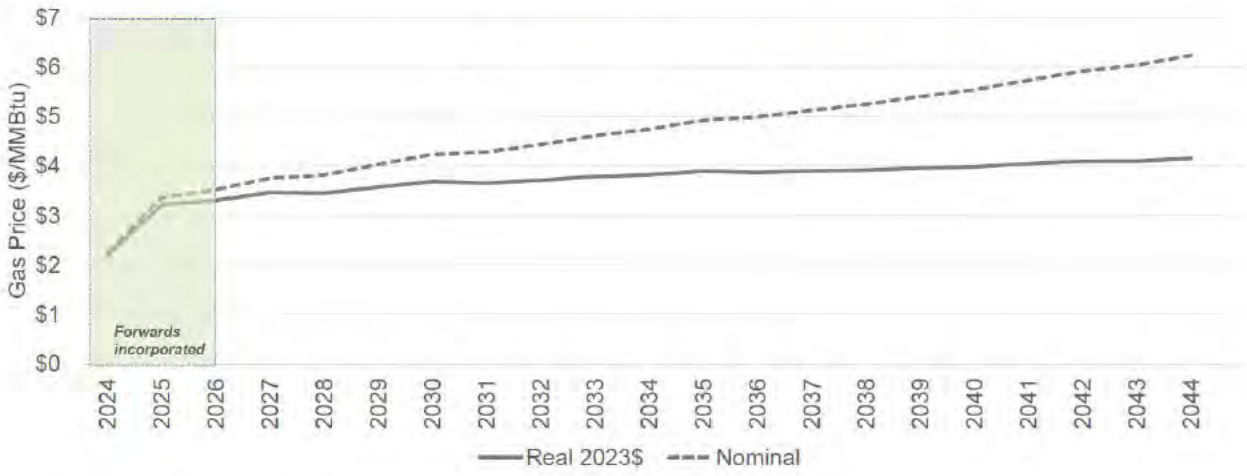


8.2.1.4 Reference Case Price Forecast

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.

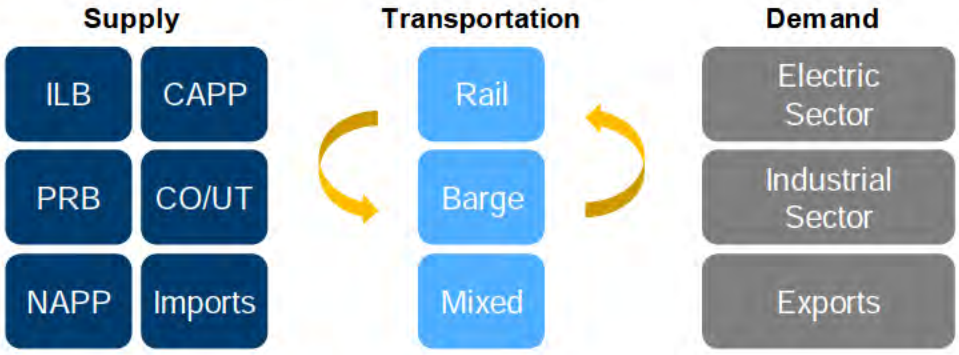
Figure 8-10: Reference Case Gas Price Forecast



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.

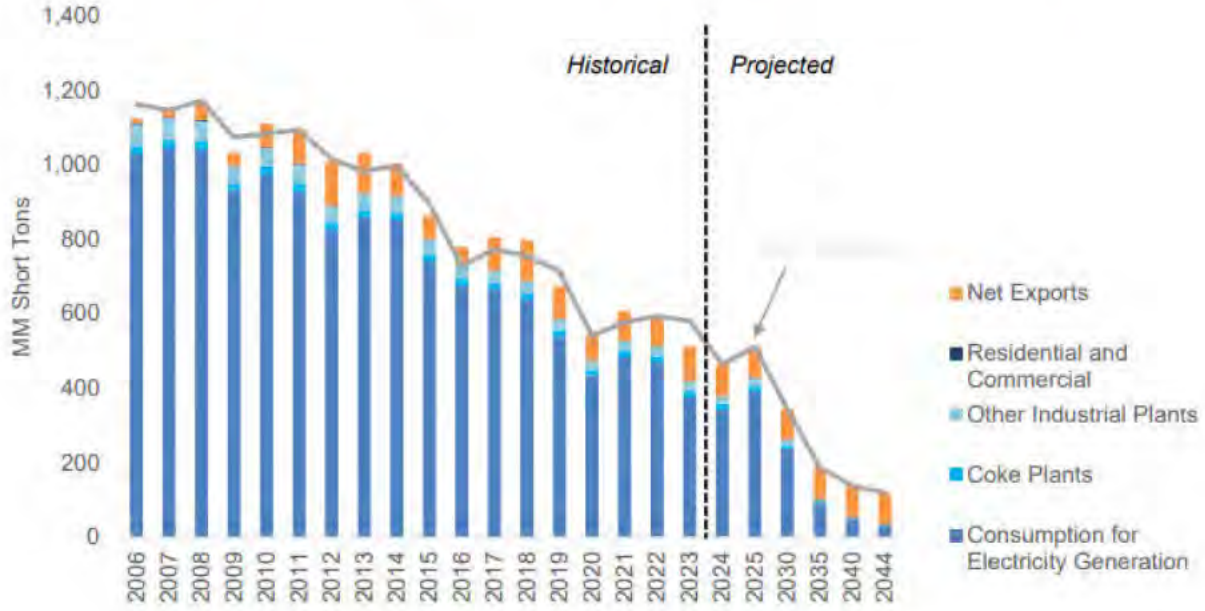
Figure 8-11: Coal Forecasting Process Overview



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]

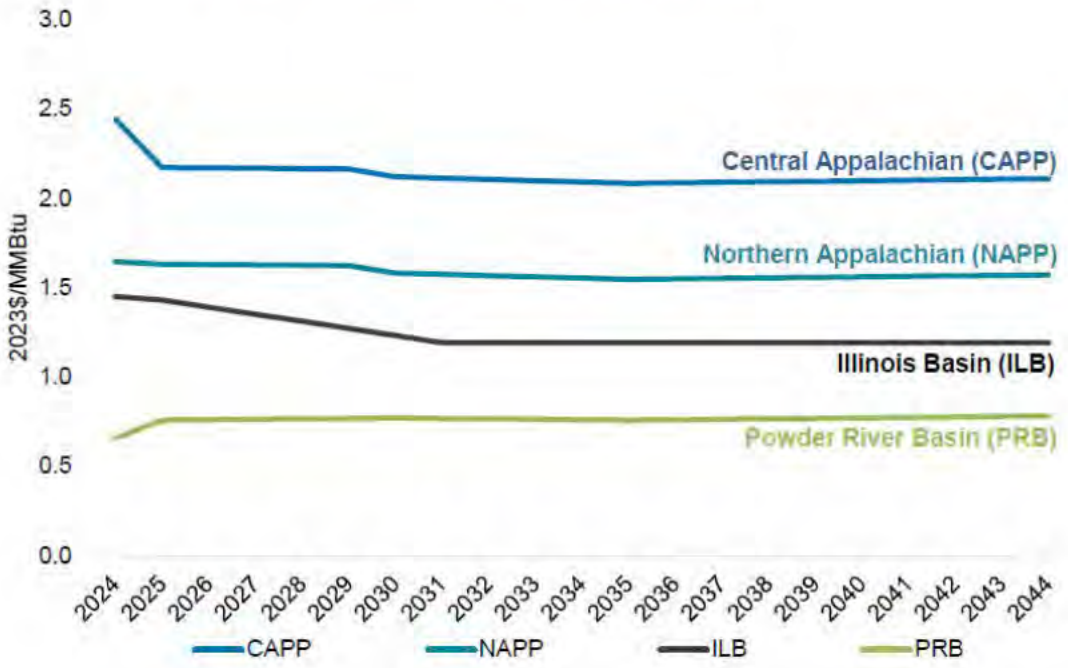


8.2.2.2 Reference Case Price Forecast

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:

[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;

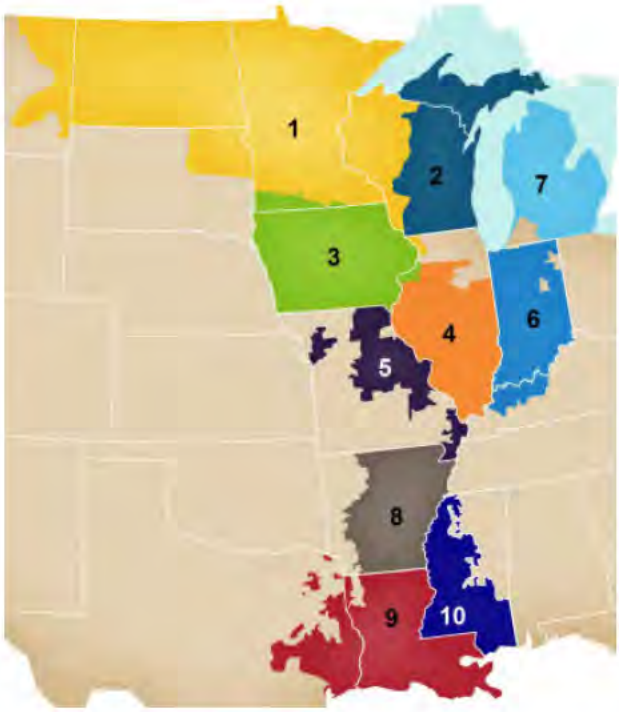
- Coordinates with utilities, states, and federal entities (FERC and NERC) to ensure the reliable, non-discriminatory operation of the bulk power transmission system; and

- 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.

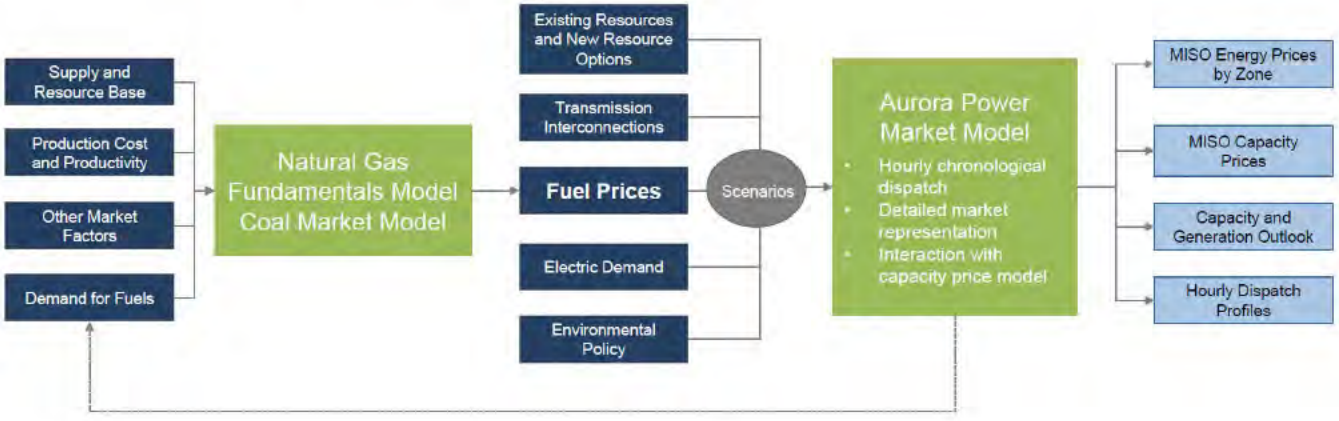
140 See https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

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.

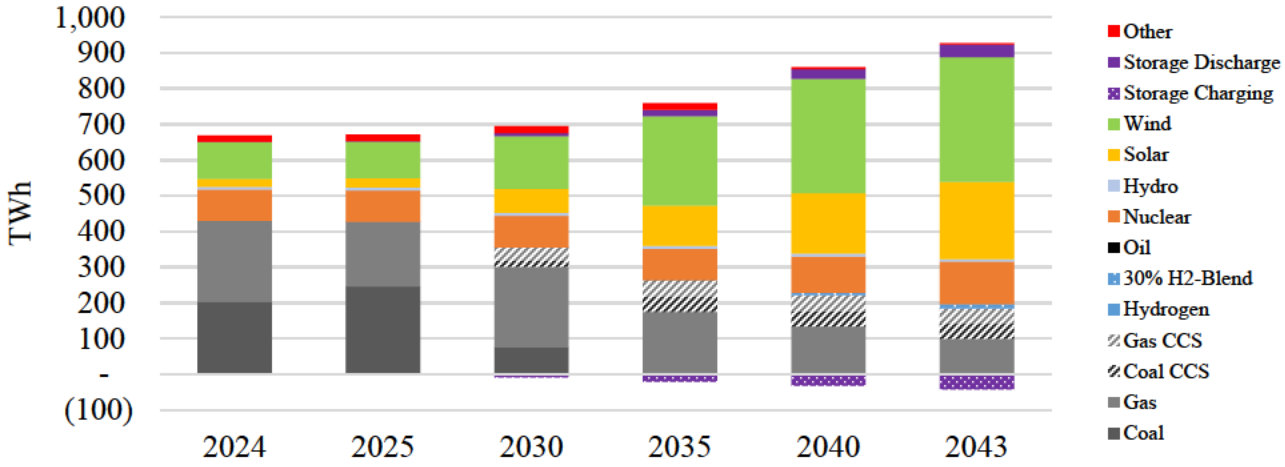
Figure 8-15: Power Market Modeling Process



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

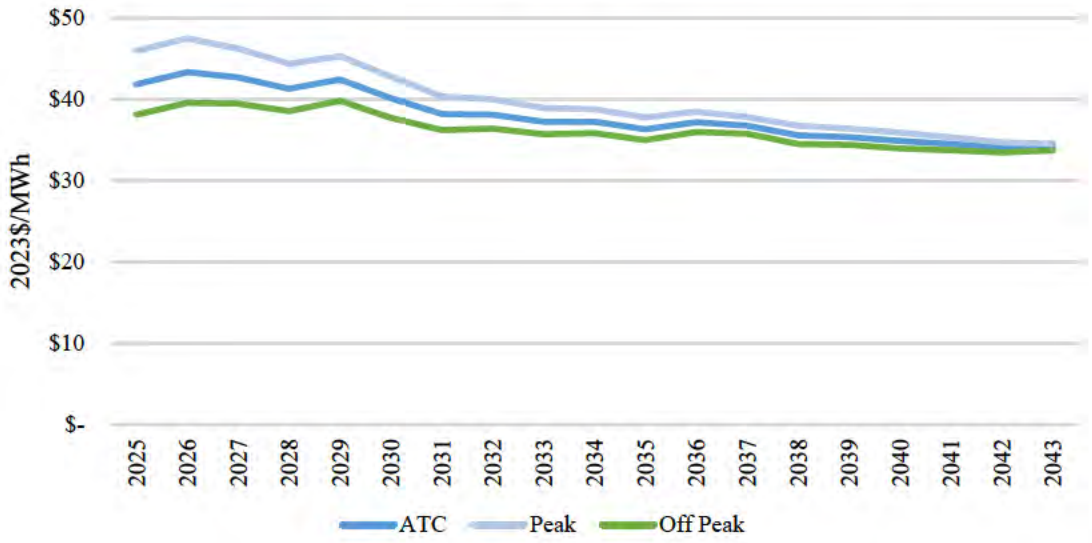
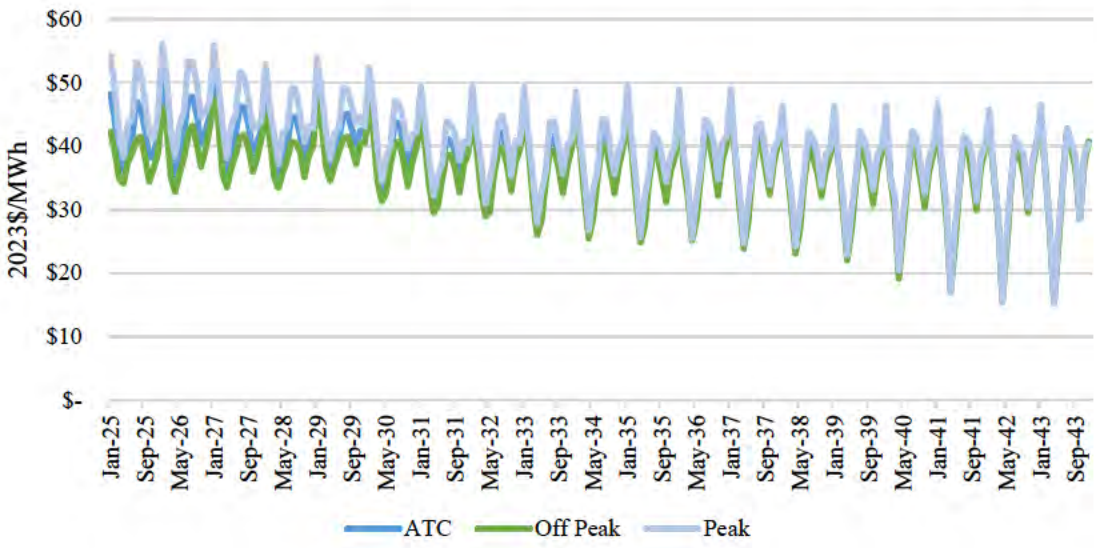
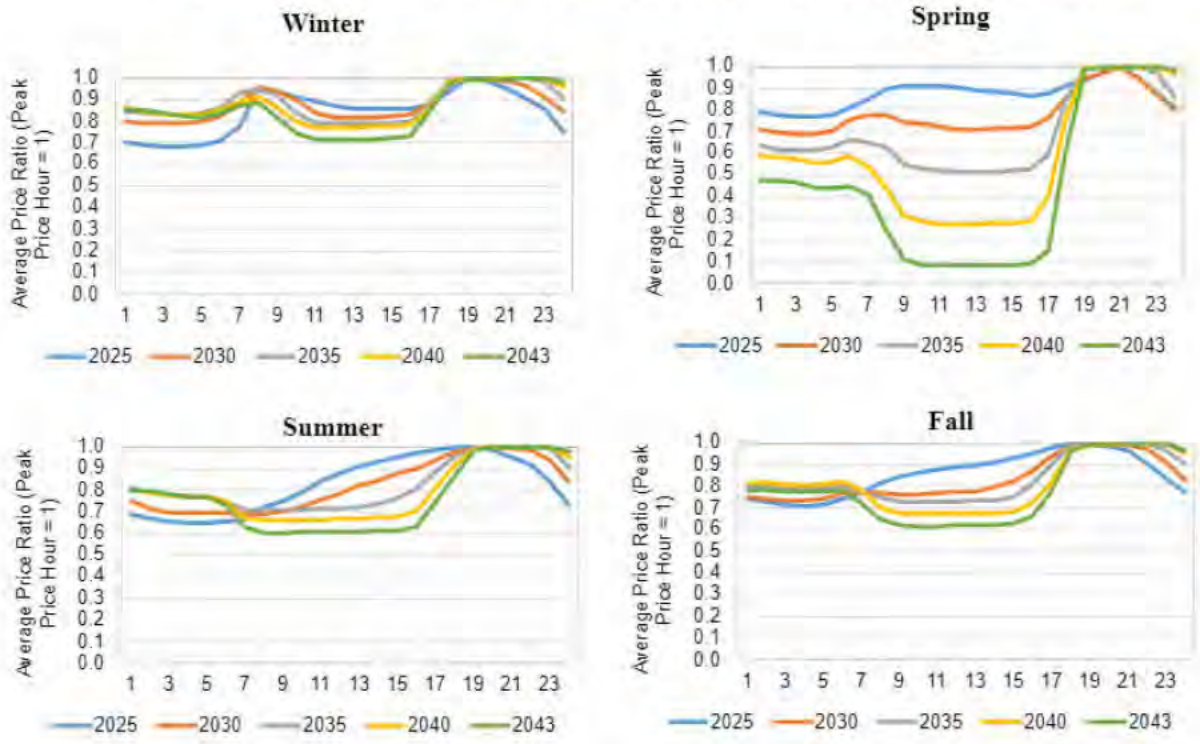


Figure 8-18: LRZ6 (Indiana) Reference Case Monthly Price Projections



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

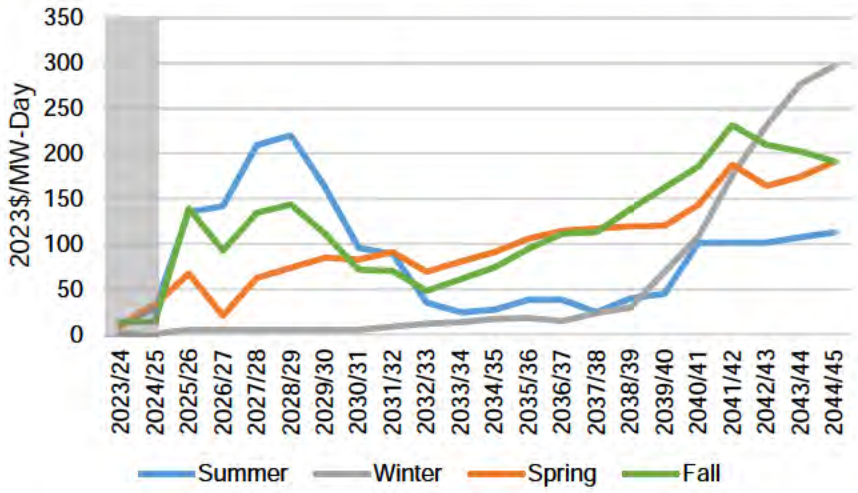


8.2.4.3 Reference Case Capacity Price Forecast

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.

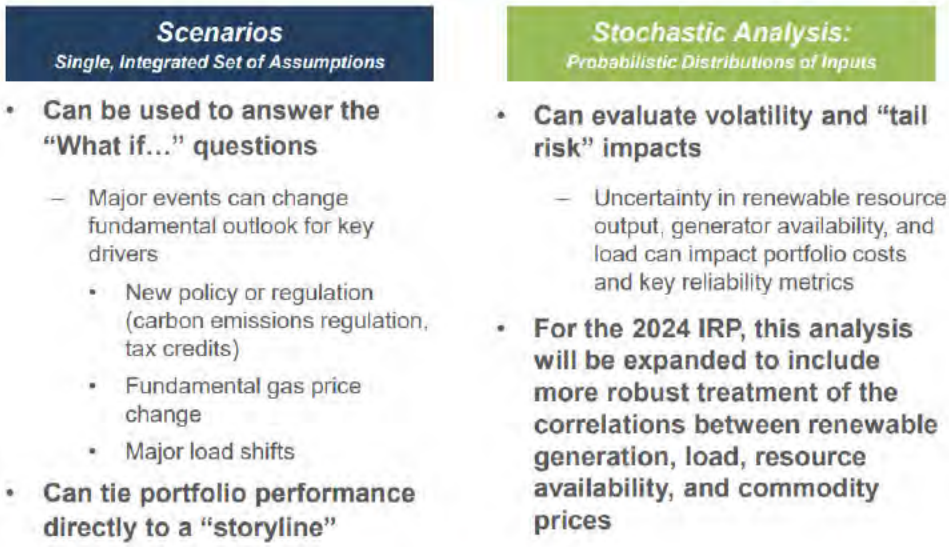
After identifying the major drivers of uncertainty, NIPSCO then assessed whether each would be best addressed through scenario or stochastic analysis.[141] In the 2024 IRP, NIPSCO has structured its risk and uncertainty analysis to analyze portfolio decisions across *both* scenario risk and stochastic 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

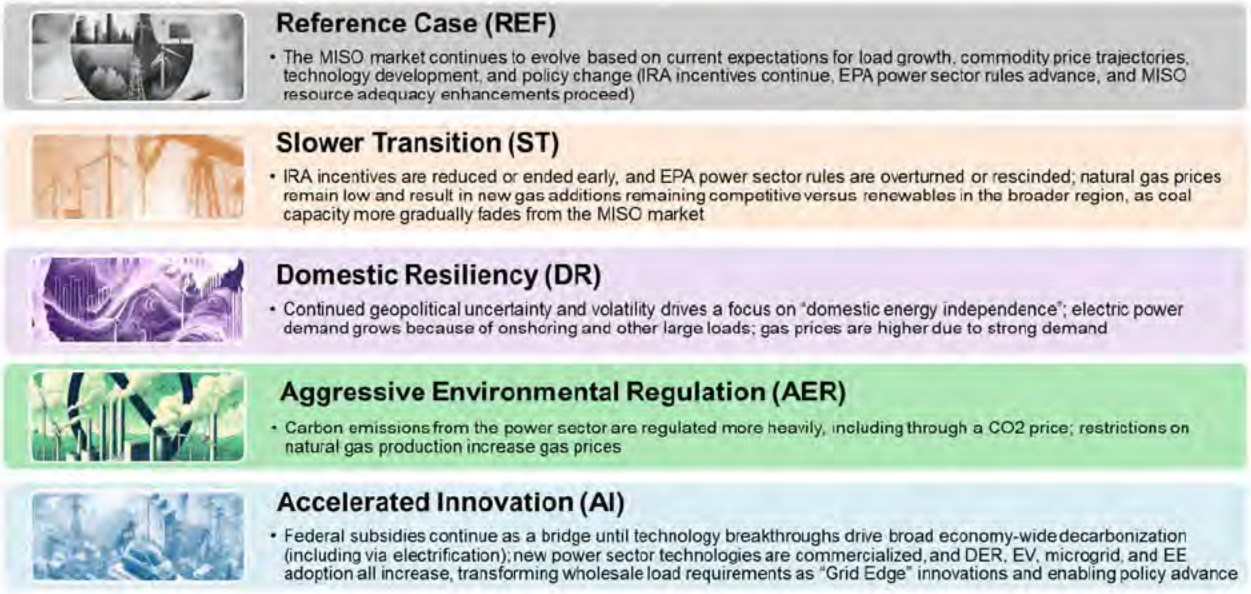


8.4 IRP Scenarios

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.

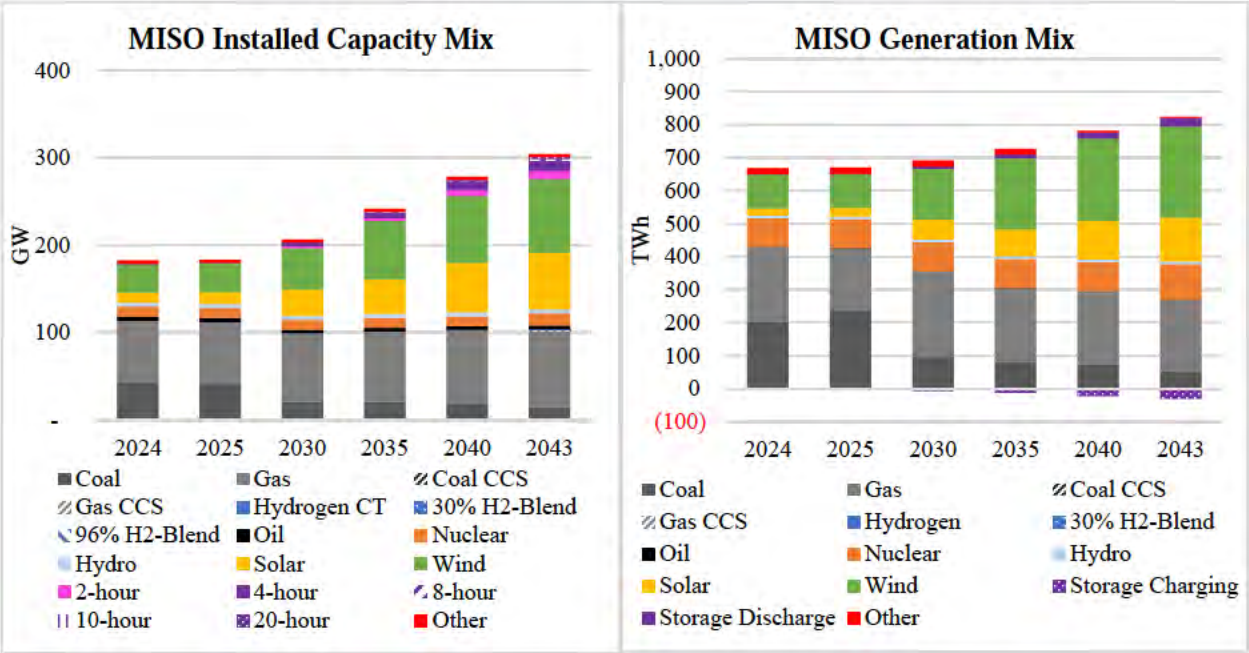
Figure 8-24: Summary of Natural Gas Price Drivers for ST Scenario

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

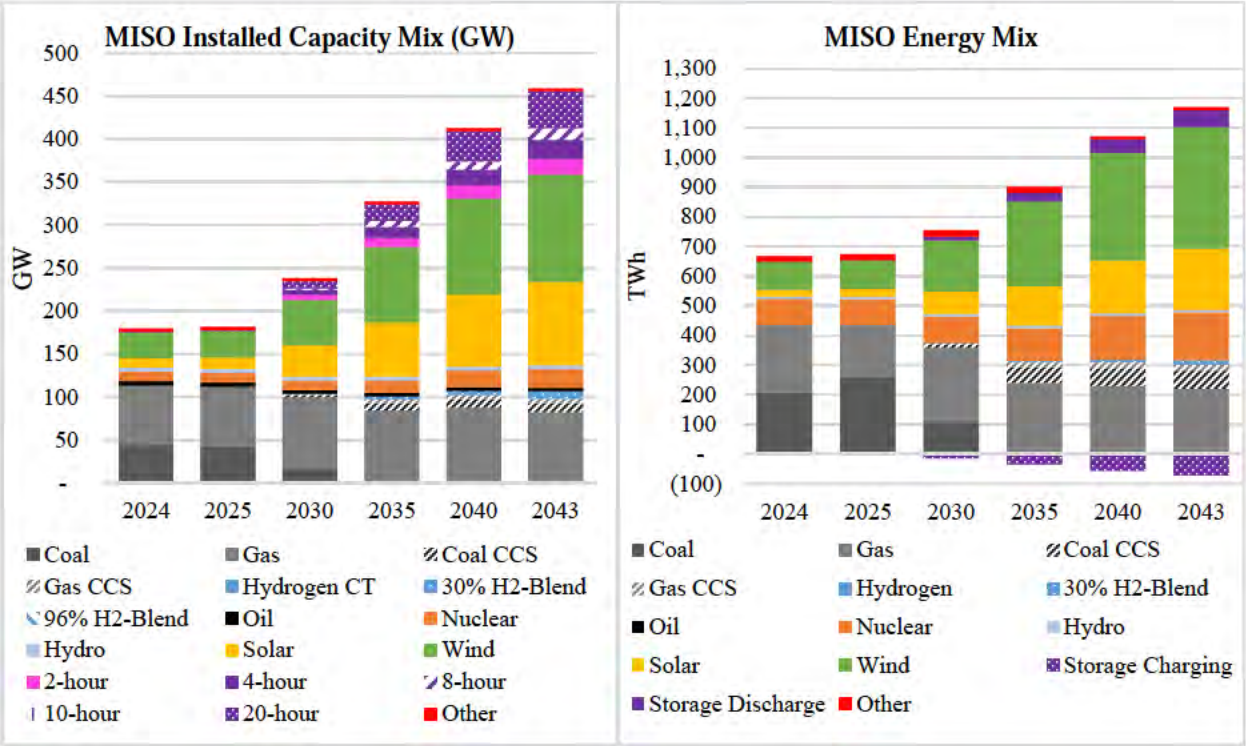
Driver	Reference Case	DR
Resource Size	• Rely on Potential Gas Committee (PGC) "Most-Likely" unproven estimates	• Base View
Well Productivity	• IP rates based on historic drilling data • IP improves as per EIA Tier 1 assumptions • Resource base is "Poor Heavy"	• Base View
Fixed & Variable Well Costs	• 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

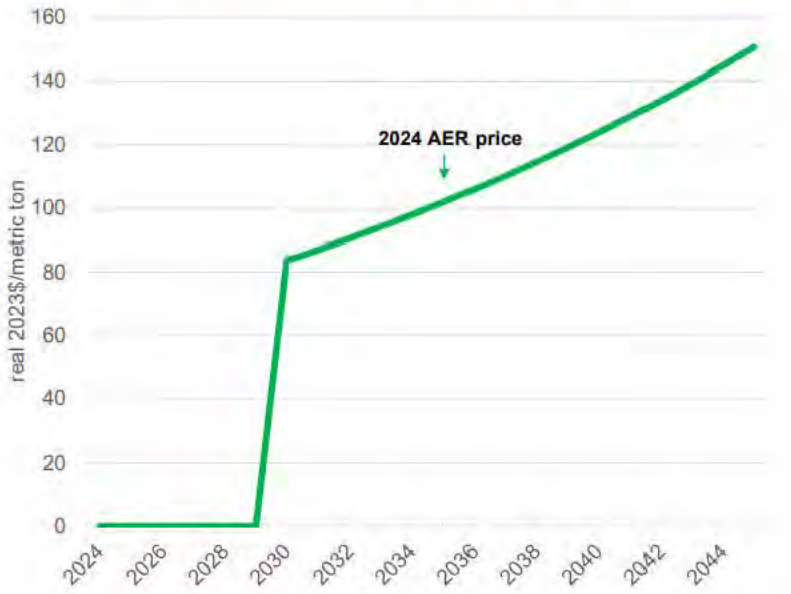
8.4.4.3 Carbon Regulation

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

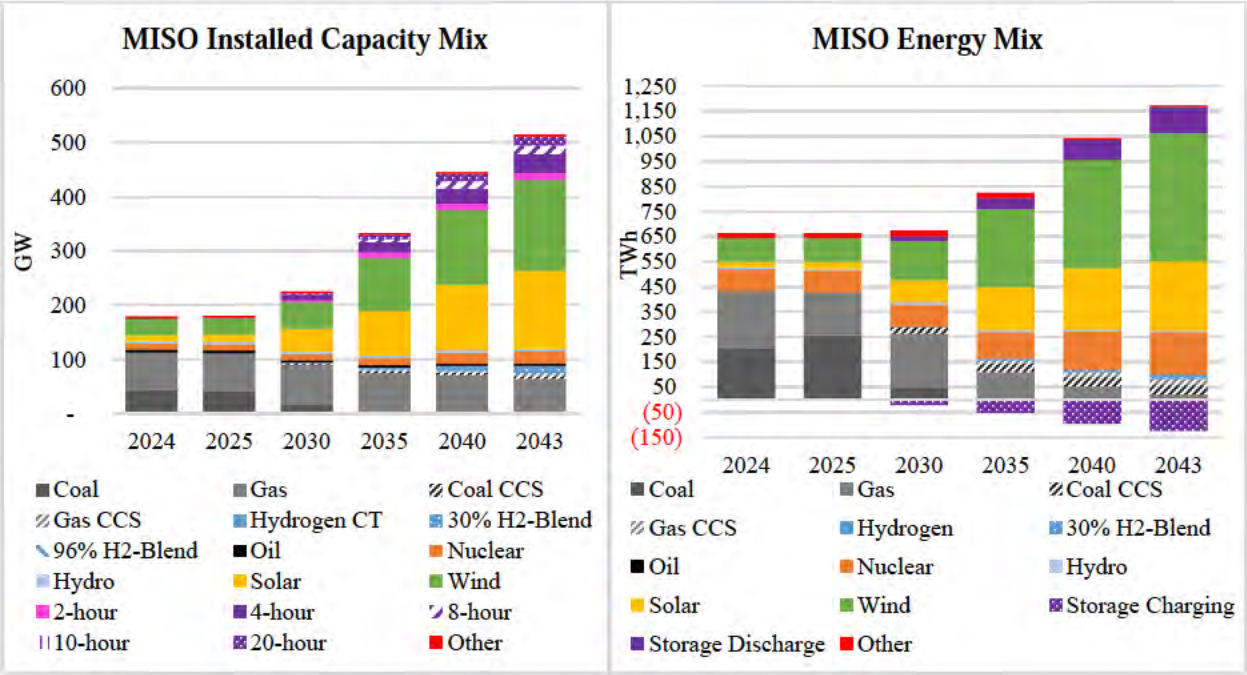


8.4.4.4 MISO Power Market Dynamics

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.

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.

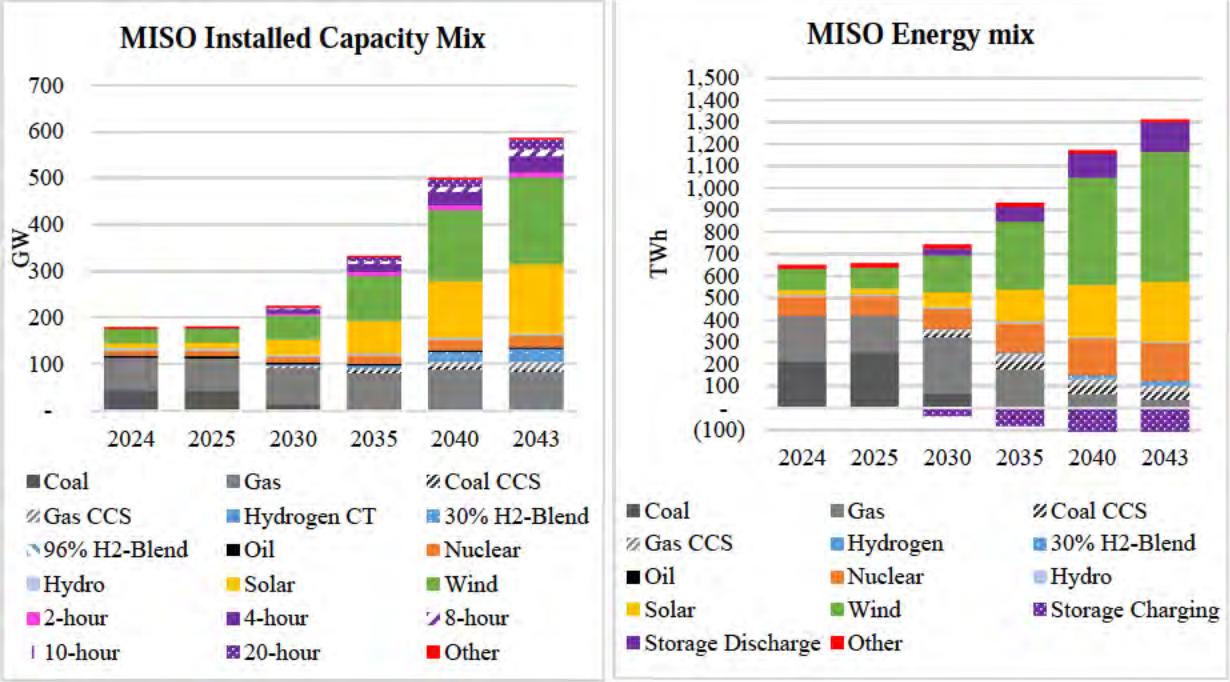
Figure 8-31: Summary of Natural Gas Price Drivers for AI Scenario

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



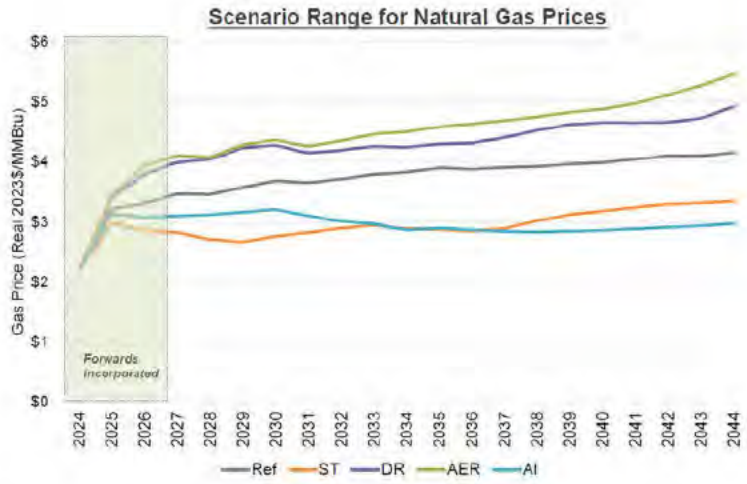
8.4.6 Scenario Comparisons

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

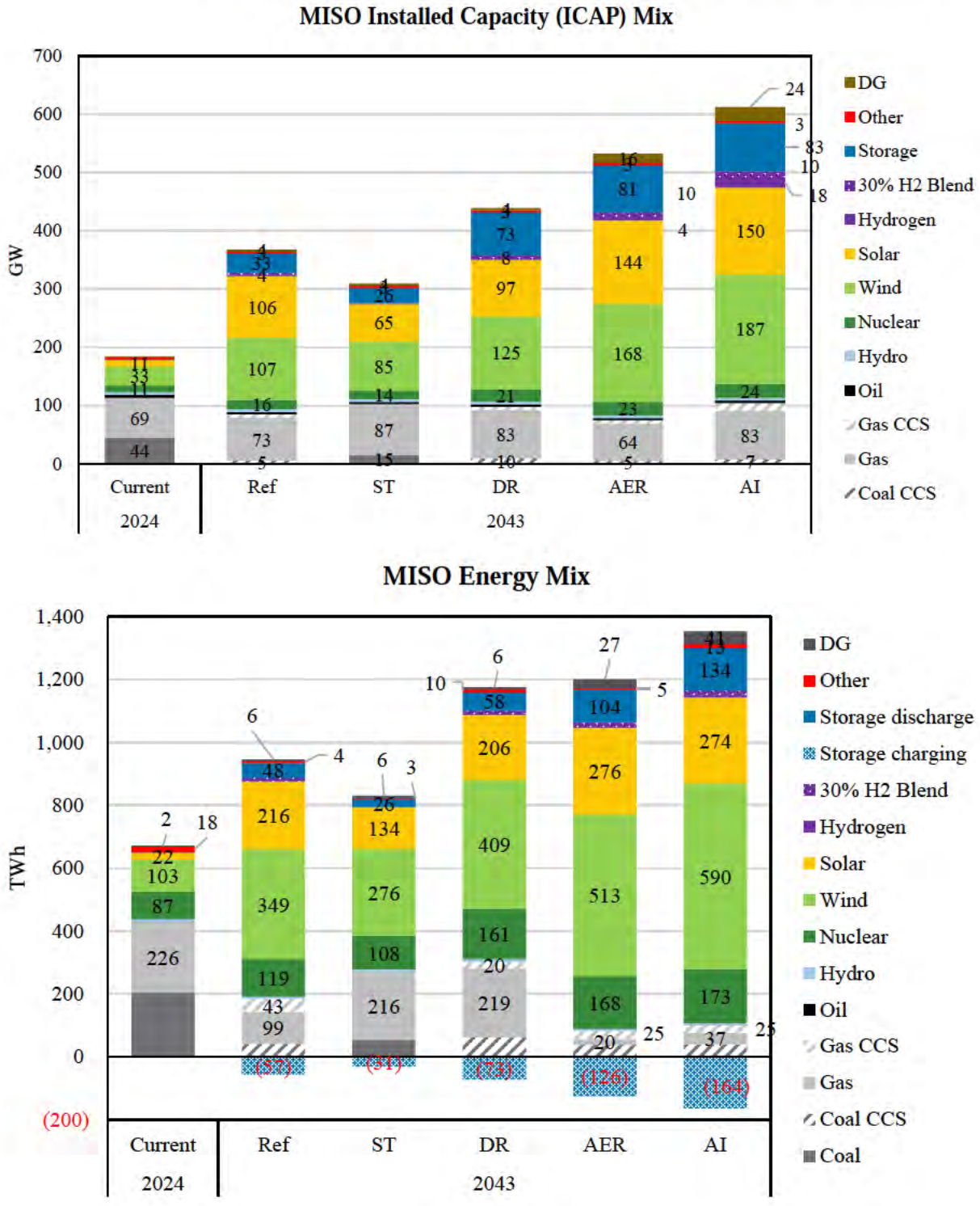
As noted earlier, NIPSCO's scenarios incorporate a range of potential carbon regulation outcomes. Four out of the five scenarios include the EPA GHG Rule, while additional bookend assumptions incorporate the possibility that carbon emissions are not regulated at the federal level over the study horizon 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

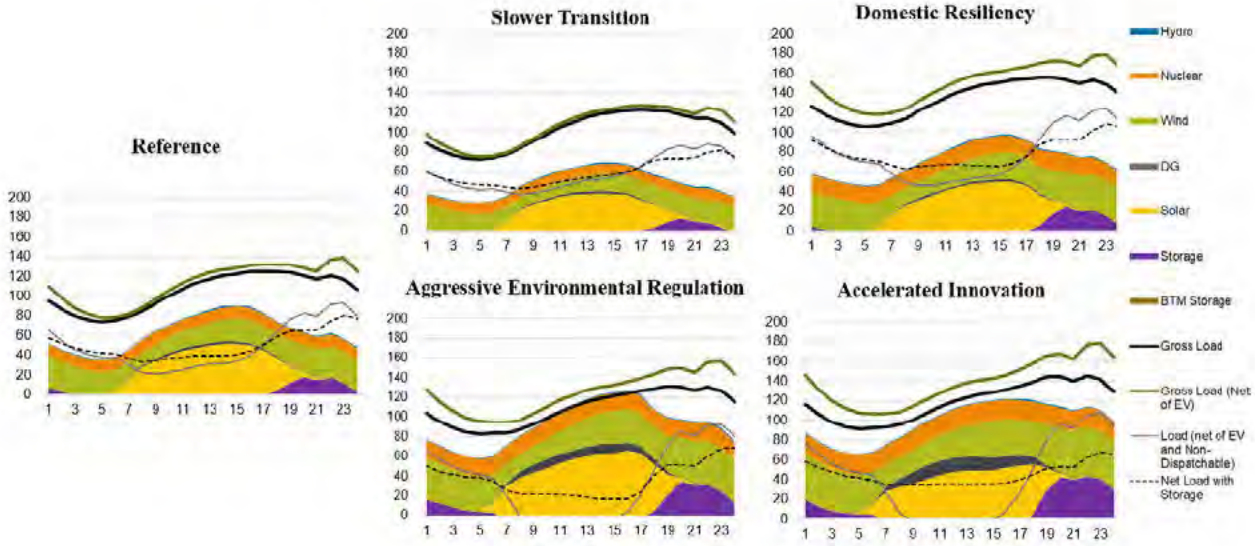


Figure 8-36: MISO Hourly Generation Projections – Winter, 2040

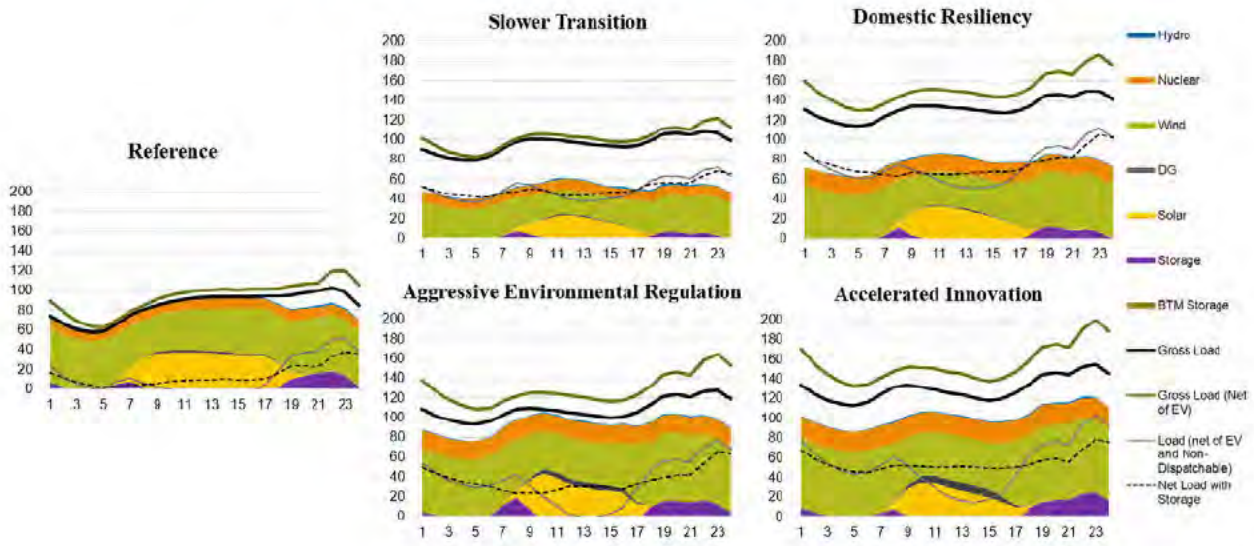


Figure 8-37: MISO Hourly Generation Projections – Spring Shoulder Month, 2040

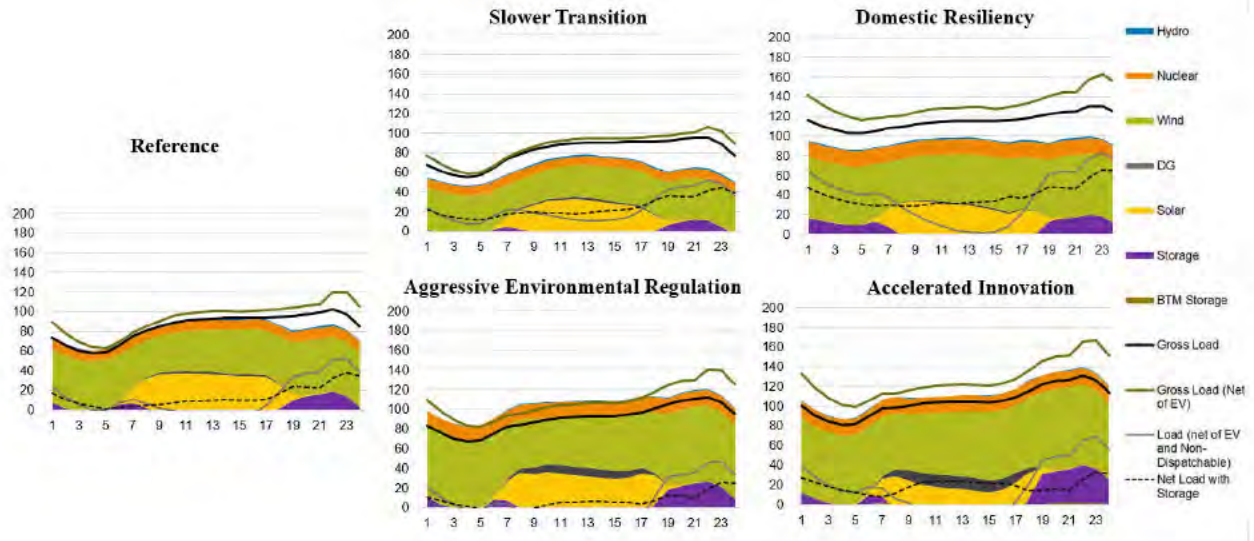
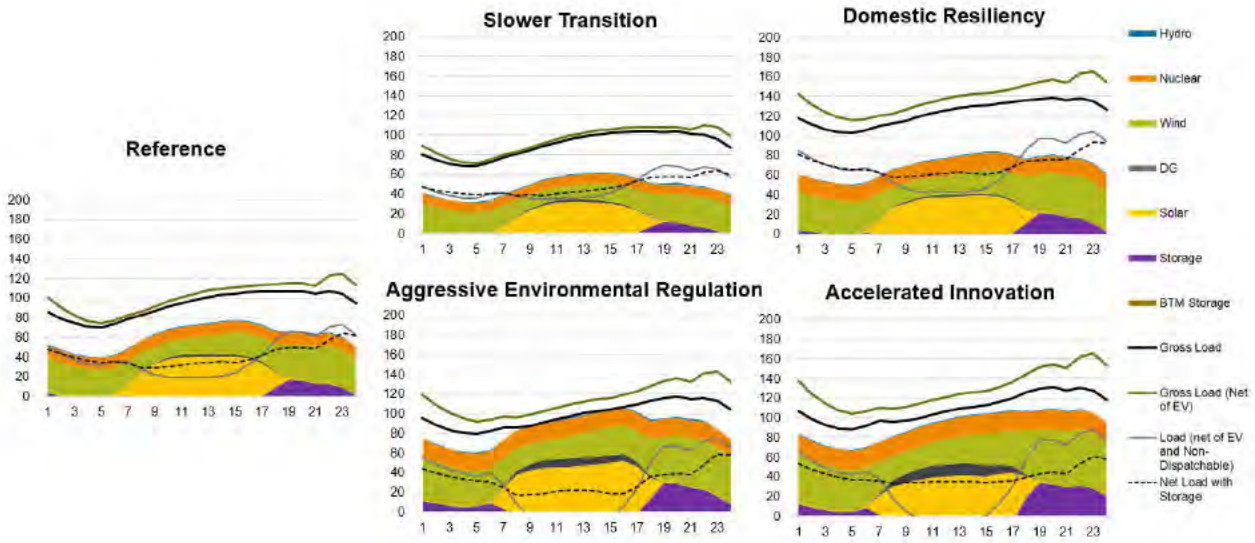


Figure 8-38: MISO Hourly Generation Projections – Fall Shoulder Month, 2040



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]

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

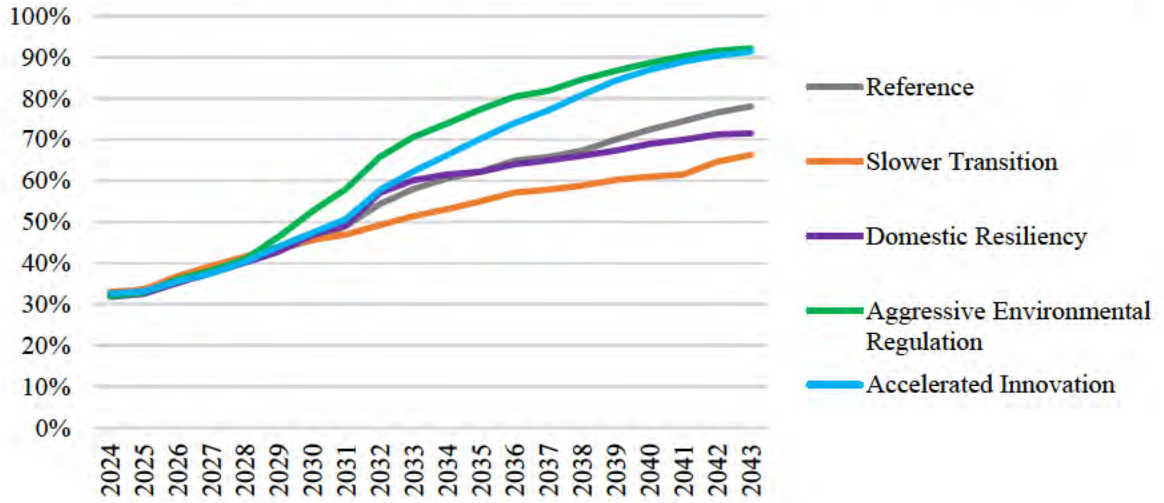
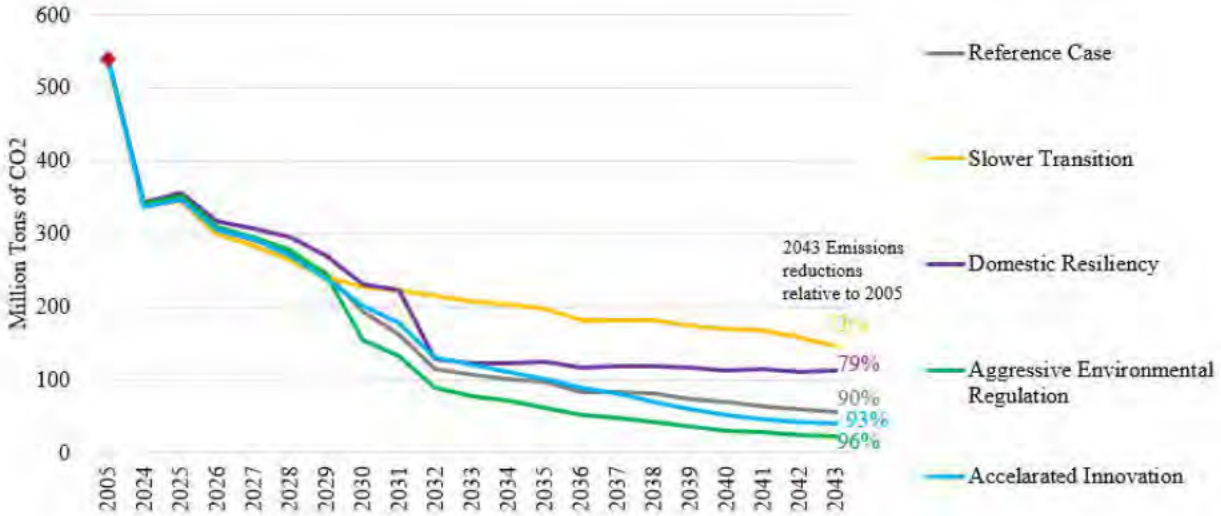
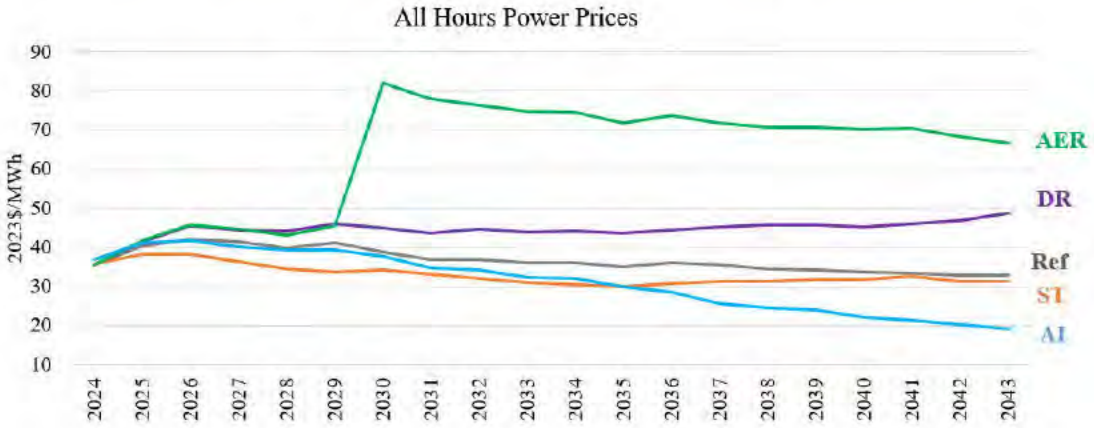


Figure 8-40: MISO CO2 Emission Reduction Projections across Scenarios



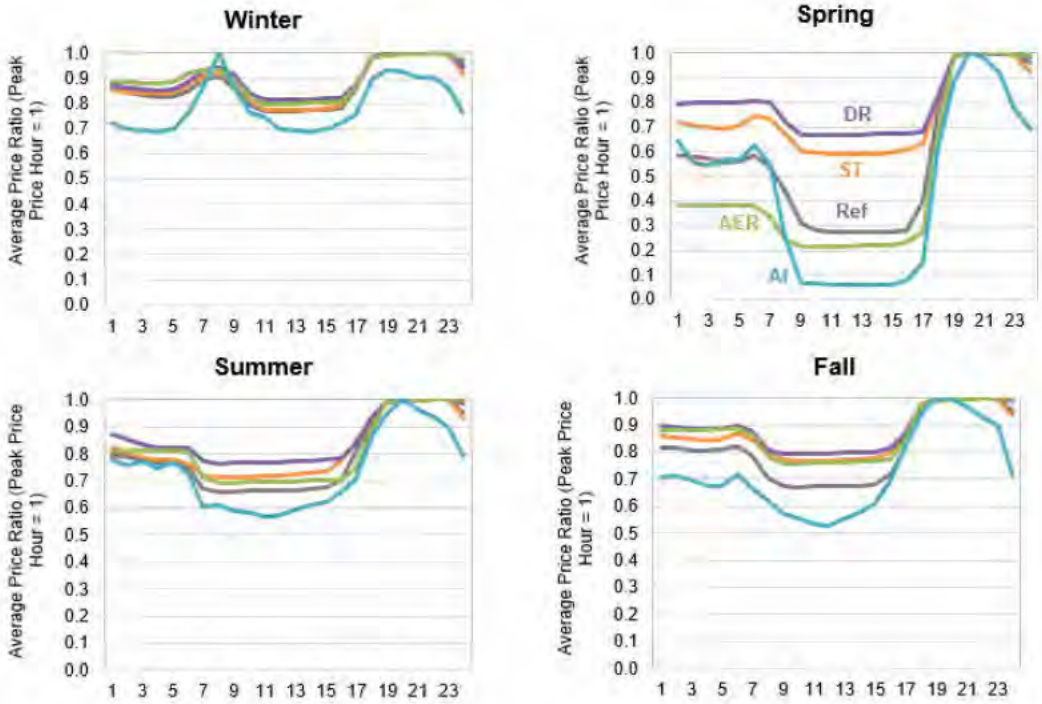
MISO energy prices are projected to vary considerably across scenarios as well. On an "all-hours" or ATC basis, the Reference Case projects prices to be relatively flat in real terms across the study period (as described above) and close to $35/MWh (real 2023$) by 2043, while the scenarios include prices 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.

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

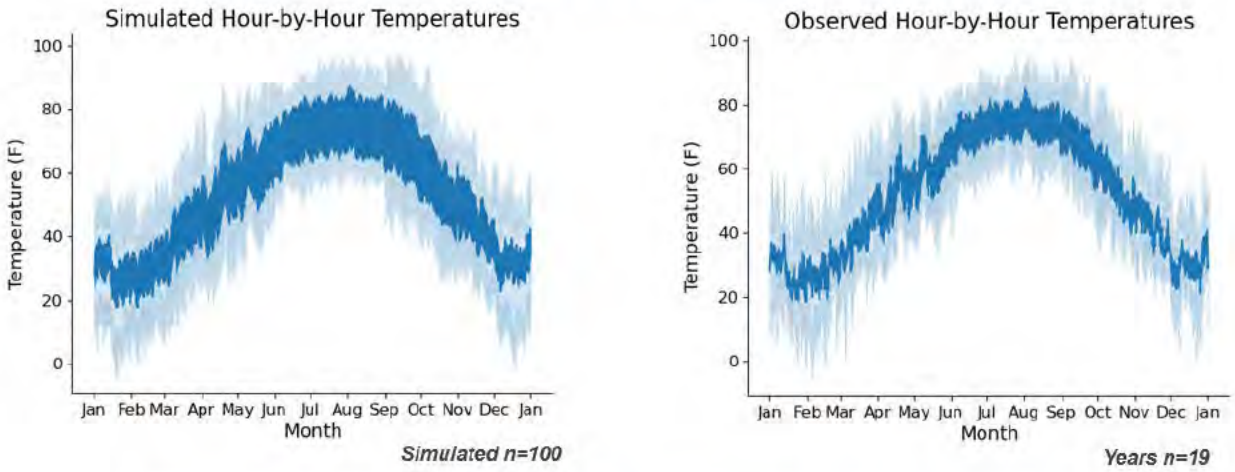


Figure 8-44: Sample Monte Carlo Iterations for Solar Generation

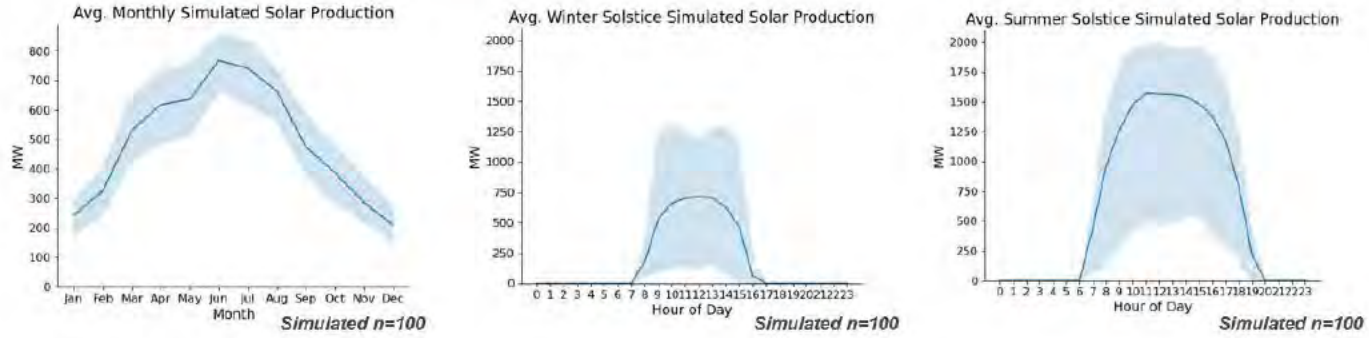
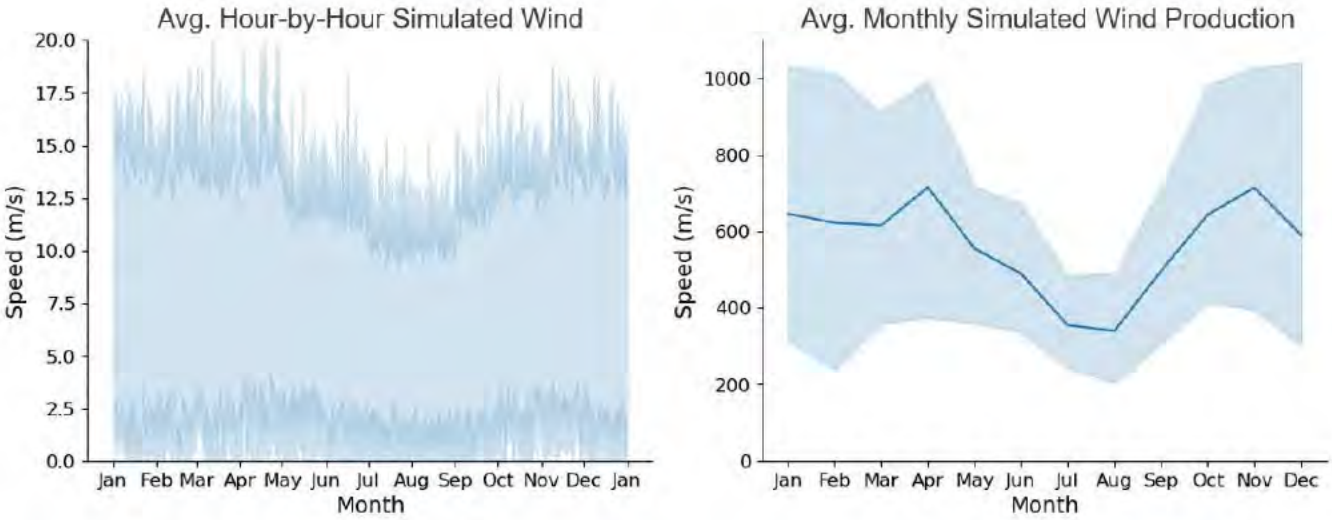


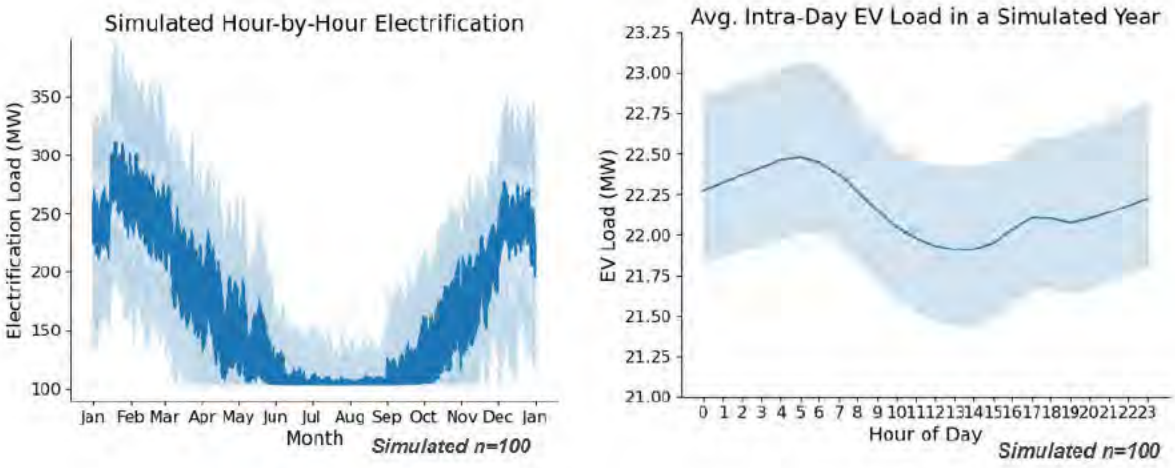
Figure 8-45: Sample Monte Carlo Iterations for Wind Speed and Generation



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

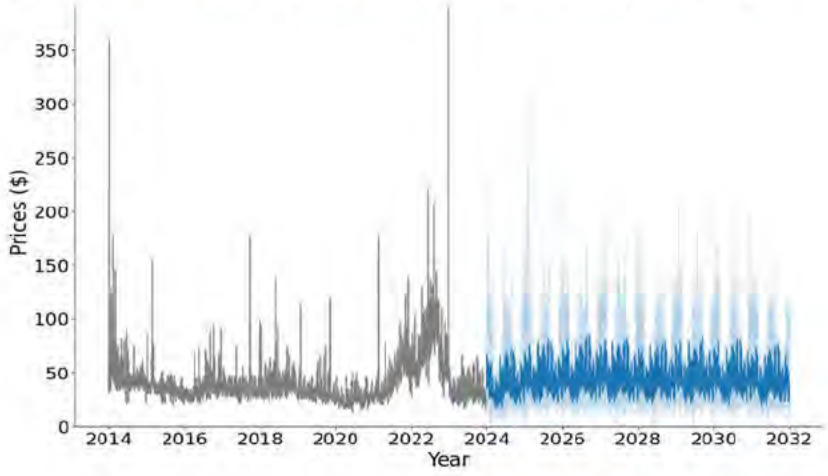
footprint, historical outages at NIPSCO's Sugar Creek natural gas combined cycle unit were not found to be correlated with temperature but were found to have seasonal variations. As such, these generator outages were simulated independently of the weather, while any additional thermal resources were 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.

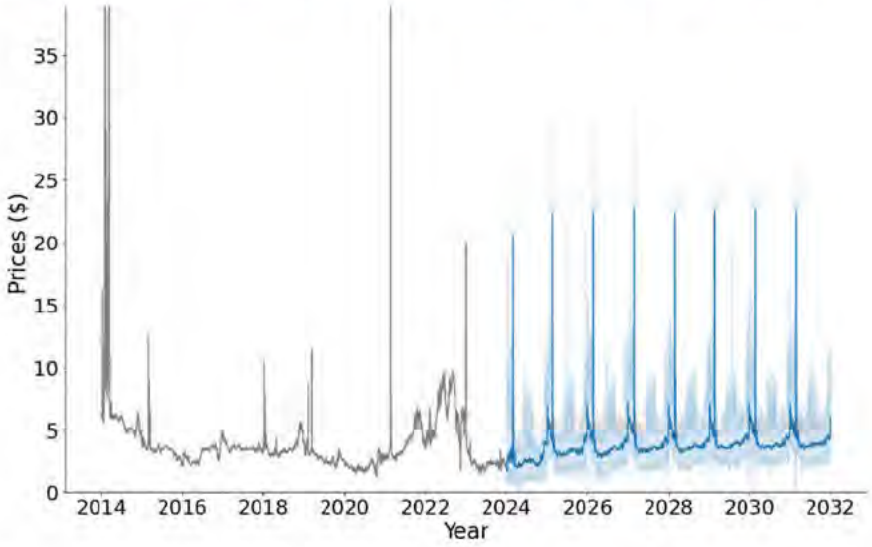
Figure 8-47: Future Electricity Price Iterations (Hourly)



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)



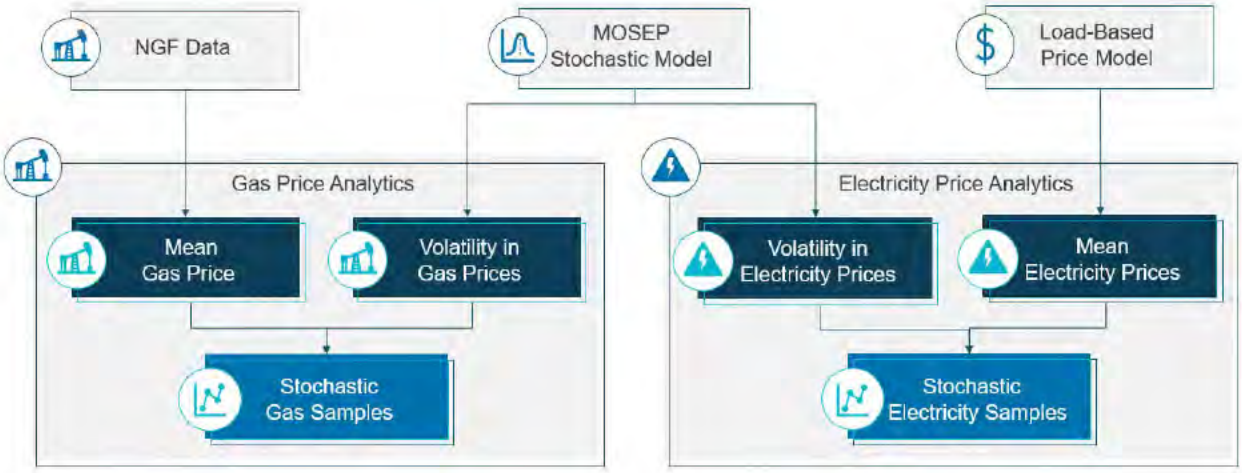
MOSEP generates its potential power prices in a manner that assumes power prices and NIPSCO's net load (load less renewable output) and the highly correlated Zone 6 net load evolve independently of each other. This assumption does not account for the fact that lower than expected net load will generally 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.

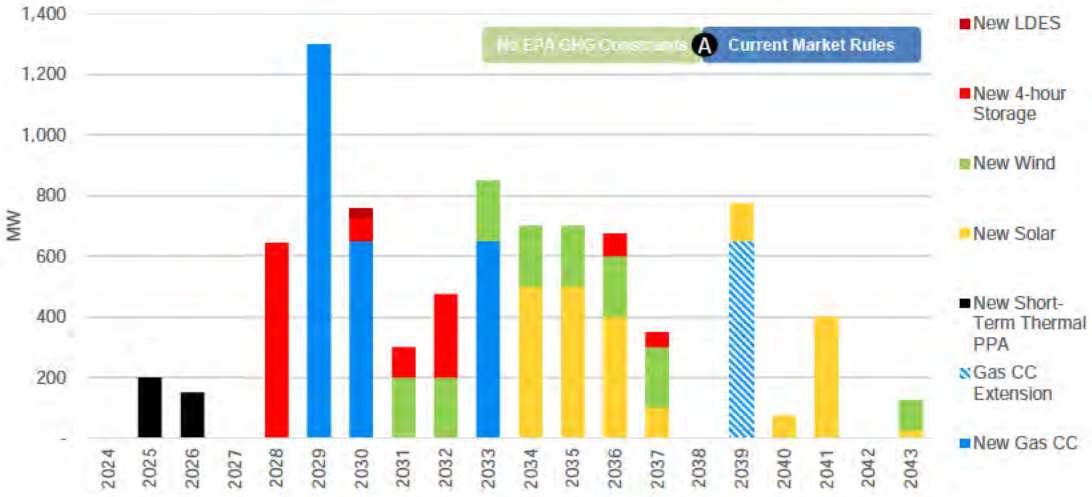
With these resource options, a least cost capacity expansion analysis was performed within Aurora's portfolio optimization tool under each of the six portfolio concepts to identify least-cost sets of new resources under Reference Case market conditions. The portfolio optimization modeling was performed 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)



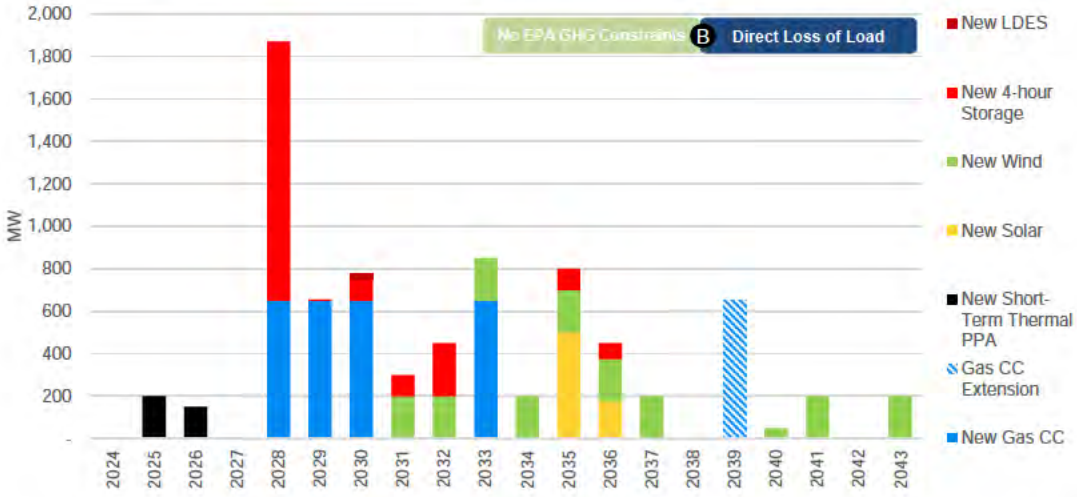
Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

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)

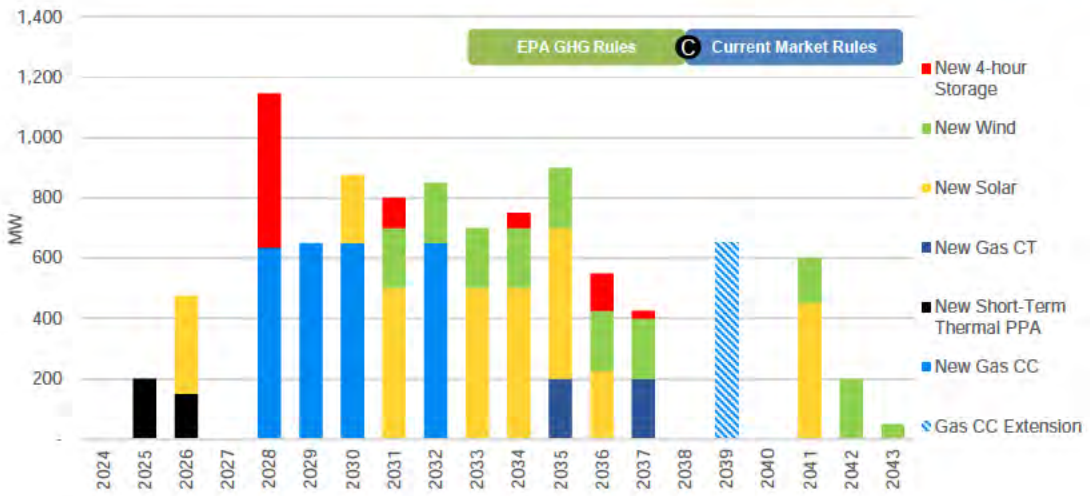


Note: The 2025 short-term PPA lasts from 2025-2027. The 2026 short-term PPA lasts from 2026-2027.

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)

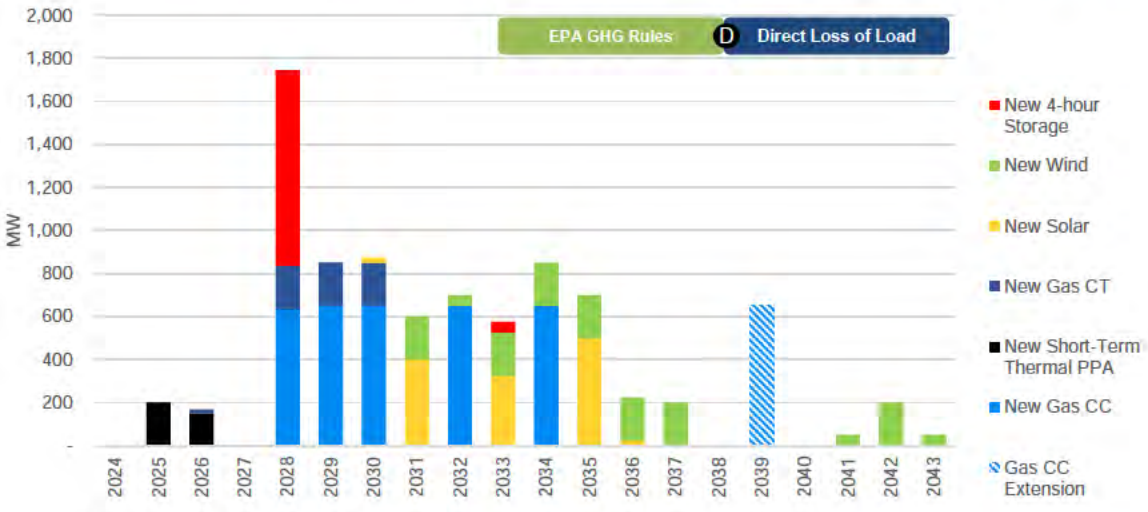


Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

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)

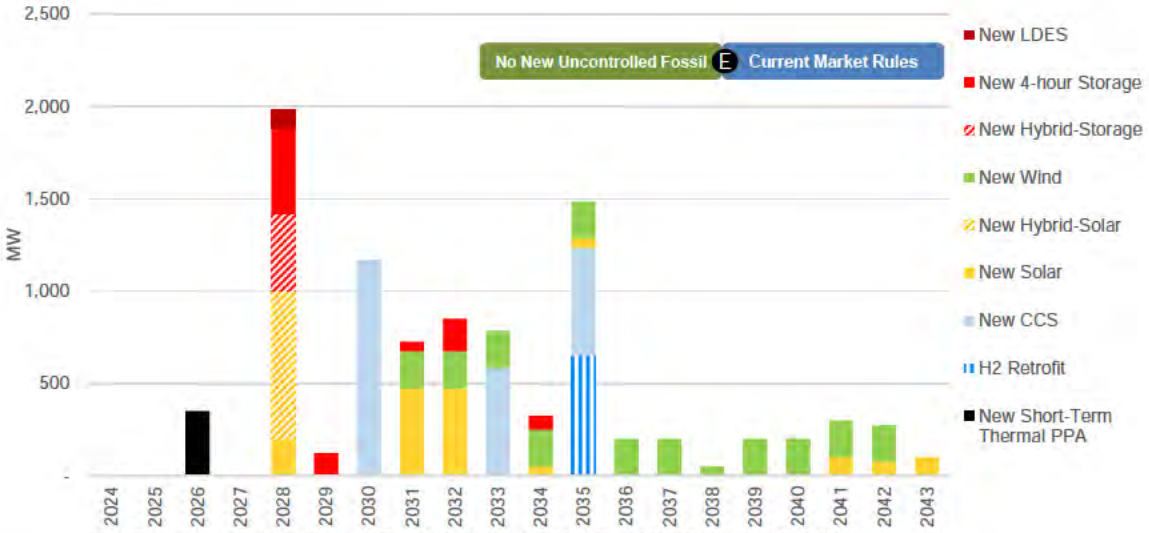


Note: The 2025 short-term PPA lasts from 2025-2029. The 2026 short-term PPA lasts from 2026-2030.

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)



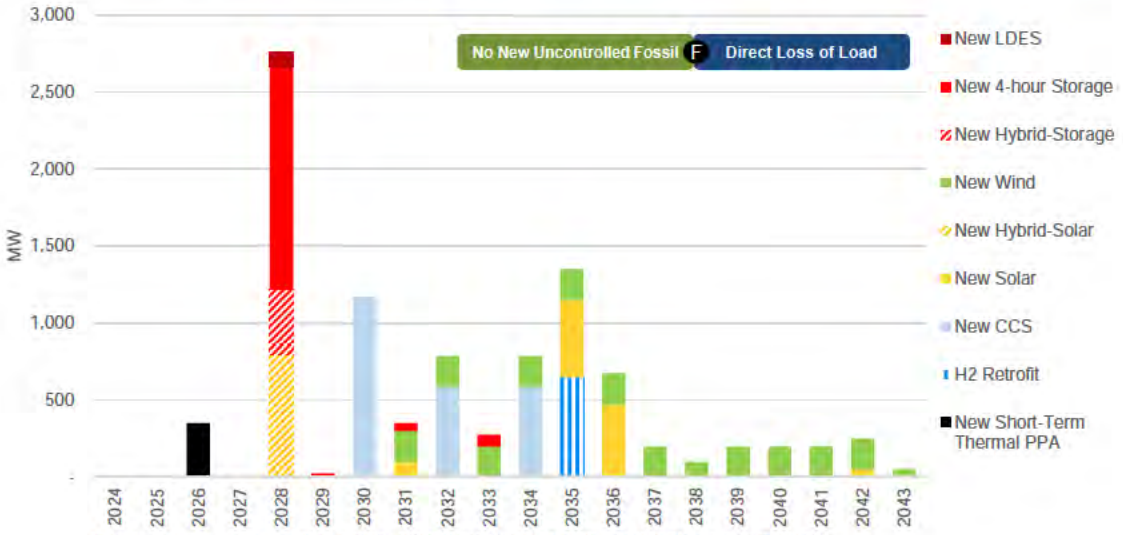
Note: There are two short-term PPAs in 2026. 200 MW lasts from 2026-2029. and 150 MW lasts from 2026-2030.

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.

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

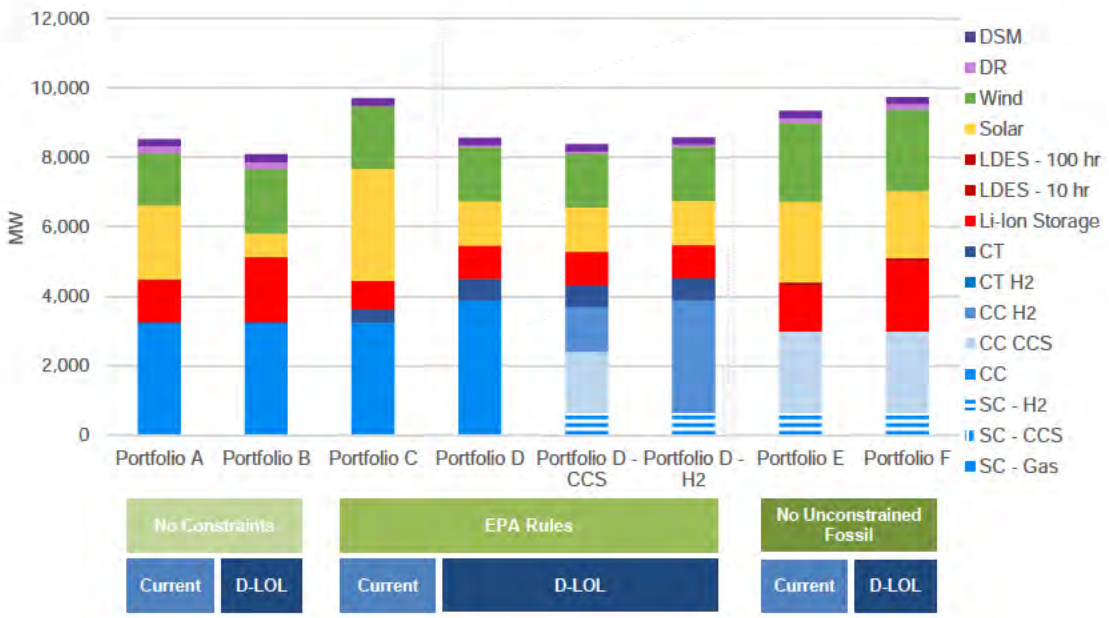
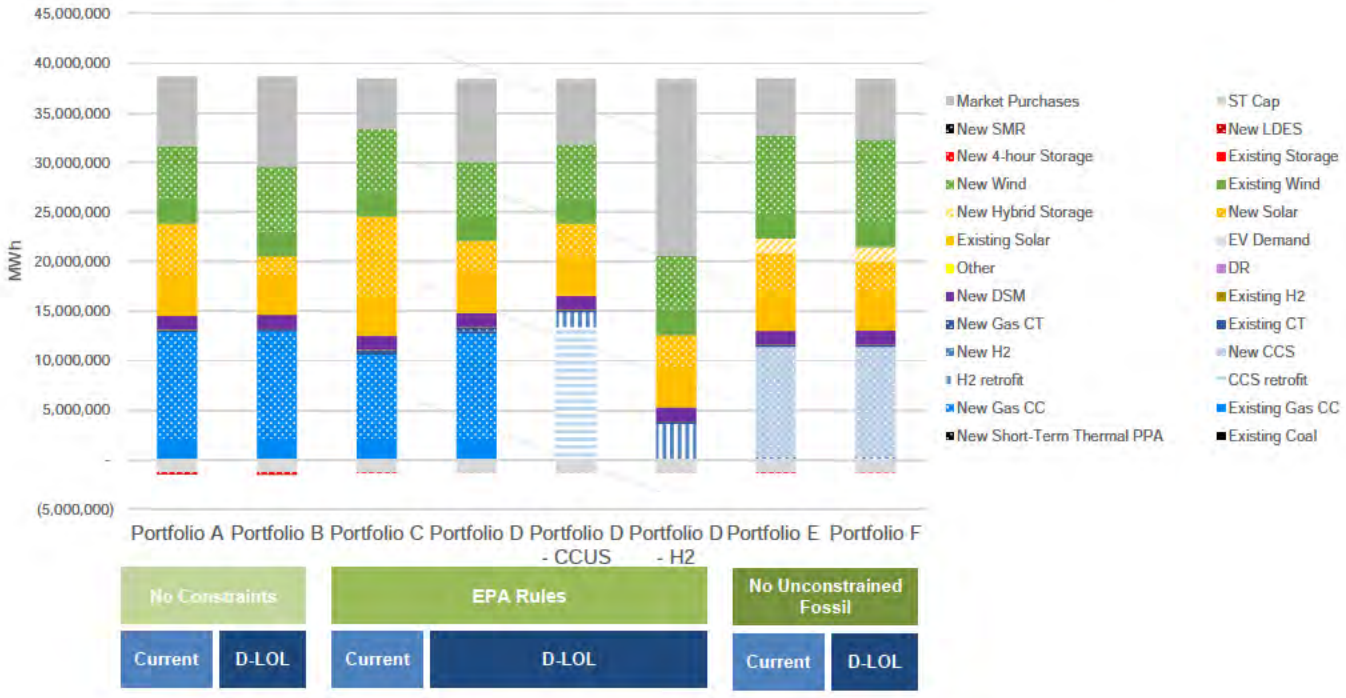


Figure 9-9: Projected Energy Mix across All Portfolios – 2043



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 addit ons 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.

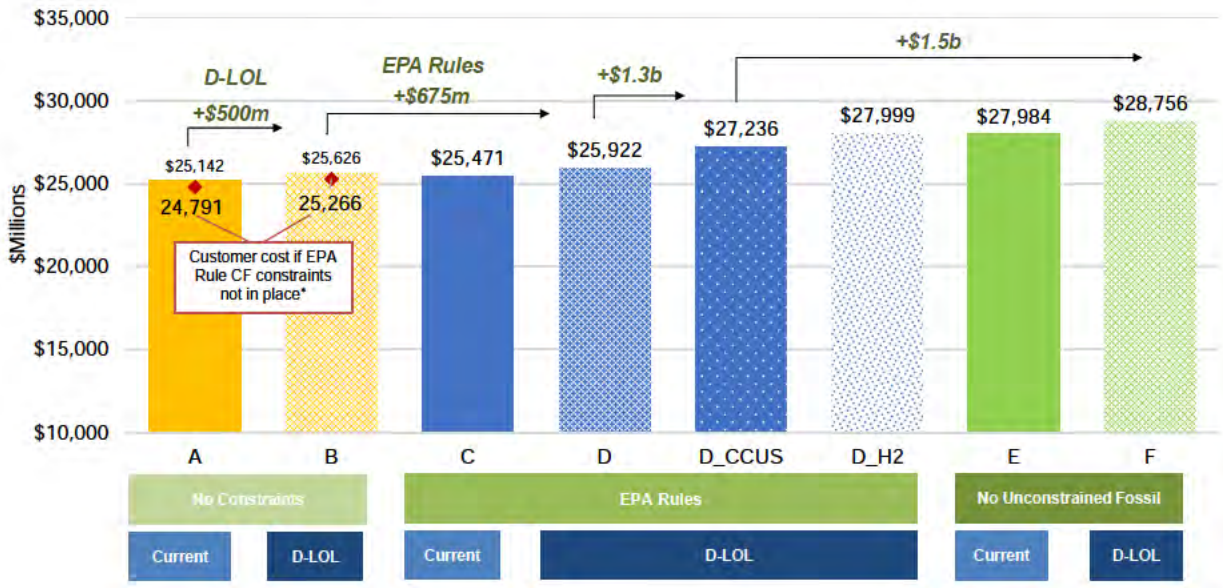
- Customer costs are projected to be higher in Portfolios C/D relative to Portfolios A/B due to new EPA GHG rules. The level of cost premium is around $675 million in NPVRR assuming no constraints on combined cycle operation under Reference Case market conditions. If the optimized portfolios were held 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

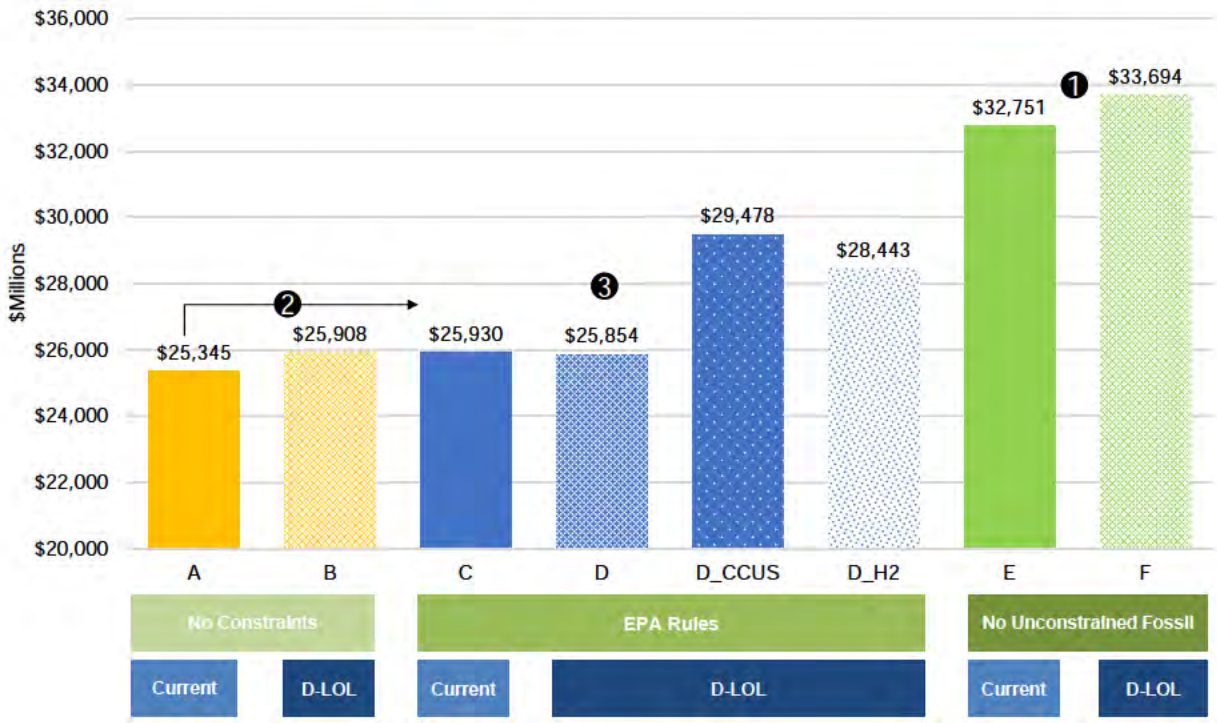
In addition to the analysis under Reference Case conditions, NIPSCO also evaluated each portfolio against each scenario, as described earlier in Section 8. Under the Slower Transition scenario, relative to the Reference Case, as shown in Figure 9-15:

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:

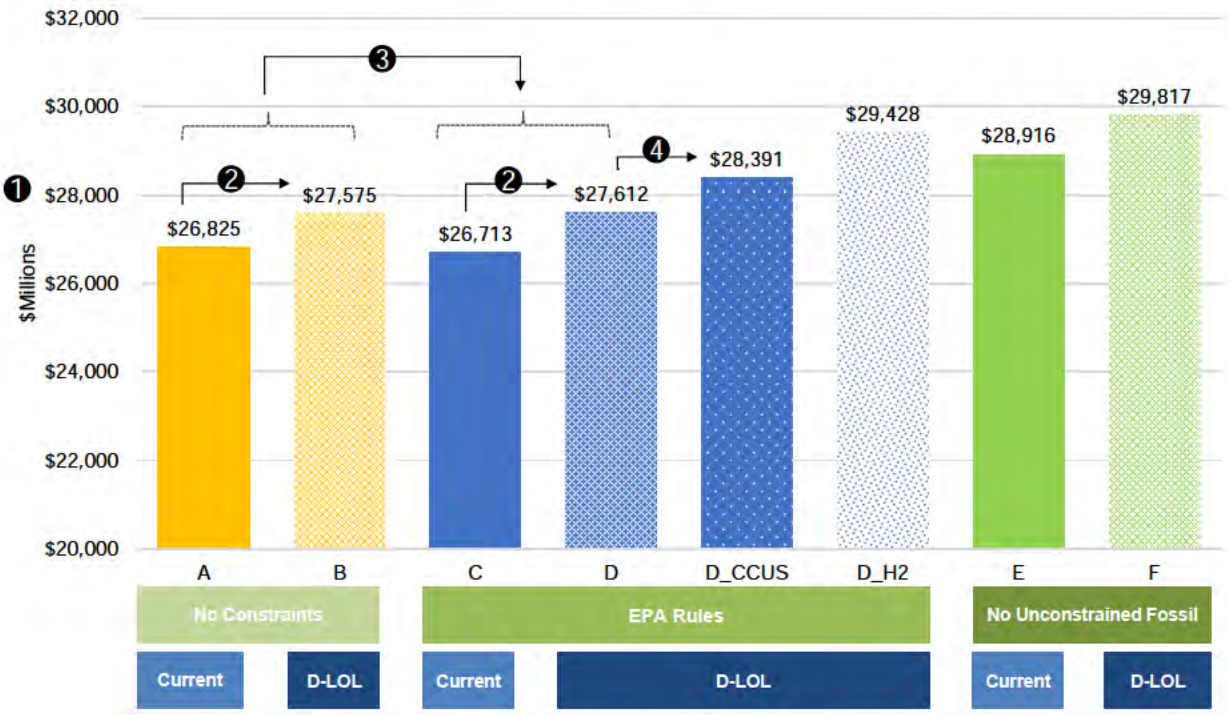
1. Overall portfolio costs are higher, driven by elevated natural gas and power prices.

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.

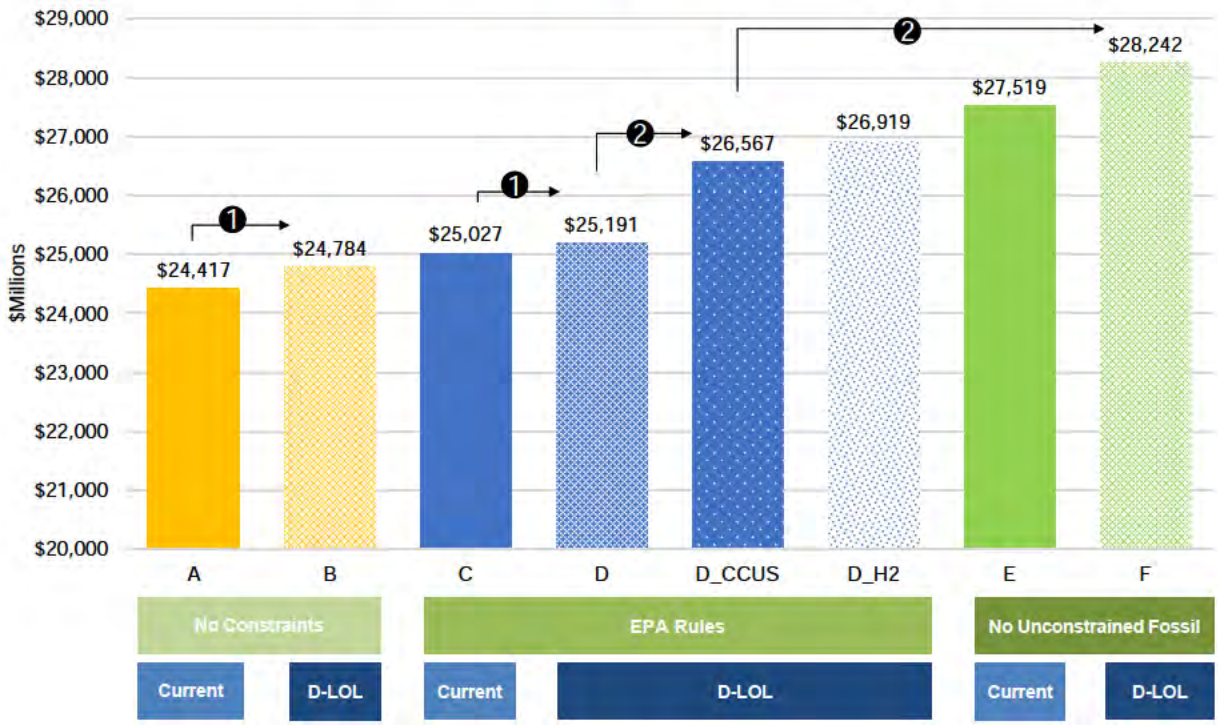
Figure 9-17: Aggressive Environmental Regulation Scenario Cost to Customer (30-year NPVRR – millions of $)

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.

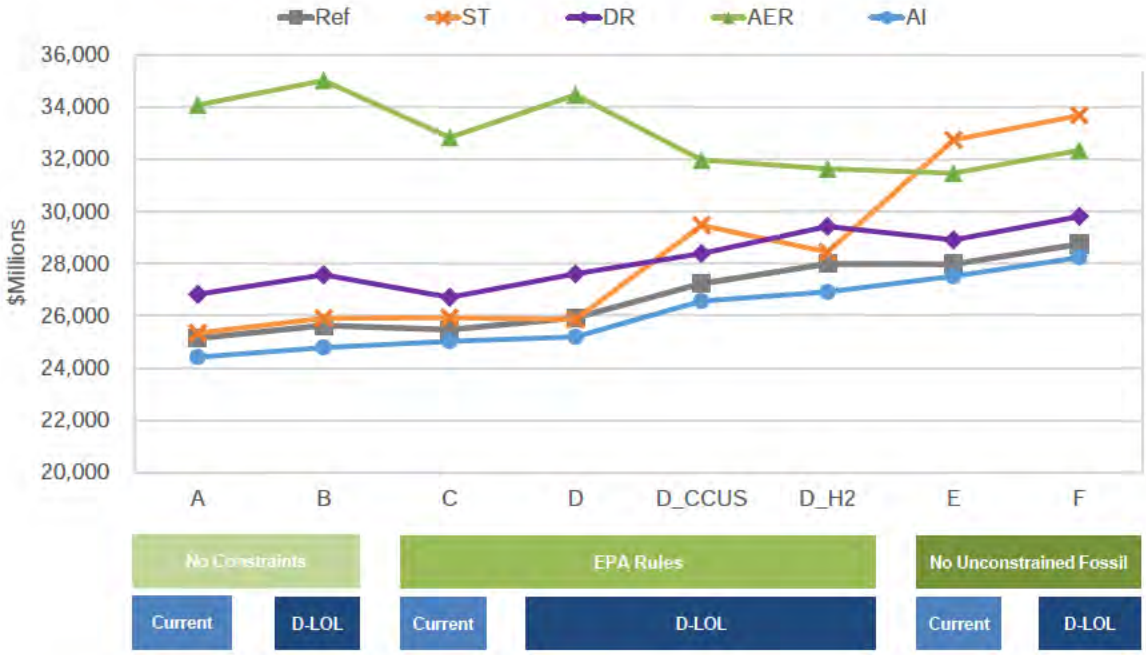
Figure 9-18: Accelerated Innovation Scenario Cost to Customer (30-year NPVRR – millions of $)



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

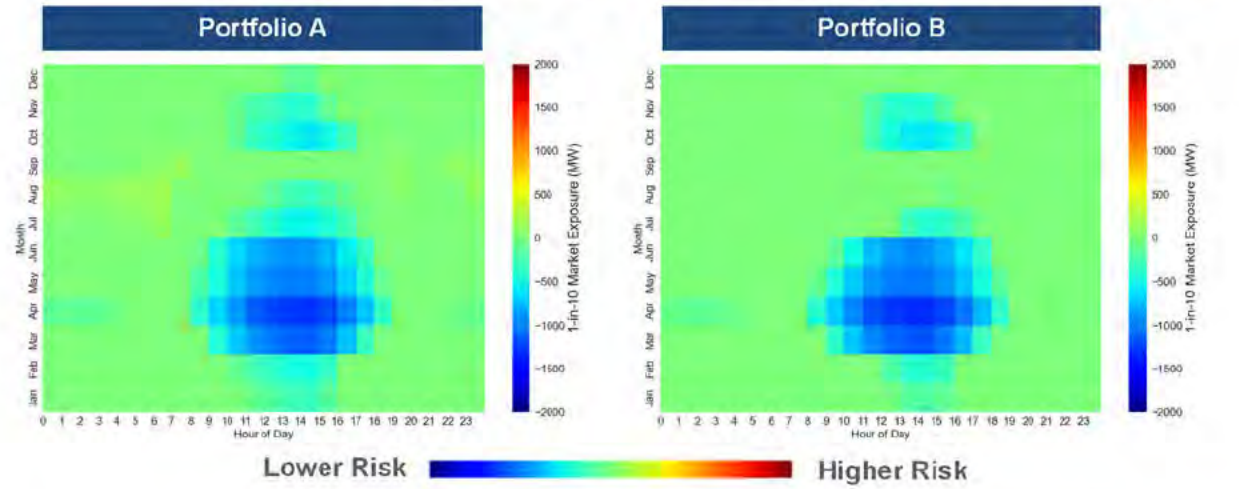


Figure 9-21: 90th Percentile of Forced Market Exposure - Portfolios C and D

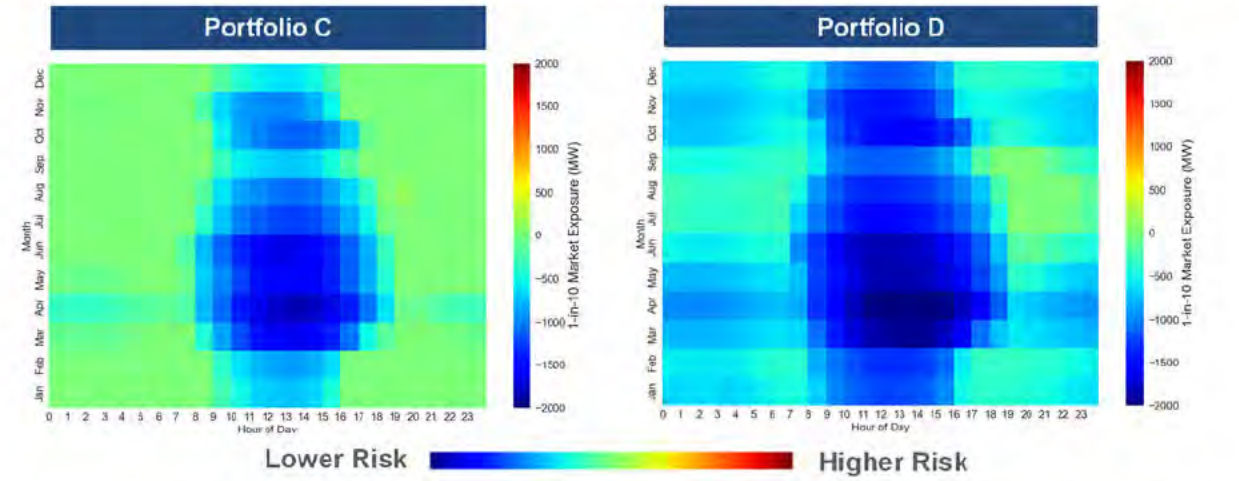
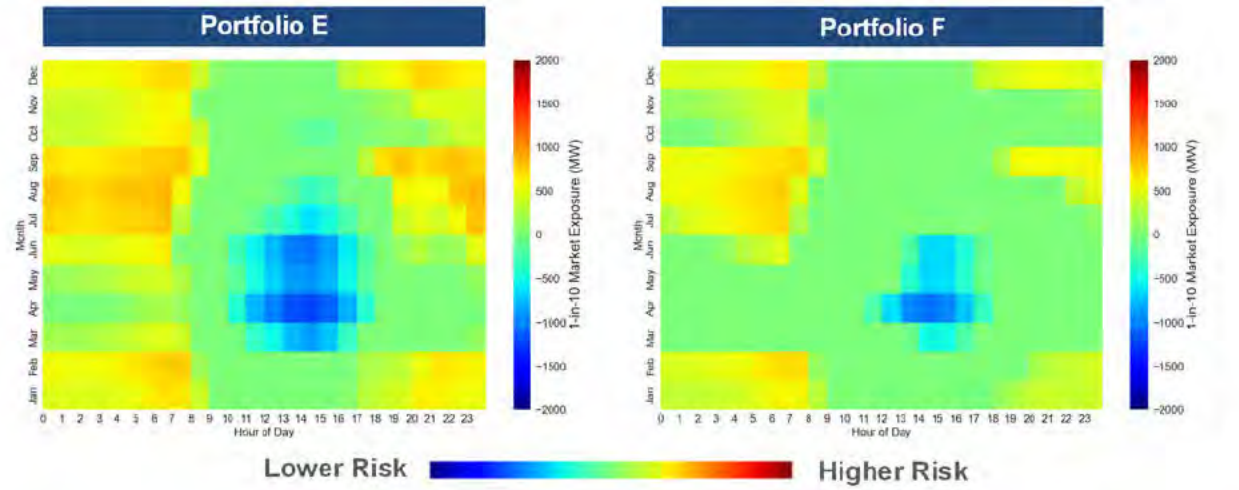


Figure 9-22: 90th Percentile of Forced Market Exposure - Portfolios E and F



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

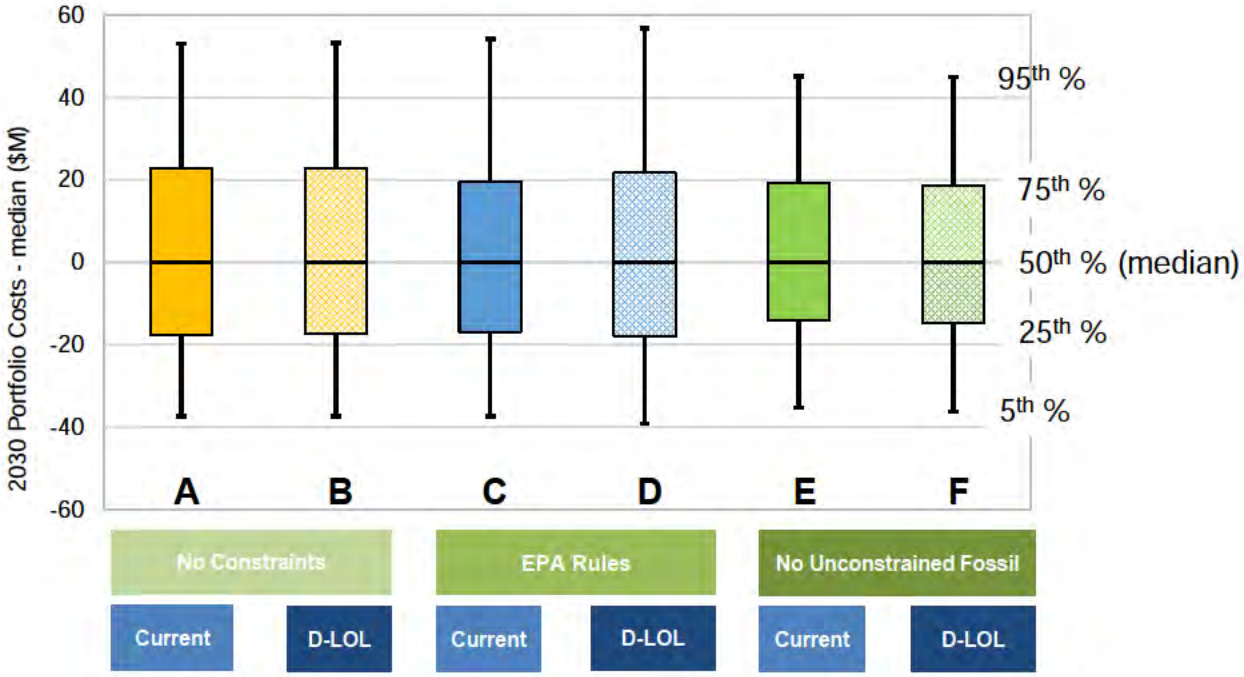
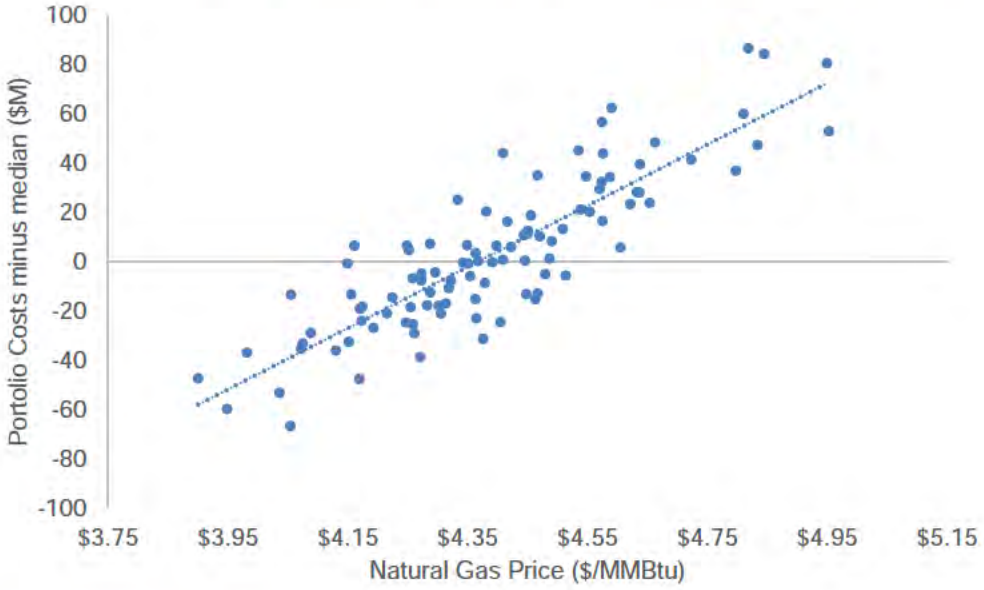


Figure 9-25: Rate Stability Scorecard Metric – Cost Risk and Low Cost Opportunity (millions of $)

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.

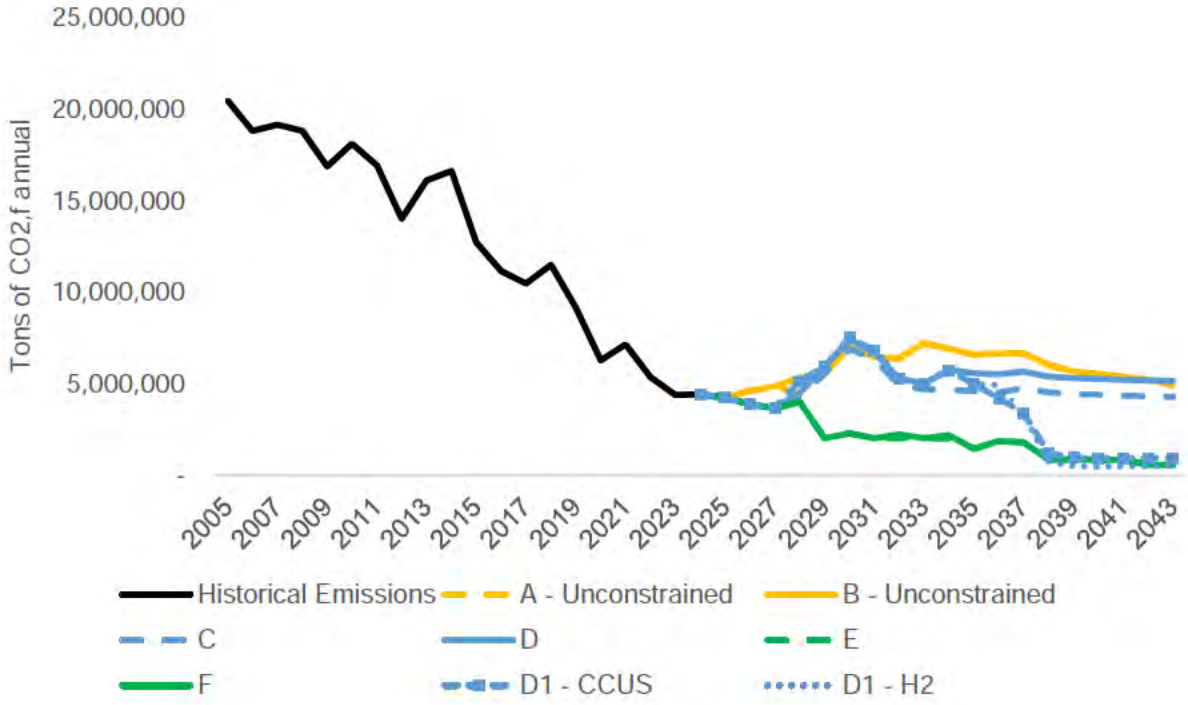
For portfolios that immediately control the emissions of new combined cycle capacity additions via CCUS (Portfolios E and F), annual emissions would be projected to fall to around 2 million tons per year after the retirement of Michigan City Unit 12, with potential additional reductions by the end of 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

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

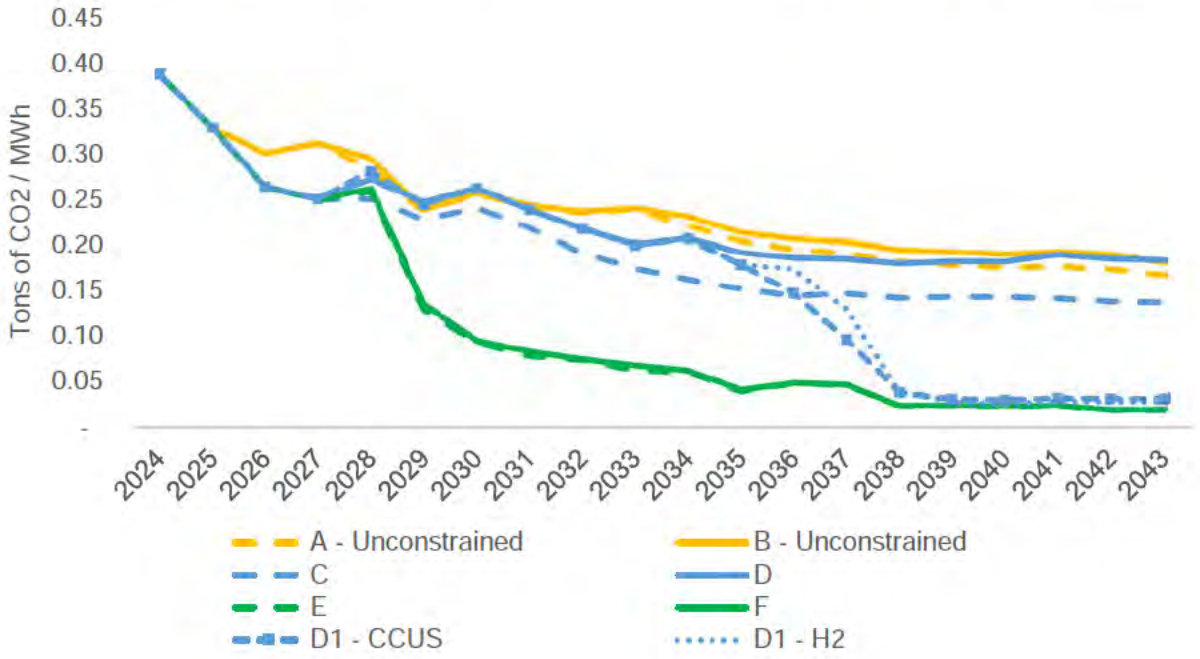


Figure 9-29: Total Emissions and Emission Intensity Average for 2024-2040

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

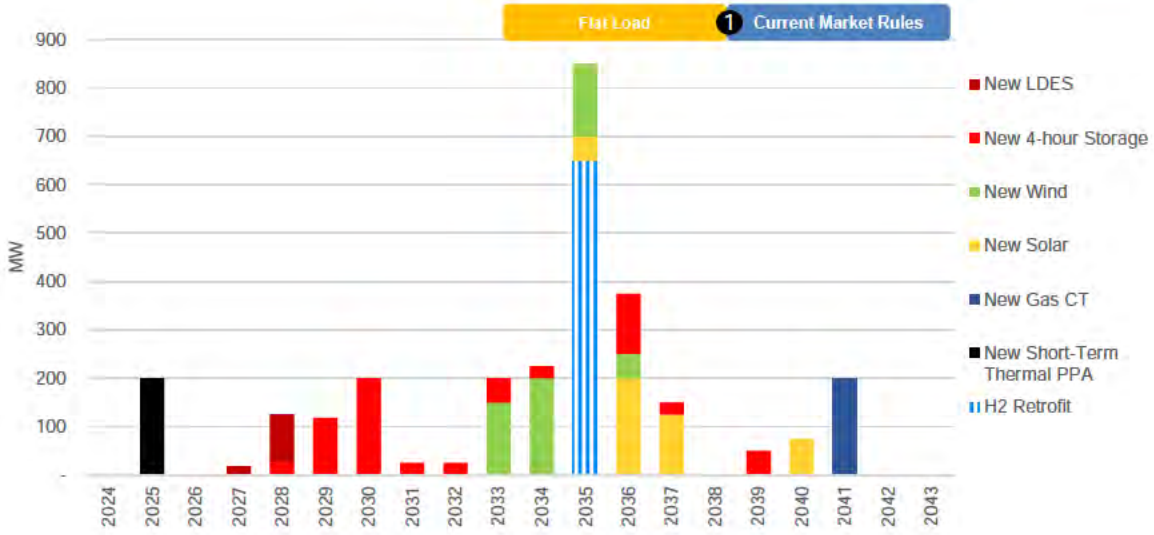
9.3.5 Sensitivity Analysis – Flat Load Growth

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)



Note: The 2025 short-term PPA lasts through 2029.

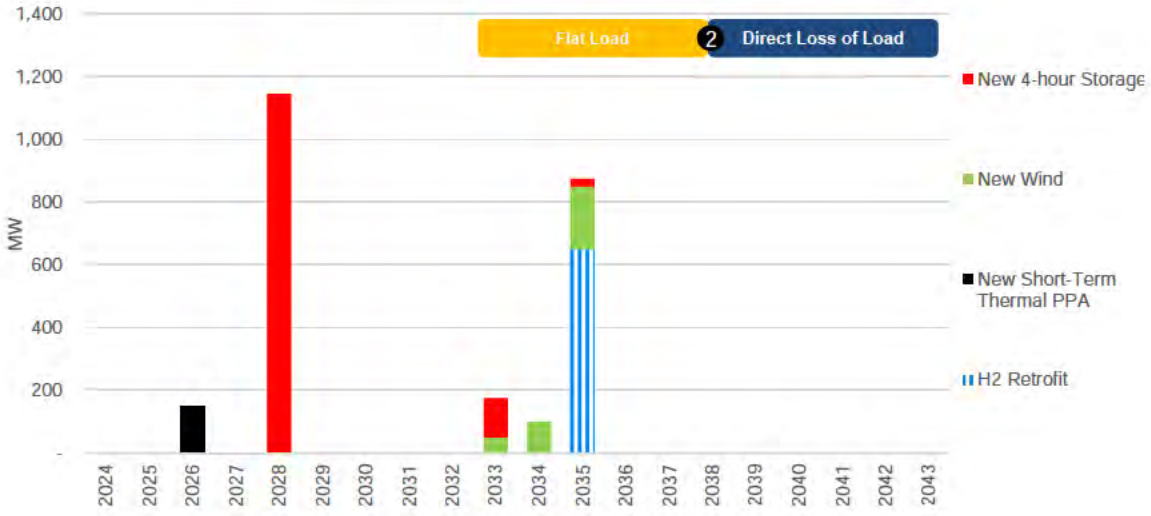
167 Note that NIPSCO found that the current portfolio's energy position means that additional combined cycle capacity additions would not fit within the energy constraints. Thus, the EPA GHG rules and potential limitations on fossil-fired resources additions without emission controls are irrelevant under 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

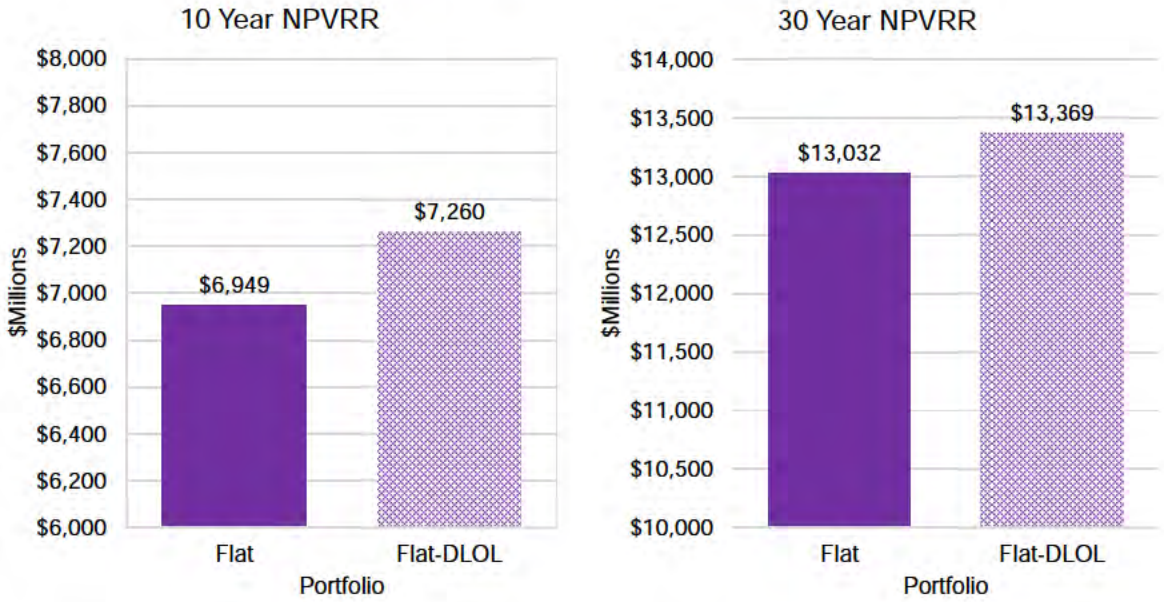
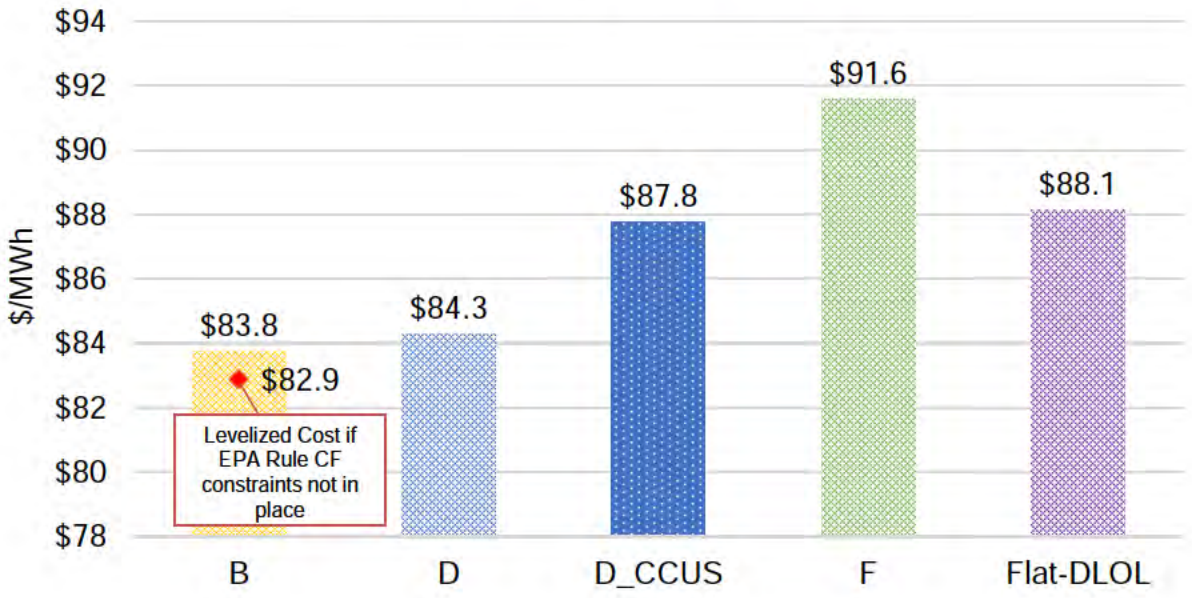


Figure 9-34: Levelized Portfolio Costs for Reference Case and Flat Load Portfolios under D-LOL market Rules



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).

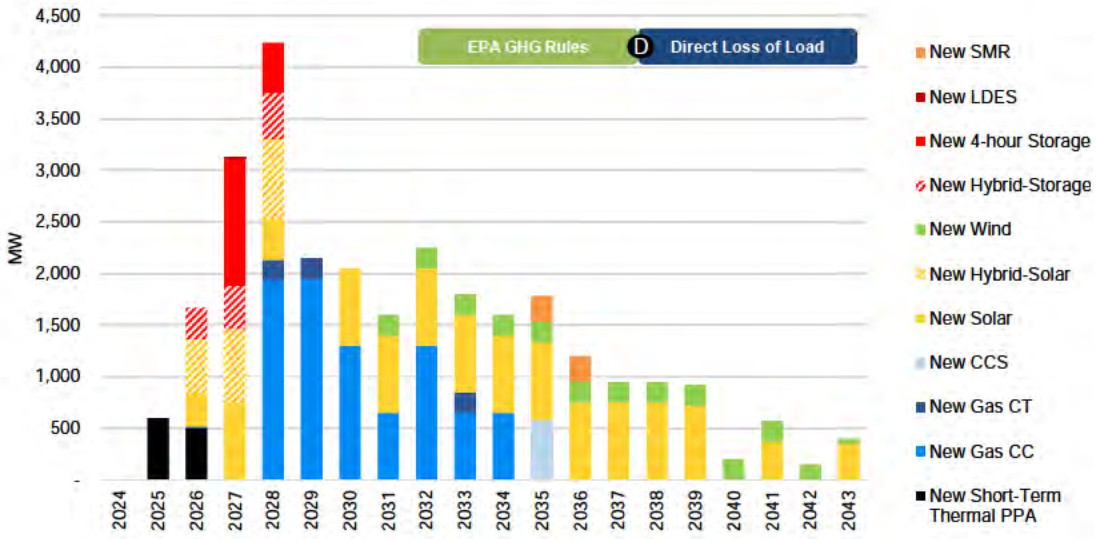
Figure 9-35: Emerging High Load Sensitivity

	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.

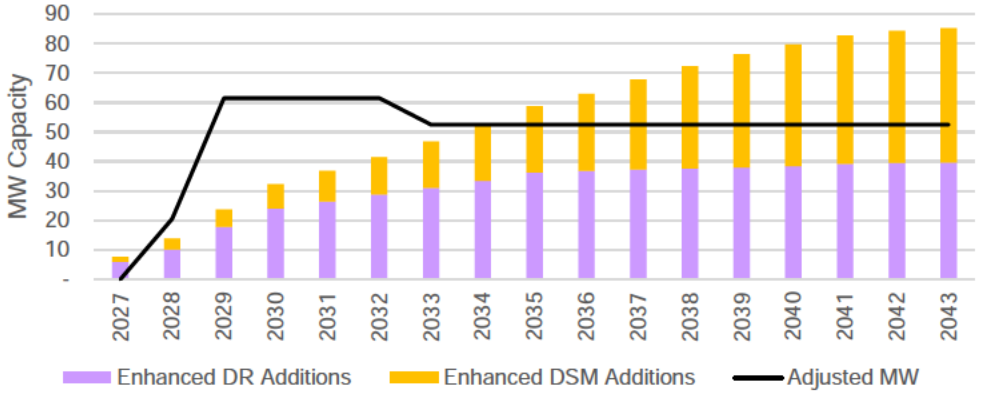
9.3.1 Sensitivity Analysis – Additional DSM

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.

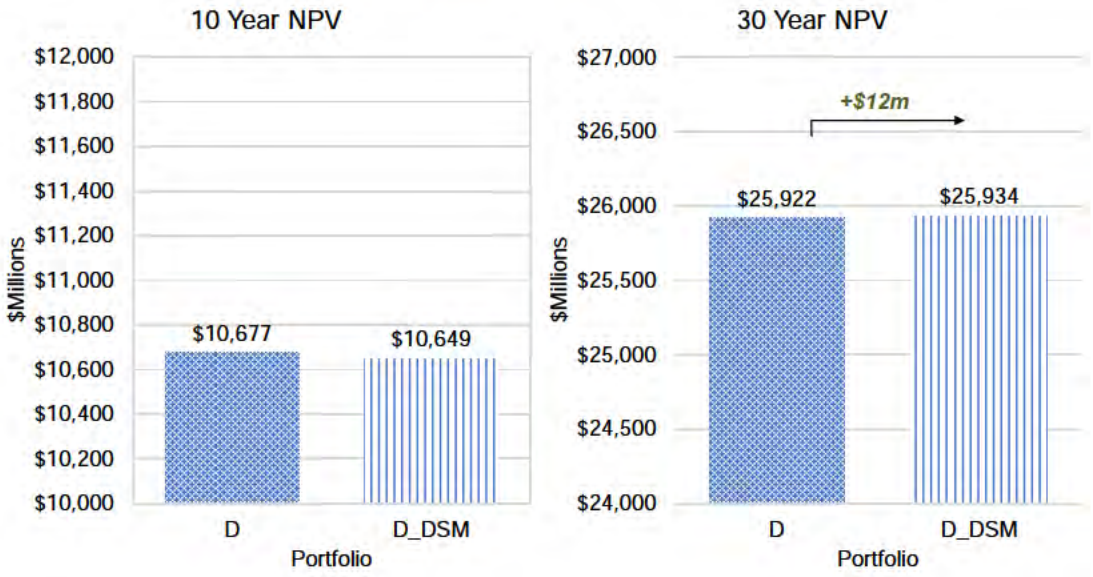
Figure 9-37: Additional DSM versus Avoided Peaking Capacity Additions



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	$10,735	$10,244	$10,677	$10,993	$10,993	$10,951	$11,309
	+$62	+$491	-	+$433	+$749	+$749	+$705	+$1,065
Cost To Customer 30-year NPVRR (Ref Case) $M	$25,142	$25,626	$25,471	$25,922	$27,236	$27,999	$27,984	$28,756
	-	+$484	+$329	+$780	+$2,094	+$2,857	+$2,842	+$3,614
Cost Certainty 30-year Scenario Range NPVRR $M	$9,669	$10,245	$7,815	$9,286	$5,414	$4,717	$5,232	$5,451
	+$4,952	+$5,529	$3,098	$4,569	$697	-	$516	+$735
Cost Risk 95th % Cost Risk	$53.1	$53.3	$54.2	$56.8	$54.1	$54.1	$45.1	$45.0
	+$8.1	+$8.4	+$9.2	+$11.9	+9.2	+9.2	+$0.2	-
Lower Cost Opp. 5th % Cost Risk	-$37.4	-$37.3	-$37.4	-$39.2	-$38.9	-$38.9	-$35.4	-$36.3
	+$1.8	+$1.9	+$1.8	-	+$0.3	+$0.3	+$3.8	+$2.9
Carbon Emissions M of tons/MWh 2024-40 Cum.	0.23	0.24	0.19	0.22	0.18	0.20	0.09	0.09
	+0.14	+0.15	+0.10	+0.13	+0.09	+0.11	-	-
Reliability Forced Market Exposure (GWh)	235	86	89	4	4	4	793	515
	+231	+82	+85	-	-	-	+789	+511
Flexibility New capacity able to respond within 30 mins (MW)	3,849	4,482	4,121	4,812	4,632	4,812	3,905	4,456
	-963	-330	-691	-	-180	-	-907	-356
Local Economy NPV of property taxes	$1,849	$1,853	$1,938	$1,840	$2,229	$2,097	$2,619	$2,698
	-$849	-$845	-$760	-$858	-$484	-$609	-$79	-

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[1] (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

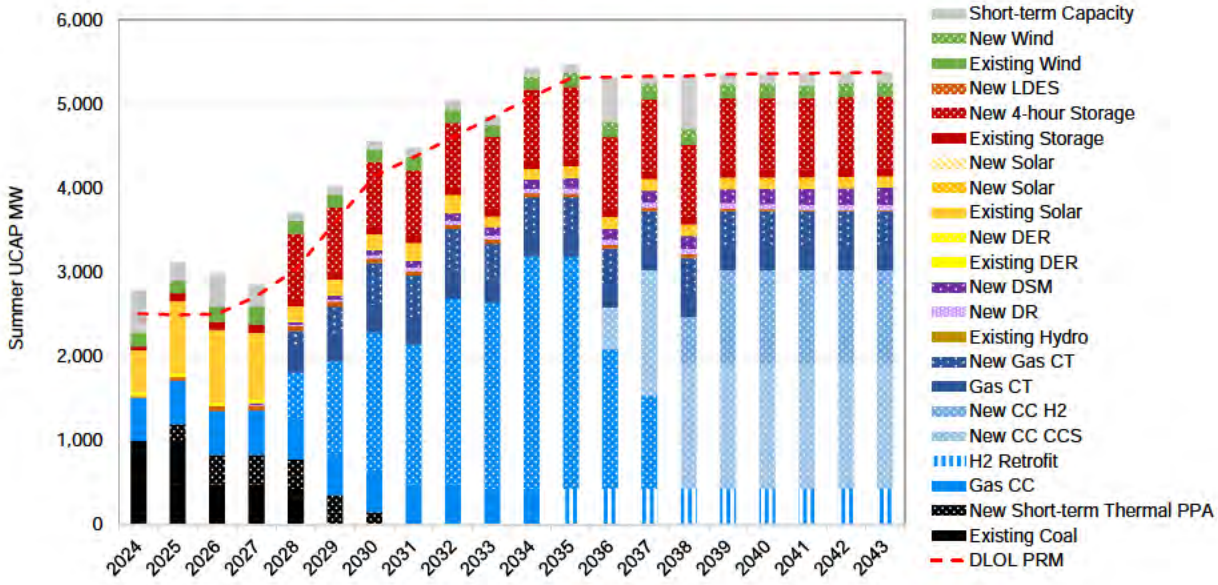
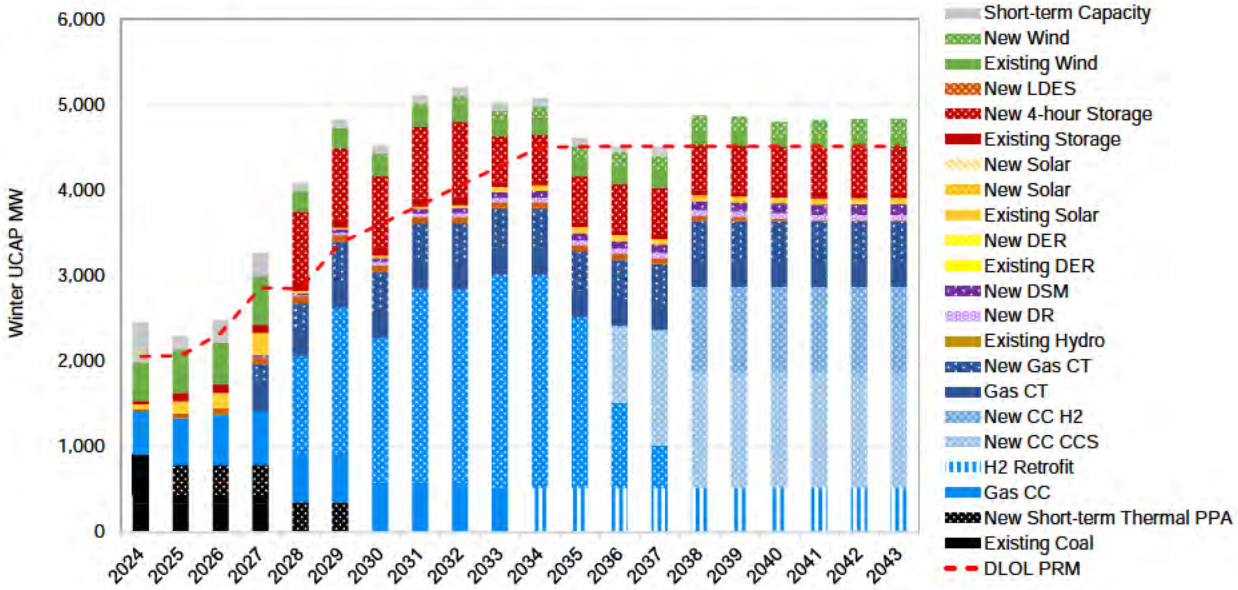


Figure 9-42: Preferred Portfolio Supply-Demand Balance - Winter



[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

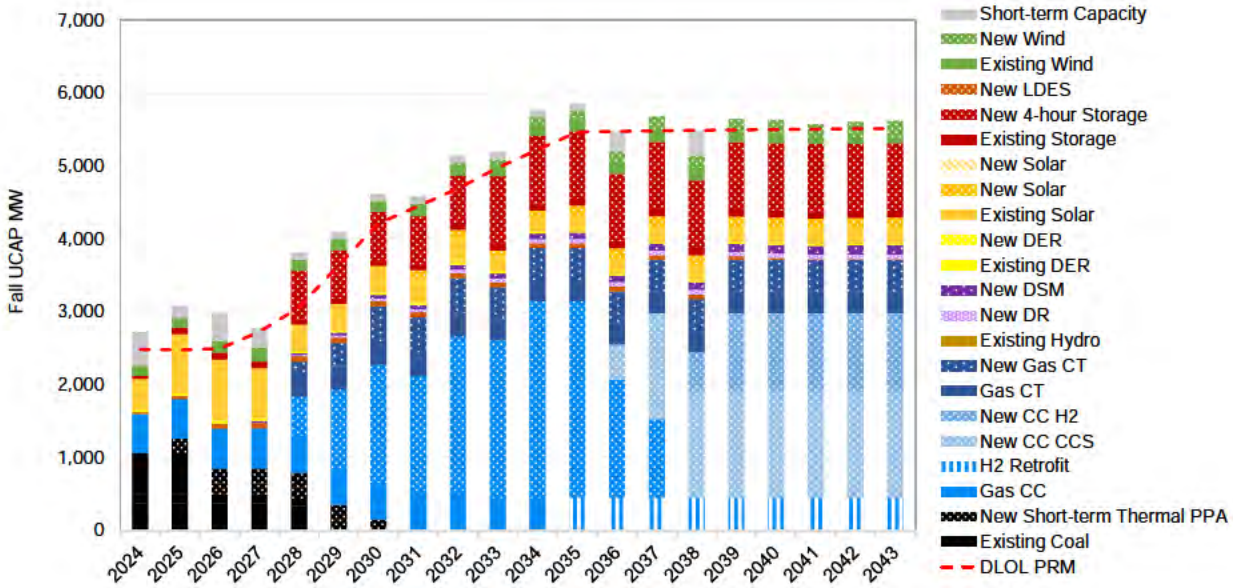


Figure 9-44: Preferred Portfolio Supply-Demand Balance - Spring

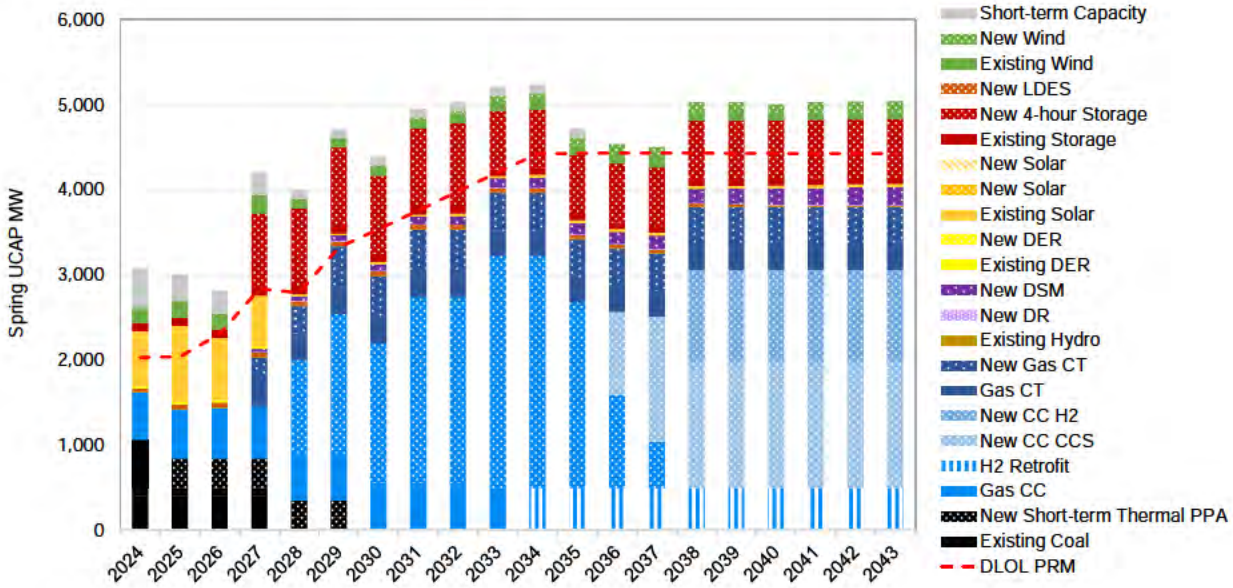
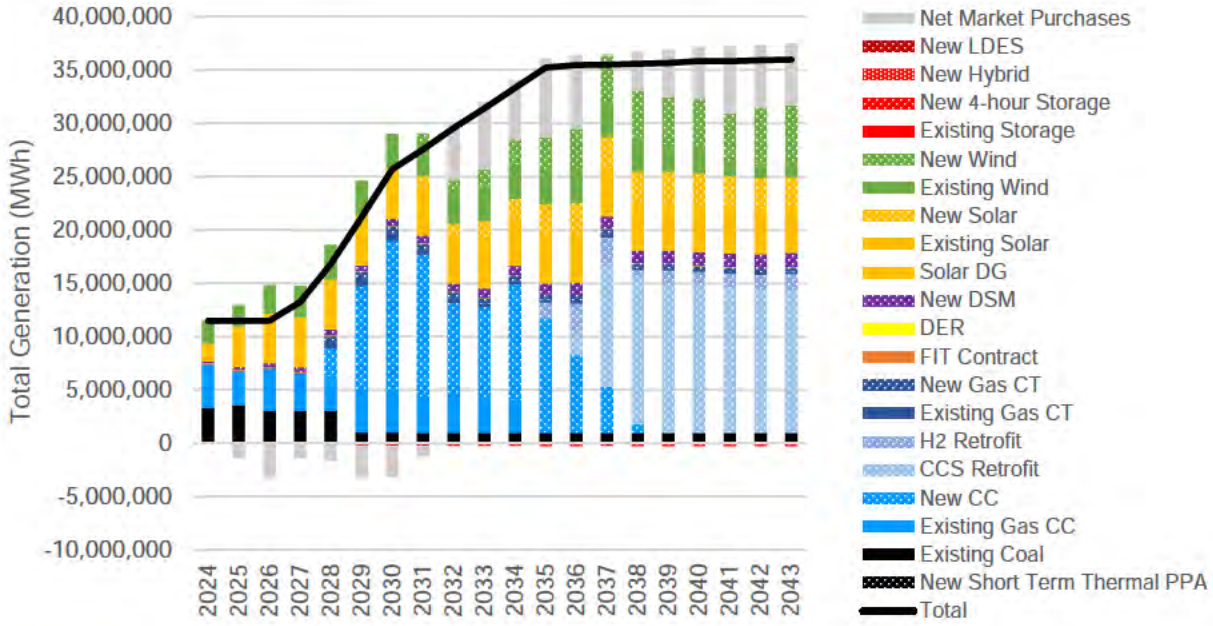


Figure 9-45 summarizes the expected energy balance for the preferred portfolio over time. As shown, new energy from combined cycle capacity additions is projected to meet growing load into the early 2030s. Under Reference Case conditions, the enforcement of a 40% capacity factor limit on new combined 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;

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

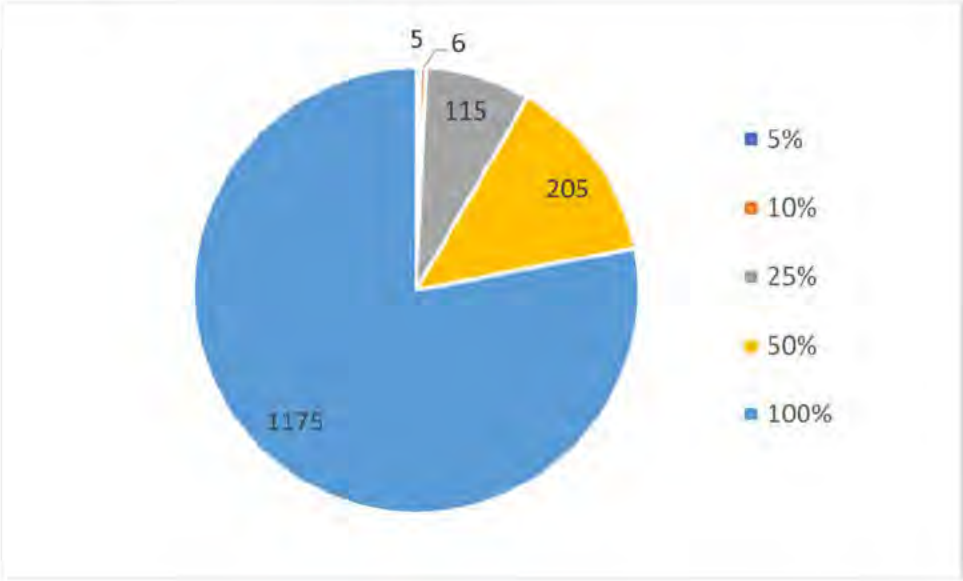
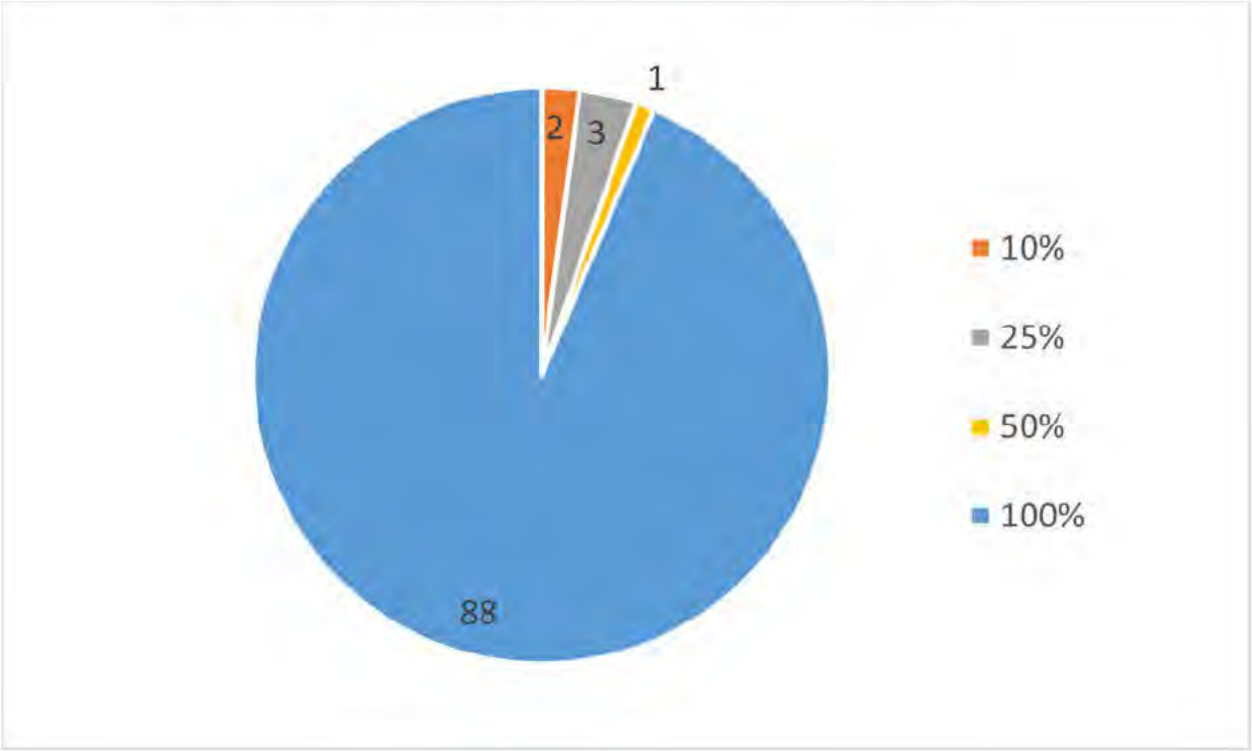


Figure 10-3 shows the breakdown of commercial and industrial customers as of December 31, 2023.

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 and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 101
Schahfer Title V Permit Modification,
February 2025

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

To:	Interested Parties
Date:	February 4, 2025
From:	Jenny Acker, Chief Permits Branch Office of Air Quality
Source Name:	Northern Indiana Public Service Company LLC RM Schahfer Generating Station
Permit Level:	TV Significant Permit Modification
Permit Number:	073-48085-00008
Source Location:	2723 E 1500 N, Wheatfield, IN 46392
Type of Action Taken:	Modification at an existing source

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the matter referenced above.

The final decision is available on the IDEM website at: https://www.in.gov/apps/idem/caats/
To view the document, choose Search Option **by Permit Number**, then enter permit 48085. This search will also provide the application received date, **draft permit** public notice start and end date, **proposed permit** EPA review period start and end date, and **final** permit issuance date.

The final decision is also available via IDEM's Virtual File Cabinet (VFC). Please go to: https://www.in.gov/idem and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

(continues on next page)

If you would like to request a paper copy of the permit document, please contact IDEM's Office of Records Management:

IDEM - Office of Records Management
Indiana Government Center North
100 North Senate Avenue
Indianapolis, IN 46204-2251
Phone: (317) 232-8667
Fax: (317) 233-6647
Email: IDEMFILEROOM@idem.in.gov

Pursuant to IC 13-17-3-4 and 326 IAC 2, this permit modification is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-7-3 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to Indiana Office of Administrative Law Proceedings, 100 N. Senate Avenue Suite N802, Indianapolis, IN 46204, **within eighteen (18) days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Indiana Office of Administrative Law Proceedings (OALP); or
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OALP by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OALP by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

Pursuant to 326 IAC 2-7-18(d), any person may petition the U.S. EPA to object to the issuance of an initial Title V operating permit, permit renewal, or permit modification within sixty (60) days of the end of the forty-five (45) day EPA review period. Such an objection must be based only on issues that were raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impractible to raise such issues, or if the grounds for such objection arose after the comment period.

The EPA requests that you file Title V petitions electronically through the Central Data Exchange. To do so, please go to: https://cdx.epa.gov/ .

If you tried but you are unable to use the Central Data Exchange to file your petition, the EPA requests that you send your petition and associated attachments via email to: titleVpetitions@epa.gov.

If you have made every effort to electronically submit your petition but are simply unable to successfully do so, please submit a hardcopy of your petition to the following address:

US EPA
Office of Air Quality Planning and Standards
Air Quality Policy Division
Operating Permits Group Leader
109 T.W. Alexander Dr. (C-504-01)
Research Triangle Park, NC 27711

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures
Decision-Title V-Mod 1/13/25

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun, *Governor*

February 4, 2025

Edward D. Pierce
Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station
2755 Raystone Drive
Valparaiso, IN 46383

Re: 073-48085-00008
Significant Permit Modification

Dear Mr. Pierce:

Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station was issued Part 70 Operating Permit Renewal No. T073-45762-00008 on November 13, 2024 for a a stationary electric utility generating station located at 2723 East 1500 North, Wheatfield, Indiana 46392. An application requesting changes to this permit was received on June 17, 2024. Pursuant to the provisions of 326 IAC 2-7-12, a Significant Permit Modification to this permit is hereby approved as described in the attached Technical Support Document.

Please find attached the entire Part 70 Operating Permit as modified, including the following new attachment(s):

Attachment F: 40 CFR 60, Subpart IIII, Stationary Compression Ignition Internal Combustion Engines [*revised]*
Attachment H: 40 CFR 63, Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines [*revised]*
Attachment I: 40 CFR 60, Subpart KKKK, Stationary Combustion Turbines [*new]*
Attachment J: 40 CFR 60, Subpart TTTTa, Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units [*new]*

The permit references the below listed attachment(s). Since these attachments have been provided in previously issued approvals for this source, IDEM OAQ has not included a copy of these attachments with this modification:

Attachment A: Decree Paragraphs and Tables
Attachment B: Northern Indiana Public Service Company LLC - Consent Decree
Attachment C: 40 CFR 60, Subpart Da, Electric Utility Steam Generating Units
Attachment D: 40 CFR 60, Subpart Y, Coal Preparation and Processing Plants Requirements
Attachment E: 40 CFR 60, Subpart GG, Stationary Gas Turbines Requirements
Attachment G: 40 CFR 63, Subpart UUUUU, : Coal- and Oil-Fired Electric Utility Steam Generating Units

Previously issued approvals for this source containing these attachments are available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

Previously issued approvals for this source are also available via IDEM's Virtual File Cabinet (VFC). To access VFC, please go to: https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria.

Federal rules under Title 40 of United States Code of Federal Regulations may also be found on the U.S. Government Printing Office's Electronic Code of Federal Regulations (eCFR) website, located on the Internet at: http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40tab_02.tpl.

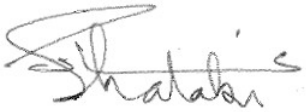
A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. A copy of the application and permit is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria. To find documents related to this air permit, click on "Advanced Search", specify "OAQ" in the Program search field, specify the five-digit permit number "48085" in the Permit # search field, then click the Search button at the top or bottom of the webpage.

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5.

If you have any questions regarding this matter, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

Sincerely,



Ghassan Shalabi, Section Chief
Permits Branch
Office of Air Quality

Attachments: Modified Permit and Technical Support Document
cc: File - Jasper County
Jasper County Health Department
U.S. EPA, Region 5
Compliance and Enforcement Branch

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun, *Governor*

Part 70 Operating Permit Renewal
OFFICE OF AIR QUALITY

Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station

2723 East 1500 North
Wheatfield, Indiana 46392

(herein known as the Permittee) is hereby authorized to operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17.

Operation Permit No.: T073-45762-00008 Master Agency Interest ID.: 11840	
Issued by: Original signed by: Ghassan Shalabi, Section Chief Permits Branch, Office of Air Quality	Issuance Date: November 13, 2023 Expiration Date: November 13, 2028

Significant Permit Modification No.: 073-48085-00008	
Issued by: Madhima Das for Ghassan Shalabi, Section Chief Permits Branch Office of Air Quality	Issuance Date: February 4, 2025 Expiration Date: November 13, 2028

Visit on.IN.gov/survey or scan the QR code to provide feedback.
We appreciate your input!

TABLE OF CONTENTS

SECTION A SOURCE SUMMARY 9

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]
A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]
A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]
A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

SECTION B GENERAL CONDITIONS 14

B.1 Definitions [326 IAC 2-7-1]
B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]
B.3 Term of Conditions [326 IAC 2-1.1-9.5]
B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]
B.5 Severability [326 IAC 2-7-5(5)]
B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]
B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]
B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]
B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]
B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]
B.11 Emergency Provisions [326 IAC 2-7-16]
B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]
B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]
B.14 Reserved
B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]
B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]
B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]
B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]
B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]
B.20 Source Modification Requirement [326 IAC 2-7-10.5]
B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]
B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]
B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]
B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

SECTION C SOURCE OPERATION CONDITIONS 25

Emission Limitations and Standards [326 IAC 2-7-5(1)] 25

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]
C.2 Opacity [326 IAC 5-1]
C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]
C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]
C.5 Fugitive Dust Emissions [326 IAC 6-4]
C.6 Reserved
C.7 Stack Height [326 IAC 1-7]
C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

Testing Requirements [326 IAC 2-7-6(1)] 27

C.9 Performance Testing [326 IAC 3-6]

Compliance Requirements [326 IAC 2-1.1-11] 27

C.10 Compliance Requirements [326 IAC 2-1.1-11]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 27
C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]
C.12 Reserved
C.13 Reserved
C.14 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6] 29
C.15 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]
C.16 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]
C.17 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]
C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 31
C.19 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]
C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]
C.21 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [40 CFR 64][326 IAC 3-8]

Stratospheric Ozone Protection 33
C.22 Compliance with 40 CFR 82 and 326 IAC 22-1

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS 34

Emission Limitations and Standards [326 IAC 2-7-5(1)] 34
D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

Compliance Determination Requirements 34
D.0.2 Compliance Determination for Combined Total HAP
D.0.3 Compliance Determination for Combined Formaldehyde
D.0.4 Testing Requirements [326 IAC 2-1.1-11]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 36
D.0.5 Record Keeping Requirement
D.0.6 Reporting Requirements

SECTION D.1 RESERVED 37

SECTION D.2 RESERVED 38

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS 39

Emission Limitations and Standards [326 IAC 2-7-5(1)] 39
D.3.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3][326 IAC 6-2-1(g)][326 IAC 7-1.1-2]
D.3.2 Reserved
D.3.3 Alternative Fuel Blends [326 IAC 2-2]
D.3.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)] 40
D.3.5 Reserved
D.3.6 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)]
D.3.7 Operation of Electrostatic Precipitator
D.3.8 Scrubber Operation
D.3.9 Reserved
D.3.10 Continuous Emissions Monitoring [326 IAC 2-2] [326 IAC 3-5] [326 IAC 7-2-1(g)][326 IAC 12]

D.3.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]
D.3.12 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 42
D.3.13 PM Monitoring System Downtime
D.3.14 SO_2 Monitoring System Downtime

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19] 43
D.3.15 Record Keeping Requirements
D.3.16 Reporting Requirements

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS 45

Emission Limitations and Standards [326 IAC 2-7-5(1)] 45
D.4.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]
D.4.2 Reserved
D.4.3 Reserved
D.4.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)] 45
D.4.5 NOx Control
D.4.6 Continuous Emissions Monitoring [326 IAC 3-5]
D.4.7 Reserved

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 46
D.4.8 Record Keeping Requirements
D.4.9 Reporting Requirements

SECTION D.5 RESERVED 47

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS 48

Emission Limitations and Standards [326 IAC 2-7-5(1)] 48
D.6.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]
D.6.2 Reserved
D.6.3 Particulate Emission Limitation for Manufacturing Processes [326 IAC 6-3-2]

Compliance Determination Requirements [326 IAC 2-7-5(1)] 49
D.6.4 Particulate Control
D.6.5 Reserved

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 50
D.6.6 Visible Emissions Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 50
D.6.7 Record Keeping Requirements

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS 51

Emission Limitations and Standards [326 IAC 2-7-5(1)] 52
D.7.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS 53

Emission Limitations and Standards [326 IAC 2-7-5(1)] 53
D.8.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]
D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 54
D.8.3 Visible Emissions Notations
D.8.4 Broken or Failed Bag Detection

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 54
D.8.5 Record Keeping Requirements

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS 56

Emission Limitations and Standards [326 IAC 2-7-5(1)] 56
D.9.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2-3]

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 56
D.9.2 Visible Emissions Notations

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 57
D.9.3 Record Keeping Requirements

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS 58

Emission Limitations and Standards [326 IAC 2-7-5(1)] 58
D.10.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS 59

Emission Limitations and Standards [326 IAC 2-7-5(1)] 59
D.11.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]
D.11.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 60
D.11.3 Record Keeping Requirements

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS 61

Emission Limitations and Standards [326 IAC 2-7-5(1)] 61
D.12.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS 62

Emission Limitations and Standards [326 IAC 2-7-5(1)] 62
D.13.1 PSD Minor Limit for PM and VOC [326 IAC 2-2]
D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

Compliance Determination Requirements [326 IAC 2-7-5(1)] 63
D.13.3 Testing Requirements [326 IAC 2-1.1-11]
D.13.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]
D.13.5 Compliance determination for PM and VOC

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)] 64
D.13.6 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19] 64
D.13.7 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]
D.13.8 Record Keeping Requirements
D.13.9 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]
D.13.10 Reporting Requirements

Acid Rain Program 67
E.1.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21][40 CFR 72 through 40 CFR 78]
E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

SECTION E.2 RESERVED 69

SECTION E.3 NSPS 70

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 70
E.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.3.2 Standards of Performance for Electric Utility Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Da]

SECTION E.4 NSPS 72

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 72
E.4.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.4.2 New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart Y]

SECTION E.5 NSPS 74

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 74
E.5.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.5.2 New Source Performance Standards for Stationary Gas Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart GG]

SECTION E.6 NSPS 75

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 75
E.6.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

SECTION E.7 RESERVED 77

SECTION E.8 NESHAP 78

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)] 78
E.8.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]
E.8.2 Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU] [326 IAC 20-89]

SECTION E.9 NESHAP 80

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)] 80
E.9.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]
E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-89]

SECTION E.10 NSPS 82

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 82
E.10.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.10.2 New Source Performance Standards for Stationary Combustion Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

SECTION E.11 NSPS 84

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)] 84
E.11.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]
E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

SECTION F EMISSIONS UNIT OPERATION CONDITIONS 86

Provisions of Northern Indiana Public Service Company LLC Consent Decree Applicable to R.M. Schahfer Generating Station 86

F.1 Consent Decree [*United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011), paragraph 169] [326 IAC 2-7-6(3)]

SECTION G RESERVED 87

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606) 88

ORIS Code: 994 88

H.1 Designated representative requirements
H.2 Emissions monitoring, reporting, and recordkeeping requirements
H.3 NOX annual emissions requirements
H.4 NOx ozone season requirements
H.5 SO_2 emissions requirements
H.6 Title V Permit Revision Requirements
H.7 Additional recordkeeping and reporting requirements
H.8 Liability
H.9 Effect on other authorities
H.10 Description of TR Monitoring Provisions

CERTIFICATION 102

EMERGENCY OCCURRENCE REPORT 103

Part 70 Quarterly Report 105

Part 70 Quarterly Report 106

Part 70 Quarterly Report 107

Part 70 Quarterly Report 108

Part 70 Quarterly Report 109

Part 70 Quarterly Report 110

QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT 111

Attachment A - Decree Paragraphs and Tables
Attachment B - Northern Indiana Public Service Company LLC - Consent Decree
Attachment C - Standards of Performance for Electric Utility Steam Generating Units [40 CFR Part 60, Subpart Da]
Attachment D - New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements [40 CFR Part 60, Subpart Y]
Attachment E - New Source Performance Standards for Stationary Gas Turbines Requirements [40 CFR Part 60, Subpart GG]
Attachment F - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60, Subpart IIII]
Attachment G - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units [40 CFR 63, Subpart UUUUU]
Attachment H - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR 63, Subpart ZZZZ]
Attachment I - New Source Performance Standards for Stationary Combustion Turbines Requirements [40 CFR Part 60, Subpart KKKK]

Attachment J - New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements [40 CFR Part 60, Subpart TTTTa]

SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.4 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

Source Address:	2723 East 1500 North, Wheatfield, Indiana 46392
General Source Phone Number:	219-956-5385
SIC Code:	4911
County Location:	Jasper
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

This stationary source consists of the following emission units and pollution control devices:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]

[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(f) Fuel storage and handling systems for Unit 17 and 18 boilers, constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

(g) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, constructed in 1980, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour, constructed in 1980.

(2) Three (3) ground limestone pneumatic truck unloading systems connected to Unit 17 and Unit 18 limestone silos, constructed in 1980, with baghouses for PM control.

(3) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour, constructed in 1980. All gypsum is handled wet.

(4) One (1) radial stacker, identified as 7MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2013.

(5) One (1) radial stacker, identified as 8MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2016.

(h) Dry fly ash handling and disposal.

(1) Pneumatic fly ash conveyance to storage silos, with a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 17, and 18, with cyclone separators, filter/separators**,** silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute, with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads and onsite disposal area.

(i) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(j) Ponded bottom ash handling/removal operations.

(k) Material handling for the flue gas desulfurization systems for Unit 17 and Unit 18 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Three (3) storage silos originally used for dual-alkali FGD system with baghouses for PM control.

(3) Two (2) upgraded incline belt conveyors, constructed in 2013, and shared among Units 17 and 18 for transfer of dewatered gypsum to the radial stackers.

(4) Transportation of off-specification gypsum by truck on unpaved roads.

(l) One (1) natural gas-fired temporary boiler, constructed in 2020, with a maximum capacity of less than or equal to 99.9 MMBtu per hour, using no control, and exhausting outdoors.

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]

This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) Conveyors as follows:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day.

(2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983.

(3) Uncovered coal conveying of less than or equal to 120 tons per day; and

(4) Underground conveyors.

(b) Coal bunker and coal scale exhausts and associated dust collector vents.

(c) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(d) Any of the following structural steel and bridge fabrication activities:

(1) Cutting 200,000 linear feet or less of one inch (1") plate or equivalent.

(2) Using 80 tons or less of welding consumables.

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(f) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations.

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(1) Coal pile wind erosion.

(2) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill.

(3) Shot blasters.

(4) Gypsum stockpiles.

(5) Cold Cleaner degreasing operations

(6) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

(h) Two (2) on-site storage piles, each with approximate storage area of 3,440 square feet.

(i) Truck transport of gypsum to the stockpiles and conveyor on paved and unpaved roads.

A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3).

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

(a) Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

(b) Notwithstanding B.1(a), the terms located in paragraphs of the Decree that are incorporated by reference into this permit in accordance with Section F and Attachment A shall have the definition, and only the definition, assigned to such terms in the Decree and are limited to Section F and Attachment A.

B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]

(a) This permit, T 073-45762-00008, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

B.3 Term of Conditions [326 IAC 2-1.1-9.5]

Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

B.5 Severability [326 IAC 2-7-5(5)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

This permit does not convey any property rights of any sort or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(35).

B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and

(5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

The Permittee shall implement the PMPs.

(b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee’s control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM,

OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency.

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(8) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

(2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

(4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T 073-45762-00008 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised under 326 IAC 2-7-10.5, or

(3) deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

B.14 Reserved

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that

meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source’s failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(c) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

(a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1) and (c)(1).

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(37)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;

(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Emission Trades [326 IAC 2-7-20(c)]
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ or U.S. EPA is required.

(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

(f) This condition does not apply to emission trades of SO_2 or NO_X under 326 IAC 21.

B.20 Source Modification Requirement [326 IAC 2-7-10.5]

A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-8590 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards [326 IAC 2-7-5(1)]

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

C.2 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.3 Open Burning [326 IAC 4-1] [IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

C.5 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.6 Reserved

C.7 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at

least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:

(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or

(2) If there is a change in the following:

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(c).

(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(d).

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(e) Procedures for Asbestos Emission Control
The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1, emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.

(f) Demolition and Renovation
The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).

(g) Indiana Licensed Asbestos Inspector
The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Licensed Asbestos Inspector to

thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

Testing Requirements [326 IAC 2-7-6(1)]

C.9 Performance Testing [326 IAC 3-6]

(a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. In the event that a previously scheduled test must be canceled and rescheduled, the Permittee of the source or emissions unit shall notify the department no less than fourteen (14) days in advance of the rescheduled test date. Tests rescheduled for less than fourteen (14) days after notifying the department of the rescheduled test date must be approved by the department. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

C.10 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]

(a) For new units:
Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.

(b) For existing units:
Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance to begin such monitoring. If, due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

(c) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

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

C.12 Reserved

C.13 Reserved

C.14 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6]

C.15 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.16 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]

If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.17 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5] [326 IAC 2-7-6]

(I) Upon detecting an excursion where a response step is required by the D Section, or an exceedance of a limitation, not subject to CAM, in this permit:

(a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned or are returning to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to normal or usual manner of operation.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;

(2) review of operation and maintenance procedures and records; and/or

(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall record the reasonable response steps taken.

(II)

(a) CAM *Response to excursions or exceedances.*

(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a Quality Improvement Plan (QIP). The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8(b)(2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or

(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*

(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(c) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

C.19 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(1) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(33) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

C.20 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:

(AA) All calibration and maintenance records.
(BB) All original strip chart recordings for continuous monitoring instrumentation.
(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.
(BB) The dates analyses were performed.
(CC) The company or entity that performed the analyses.
(DD) The analytical techniques or methods used.
(EE) The results of such analyses.
(FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

C.21 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a

"responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C - Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(b) The address for report submittal is:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

Stratospheric Ozone Protection

C.22 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with applicable standards for recycling and emissions reduction.

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

Pursuant to SSM No. 073-47965-00008 and in order to render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA), prior to the startup, as defined at 40 CFR 63.2, of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20, and the emergency generator EDG1 and emergency fire pump FP1, the Permittee shall comply with following:

(a) The combined total HAPs emissions from the combustion turbines (16A, 16B, 19A, 19B, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined formaldehyde emissions from the combustion turbines (16A, 16B, 19A, 19B, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) Upon the commencement of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20, the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from the source.

(d) The limits in paragraphs (a) and (b) will be effective after the permanent shutdown and decommissioning of the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18 and the start of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20.

Compliance with these limits, combined with the potential to emit HAP from all other emission units at the source, shall limit the source-wide potential to emit single HAP to less than 10 tons per twelve (12) consecutive month period and the source-wide potential to emit total HAPs to less than 25 tons per twelve (12) consecutive month period, and shall render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA).

Compliance Determination Requirements

D.0.2 Compliance Determination for Combined Total HAP

In order to determine compliance with Condition D.0.1(a), the combined total HAP emissions from the entire source shall be determined using the following equation:

$$E_{THAP} = \sum_{i=1}^{12}\left(\sum_{n}\frac{\begin{array}{c}EF_{n19} * HI_{19A} + EF_{n19} * HI_{19B} + EF_{n19} * HI_{19C} + EF_{nU20} * HI_{U20} + EF_{n16} * HI_{16A} + \\ EF_{n16} * HI_{16B} + EF_{nTB} * NT_{TB} + EF_{n350FP} * DT_{350FP} + EF_{nFP1} * DT_{FP1} + EF_{nEDG1} * DT_{EDG1}\end{array}}{2000}\right)$$

Where:

E_{THAP} = Combined total HAP emissions (tons/month)
HI_{19A} = Heat input from turbine Unit 19A (MMBtu/month)
HI_{19B} = Heat input from turbine Unit 19B (MMBtu/month)
HI_{19C} = Heat input from turbine Unit 19C (MMBtu/month)
HI_{U20} = Heat input from turbine Unit 20 (MMBtu/month)
HI_{16A} = Heat input from turbine Unit 16A (MMBtu/month)
HI_{16B} = Heat input from turbine Unit 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (gallons/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (gallons/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (gallons/month)
EF_{n19} = Emission factors (in lb/MMBtu) for every single HAP from Units 19A, 19B, and 19C
EF_{nU20} = Emission factors (in lb/MMBtu) for every single HAP from Unit 20
EF_{n16} = Emission factors (in lb/MMBtu) for every single HAP from Units 16A and 16B
EF_{nTB} = Emission factors (in lb/MMscf) for every single HAP from temporary boiler
EF_{n350FP} = Emission factors (in lb/gallon) for every single HAP from 350 HP diesel fire pump
EF_{nEDG1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency generator EDG1
EF_{nFP1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency fire pump FP1
i = Each calendar month within the twelve (12) consecutive month period
n = Every single HAP emitted by emission units included in the HAP limit

D.0.3 Compliance Determination for Combined Formaldehyde

In order to determine compliance with Condition D.0.1(b), the combined single HAP (formaldehyde) emissions from the entire source shall be determined using the following equation:

$$\sum_{i=1}^{12} E_{Single\ HAP\ (Formaledyde)} = \frac{ER_{19} * HR_{19A} + ER_{19} * HR_{19B} + ER_{19} * HR_{19C} + ER_{U20} * HR_{U20} + EF_{16} * HI_{16A} + EF_{16} * HI_{16B} + EF_{TB} * NT_{TB} + EF_{350FP} * DT_{350FP} + EF_{FP1} * DT_{FP1} + EF_{EDG1} * DT_{EDG1}}{2000}$$

Where:

$E_{Single\ HAP\ (Formaldehyde)}$ = Single HAP (Formaldehyde) Emissions (tons/month)
ER_{19} = 0.920 lb/hr, emission rate for formaldehyde for turbines 19A, 19B, and 19C or value established in latest compliant stack test
ER_{U20} = 1.10 lb/hr, emission rate for formaldehyde for turbine Unit 20 or value established in latest compliant stack test
HR_{19A} = Number of operating hours per month for turbine 19A
HR_{19B} = Number of operating hours per month for turbine 19B
HR_{19C} = Number of operating hours per month for turbine 19C
HR_{U20} = Number of operating hours per month for turbine Unit 20
HI_{16A} = Heat input from turbine 16A (MMBtu/month)
HI_{16B} = Heat input from turbine 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (hp-hr/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (hp-hr/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (hp-hr/month)
EF_{16} = 7.10E-04 lb/MMBtu, formaldehyde emission factor from AP-42 (Chapter 3.1 - Table 3.1-3)
EF_{TB} = 7.50E-02 lb/MMscf, formaldehyde emission factor from AP-42 (Chapter 1.4 - Table 1.4-3)
EF_{350FP} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*

EF_{EDG1} = 5.52E-07 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.4 - Table 3.4-3)*
EF_{FP1} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*
i = Each calendar month within the twelve (12) consecutive month period
* Emission Factors in lb/hp-hr were calculated as follows: EF (lb/MMBtu) x 7,000 (Btu/hp-hr) x (1 MMBtu / 1,000,000 Btu)

D.0.4 Testing Requirements [326 IAC 2-1.1-11]

In order to demonstrate compliance with Condition D.0.1 and to verify the emission rates for formaldehyde, not later than 180 days after the startup of the following emission units, the Permittee shall perform formaldehyde testing as follows:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	Formaldehyde (0.920 lb/hr)	One time
Frame type combustion turbine	Unit 20	Formaldehyde (1.10 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.0.5 Record Keeping Requirement

(a) To document the compliance status with Conditions D.0.1, the Permittee shall maintain monthly records in accordance with (1) and (3) below. Records maintained for (1) and (3) shall be taken as stated below and shall be complete and sufficient to establish compliance with the combined HAPs and single HAP emission limits established in Conditions D.0.1:

(1) Monthly combined total HAP emissions as calculated using the equation in Condition D.0.2.

(2) Monthly combined single HAP (formaldehyde) emissions as calculated using the equation in Condition D.0.3.

(3) The dates of shutdown for each unit listed in Condition D.0.1(c).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.0.6 Reporting Requirements

A quarterly summary of the information to document the compliance status with D.0.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1(35).

SECTION D.1 RESERVED

SECTION D.2 RESERVED

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.3.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3][326 IAC 6-2-1(g)][326 IAC 7-1.1-2]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1460, issued on April 14, 1980:

(a) Each boiler unit (Units 17 and 18) shall not be operated in excess of 3,967 MMBtu per hour heat input. (in EPA-5-A-80-18 only)

(b) Stack gas particulate emissions shall be controlled to 0.03 pound or less of total suspended particulates per million BTU (lb/MMBtu) of heat input.

This requirement will be met by using electrostatic precipitators (ESP) which will provide a 99.8 percent guaranteed control efficiency. (in PC (37) 1460 only)

(c) The opacity of the exhaust gases shall not exceed twenty percent (20%) based on a six-minute average except for one six-minute period per hour of opacity not exceeding twenty-seven percent (27%). (EPA 5-A-80-18 only)

(d) Reserved.

(e) Nitrogen oxide emissions from each boiler shall not exceed 0.6 pound per million BTU (lb/MMBTU) of heat input.

(f) Reserved.

D.3.2 Reserved

D.3.3 Alternative Fuel Blends [326 IAC 2-2]

(a) Pursuant to a letter from IDEM, OAQ, to Northern Indiana Public Service Company LLC dated June 13, 1996, based on the results of emissions testing performed in 1995 and subsequent ambient air modeling studies, petroleum coke may be combusted in Units 17 and 18 at a blend rate of no more than 30 percent (30%) petroleum coke (by weight). The conditions of the Units 17 and 18 federal PSD construction permit are not affected by this ruling, and all requirements contained therein still apply.

(b) The flue gas desulfurization (FGD) system shall be in operation at all times when pet coke is being fired. Should an emergency condition occur which causes a malfunction of the FGD system, the Permittee shall cease bunkering pet coke until the FGD system is fully operational.

D.3.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.3.5 Reserved

D.3.6 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A) (iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment as specified in Section D.3.

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60, 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a continuous emission monitors other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

(1) If the CEM is required for monitoring NOx or SO2 emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 (SO2 and NOx Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.

(2) If the CEM is not used to monitor NOx or SO2 emissions pursuant to 40 CFR 75 or 326 IAC 24 (SO2 and NOx Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, or 40 CFR 75.

D.3.7 Operation of Electrostatic Precipitator

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator (ESP) shall be operated at all times that the corresponding boilers are in operation.

D.3.8 Scrubber Operation

Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with all applicable SO_2 emission limits.

D.3.9 Reserved

D.3.10 Continuous Emissions Monitoring [326 IAC 2-2] [326 IAC 3-5] [326 IAC 7-2-1(g)][326 IAC 12]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued on April 14, 1980, and 326 IAC 2-2, continuous emission monitoring systems for Units 17 and 18 shall be calibrated, maintained, and operated for measuring opacity, SO_2, NO_X, and either CO_2 or O_2, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 326 IAC 10-4, 40 CFR 60, or 40 CFR 75.

D.3.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

Compliance with the PM limitation in Condition D.3.1(b) shall be determined by use of a CEMS measuring PM emissions in accordance with the procedures in 40 CFR 63 Subpart UUUUU and this Condition. The Permittee shall certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 17 and Unit 18 to the atmosphere and record the output of the system as specified in paragraphs (a) through (e):

(a) The PM CEMS shall be certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).

(b) Compliance with the applicable particulate emission limitations in Condition D.3.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.

(c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.3.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO2) values that are below 5%.

(d) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3.

D.3.12 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3]

The Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the limits as established in PSD Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Construction Permit PC (37) 1460, issued on April 14, 1980, using a thirty (30) day rolling arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or emergency conditions for SO_2. Compliance with the percentage reduction requirements for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.3.13 PM Monitoring System Downtime

(a) Whenever the PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used to provide information related to particulate emissions:

(1) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 17 or Unit 18 is in operation by measuring and recording the following:

(A) the primary and secondary currents of the T-R sets.

(B) the primary and secondary voltages of the T-R sets

(C) daily number of TR sets in service

D.3.14 SO_2 Monitoring System Downtime

Whenever both the primary and back up SO2 continuous emission monitoring systems (CEMS) are malfunctioning or down for repairs or adjustments for a period of twenty-four (24) hours or more, the Permittee shall monitor and record boiler load, recirculation pH, slurry valve position, and absorber level to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load, and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a back-up CEMs is brought online, the following shall be used to provide information related to SO2 emissions:

(a) If the CEMS is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(b) If the CEMS is down for twenty-four (24) hours or more:

(1) Either fuel sampling and fuel preparation and analysis shall be conducted in accordance with 326 IAC 3-7-2(b) and (c), 326 IAC 3-7-2(d) and 326 IAC 3-7-2(e) or, alternatively, a portable analyzer, properly calibrated according to manufacturer specifications (such as manufacturer operating or maintenance manuals), shall be used to monitor SO_2 emissions. To the extent the Permittee elects to conduct fuel sampling: the Permittee shall collect the coal sample as bunkered; coal shall be sampled at least three (3) times per day and at least one (1) time per eight (8) hour period unless no coal is bunkered during the preceding eight (8) hour period; and minimum sample size shall be five hundred (500) grams.

or

(2) Pursuant to 326 IAC 3-7-3, other manual and other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

(c) To the extent the Permittee elects to conduct fuel sampling to comply with Condition D.3.12, pursuant to 326 IAC 3-7-5(a), the Permittee shall develop a standard operating procedure (SOP) to be followed for sampling, handling, analysis, quality control, quality assurance, and data reporting of any information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4 under this Condition D.3.12. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.3.15 Record Keeping Requirements

(a) To document the compliance status with requirements in Conditions D.3.1(b) the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the limits established in Condition D.3.1(b).

(1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(2) All ESP Parametric monitoring readings when used as backup for the duration when PM CEMS are down.

(b) The Permittee shall maintain all PM continuous emissions monitoring data, with calendar dates and beginning and ending times of any CEM downtime, the reasons for each CEM downtime, and the efforts made to correct the problem.

(c) To document the compliance status with SO_2 Conditions D.3.1, D.3.8, D.3.10, and D.3.12, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limit(s) as required in Conditions D.3.1, D.3.8, D.3.10, and D.3.12. The Permittee shall maintain records in accordance with (2) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g).

(2) All scrubber parametric monitoring readings taken during any periods of CEM downtime, in accordance with Condition D.3.12.

(d) To document the compliance status with NO_X Conditions D.3.1(e) and D.3.10, the Permittee shall maintain records of all NO_X and CO_2 or O_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6 and 326 IAC 2-2. Records shall be complete and sufficient to establish compliance with the NO_X limits as required in Conditions D.3.1(e) and D.3.10.

(e) Reserved.

(f) To document the compliance status with Condition D.3.3, the Permittee shall maintain records of the amount of petroleum coke combusted and the pet coke/coal blend rate for each boiler. Records shall be complete and sufficient to establish compliance with the fuel limit of Condition D.3.3 using a thirty (30) day rolling weighted average.

(g) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.3.16 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7, a quarterly report of PM, SO2, and NOx exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(b) Reserved

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.4.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-79-A-25, issued on August 16, 1979, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1380, issued on May 9, 1979:

(a) Nitrogen oxide (NO_X) emissions from each turbine shall not exceed 93 ppm at 15% oxygen on a dry basis.

(b) Each turbine unit shall not operate in excess of 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

D.4.2 Reserved

D.4.3 Reserved

D.4.4 Reserved

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.4.5 NOx Control

To the extent necessary to comply with Condition D.4.1, the water injection systems which are used to control the NOx emissions from turbines 16A and 16B shall be in operation and control emissions from turbines 16A and 16B.

D.4.6 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 326 IAC 2-2 (PSD), the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring NOx and O_2 emissions rates from the combustion turbine stacks in accordance with 326 IAC 3-5 to demonstrate compliance with Condition D.4.1(a).

(b) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Pursuant to 326 IAC 3-5-4(a), if revisions are made to the continuous monitoring standard operating procedures (SOP), the Permittee shall submit updates to the department biennially.

(d) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, or 40 CFR 75.

D.4.7 Reserved

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.4.8 Record Keeping Requirements

(a) To document the compliance status with Conditions D.4.1(a) and D.4.5, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the nitrogen oxides (NO_X) limits established in Conditions D.4.1(a).

(1) Data and results from the most recent stack test.

(2) To document the compliance status with Condition D.4.5, the Permittee shall maintain records of:

(i) All continuous monitoring system data of fuel consumption and the ratio of water to fuel being fired; or

(i) All continuous emission monitoring system (CEMS) data of NO_x and O_2 whenever Permittee elects to use CEMS to monitor NO_x and O_2.

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall maintain records of the date and times for all periods of turbine operation.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.4.9 Reporting Requirements

(a) To document the compliance status with Condition D.4.1(a), the Permittee shall submit a quarterly summary of:

(1) The ratio of water to fuel if using the continuous monitoring method outlined in 40 CFR 60, Subpart GG; or

(2) The NO_x emissions if using the continuous emissions monitoring method outlined in Condition D.4.5.

The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(35).

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall submit a quarterly summary of the hours of operation for each combustion turbine. These reports shall be submitted to the address listed in Section C - General Reporting Requirements, of this approval. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.5 RESERVED

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Fuel storage and handling systems for Unit 17 and 18 boilers constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:

(a) Conveyors as follows:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;

(3) Uncovered coal conveying of less than or equal to 120 tons per day.

(4) Underground conveyors.

(b) Coal bunker and coal scale exhausts and associated dust collector vents.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.6.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

(a) Particulate emissions from coal unloading shall not exceed ten percent (10%) opacity for the duration of the unloading operation.

(b) All coal conveyors shall be completely enclosed.

(c) All transfer points shall be completely enclosed except those at the storage pile.

(d) Particulate emissions from the crusher house, conveyor room and reclaim tunnels shall be controlled to 99 percent.

(e) Fugitive emissions from the coal piles shall be minimized by compaction and other appropriate measures (surfactant spray etc.).

D.6.2 Reserved

D.6.3 Particulate Emission Limitation for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), for the fuel storage and handling systems for Units 17 and 18 other than the coal storage piles, allowable particulate emissions for the coal handling operations shall be calculated as follows:

(a) Particulate shall not be emitted in excess of the amount shown in the table in 326 IAC 6-3-2(e). The allowable rate of emission shall be based on the process weight rate for the process.

(b) Interpolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$

where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

(c) Interpolation and extrapolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates in excess of sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0\ P^{0.11} - 40$

where E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour.

(d) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emission may exceed that shown in the table in 326 IAC 6-3-2(e), provided the concentration of particulate in the discharge gases to the atmosphere is less than one-tenth (0.10) pound per one thousand (1,000) pounds of gases.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.6.4 Particulate Control

In the event that bag failure is observed in a multi-compartment baghouse, if operations will continue for ten (10) days or more after the failure is observed before the failed bag will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed bag will be repaired or replaced. The notification shall also include the results of any

response actions taken up to the time of notification.

D.6.5 Reserved

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.6.6 Visible Emissions Notations

(a) Visible emission notations of the rail car unloading station openings shall be performed once per day during normal daylight operations when unloading coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the fuel transfer exhaust points shall be performed once per week during normal daylight operations when transferring fuel. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the coal crusher exhaust shall be performed once per week during normal daylight operations when the crusher is in operation. A trained employee shall record whether emissions are normal or abnormal.

(d) If abnormal emissions of dust are observed from the rail car unloading station openings, the fuel transfer exhaust points, or the coal crusher exhaust, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(e) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(f) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(g) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.6.7 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.6(a) - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the coal rail car unloading station openings. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.6.6(b) and (c) - Visible Emission Notations, the Permittee shall maintain weekly records of the visible emission notations of the coal transfer exhaust points and crusher baghouse exhaust. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, constructed 1980, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour, constructed in 1980.

(2) Three (3) ground limestone pneumatic truck unloading systems connected to Unit 17 and Unit 18 limestone silos, constructed in 1980, with baghouses for PM control.

(3) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour, constructed in 1980. All gypsum is handled wet.

(4) One (1) radial stacker, identified as 7MX04G-RS, shared among Unit 17 and 18, with rated capacity of 220 tons/hour, constructed in 2013.

(5) One (1) radial stacker, identified as 8MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2016.

(i) Material handling for the flue gas desulfurization systems for Unit 17and Unit 18 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Three (3) storage silos originally used for dual-alkali FGD system with baghouses for PM control.

(3) Two (2) upgraded incline belt conveyors constructed in 2013 and shared among Units 17 and 18 for transfer of dewatered gypsum to the radial stackers.

(4) Transportation of off-specification gypsum by truck on unpaved roads.

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:

(a) Conveyors as follows:

(2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983.

(4) Underground conveyors.

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(4) Gypsum stockpiles.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.7.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the limestone handling systems and gypsum transfer systems shall not exceed 30 pounds per hour, each, when operating at a process weight rate of 38,941 pounds per hour. This pounds per hour limitation was calculated using the following equation:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10 P^{0.67}$

Where:

E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

(b) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the two (2) radial stackers, identified as 7MX04G-RS and 8MX04G-RS, shall not exceed 59.55 pounds per hour, each, when operating at a process weight rate of 220 tons per hour. This pounds per hour limitation was calculated using the following equation:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 55.0 P^{0.11} - 40$

Where:

E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes) when the process weight rate exceeds 200 tons per hour, the allowable emission may exceed the calculated (E) pounds per hour rate, provided the concentration of particulate in discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1000) pounds of gases.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(f) Dry fly ash handling and disposal.

(1) Pneumatic fly ash conveyance to storage silos, with a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 17, and 18, with cyclone separators, filter/separators**,** silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads; and onsite disposal area.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.8.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

For the fly ash from Units 17 and 18, pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

Fly ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. Trucks utilized for dry or unconditioned ash disposal shall be covered. (in EPA-5-A-80-18 only)

D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the Pneumatic fly ash conveyance from each of Units 17 and 18 shall not exceed 46.8 pounds per hour when operating at a process weight rate of 63 tons per hour of fly ash from each of Units 17 and 18. These pounds per hour limitations were calculated using the following equation:

Interpolation and extrapolation of the data for the process weight rate in excess of 60,000 pounds per hour shall be accomplished by use of the equation:

$E = 55.0\ P^{0.11} - 40$

Where:

E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for dry fly ash silo unloading at a throughput rate greater than 200 tons per hour, the concentration of particulate in the discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1,000) pounds of gases.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.8.3 Visible Emissions Notations

(a) Visible emission notations of the ash silo unloading station openings shall be performed at least once per day during normal daylight operations when ash is being unloaded. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the fly ash conveyance and silo bag filter and bin vent filter exhausts shall be performed at least once per day during normal daylight operations when transferring ash to the corresponding silo. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the nozzle of each telescoping chute shall be performed at least once per day during normal daylight operations when unloading ash through the chute. A trained employee shall record whether emissions are normal or abnormal.

(d) If abnormal visible emissions of ash are observed from the ash silo unloading station openings, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(e) If abnormal emissions are observed at any bag filter exhaust, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(f) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(g) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(h) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

D.8.4 Broken or Failed Bag Detection

In the event that bag failure has been observed:

For bin vent filters, if failure is indicated by an opacity violation, or if filter failure is determined by other means, such as gas temperatures, flow rates, air infiltration, leaks, dust traces or triboflows, then failed unit and the associated process will be shut down immediately until the failed unit has been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.8.5 Record Keeping Requirements

(a) To document the compliance status with Condition D.8.3 - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the Unit 17 and 18 ash silo unloading station openings, the Unit 17 and 18 baghouse stack exhaust, and nozzle of each telescoping chute. The Permittee shall include in its daily record when

a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g., the process did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(h) Ponded bottom ash handling/removal operations.

Insignificant Activities:

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(2) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.9.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2-3]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued on April 14, 1980, with respect to Units 17 and 18:

(a) The bottom ash shall be sluiced to waste disposal ponds. (in PC (37) 1460 only)

(b) Bottom ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. (in EPA-5-A-80-18 only)

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.9.2 Visible Emissions Notations

(a) Visible emission notations of any active onsite landfill area(s) shall be performed at least once per day during normal daylight operations. Any storage pond in the Waste Disposal Area or the Material Storage Runoff Pond area that contains either bottom ash and/or FGD sludge shall be observed once per week to determine if sufficient water is present in the pond to cover or saturate bottom ash and/or sludge deposited in the pond. During any period when there is not sufficient water in the pond to cover or saturate bottom ash and/or sludge present in the pond, visible emission notations of such storage pond area(s) shall be performed at least once per day during normal daylight operations. When daily visible emission notations are made, a trained employee shall record whether emissions are normal or abnormal.

(b) If visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(c) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(d) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(e) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.9.3 Record Keeping Requirements

(a) To document the compliance status with Condition D.9.2 - Visible Emission Notations, the Permittee shall maintain records of visible observations, and any resulting visible emission notations of the Waste Disposal Area and the Material Storage Runoff Pond area, and records of visible emission notations relating to any active onsite landfill area(s).The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Insignificant Activities:

(c) The following equipment related to manufacturing activities not resulting in the emission of HAPs: brazing equipment, cutting torches, soldering equipment, welding equipment.

(d) Any of the following structural steel and bridge fabrication activities:

(1) Cutting 200,000 linear feet or less of one inch (1") plate or equivalent.

(2) Using 80 tons or less of welding consumables.

(f) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations.

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(3) Shot blasters.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.10.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emission rate from the brazing, cutting, soldering, welding, grinding, and machining operations shall not exceed an amount determined by the following, for a process weight rate equal to or greater than 100 pounds per hour:

Interpolation of the data for the process weight rate up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$

Where:

E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)]:

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(5) Cold Cleaner degreasing operations

(6) Degreasing operations that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.11.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-1 and 8-3-2 (Cold Cleaner Degreaser Control and Equipment Operating Requirements), the Permittee shall:

(a) Pursuant to 326 IAC 8-3-1(c)(1)(B) for equipment constructed after January 1, 1980, ensure the following control equipment and operating requirements are met:

(1) Equip the degreaser with a cover.

(2) Equip the degreaser with a device for draining cleaned parts.

(3) Close the degreaser cover whenever parts are not being handled in the degreaser.

(4) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases.

(5) Provide a permanent, conspicuous label that lists the operating requirements in subdivisions (3), (4), (6), and (7).

(6) Store waste solvent only in closed containers.

(7) Prohibit the disposal or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.

(b) Pursuant to 326 IAC 8-3-1(c)(2)(A)(ii) for equipment constructed after July 1, 1990, ensure the following additional control equipment and operating requirements are met:

(1) Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent used is insoluble in, and heavier than, water.
(C) A refrigerated chiller.
(D) Carbon adsorption.
(E) An alternative system of demonstrated equivalent or better control as those outlined in clauses (A) through (D) that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

(2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.

(3) If used, solvent spray:
(A) must be a solid, fluid stream; and
(B) shall be applied at a pressure that does not cause excessive splashing.

D.11.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, the Permittee shall not operate a cold cleaning degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.11.3 Record Keeping Requirements

To document the compliance status with Condition D.11.2, on and after January 1, 2015, the Permittee shall maintain the following records for each purchase of solvent used in the cold cleaner degreasing operations. These records shall be retained on-site or accessible electronically for the most recent three (3) year period and shall be reasonably accessible for an additional two (2) year period.

(a) The name and address of the solvent supplier.

(b) The date of purchase.

(c) The type of solvent purchased.

(d) The total volume of the solvent purchased.

(e) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(j) One (1) natural gas-fired temporary boiler, constructed in 2020, with a maximum capacity of less than or equal to 99.9 MMBtu per hour, using no control, and exhausting outdoors.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.12.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1(f) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate emissions from the temporary boiler shall be limited to 0.10 pound per MMBtu heat input.

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.13.1 PSD Minor Limit for PM and VOC [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 157-47442-00044, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits shall limit the potential to emit PM and VOC to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008.

D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), the Permittee shall minimize VOC emissions from the frame-type natural gas-fired combustion turbine, identified as Unit 20, using the Best Available Control Technology (BACT), which has been determined to be the following:

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.13.3 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for NOx and demonstrate compliance with VOC limitation under Condition D.13.2(b), not later than 180 days after the startup of the following emission units, the Permittee shall perform NOx and VOC testing on the following emission units:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	NOx (45.90 lb/hr)	One time
Frame type combustion turbine	Unit 20	NOx (139.80 lb/hr) VOC (6.50 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.13.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the natural gas-fired combustion turbines Units 19A, 19B, 19C, and 20, shall be calibrated, maintained, and operated for measuring NOx, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, Subpart KKKK.

D.13.5 Compliance determination for PM and VOC

(a) To determine the compliance status with Condition D.13.1(a), the following equation shall be used to determine combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20 using the equation shown below for each:

$$E_{PM} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{PM} = Total PM emissions (tons/month) form the combustion turbine Units 19A, 19B, 19C, 20

ER_N = 4.90 lb/hr PM emission rate in normal operation for Units 19A, 19B, and 19C or 11.6 lb/hour PM emission rate in normal operation for Unit 20, or value established in latest stack tests

$ER_{(SU/SD)}$ = 4.90 lb/event, PM emission rate in startup/shutdown events for Units 19A, 19B, and 19C or 11.60 lb/event, PM emission rate in startup/shutdown events for Unit 20

Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle

H = Number of hours of normal operation for the month for Units 19A, 19B, 19C,

and 20
i = Each calendar month within the twelve (12) consecutive month period
n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

(b) To determine the compliance status with Condition D.13.1(b), the following equation shall be used to determine the combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20:

$$E_{VOC} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{VOC} = Total VOC emissions (tons/month) from the combustion turbine Units 19A, 19B, 19C, 20
ER_N = 5.40 lb/hr, VOC emission rate in normal operation for Units 19A, 19B, and 19C, or 6.50 lb/hr VOC emission rate in normal operation for Unit 20, or value established in latest stack test.
$ER_{(SU/SD)}$ = 1.40 lb/event, VOC emission rate in startup/shutdown events for Units 19A, 19B, and 19C, or 101.00 lb/event, VOC emission rate in startup/shutdown events for Unit 20
Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle
H = Number of hours of normal operation for the month for Units 19A, 19B, 19C, and 20
i = Each calendar month within the twelve (12) consecutive month period
n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.13.6 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.13.7 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Permittee shall record the output of the continuous monitoring system (lb/hr) and shall

perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligation with regard to the records required by this condition.

D.13.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.13.1, the Permittee shall maintain monthly records in accordance with (1) and (2) below. Records maintained for (1) and (2) shall be taken as stated below and shall be complete and sufficient to establish compliance with the PM and VOC emission limits established in Condition D.13.1:

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.6(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13.6(b).

(b) The number of startup and shutdown events per month.

(c) The number of minutes for each startup event and each shutdown event.

(d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.13.9 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;

(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official,” as defined by 326 IAC 2-7-1 (35).

D.13.10 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.13.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION E.1 TITLE IV CONDITIONS

ORIS Code: 6085

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NOX burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NOX burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Acid Rain Program

E.1.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21][40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78.

E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

SECTION E.2 RESERVED

SECTION E.3 NSPS

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Da.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.3.2 Standards of Performance for Electric Utility Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Da]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Da (included as Attachment C to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.40Da(a)
(2) 40 CFR 60.42Da(a)
(3) 40 CFR 60.43Da(a), (b), and (h)
(4) 40 CFR 60.44Da(a)
(5) 40 CFR 60.48Da(a), (b), (d), (e), (h), (p), and (s)
(6) 40 CFR 60.49Da(b)(1), (4), (c), (d), (e), (f)(1), (g), (h), (i), (j), (s), and (w)
(7) 40 CFR 60.50Da(a), (b)(1), (3), (c), (d), and (e)
(8) 40 CFR 60.51Da(a), (b), (c), (j), and (k)

SECTION E.4 NSPS

Emissions Unit Description:

(d) Fuel storage and handling systems for Unit 17 and 18 boilers constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.4.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Y.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.4.2 New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart Y]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart Y (included as Attachment D to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.250(a)&(b)
(2) 40 CFR 60.254(a)
(3) 40 CFR 60.255(a)

SECTION E.5 NSPS

Emissions Unit Description:

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.5.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart GG.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.5.2 New Source Performance Standards for Stationary Gas Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart GG]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart GG (included as Attachment E to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.330
(2) 40 CFR 60.332(a)&(f)
(3) 40 CFR 60.333
(4) 40 CFR 60.334
(5) 40 CFR 60.335

SECTION E.6 NSPS

Emissions Unit Description:

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.6.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart IIII (included as Attachment F to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit listed above:

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

(1) 40 CFR 60.4200(a)(2)(ii)
(2) 40 CFR 60.4205(c)
(3) 40 CFR 60.4206

(4) 40 CFR 60.4207(a)
(5) 40 CFR 60.4207(b)
(6) 40 CFR 60.4209(a)
(7) 40 CFR 60.4211(a)
(8) 40 CFR 60.4211(c)
(9) 40 CFR 60.4211(f)
(10) 40 CFR 60.4211(g)(2)
(11) 40 CFR 60.4214(b)
(12) 40 CFR 60.4218
(13) Table 3 to Subpart IIII of Part 60
(14) Table 4 to Subpart IIII of Part 60
(15) Table 8 to Subpart IIII of Part 6

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 60.4200(a)
(2) 40 CFR 60.4205(b) and (c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4208
(6) 40 CFR 60.4209
(7) 40 CFR 60.4211(a), (c), and (f)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b) and (c)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 2 to Subpart IIII of Part 60
(13) Table 5 to Subpart IIII of Part 60
(14) Table 8 to Subpart IIII of Part 60

SECTION E.7 **RESERVED**

SECTION E.8 NESHAP

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.8.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart UUUUU.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.8.2 Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU] [326 IAC 20-89]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart UUUUU (included as Attachment G to the operating permit), which are incorporated by reference as 326 IAC 20-89, for the emission unit(s) listed above:

(1) 40 CFR 63.9980
(2) 40 CFR 63.9981
(3) 40 CFR 63.9982(a)(1) and (d)
(4) 40 CFR 63.9984(b), (c), and (f)
(5) 40 CFR 63.9990(a)(2) and (c)
(6) 40 CFR 63.9991(a)(1) and (b)
(7) 40 CFR 63.10000(a), (b), (c)(1), (d), (e), (f), (j), (k), and (l)
(8) 40 CFR 63.10005(a)(1), (a)(2), (b), (d)(1), (d)(3), (e), (j), and (k)
(9) 40 CFR 63.10006
(10) 40 CFR 63.10007(a)(1), (b), (e)(2), (f), and (g)
(11) 40 CFR 63.10009
(12) 40 CFR 63.10010(a)(1), (b), (d), (f), (g), and (i)
(13) 40 CFR 63.10011(a), (c), (e), (f), and (g)
(14) 40 CFR 63.10020(a), (b), (c), and (d)
(15) 40 CFR 63.10021(a), (b), (e), (f), (g), and (h)
(16) 40 CFR 63.10022
(17) 40 CFR 63.10030(a), (b), (d), and (e)
(18) 40 CFR 63.10031(a)(1), (a)(3), (a)(5), (b), (c)(1), (c)(2), (c)(3), (c)(4), (c)(8), (c)(9), (c)(10), (d), (e), (f), (g), and (j)
(19) 40 CFR 63.10032(a), (b), (c), (d)(1), (f)(1), (g), (h), and (i)
(20) 40 CFR 63.10033
(21) 40 CFR 63.10040
(22) 40 CFR 63.10041
(23) 40 CFR 63.10042
(24) Table 2 Item 2 to Subpart UUUUU of Part 63
(25) Table 3 Item 1, 3, and 4 to Subpart UUUUU of Part 63
(26) Table 5 Item 4 to Subpart UUUUU of Part 63
(27) Table 7 Item 4, 5, 6, and 7 to Subpart UUUUU of Part 63
(28) Table 8 to Subpart UUUUU of Part 63
(29) Table 9 to Subpart UUUUU of Part 63
(30) Appendix A to Subpart UUUUU of Part 63
(29) Appendix C to Subpart UUUUU of Part 63
(30) Appendix E to Subpart UUUUU of Part 63

SECTION E.9 NESHAP

Emissions Unit Description:

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

E.9.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart ZZZZ.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-89]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart ZZZZ (included as Attachment H to the operating permit), which are incorporated by reference as 326 IAC 20-82, for the emission unit(s) listed above:

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585

(3) 40 CFR 63.6590(c)(7)
(4) 40 CFR 63.6595(a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(a)(2)(ii) and (c)(7)

SECTION E.10 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.10.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart KKKK.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.10.2 New Source Performance Standards for Stationary Combustion Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart KKKK (included as Attachment I to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.4305
(2) 40 CFR 60.4315
(3) 40 CFR 60.4320(a)
(4) 40 CFR 60.4330(a)
(5) 40 CFR 60.4333
(6) 40 CFR 60.4340
(7) 40 CFR 60.4345
(8) 40 CFR 60.4350
(9) 40 CFR 60.4355

(10) 40 CFR 60.4365
(11) 40 CFR 60.4370(b)
(12) 40 CFR 60.4375
(13) 40 CFR 60.4380
(14) 40 CFR 60.4395
(15) 40 CFR 60.4400
(16) 40 CFR 60.4405
(17) 40 CFR 60.4410
(18) 40 CFR 60.4420
(19) Table 1 to Subpart KKKK of Part 60

SECTION E.11 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.11.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart TTTTa.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart TTTTa (included as Attachment J to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.5509a(a)
(2) 40 CFR 60.5515a
(3) 40 CFR 60.5520a
(4) 40 CFR 60.5525a
(5) 40 CFR 60.5535a
(6) 40 CFR 60.5550a
(7) 40 CFR 60.5555a

(8) 40 CFR 60.5560a
(9) 40 CFR 60.5565a
(10) 40 CFR 60.5580a
(11) Table 1 to Subpart TTTTa of Part 60
(12) Table 3 to Subpart TTTTa of Part 60

SECTION F EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Provisions of Northern Indiana Public Service Company LLC Consent Decree Applicable to R.M. Schahfer Generating Station

F.1 Consent Decree [*United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011), paragraph 169] [326 IAC 2-7-6(3)]

This source is subject to certain conditions, requirements and limitations set forth in the consent decree entered into by and among the United States, the State of Indiana, and the Permittee in *United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011) (herein referred to as the "Decree"). Pursuant to paragraph 169 of the Decree, those paragraphs and tables of the Decree listed in Attachment A of this permit are incorporated by reference into this permit and are applicable requirements under this permit. Subject to the terms and conditions of this Section F.1, the Permittee shall comply with the paragraphs and tables of the Decree that are listed in Attachment A of this permit. A copy of the Decree is attached to this permit as Attachment B. However, only those specific paragraphs and tables of the Decree that are included in Attachment A of this permit and incorporated by reference pursuant to this Section F.1, are applicable requirements enforceable through this permit.

Each paragraph and table listed in Attachment A of this permit is incorporated by reference in its entirety, including any and all paragraphs, conditions, requirements and/or limitations of the Decree explicitly referenced in such paragraphs or tables. However, the Permittee's obligations under this permit to comply with the conditions, requirements and limitations incorporated by reference in the paragraphs and tables listed in Attachment A of this permit shall be limited to those conditions, requirements and limitations applicable to, and only to the extent applicable to, the R.M. Schahfer Station while this permit is in effect. For clarity, such applicable conditions, requirements and limitations shall, subject to the subsequent paragraph, include the annual system tonnage limitations applicable to the Northern Indiana Public Service Company LLC System (as that term is defined under paragraph 36 of the Decree) as a whole as provided under Table 4 and Table 6 of the Decree as listed in Attachment A hereto.

In accordance with paragraph 169 of the Decree, any noncompliance with an annual system tonnage limitation incorporated by reference pursuant to this Section F.1 and Attachment A shall constitute a single violation for the Northern Indiana Public Service Company LLC System (as that term is defined under paragraph 36 of the Decree) as a whole and does not create a separate violation or violations for each unit or source within the Northern Indiana Public Service Company LLC System. Compliance with the paragraphs and tables listed in Attachment A of this permit shall be determined exclusively by reference to the conditions, requirements, and limitations of the Decree. Whenever any conflict or inconsistency arises between the Decree and this permit, the terms and conditions of the Decree control.

SECTION G **RESERVED**

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)

ORIS Code: 994

Transport Rule (TR):

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source.]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility.]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source.]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NOX control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities.]

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate load affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20,

approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate load affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

H.1 Designated representative requirements

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with the following:

(a) 40 CFR 97.413 through 97.418.
(b) 40 CFR 97.513 through 97.518; and
(c) 40 CFR 97.613 through 97.618.

H.2 Emissions monitoring, reporting, and recordkeeping requirements

(1) The owners and operators, and the designated representative, of each TR NO_X Annual source, TR NOx Ozone Season source, and TR SO2 Group 1 source, and each TR NO_X Annual unit at the source, TR NOx Ozone Season unit at the source, and TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.530, and 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.531, and 97.631 (initial monitoring system certification and recertification procedures), 97.432, 97.532, and 97.632 (monitoring system out-of-control periods), 97.433, 97.533, and 97.633 (notifications concerning monitoring), 97.434, 97.534, and 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.535, and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under Condition H.3 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(3) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under Condition H.4 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in

accordance with 40 CFR 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(4) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under Condition H.5 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

H.3 NOX annual emissions requirements

(1) TR NO_X Annual emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the TR NO_X Annual units at a TR NO_X Annual source are in excess of the TR NO_X Annual emissions limitation set forth in Condition H.3(1)(i) above, then:

(A). The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each TR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) TR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all TR NO_X Annual units at TR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to

the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NO_X Annual allowances required under Condition H.3(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Annual units at TR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NO_X Annual allowances for a control period in a given year in accordance with Condition H.3(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with Condition H.3(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A TR NO_X Annual unit shall be subject to the requirements under Condition H.3(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A TR NO_X Annual unit shall be subject to the requirements under Condition H.3(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NO_X Annual allowance held for compliance with the requirements under Condition H.3(1)(i) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NO_X Annual allowance held for compliance with the requirements under Condition H.3(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the TR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Annual allowance does not constitute a property right.

H.4 NOx ozone season requirements

(1) TR NO_X Ozone Season emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

(ii). If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source are in excess of the TR

NO_X Ozone Season emissions limitation set forth in Condition H.4(1)(i) above, then:

(A). The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under 40 CFR 97.524(d); and

(B). The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(2) TR NO_X Ozone Season assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.525(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NO_X Ozone Season allowances required under Condition H.4(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season trading budget under 40 CFR 97.510(a) and the state's variability limit under 40 CFR 97.510(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart BBBBB or of the Clean Air Act if total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NO_X Ozone Season allowances for a control period in a given year in accordance with Condition H.4(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NOX Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (d)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(3) Compliance Periods.

(i). A TR NOx Ozone Season unit shall be subject to the requirements under Condition H.4(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.530(b) and for each control period thereafter.

(ii). A TR NOx Ozone Season unit shall be subject to the requirements under Condition H.4(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NOx Ozone Season allowance held for compliance with the requirements under Condition H.4(1)(i) above for a control period in a given year must be a TR NOx Ozone Season Allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NOx Ozone Season allowance held for compliance with the requirements under Condition H.4(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a

control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowances Management System Requirements.

(i). Each TR NOx Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart BBBBB.

(6) Limited Authorization.

(i). A TR NOx Ozone Season allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(A). Such authorization shall only be used in accordance with the TR NOx Ozone Season Trading Program; and

(B). Notwithstanding any other provision of 40 CFR Part 97, Subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property Right.

(i). A TR NOx Ozone Season allowance does not constitute a property right.

H.5 SO_2 emissions requirements

(1) TR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 1 source and each TR SO2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source are in excess of the TR SO_2 Group 1 emissions limitation set forth in Condition H.5(1)(i) above, then:

(A). The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such

control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) TR SO_2 Group 1 assurance provisions

(i). If total SO_2 emissions during a control period in a given year from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR SO_2 Group 1 allowances required under Condition H.5(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR SO_2 Group 1 allowances for a control period in a given year in accordance with Condition H.5(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Condition H.5(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i) A TR SO_2 Group 1 unit shall be subject to the requirements under Condition H.5(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii) A TR SO_2 Group 1 unit shall be subject to the requirements under Condition H.5(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR SO_2 Group 1 allowance held for compliance with the requirements under Condition H.5(1)(i) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO_2 Group 1 allowance held for compliance with the requirements under Condition H.5(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the TR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO_2 Group 1 allowance does not constitute a property right.

H.6 Title V Permit Revision Requirements

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA, TR NO_X Ozone Season allowances in accordance with 40 CFR part 97, subpart BBBBB, and TR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.530 through 97.535, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.506(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

H.7 Additional recordkeeping and reporting requirements

(1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit, TR NO_X Ozone Season source and each TR NO_X Ozone Season unit, and TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 for the designated representative for the source and each TR NO_X Annual unit, TR NOx Ozone Season unit, and TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.516, and 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA, 40 CFR part 97, subpart BBBBB, and 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the

requirements of, the TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit, a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit, and a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.518, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

H.8 Liability

(1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(3) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season source or the designated representative of a TR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season units at the source.

(4) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season unit or the designated representative of a TR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(5) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(6) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

H.9 Effect on other authorities

No provision of the TR NO_X Annual Trading Program or exemption under 40 CFR 97.405, TR NO_X Ozone Season Trading Program or exemption under 40 CFR 97.505, and TR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit, TR NO_X Ozone Season source or TR NO_X Ozone Season unit, and TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

H.10 Description of TR Monitoring Provisions

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NOx Annual Trading Program and TR NOx Ozone Season Trading Program and TR SO2 Group 1 Trading Program.

Unit ID: Unit 17 and Unit 18					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X	-------	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	X	-------	-------	-------	-------

Unit ID: 16A and 16B					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	X	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	-------	X	-------	-------	-------

Unit ID: 19A, 16B, 19C, and Unit 20					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	X	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	-------	X	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify) _____

☐ Report (specify) _____

☐ Notification (specify) _____

☐ Affidavit (specify) _____

☐ Other (specify) _____

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
Signature:
Printed Name:
Title/Position:
Phone:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: (317) 233-0178
Fax: (317) 233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

This form consists of 2 pages **Page 1 of 2**

□ This is an emergency as defined in 326 IAC 2-7-1(12)
- The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile within two (**2**) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by: _____

Title / Position: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Turbine 16A
Parameter: Operating Hours
Limit: Less than 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	(Hrs.)	***(Hrs.)***	***(Hrs.)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Turbine 16B
Parameter: Operating Hours
Limit: Less than 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	(Hrs.)	***(Hrs.)***	***(Hrs.)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: PM Emissions
Limit: Shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	PM Emissions (tons)	***PM Emissions (tons)***	***PM Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: VOC Emissions
Limit: Shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	VOC Emissions (tons)	***VOC Emissions (tons)***	***VOC Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Source-wide
Parameter: Combined Total HAP Emissions
Limit: Shall be less than 25 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Total HAP Emissions (tons)	***Total HAP Emissions (tons)***	***Total HAP Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Source-wide
Parameter: Combined Single HAP (Formaldehyde) Emissions
Limit: Shall be less than 10 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Single HAP (Formaldehyde) Emissions (tons)	***Single HAP (Formaldehyde) Emissions (tons)***	***Single HAP (Formaldehyde) Emissions (tons)***
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone:_____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

Months: _____ to _____ Year: _____

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B - Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C-General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.

☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

Attachment F

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on September 5, 2024]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C, except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 86 FR 34357, June 29, 2021]

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 1039.102, 1039.104, 1039.105, 1039.107, and 1039.115 and 40 CFR part 1039, appendix I, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34357, June 29, 2021]

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The Tier 2 emission standards for new nonroad CI engines for the appropriate rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 for model year 2007 engines; and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section. Engines that would be subject to the Tier 4 standards in 40 CFR part 1042 that are used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section may instead continue to be certified to the previous tier of standards in 40 CFR part 1042. The previous tier is Tier 3 in most cases; however, the previous tier is Tier 2 if there are no Tier 3 standards specified for engines of a certain size or power rating.

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this

section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021; 88 FR 4471, Jan. 24, 2023]

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0\,23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0\ 20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0\,23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 86 FR 34358, June 29, 2021]

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) [Reserved]

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder must use diesel fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 85 FR 78463, Dec. 4, 2020]

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a

backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §§ 60.4201(a) through (c) and 60.4202(a), (b), and (d) using the certification procedures required in 40 CFR part 1039, subpart C, and must test their engines as specified in 40 CFR part 1039. For the purposes of this subpart, engines certified to the standards in Table 1 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I. For the purposes of this subpart, engines certified to the standards in Table 4 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §§ 60.4201(d) and (e) and 60.4202(e) and (f) using the certification procedures required in 40 CFR part 1042, subpart C, and must test their engines as specified in 40 CFR part 1042.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135 and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking, and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of § 60.4201 or § 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR part 1039, appendix I, when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in

sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

(k) Manufacturers of any size may certify their emergency stationary CI internal combustion engines under this section using assigned deterioration factors established by EPA, consistent with 40 CFR 1039.240 and 1042.240.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016; 86 FR 34358, June 29, 2021]

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR part 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(a) or § 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified to emission standards for the same model year and maximum engine power as described in 40 CFR parts 1039 and 1042, as applicable. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the

owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain

and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021; 87 FR 48605, Aug. 10, 2022]

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or with Tier 2 emission standards as described in 40 CFR part 1042, appendix I, may follow the testing procedures specified in § 60.4213, as appropriate.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE subject to Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or Tier 2 emission standards as described in 40 CFR part 1042, appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR part 1039 or 1042, as applicable.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011; 86 FR 34359, June 29, 2021]

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\ O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section. Beginning on February 26, 2025, submit the notification electronically according to paragraph (g) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)-(vi) [Reserved]

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

(f) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test required under this section following the procedures specified in paragraphs (f)(1) and (2) of this section.

(1) ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.*** Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to paragraph (g) of this section. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to paragraph (g) of this section.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is

required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 87 FR 48606, Aug. 10, 2022; 89 FR 70512, Aug. 30, 2024]

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0\,23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the Tier 2 or Tier 3 emission standards described in 40 CFR part 1042 for the same model year, displacement, and maximum engine power, as appropriate, rather than the otherwise applicable requirements of 40 CFR part 1039, as indicated in §§ 60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§ 60.4202 and 60.4205, and not those for non-emergency engines in §§ 60.4201 and 60.4204, except that for 2014 model year and later nonemergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards identified in appendix I of 40 CFR part 1039 or in 40 CFR 1042.101.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016; 86 FR 34359, June 29, 2021]

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

General Provisions

§ 60.4218 What General Provisions and confidential information provisions apply to me?

(a) Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

(b) The provisions of 40 CFR 1068.10 and 1068.11 apply for engine manufacturers. For others, the general confidential business information (CBI) provisions apply as described in 40 CFR part 2.

[88 FR 4471, Jan. 24, 2023]

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 1042.101(e).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013; 81 FR 44219, July 7, 2016; 86 FR 34360, June 29, 2021; 87 FR 48606, Aug. 10, 2022]

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	Emission standards for stationary fire pump engines in g/KW-hr (g/HP-hr)		
		NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
KW<8 (HP<11)	2011 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
8≤KW<19 (11≤HP<25)	2011 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	2011 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
37≤KW<56 (50≤HP<75)	2011 +[1]	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
56≤KW<75 (75≤HP<100)	2011 +[1]	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
75≤KW<130 (100≤HP<175)	2010 +[2]	4.0 (3.0)	5.0 (3.7)	0.30 (0.22)

130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
130≤KW<225 (175≤HP<300)	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
225≤KW<450 (300≤HP<600)	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)	2009 +	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
KW>560 (HP>750)	2008 +	6.4 (4.8)	3.5 (2.6)	0.20 (0.15)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

[89 FR 70513, Aug. 30, 2024]

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Each	Complying with the requirement to	You must	Using	According to the following requirements
	b. Limit the concentration of NO_X in the stationary CI nternal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI nternal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Attachment H

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on September 5, 2024]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source:69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) ***Affected source.*** An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) ***Existing stationary RICE.***

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) ***New stationary RICE.***

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) ***Reconstructed stationary RICE.***

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in § 63.2 and reconstruction is commenced on or after June 12, 2006.

(b) ***Stationary RICE subject to limited requirements.***

(1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of § 63.6645(f) and the requirements of §§ 63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) ***Stationary RICE subject to Regulations under 40 CFR Part 60.*** An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010; 78 FR 6700, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

§ 63.6595 When do I have to comply with this subpart?

(a) ***Affected sources.***

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) ***Area sources that become major sources.*** If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in § 63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250

and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013; 89 FR 70515, Aug. 30, 2024]

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR

1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) [Reserved]

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013, as amended at 85 FR 78463, Dec. 4, 2020; 87 FR 48607, Aug. 10, 2022]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)

(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_O = \frac{0.209\ F_d}{F_C} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters,

kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

(j) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test following the procedure specified in § 63.9(k). Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test must be included as an attachment in the ERT or alternate electronic file.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in § 63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in § 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(5) Beginning on February 26, 2025, within 60 days after the date of completing each continuous emissions monitoring system (CEMS) performance evaluation (as defined in § 63.2) that includes a relative accuracy test audit (RATA), you must submit the results of the performance evaluation following the procedures specified in § 63.9(k). The results of performance evaluations of CEMS measuring RATA pollutants that are supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website. The results of performance evaluations of CEMS measuring RATA pollutants that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the evaluation must be included as an attachment in the ERT or alternate electronic file.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in § 63.8(d). As specified in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also § 63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of table 2c to this subpart or in items 1 or 4 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of table 2c to this subpart or in items 5, 6, 7, 8, 10, 11, or 13 of table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil and filter change requirement in tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil and filter in table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil and filter. If any of the limits are exceeded, the engine owner or operator must change the oil and filter within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil and filter within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil and filter changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013; 89 FR 70516, Aug. 30, 2024]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in § 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii)-(iii) [Reserved]

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an initial notification not later than December 13, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in portable document format (PDF) consistent with § 63.9(k).

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(d) As specified in § 63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an initial notification not later than July 16, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008, and you are required to submit an initial notification, you must submit an initial notification not later than 120 days after you become subject to this subpart. Beginning on February 26, 2025, submit the notification electronically in PDF consistent with § 63.9(k).

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with § 63.6590(b), your notification should include the information in § 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in § 63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) Before February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to § 63.10(d)(2). Beginning on February 26, 2025, for each initial compliance demonstration required in table 5 to this subpart that includes a performance test conducted according to the requirements in table 3 to this subpart, you must submit the Notification of Compliance Status, including a summary of the performance test results, in PDF to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), before the close of business on the 60th day following the completion of the performance test following the procedure specified in § 63.9(k), except any Confidential Business Information (CBI) is to be submitted according to paragraphs (h)(2)(i) and (ii) of this section. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report, you must submit a complete file, including information claimed to be CBI, to the EPA following the procedures in paragraphs (h)(2)(i) and (ii) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as

CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (h)(2).

(i) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in paragraph (h)(2) of this section, should include clear CBI markings and be flagged to the attention of the Reciprocating Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(ii) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711, Attention Reciprocating Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013; 85 FR 73912, Nov. 19, 2020; 89 FR 70516, Aug. 30, 2024]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in § 63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in § 63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (8) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the starting and ending date and time, the duration (in hours), and a brief description for each malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(7) Engine site rating in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

(8) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(9) An engine can be claimed as exempt from reporting coordinates (latitude/longitude) via CEDRI if:

(i) During the reporting period, the engine will be owned by, or operated by or for, an agency of the Federal Government responsible for national defense; and

(ii) The agency determines that disclosing the coordinates to the general public would be a threat to national security.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (8) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time (in hours) of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration (in hours), and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(3) A description of any changes in processes, or controls since the last reporting period.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (8) and (e)(1) through (13) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The start and end date and time and the duration (in hours) that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The start and end date and time and the duration (in hours) that each CMS was out-of-control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration (in hours) of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration (in hours) of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration (in hours) of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) [Reserved]

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(13) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any

emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. Beginning on February 26, 2025, the semiannual and annual compliance report required in table 7 of this subpart must be submitted according to paragraph (i) of this section. Only those elements required under this subpart are required to be submitted according to paragraph (i) of this section.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating in brake HP, year construction of the engine commenced (as defined in § 63.2, where the exact year is not known, provide the best estimate), and type of engine (CI, SI 2SLB, SI 4SLB, or SI 4SRB).

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v)-(vi) [Reserved]

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration (in hours), and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) Before February 26, 2025, the annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart

is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13. Beginning on February 26, 2025, the annual report must be submitted according to paragraph (i) of this section.

(i) Beginning on February 26, 2025 for the annual report specified in § 63.6650(h) and February 26, 2025 or one year after the report becomes available in CEDRI, whichever is later for all other semiannual or annual reports, submit all semiannual and annual subsequent compliance reports using the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for this subpart and following the procedure specified in § 63.9(k), except any CBI must be submitted according to the procedures in § 63.6645(h). The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated state agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70517, Aug. 30, 2024]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in § 63.10(b)(2)(xiv).

(2) Records of the occurrence and duration (in hours) of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in § 63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purpose specified in § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013; 87 FR 48607, Aug. 10, 2022; 89 FR 70518, Aug. 30, 2024]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in § 63.6600 under § 63.6(g).

(2) Approval of major alternatives to test methods under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90.

(3) Approval of major alternatives to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under § 63.10(f) and as defined in § 63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in § 63.6610(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

[69 FR 33506, June 15, 2004, as amended at 89 FR 70518, Aug. 30, 2024]

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in § 63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in § 63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to § 63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to § 63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013; 87 FR 48608, Aug. 10, 2022]

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.		

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.	

[78 FR 6706, Jan. 30, 2013]

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	

3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.		

[75 FR 9680, Mar. 3, 2010]

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	**You must meet the following operating limitation, except during periods of startup . . .**
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	

existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	
[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.	

[78 FR 6707, Jan. 30, 2013]

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first[2]. b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first[2].	
	b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[2]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	b. Inspect spark plugs every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[89 FR 70518, Aug. 30, 2024]

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary;	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1] b. Inspect spark plugs every 1,000 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1]	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	b. Inspect spark plugs every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or within 1 year + 30 days of the previous change, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or within 1 year + 30 days of the previous inspection, whichever comes first, and replace as necessary	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, state or local law under which the risk was deemed unacceptable.

[89 FR 70520, Aug. 30, 2024]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.
[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.		

[78 FR 6711, Jan. 30, 2013]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device; and	(2) ASTM D6522-00 (Reapproved 2005)[123] (heated probe not necessary) or method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O_2, dry basis.
		iv. Measure moisture content at the inlet and outlet of the control device as needed to determine CO and O_2 concentrations on a dry basis	(3) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(d) Measurements to determine moisture content must be made at the same time and location as the measurements for CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE	a. Reduce formaldehyde or THC emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, THC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device as needed to determine formaldehyde or THC and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[13] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(4) (1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(e) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM D6522-00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location as needed to determine formaldehyde or CO and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A-3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03,[13] provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(4) Method 10 of 40 CFR part 60, appendix A-4, ASTM D6522-00 (2005),[13] method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03[13]	(e) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[1] You may also use methods 3A and 10 as options to ASTM-D6522-00 (2005).

[2] You may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[3] Incorporated by reference, see § 63.14.

[88 FR 18413, Mar. 29, 2023]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

[78 FR 6712, Jan. 30, 2013]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.
[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.		

[78 FR 6715, Jan. 30, 2013]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in § 63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)-(9) and (i) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in § 63.6650(b) and (i).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4)	i. Semiannually according to the requirements in § 63.6650(b) and (i).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters	i. See item 2.a.i.

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period	i. Semiannually according to the requirements in § 63.6650(b)(1)-(5) and (i).
4. Emergency stationary RICE that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in § 63.6650(h)(1)	i. Annually according to the requirements in § 63.6650(h)(2)-(3) and (i).

[89 FR 70522, Aug. 30, 2024]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ

As stated in § 63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.1	General applicability of the General Provisions	Yes	
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6675.
§ 63.3	Units and abbreviations	Yes	
§ 63.4	Prohibited activities and circumvention	Yes	
§ 63.5	Construction and reconstruction	Yes	
§ 63.6(a)	Applicability	Yes	
§ 63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes	
§ 63.6(b)(5)	Notification	Yes	
§ 63.6(b)(6)	[Reserved]		
§ 63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes	
§ 63.6(d)	[Reserved]		
§ 63.6(e)	Operation and maintenance	No	
§ 63.6(f)(1)	Applicability of standards	No	
§ 63.6(f)(2)	Methods for determining compliance	Yes	
§ 63.6(f)(3)	Finding of compliance	Yes	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.6(g)(1)-(3)	Use of alternate standard	Yes	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes	
§ 63.6(j)	Presidential compliance exemption	Yes	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§ 63.6610, 63.6611, and 63.6612.
§ 63.7(a)(3)	CAA section 114 authority	Yes	
§ 63.7(b)(1)	Notification of performance test	Yes	Except that § 63.7(b)(1) only applies as specified in § 63.6645.
§ 63.7(b)(2)	Notification of rescheduling	Yes	Except that § 63.7(b)(2) only applies as specified in § 63.6645.
§ 63.7(c)	Quality assurance/test plan	Yes	Except that § 63.7(c) only applies as specified in § 63.6645.
§ 63.7(d)	Testing facilities	Yes	
§ 63.7(e)(1)	Conditions for conducting performance tests	No	Subpart ZZZZ specifies conditions for conducting performance tests at § 63.6620.
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at § 63.6620.
§ 63.7(e)(3)	Test run duration	Yes	
§ 63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes	
§ 63.7(f)	Alternative test method provisions	Yes	
§ 63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes	
§ 63.7(h)	Waiver of tests	Yes	
§ 63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at § 63.6625.
§ 63.8(a)(2)	Performance specifications	Yes	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No	
§ 63.8(b)(1)	Monitoring	Yes	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§ 63.8(d)	CMS quality control	Yes	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
			Except that § 63.8(e) only applies as specified in § 63.6645.
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that § 63.8(f)(4) only applies as specified in § 63.6645.
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that § 63.8(f)(6) only applies as specified in § 63.6645.
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6635 and 63.6640.
§ 63.9(a)	Applicability and State delegation of notification requirements	Yes	
§ 63.9(b)(1)-(5)	Initial notifications	Yes	Except that § 63.9(b)(3) is reserved.
			Except that § 63.9(b) only applies as specified in § 63.6645.
§ 63.9(c)	Request for compliance extension	Yes	Except that § 63.9(c) only applies as specified in § 63.6645.
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that § 63.9(d) only applies as specified in § 63.6645.
§ 63.9(e)	Notification of performance test	Yes	Except that § 63.9(e) only applies as specified in § 63.6645.
§ 63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	Except that § 63.9(g) only applies as specified in § 63.6645.
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use. Except that § 63.9(g) only applies as specified in § 63.6645.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
			Except that § 63.9(h) only applies as specified in § 63.6645.
§ 63.9(i)	Adjustment of submittal deadlines	Yes	
§ 63.9(j)	Change in previous information	Yes	
§ 63.9(k)	Electronic reporting procedures	Yes	Only as specified in §§ 63.9(j), 63.6620, 63.6625, 63.6645, and 63.6650.
§ 63.10(a)	Administrative provisions for recordkeeping/reporting	Yes	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§ 63.10(b)(2)(i)-(v)	Records related to SSM	No	
§ 63.10(b)(2)(vi)-(xi)	Records	Yes	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes	
§ 63.10(b)(3)	Records of applicability determination	Yes	
§ 63.10(c)	Additional records for sources using CEMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(d)(1)	General reporting requirements	Yes	
§ 63.10(d)(2)	Report of performance test results	Yes	
§ 63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No	
§ 63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§ 63.10(e)(3)	Excess emission and parameter exceedances reports	No	Excess emissions and exceedance reporting is specified in § 63.6650.
§ 63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§ 63.10(f)	Waiver for recordkeeping/reporting	Yes	
§ 63.11	Flares	No	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 63.12	State authority and delegations	Yes	
§ 63.13	Addresses	Yes	
§ 63.14	Incorporation by reference	Yes	
§ 63.15	Availability of information	Yes	

[89 FR 70522, Aug. 30, 2024]

Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or

modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 ***Measurement System.*** The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 ***Data Recorder.*** A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 ***Electrochemical (EC) Cell.*** A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 ***Interference Gas Scrubber.*** A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 ***Moisture Removal System.*** Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 ***Sample Interface.*** The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 ***Nominal Range.*** The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 ***Calibration Gas.*** A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 ***Zero Calibration Error.*** The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 ***Up-Scale Calibration Error.*** The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 ***Interference Check.*** A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 ***Repeatability Check.*** A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 ***Sample Flow Rate.*** The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 ***Sampling Run.*** A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 ***Sampling Day.*** A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 ***Pre-Sampling Calibration/Post-Sampling Calibration Check.*** The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 ***Performance-Established Configuration.*** The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 ***Sample Probe.*** A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 ***Sample Line.*** Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 ***Calibration Assembly (optional).*** A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 ***Particulate Filter (optional).*** Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 ***Sample Pump.*** A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 ***Sample Flow Rate Monitoring.*** An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 ***Sample Gas Manifold (optional).*** A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 ***EC cell.*** A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 ***Data Recorder.*** A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 ***Interference Gas Filter or Scrubber.*** A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 ***Calibration Gases.*** CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 ***Up-Scale CO Calibration Gas Concentration.*** Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 ***Up-Scale O_2 Calibration Gas Concentration.***

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 ***Zero Gas.*** Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 ***Selection of Sampling Sites.***

8.1.1 ***Control Device Inlet.*** Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 ***Exhaust Gas Outlet.*** Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 ***Stack Gas Collection and Analysis.*** Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O_2 concentrations.

8.3 ***EC Cell Rate.*** Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 ***Pre-Sampling Calibration.*** Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 ***Zero Calibration.*** For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 ***Zero Calibration Tolerance.*** For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 ***Up-Scale Calibration.*** Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 ***Up-Scale Calibration Error.*** The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 ***Post-Sampling Calibration Check.*** Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 ***Measurement Data Phase Performance Check.*** Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example:

A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 ***Interference Check.*** Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 ***Interference Response.*** The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 ***Repeatability Check.*** Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 ***Repeatability Check Procedure.*** Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 ***Repeatability Check Calculations.*** Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) ***"Development of an Electrochemical Cell Emission Analyzer Test Protocol"*** , Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) ***"Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers"*** , EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) ***"ICAC Test Protocol for Periodic Monitoring"*** , EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) ***"Code of Federal Regulations"*** , Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility_____ Engine I.D._____ Date_____

Run Type: (X)	(_) Pre-Sample Calibration		(_) Stack Gas Sample		(_) Post-Sample Cal. Check		(_) Repeatability Check				
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
″											
″											
″											
″											
Measurement Data Phase											
″											
″											
″											
″											
″											
″											
″											
″											
″											
″											
Mean											
Refresh Phase											
″											
″											
″											
″											

[78 FR 6721, Jan. 30, 2013]

Attachment I

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on May 12, 2021]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

SOURCE: 71 FR 38497, July 6, 2006, unless otherwise noted.

INTRODUCTION

§60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

APPLICABILITY

§60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

EMISSION LIMITS

§60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_X specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§60.4330 What emission limits must I meet for sulfur dioxide (SO2?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

GENERAL COMPLIANCE REQUIREMENTS

§60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

MONITORING

§60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly

NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad (Eq. 1)$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.*, calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq. 2)$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (Eq. 3)$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and $3.413 \times 10_6$ = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \qquad (Eq. 4)$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for

noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

REPORTING

§60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§60.4380 How are excess emissions and monitor downtime defined for NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a “4-hour rolling average NO_X emission rate” is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a “30-day rolling

average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§60.4385 How are excess emissions and monitoring downtime defined for SO2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

PERFORMANCE TESTS

§60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad (Eq. 5)$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies that you may use to conduct the performance tests.

(1) The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the affected facility. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter may be used.

(2) Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels or ASTM D4177 (incorporated by reference, see §60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, GPA 2166, or ISO 10715 (all incorporated by reference, see §60.17). For manual sampling of liquid fuels, follow GPA 2174 or the procedures for manual pipeline sampling in section 14 of ASTM D4057 (both incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, D5453, D5623, or D7039 (all incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or GPA 2140, 2261, or 2377 (all incorporated by reference, see §60.17).

(3) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad (Eq. 6)$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664 × 10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(4) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

[71 FR 38497, July 6, 2006, as amended at 85 FR 63410, Oct. 7, 2020]

DEFINITIONS

§60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_X emissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

Attachment J

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on July 18, 2024]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Source:89 FR 40035, May 9, 2024, unless otherwise noted.

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for

sources that do not qualify under paragraphs (c) and (d) of this section), where the term “gross or net energy output” is used, the term that applies to you is “gross energy output.”

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term “gross or net energy output” is used, the term that applies to you is “net energy output.” Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (e.g., non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard\ = \frac{(50\ \mathrm{x}\ HTIP_{ng}) + (69\ \mathrm{x}\ HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * \left[\frac{HIER_A}{HIER_{NG}}\right]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for “valid operating hours”, as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F-7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of 40 CFR part 98. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as “stack operating hours” (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the “stack operating time” (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this

section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.,* operating hours for which:

(i) "Valid data" (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{E}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii)
$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \text{ (Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)

(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)

(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not “valid operating hours” (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)

(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions) of this part.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388-99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as “cogeneration”) means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22-2014, ASME PTC 46-1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.,* onsite photovoltaics), integrated energy storage (*e.g.,* onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may,

however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP-011-2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	**CO_2 emission standard**
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Table 2 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After May 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

Table 3 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)-(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)-(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a Significant Source Modification and Significant Permit Modification

Source Background and Description

Source Name:	**Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T 073-45762-00008**
Operation Permit Issuance Date:	**October 13, 2023**
Significant Source Modification No.:	**073-47965-00008**
Significant Permit Modification No.:	**073-48085-00008**
Permit Reviewer:	**Hachem Ismaili Alaoui**

On November 19, 2024, the Office of Air Quality (OAQ) had a notice posted on IDEM's website (https://www.in.gov/idem/public-notices/), stating that Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station had applied for a Significant Source Modification and Significant Permit Modification to construct and operate three (3) aero-derivative natural gas fired simple cycle turbines, one (1) frame-type natural gas-fired simple cycle combustion turbine, one (1) diesel emergency generator, and one (1) diesel emergency fire pump. The notice also stated that the OAQ proposed to issue a Significant Source Modification and Significant Permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

The Technical Support Document (TSD) is used by IDEM, OAQ for historical purposes. IDEM, OAQ does not make any changes to the original TSD, but the Permit will have the updated changes. The comments and revised permit language are provided below with deleted language as ~~strikeouts~~ and new language **bolded**.

NIPSCO Comments and Responses

On December 19, 2024, Gurinder Saini, a consultant for Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station (NIPSCO), submitted comments to IDEM, OAQ on the draft Significant Source Modification and Significant Permit Modification.

NIPSCO Comment 1:

Condition D.0.1 includes a typographical error in terms of the units' ID numbers. D.0.1 should be revised as follows:

(a) The combined total HAPs emissions from the combustion turbines (16A, 16B, 19A, **19B** ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined formaldehyde emissions from the combustion turbines (16A, 16B, 19A, **19B** ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency

generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Response to NIPSCO Comment 1:

IDEM agrees with the recommended changes, since they are typographical errors. The permit has been revised as requested above or as follows:

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

*****

(a) The combined total HAPs emissions from the combustion turbines (16A, 16B, 19A, **19B** ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined formaldehyde emissions from the combustion turbines (16A, 16B, 19A, **19B**, ~~16B~~, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

NIPSCO Comment 2:

In the equipment description sections of the draft permit, the four new simple cycle combustion turbines (Units 19A, 19B, 19C, and 20) are noted as "[u]nder 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities." We disagree with the inclusion of the text 'intermediate mode affected facilities' in the description part of the permit and request deletion of the same. We recognize that the descriptions in the permit are NOT enforceable. However, we believe the inclusion of this language is arbitrary and unnecessary under the applicable NSPS 40 CFR 60 Subpart TTTTa. First, the term 'intermediate mode' does not exist in the regulatory provisions of NSPS 40 CFR 60 Subpart TTTTa. Therefore, this is an arbitrary creation of a category in the draft permit by IDEM and is inconsistent with the regulatory compliance option category. Secondly, the regulation provides flexibility for the affected facilities to switch from one compliance option category to another. For example, if a CT was cofiring hydrogen to meet the 'Intermediate Load combustion turbine' CO2 emission limitation, the NSPS regulations allow such a unit to stop firing hydrogen and meet the capacity factor criteria for 'Low Load combustion turbine' and meet the heat input-based limit. Thereafter, such a unit could reverse the compliance option category and elect to comply with the Intermediate Load combustion turbine standard. The inclusion of the compliance option category in description is unnecessary and could become obsolete if NIPSCO chooses to change the compliance option. In addition, it would create an administrative burden both on the agency and the source that is not useful for compliance with the applicable standard. Relevant applicable requirements are specifically listed under condition E.11.2 of the draft permit and have been incorporated by reference. We do not believe that there is any obligation on the part of the permittee to update the description of the affected facility in the permit for the purposes of NSPS compliance option when IDEM has incorporated the entire relevant provisions of the standard by reference in the permit.

Response to NIPSCO Comment 2:

IDEM agrees that the term 'intermediate mode" does not exist in 40 CFR 60, Subpart TTTTa. The correct terminology is "intermediate load".

Section E.11.2 of the permit incorporates the applicable requirements under 40 CFR 60, Subpart TTTTa. To identify what requirements are applicable upon startup of the four new simple cycle

combustion turbines (Units 19A, 19B, 19C, and 20), the proposed operating load must be identified.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

*****

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

*****

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

SECTION E.10 NSPS

Emissions Unit Description:

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

SECTION E.11 NSPS

Emissions Unit Description:

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate ~~mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)

ORIS Code: 994

Emissions Unit Description:

*****

(d)

*****

[Under 40 CFR Part 60, Subpart TTTTa these units are ~~intermediate mode~~ **load** affected facilities.]

(e)

*****

[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate ~~mode~~ **load** affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

NIPSCO Comment 3:

On December 13, 2024, the U.S. EPA published a proposal for a new NSPS as 40 CFR 60 Subpart KKKKa for combustion/gas turbines. The new standard will be applicable to combustion/gas turbines that would be newly constructed, reconstructed, or modified after December 13, 2024. NIPSCO entered a memorandum of understanding ("MOU") with General Electric Vernova Operations LLC on March 29, 2024. This MOU is for the fabrication of the four CTs (three Aero units and one Frame unit) for installation at the R.M. Schahfer site. The MOU includes contractual provisions necessary for NIPSCO to continue planning to allow for a continuous program of construction to be completed within a 'reasonable time.' It includes penalties associated with cancellation of the MOU by NIPSCO. In accordance with 40 CFR § 60.2, definition of 'commenced,' for purposes of NSPS provisions, NIPSCO has determined that the construction on the four combustion turbines under consideration in the draft permit here commenced on March 29th, 2024. Since, the construction of the CTs commenced prior to the publication date of the proposed NSPS 40 CFR 60 Subpart KKKKa, these units are grandfathered for purposes of this standard and are considered 'existing facilities.' We request that IDEM include this non-applicability determination in the ATSD for this permit action.

Response to NIPSCO Comment 3:

40 CFR 60, Subpart KKKKa applies to combustion/gas turbines that would be newly constructed, reconstructed, or modified after December 13, 2024. NIPSCO has provided information the above information indicating that construction of four combustion turbines (Units 19A, 19B, 19C, and 20) commenced prior to December 13, 2024. Based on the provided information, commencement of construction occurred prior to December 13, 2024 and the proposed four combustion turbines (Units 19A, 19B, 19C, and 20) are not subject to the requirements of 40 CFR 60, Subpart KKKKa.

EPA Comments and Responses

On December 20, 2024, Priyanka Painuly from EPA submitted comments to IDEM, OAQ on the draft Significant Source Modification and Significant Permit Modification.

EPA Comment 1:

Condition D.0.1 (c) [page 34 of 112] of the draft permit specifies that coal fired boilers, Unit 17 and Unit 18, shall be permanently shutdown and decommissioned from the facility. However, this requirement doesn't appear enforceable without a timeframe for the shutdown/decommissioning of Unit 17 and Unit 18. Please add a timeframe for Unit 17 and Unit 18 shutdown, so the facility doesn't simultaneously operate Unit 17, Unit 18 and the proposed turbines, Unit 19A, Unit 19B, Unit 19C, and Unit 20 and violate the permit limits and conditions. For example, because the shutdown is not immediately after the issuance of this permit, you could specify: "Unit 17 and Unit 18, shall be permanently shutdown and decommissioned from the facility prior to the start of operation of the simple cycle combustion turbines, Unit 19A, Unit 19B, Unit 19C, and Unit 20".

Response to EPA Comment 1:

IDEM agrees with the recommended changes. The permit has been revised as follows:

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

*****

(c) **Upon the commencement of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20,** ~~The~~ **the** two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from the source.

EPA Comment 2:

It appears that the HAP emission calculations as specified in Condition D.0 are not necessary/applicable immediately after the permit issuance. The facility will comply with Condition D.0. [page 34 of 112] after the start of operation of the simple cycle combustion turbines, Unit 19A, Unit 19B, Unit 19C, and Unit 20. Please update the permit to clarify this (preferably in Condition D.0) to avoid confusion regarding the applicability of Condition D.0.

Response to EPA Comment 2:

IDEM agrees with the recommended changes. The permit has been revised as follows:

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

*****

(d) The limits in paragraphs (a) and (b) will be effective after the permanent shutdown and decommissioning of the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18 and the start of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20.

EPA Comment 3:

Condition D.13.2 [page 62 of 112] limits the VOC emissions from Unit 20, during normal operation, to not exceed 6.5 lb/hr per 326 IAC 8-1-6. Adding a one-time VOC test is recommended for Unit 20 to demonstrate compliance with Indiana's VOC BACT limit.

Response to EPA Comment 3:

IDEM agrees with the recommended changes. A one-time VOC stack testing is necessary to verify the VOC emission rate from the natural gas-fired combustion turbine, identified as Unit 20, to verify VOC BACT limit. The permit has been revised as follows:

D.13.3 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for NOx **and demonstrate compliance with VOC limitation under Condition D.13.2(b)**, not later than 180 days after the startup of the following emission units, the Permittee shall perform NOx **and VOC** testing on the following emission units:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	NOx (45.90 lb/hr)	One time

Frame type combustion turbine	Unit 20	NOx (139.80 lb/hr) **VOC (6.50 lb/hr)**	One time

EPA Comment 4:

Condition D.13.1 [page 62 of 112] specifies PSD minor limits for PM and VOC. Condition D.13.5, specifies equations, and emission rates to be utilized for compliance determination with PSD minor limits established in Condition D.13.1. EPA recommends adding a one-time performance test to demonstrate compliance with the established PM and VOC emission rates, for any one of the Units 19A, 19B, and 19C, operating under normal scenario.

Response to EPA Comment 4:

IDEM-OAQ requires sources to perform one-time stack testing to verify emission rates provided by the source when the proposed emission rates are greater than those published by EPA in AP-42 chapters. IDEM-OAQ compared the emission rates for PM and VOC proposed by NIPSCO with PM and VOC emission rates based on AP-42 chapter 3.1 (Stationary Gas Turbines) and found that PM and VOC emission rates proposed by NIPSCO are greater than those calculated based on AP-42 emission factors.

Emission rates proposed by the source for Units 19A, 19B, and 19C are:
PM = 4.90 lb/hr
VOC = 5,40 lb/hr
Heat input to each Unit is 519 MMBtu/hr

Emission rates based on AP-42 emission factors
PM = 0.0019 (lb/MMBtu) * 519 (MMBtu/hr) = 0.99 lb/hr
VOC = 0.0021 (lb/MMBtu) * 519 (MMBtu/hr) = 1.09 lb/hr

0.0019 lb/MMBtu = Emission factor for PM, AP-42, chapter 3.1, table 3.1-2a
0.0021 lb/MMBtu = Emission factor for VOC, AP-42, chapter 3.1, table 3.1-2a

Therefore, IDEM-OAQ believes that NIPSCO are not required to perform any stack testing for PM and VOC for Units 19A, 19B, and 19C. No changes were made as a result of this comment.

EPA Comment 5:

In Appendix A, page 2 of 20 of the TSD, the facility inadvertently left out GHG emissions estimates from the turbines 19A, 19B, 19C and 20. The facility estimated GHG emissions for all other units included in the application. Please request the facility to provide GHG estimates for the proposed turbines Unit 19A, Unit 19B, Unit 19C, and Unit 20, and update the emission calculations in Appendix A.

Response to EPA Comment 5:

IDEM agrees with the recommended changes. The calculations have been updated as requested and provided as ATSD calcs.

Additional Changes

IDEM, OAQ has decided to make additional revisions to the permit as described below, with deleted language as ~~strikeouts~~ and new language **bolded**.

(a) Correct typographical errors

D.13.8 Record Keeping Requirements

*****

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.**5**~~6~~(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13. **5**~~6~~ (b).

IDEM Contact

(a) If you have any questions regarding this permit, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073 47965 00008
Significant Permit Modification No: 073 48085 00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled Potential to Emit (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51 784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	69,589	16,006	16,006	95,079	9,383	46.91	390.95	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	69 589	16 006	16 006	95 079	9 383	46.91	390.95	3 768 728	1211.34	938.28	HCl
Turbine 16A	41.92	41.92	41.92	21.49	2 032	13.34	520.78	705 653	7.90	4.51	Formaldehyde
Turbine 16B	41.92	41.92	41.92	21.49	2,032	13.34	520.78	705,653	7.90	4.51	Formaldehyde
Turbine 19A 19B and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	269 027	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	1,252,349	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**139393**	**32227**	**32225**	**190236**	**24056**	**259**	**3010**	**10522968**	**2466**	**1877**	**HCl**

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Limited Potential to Emit (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	269,027	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	1,252,349	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**1129**	**32162**	**32160**	**190203**	**23004**	**184**	**2206**	**9433877**	**2454**	**1896**	**HCl**

Limited Potential to Emit After Removal of Boilers Unit 17 and Unit 18 (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	269,027	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	1,252,349	10.82	4.82	Formaldehyde
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**81.46**	**147.29**	**147.28**	**44.19**	**2153.22**	**90.02**	**1424.50**	**1896421.36**	**<25**	**<10**	**Formaldehyde**

Appendix A: Emission Calculations
Modofication Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled PTE of New Units (ton/yr)										
	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	Total HAPs	Single HAPs	
Turbine 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	10.82	4.82	Formaldehyde
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	0.008	0.004	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.002	0.001	Benzene
Total	***124.49***	***124.69***	***124.68***	***33.94***	***1206.60***	***135.83***	***1169.94***	***26.79***	***16.91***	**Formaldehyde**

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Contemporaneous Emissions Decreases

Existing Emission Units (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Unit 14 and Unit 15							
Baseline Actual Emissions	102.30	400.91	361.89	310.73	2166.44	82.31	4834.98
Baseline period 2018-2019							
BAE	***-102.30***	***-400.91***	***-361.89***	***-310.73***	***-2166.44***	***-82.31***	***-4834.98***

Contemporaneous Emissions Increases

Emissions (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Temporary Boiler Operation							
Actual Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17
Period of emissions 2023							
BAE	***0.11***	***0.44***	***0.44***	***0.03***	***2.13***	***0.32***	***2.17***

New Emission Units (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C							
Potential Emissions	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*36.49*	*71.72*	*71.72*	*13.24*	*595.38*	*31.45*	*710.10*
ATP	***36.49***	***71.72***	***71.72***	***13.24***	***595.38***	***31.45***	***710.10***
Turbine 20							
Potential Emissions	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*24.56*	*52.50*	*52.50*	*20.52*	*602.99*	*48.25*	*455.17*
ATP	***24.56***	***52.50***	***52.50***	***20.52***	***602.99***	***48.25***	***455.17***
Emergency Generator EDG1							
Potential Emissions	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.24*	*0.29*	*0.28*	*0.01*	*7.69*	*1.54*	*4.20*
ATP	***0.24***	***0.29***	***0.28***	***0.01***	***7.69***	***1.54***	***4.20***
Emergency Fire Pump FP1							
Potential Emissions	0.03	0.18	0.18	0.17	0.54	0.11	0.47
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.03*	*0.18*	*0.18*	*0.17*	*0.54*	*0.11*	*0.47*
ATP	***0.03***	***0.18***	***0.18***	***0.17***	***0.54***	***0.11***	***0.47***

Grey Cells are limited emissions

New Emissions Units Potential to Emit (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Turbine 20	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Emergency Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47
ATP	***61.31***	***124.69***	***124.68***	***33.94***	***1206.60***	***81.35***	***1169.94***

Net Emissions Increase (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
ATP for New Emission Units	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94
Contemporaneous Increases	0.11	0.44	0.44	NA	2.13	0.32	2.17
Contemporaneous Decreases	-102.30	-400.91	-361.89	NA	-2166.44	-82.31	-4834.98
Net Emissions Increase	**-40.88**	**-275.77**	**-236.77**	**33.94**	**-957.71**	**-0.65**	**-3662.87**
Significance Threshold (tpy)	25	15	10	40	40	40	100

Unit 14 was shutdown in July 2020 and removed fom the permit in November 2023. Unit 15 was shutdown in September 2021 and removed from the permit in November 2023. The period between the shutdown/removal of Units 14 and 15 and the construction and operation of the new units (Turbines 19A, 19B, 19C, and 20, Engine EDG1, and Fire Pump FP1) will be within the contemporaneous peride. Therefore, emissions decrease for

PM and VOC should be subject to the 40% capacity factor limited to avoid being subject to PSD BACT analysis

Appendix A Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
99.9	1020	858.0

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1 9	7.6	7.6	0.6	37.1 **see below	5 5	37.7
Potential Emission in tons/yr	0.82	3 26	3 26	0.26	15 92	2.36	16.17

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.50E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	9.0E-04	5.1E-04	3.2E-02	0.77	1.5E-03	**0.81**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	2.1E-04	4.7E-04	6.0E-04	1.6E-04	9.0E-04	**2.4E-03**
Methodology is the same as above.					**Total HAPs**	**0.81**
The five highest organic and metal HAPs emission factors are provided above.					**Worst HAP**	**0.77**
Additional HAPs emission factors are available in AP-42, Chapter 1.4.						

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	51,478	0 99	0 94
Summed Potential Emissions in tons/yr	51,480		
CO2e Total in tons/yr	51,784		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0 64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A Emission Calculations
Coal Burning - Coal Boilers #17

Company Name NIPSCO - R.M. Schahfer Generating Station
Source Address 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No. 073-47965-00008
Significant Permit Modification No 073-48085-00008
Reviewer Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %		Weight %
Sulfur =	3.2	Ash =	8 90

Uncontrolled PTE	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89 0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0 06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0 60		
Uncontrolled Potential Emission in tons/yr	69 589	16 006	16 006	95 079	9 383	47	391
Limited Potential Emission in tons/yr	*521*				*10,425*		

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 17.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1yr * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1 5E-01	1 3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2 98E-03	1 29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2 01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8 81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/

Total HAPs	1211 34
Worst Single	938 3

Methodology
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24 93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #18

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)	Potential Throughput (ton/hr)
3967	11111	1.56E+06	1.79E+02

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Uncontrolled PTE

	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*	--	--	--	*10,425*	--	--

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 18.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1year * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/22)

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of C	Potential Throughput (ton/yr)
3967	11111	1560000

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Limited

	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7 (10A)	20.47 (2.3A)	3.6 *(38S)*	4.4	0.06	6.00
Potential Emission in tons/yr	524	16,006	2,852	3,475	47	4,691

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A Emission Calculations
Natural Gas Combustion Only
Turbine 16A

Company Name **NIPSCO - R.M. Schahfer Generating Station**
Source Address **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No. **073-47965-00008**
Significant Permit Modification No **073-48085-00008**
Reviewer **Hachem Ismaili Alaoui**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450 0	1020	12452 9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/MMBtu	0 0066	0 0066	0 0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41 92	41.92	41.92	21.49	2032.32	13 34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Uncontrolled Emission Factor in lb/MMBtu * 2000hours/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1 2E-05	4 3E-07	7.10E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4 06E-01	8 26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4 0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2 03E-01	8 26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0 0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698 610	55	19	Limited Potential Emission in tons/yr	159 500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O
Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 200hours/yr /2000lb/ton

Appendix A Emission Calculations
Natural Gas Combustion Only
Turbine 16B

Company Name **NIPSCO - R.M. Schahfer Generating Station**
Source Address **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No. **073-47965-00008**
Significant Permit Modification No **073-48085-00008**
Reviewer **Hachem Ismaili Alaoui**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450 0	1020	12452 9	0 0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0 32	0 0021	0.0820
Uncontrolled Potential Emission in tons/yr	41 92	41.92	41.92	21.49	2032 32	13 34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor in lb/MMBtu * 2000hrs/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1 2E-05	4.3E-07	7.1E-04	6.4E-05	1.3E-04	2 9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4 51E+00	4 06E-01	8 26E-01	1 84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4 0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8 26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/yr * 1ton/2,000 lb
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 2000hours/1 year * 1ton/2000lbs

Appendix A: Emissions Calculations
Turbines 19A, 19B, and 19C

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation			HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Maximum Heat input per Turbine	519	MMBtu/hr	1020	4457.29
Output (gross)	55	MW		
Number of Turbines:	3			
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)		
Number of SU/SD	4	events per day		
CT operation	1,460	events/year		
Startup duration for CT*	0.17	hour		
Shutdown duration for CT**	0.15	hour		
Heat input during events***	73.60	MMBtu/event		
Worst case sulfur in NG	0.50	gr/100 cf		
SO2 emission factor	0.002	lb/MMBtu		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 turbines)
PM	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM10	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM2.5	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	12.92 tons/yr	0.32 tons/yr	13.24 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	571.29 tons/yr	24.09 tons/yr	595.38 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	67.21 tons/yr	3.07 tons/yr	70.28 tons/yr
CO	50.70 lb/hr	36.10 lb/event	631.04 tons/yr	79.06 tons/yr	710.10 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 Turbines)
PM	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	28.38 tons/yr	3.07 tons/yr	31.45 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors		***Unlimited HAP Emissions***		
Hexane	2.50E-04	lb/MMBtu	1.70	tons/yr	
1,3-Butadiene	4.3E-07	lb/MMBtu	0.00	tons/yr	
Acetaldehyde	4.00E-05	lb/MMBtu	0.27	tons/yr	
Acrolein	6.40E-06	lb/MMBtu	0.04	tons/yr	
Benzene	1.20E-05	lb/MMBtu	0.08	tons/yr	
Ethylbenzene	3.20E-05	lb/MMBtu	0.22	tons/yr	
Formaledyhyde	0.920	lb/hr	12.09	tons/yr	
Napathalene	1.30E-06	lb/MMBtu	0.01	tons/yr	
PAH	2.20E-06	lb/MMBtu	0.02	tons/yr	
Proplene Oxide	2.90E-05	lb/MMBtu	0.20	tons/yr	
Toluene	1.30E-04	lb/MMBtu	0.89	tons/yr	
Xylene	6.40E-05	lb/MMBtu	0.44	tons/yr	
	Total HAP Emissions		**15.96**	**tons/yr**	
	Single Worst HAP Emission		**12.09**	**tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) = 1.77E-03
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	267,438	5.1	4.9
Summed Potential Emissions in tons/yr	267,448		
CO2e Total in tons/yr	269,027		

Methodology
The N2O Emission Factor for uncontrolled is 2.2.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emissions Calculations
Turbine 20

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation			HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Maximum Heat input per Turbine	2416	MMBtu/hr	1020	20749.18
Output (gross)	247	MW		
Number of Turbines:	1			
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)		
Number of SU/SD	2	events per day		
CT operation	730	events/year		
Startup duration for CT	0.35	hour		
Shutdown duration for CT	0.25	hour		
Heat input during events	564	MMBtu/event		
Worst case sulfur in NG	0.50	gr/100 cf		
SO2 emission factor	0.002	lb/MMBtu		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
PM10	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
PM2.5	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	20.11 tons/yr	0.41 tons/yr	20.52 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	581.71 tons/yr	21.28 tons/yr	602.99 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	27.05 tons/yr	36.87 tons/yr	63.91 tons/yr
CO	51.10 lb/hr	664.50 lb/event	212.63 tons/yr	242.54 tons/yr	455.17 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	11.39 tons/yr	36.87 tons/yr	48.25 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors		***Unlimited HAP Emissions***		
Hexane	2.50E-04	lb/MMBtu	2.65	tons/yr	
1,3-Butadiene	4.3E-07	lb/MMBtu	0.00	tons/yr	
Acetaldehyde	4.00E-05	lb/MMBtu	0.42	tons/yr	
Acrolein	6.40E-06	lb/MMBtu	0.07	tons/yr	
Benzene	1.20E-05	lb/MMBtu	0.13	tons/yr	
Ethylbenzene	3.20E-05	lb/MMBtu	0.34	tons/yr	
Formaledyhyde	1.10	lb/hr	4.82	tons/yr	
Napathalene	1.30E-06	lb/MMBtu	0.01	tons/yr	
PAH	2.20E-06	lb/MMBtu	0.02	tons/yr	
Proplene Oxide	2.90E-05	lb/MMBtu	0.31	tons/yr	
Toluene	1.30E-04	lb/MMBtu	1.38	tons/yr	
Xylene	6.40E-05	lb/MMBtu	0.68	tons/yr	
	Total HAP Emissions		**10.82**	**tons/yr**	
	Single Worst HAP Emission		**4.82**	**tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) = 4.55E-04
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	1,244,951	23.9	22.8
Summed Potential Emissions in tons/yr	1,244,997		
CO2e Total in tons/yr	1,252,349		

Methodology
The N2O Emission Factor for uncontrolled is 2.2.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Gypsum Material Handling System
Radial Stackers

Company Name: **NIPSCO - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-47965-00008**
Significant Permit Modification No: **073-48085-00008**
Reviewer: **Hachem Ismaili Alaoui**

Parameter		Value	Units	Source / Basis
New stacker throughput capacity	=	220	tons/hour	For each stacker. Information from the S&L Study 3-29-2012
New maximum throughput per stacker	=	1,927,200	tons/year	Based on 8,760 hours/year
Number of Stackers for Replacement	=	2		
Number of drop pont per stacker	=	1	Number	One drop point from stacker to pile
Moisture Content (M)	=	4.80	%	Conservative estimate
Annual Mean Wind speed (U)	=	10.00	mph	From RMS Calculations for Material Handling Emissions
PM Particle size multiplier (kP)	=	0.740	dimensionl	Ref. 1
PM10 Particle size multiplier (kP)	=	0.350	dimensionl	Ref. 1
PM2.5 Particle size multiplier (kP)	=	0.053	dimensionl	Ref. 1
PM Emission Factor	=	0.00171	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM10 Emission Factor	=	0.00081	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM2.5 Emission Factor	=	0.00012	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1

PTE Calculation Results

	PTE (TPY)		
Emission Unit	PM	PM10	PM2.5
Stacker 7MX04G-RS	1.65	0.78	0.12
Stacker 8MX04G-RS	1.65	0.78	0.12
Total	3.30	1.56	0.24

References:
1. EPA AP-42 Chapter 13.2.4; 11/2006.

Methodology:

PM/PM10/PM2.5 PTE (TPY) = New maximum throughput per stacker (tons/year) * Emission Factor (lb/ton/drop) * 1ton/2000lbs

Appendix A Emission Calculations
Unit 17 & Unit 18
Activated Carbon Injection Grid

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

Parameter		Value	Units	Source / Basis
Unit 17 AC Throughput Annual	=	365	tons/year	Design basis[1]
Unit 18 AC Throughput Annual	=	365	tons/year	Design basis[1]
PM Emission Factor	=	100%	fraction	AC particles in the 15 to 25 micrometer range[2]
PM10 Emission Factor	=	100%	fraction	Assumed 100% fractures to PM10[3]
PM2.5 Emission Factor	=	100%	fraction	Assumes 100% fractures to PM2.5[3]
Control Efficiency	=	99.75%		Use of ESP & Wet Scrubber[4]

PTE Calculation Results

	PTE, Controlled					
	Unit 17 (TPY)			Unit 18 (TPY)		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
ACI Stack Emissions	0.91	0.91	0 91	0.91	0.91	0 91

[1] Design basis establishes injection rate of ~2,000 pounds per day per unit.

[2] Activated Carbon Injection for Mercury Control on Industrial Coal-Fired Boilers Richard Miller Vice President Business Development ADA Environmental Solutions Co-Chairman ICAC Mercury Committee.

[3] Conservative assumption as worst case scenario.

[4] ESP design efficincies approximately 99.5%. Conservatively assumed that wet scrubber will achieve 50% additional reduction.

Appendix A: Emission Calculations
Fugitive Dust Emissions - Unpaved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Unpaved Roads at Industrial Site
The following calculations determine the amount of emissions created by unpaved roads, based on 8,760 hours of use and AP-42, Ch 13.2.2 (11/2006).

Vehicle Information (provided by source)

Type	Maximum number of vehicles	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	264	0.050	0.0	2.6
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	264	0.050	0.0	2.6
		Totals	**0.3**		**6.6**			**0.0**	**5.1**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.05 miles/trip

Unmitigated Emission Factor, Ef = k*[(s/12)^a]*[(W/3)^b] (Equation 1a from AP-42 13.2.2)

	PM	PM10	PM2.5	
where k =	4.9	1.5	0.15	lb/mi = particle size multiplier (AP-42 Table 13.2.2-2 for Industrial Roads)
s =	4.8	6.0	6.0	% = mean % silt content of unpaved roads (AP-42 Table 13.2.2-1 Iron and Steel Production)
a =	0.7	0.9	0.9	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)
W =	23.5	23.5	23.5	tons = average vehicle weight
b =	0.45	0.45	0.45	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [(365 - P)/365] (Equation 2 from AP-42 13.2.2)
Mitigated Emission Factor, Eext = E * [(365 - P)/365]
where P = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.2-1)

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	6.51	2.03	0.20	lb/mile
Mitigated Emission Factor, Eext =	4.37	1.36	0.14	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.01**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Mitigated PTE (Before Control) (tons/yr) = (Maximum one-way m les (miles/yr)) * (Mitigated Emission Factor (lb/mile)) * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = (Mitigated PTE (Before Control) (tons/yr)) * (1 - Dust Control Efficiency)

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particulate Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Paved Roads at Industrial Site
The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	1056	0.200	0.0	10.2
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	1056	0.200	0.0	10.2
		Totals	**0.3**		**6.6**			**0.1**	**20.4**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.20 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	23.5	23.5	23.5	tons = average vehicle weight
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	2.177	0.435	0.1069	lb/mile
Mitigated Emission Factor, Eext =	1.998	0.400	0.0981	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.02**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (Before Control) (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = [Mitigated PTE (Before Control) (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

One (1) diesel fire pump 350 HP

Output Horsepower Rating (hp)	350.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	175,000

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.0022	0.0021	0.0310	0 0025	0.0067
Potential Emission in tons/yr	0.19	0.19	0.19	0.18	2.71	0.22	0.58

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.71E-04	2.51E-04	1.75E-04	2.39E-05	7.23E-04	4.70E-04	5.67E-05	1.03E-04

***PAH = Polyaroma ic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.37E-03**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Green House Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	1.01E+02	4.05E-03	8.10E-04

Summed Potential Emissions in tons/yr	**1.01E+02**
CO2e Total in tons/yr	**1.01E+02**

Methodology
Emission Factors are from AP42 (Supplement B 10/96), Tables 3.3-1 and 3.3-2
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Poten ial Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O
Potential Emission ton/yr x N2O GWP (298).

Appendix A Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)
Emergency Engine EDG1

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	2922.0	NSPS Subpart IIII Emission Standards based on a: 2007 model year emergency engine
Output Horsepower Rating (kw)	2178.9	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	1,461,000	
Potential Throughput (kw-hr/yr)	1,089,468	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2 *(.00809S)*	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		4.01E-04	3.89E-04	1.21E-05			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				6.40	1.28	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0 29	0.28	0.01			
Based on g/kw-hr Emission Factor	0.24				7 69	1.54	4.20
Potential Emission in tons/yr	**0.24**	**0.29**	**0.28**	**0.01**	**7.69**	**1.54**	**4.20**

*The PM10 and PM2 5 emission factors for are from AP-42 Table 3.4-2. The PM10 emission factor is the sum of filterable PM10 and condensable particulate. The PM2.5 emission factor is the sum of filterable particulate less than 3 um and condensable particulate. Emission factors in lb/hp-hr were calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3 3-1 and 3.4-1).
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5 52E-08	1.48E-06
Potential Emission in tons/yr	3 97E-03	1.44E-03	9.87E-04	4.03E-04	1.29E-04	4 03E-05	1.08E-03

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Potential Emission of Total HAPs (tons/yr)	**8.05E-03**	
Worste Single HAP	**3.97E-03**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.16E+00	6.35E-05	9.30E-06
Potential Emission in tons/yr	8.47E+02	4.64E-02	6.79E-03

Summed Potential Emissions in tons/yr	**8.47E+02**
CO2e Total in tons/yr	**8.51E+02**

Methodology
CO2 Emission Factor is from AP 42 (Supplement B 10/96) Table 3.4-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) based on 11/29/2013 federal GWPs= CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr

Appendix A Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)
Fire Pump FP1

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

NSPS Subpart IIII Emission Standards based on a: 2009 model year emergency engine

Output Horsepower Rating (hp)	327.0	
Output Horsepower Rating (kw)	243.8	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	163 500	
Potential Throughput (kw-hr/yr)	121,922	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		0.0022	0.0022	0.00205			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				4.00	0.80	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0.18	0.18	0.17			
Based on g/kw-hr Emission Factor	0.03				0.54	0.11	0.47
Potential Emission in tons/yr	**0.03**	**0.18**	**0.18**	**0.17**	**0.54**	**0.11**	**0.47**

*PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8 26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.34E-04	2.34E-04	1.63E-04	2 24E-05	6.75E-04	4.39E-04	5.29E-05	9.61E-05

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.22E-03**	
Worste Single HAP	**6.75E-04**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3 3-1 and 3 3-2.
Output Horsepower Rating (kw) = Output Horsepower Rating (hp) * (0.7457 kw/hp)
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Throughput (kw-hr/yr) = [Output Horsepower Rating (kw)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] * [ton/2,000 lbs]
Potential Emission (tons/yr) = [Potential Throughput (kw-hr/yr)] * [Emission Factor (g/kw-hr)] * [lb / 453.592 g] * [ton/2,000 lbs]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	9.40E+01	3.78E-03	7.57E-04

Summed Potential Emissions in tons/yr	**9.40E+01**
CO2e Total in tons/yr	**9.43E+01**

Methodology
CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential

Appendix A: Emission Calculations
Unit 14 & Unit 15 Actual Emissions

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Baseline Actual Emissions for Contemporaneous Changes

	2018 Emissions (ton/yr)		2019 Emissions (ton/yr)		BAE* (ton/yr)		Total
Pollutant	**Unit 14**	**Unit 15**	**Unit 14**	**Unit 15**	**Unit 14**	**Unit 15**	
PM	43.9	59.8	64.2	36.8	54.0	48.3	**102.3**
PM10	139.9	301.1	142.7	218.2	141 3	259.6	**400.9**
PM2.5	119.3	284.2	112.5	207.9	115 9	246.0	**361.9**
SO2	163.4	211.4	115.0	131.7	139 2	171.5	**310.7**
NOx	760.2	1,668.6	676.5	1,227.7	718 3	1448.1	**2166.4**
VOC	50.4	41.5	41.8	31.0	46.1	36.2	**82.3**
CO	232.8	5,262.4	192.4	3,982.3	212.6	4622.3	**4835.0**

* BAE: Baseline Actual Emissions

Emissions reported in the site emissions inventories

	2018	2019	
Unit 15 coal heat input	25,545,640	19,331,471	MMBtu
CO factor for Unit 15	0.41	lb/MMBtu	
CO stack test for Unit 15 - December 3, 2019			

	2018	2019	BAE	
Unit 15 CO emissions	5,262.4	3,982.3	4,622.3	TPY

Notes
PM, PM10, PM2.5 NOx, and VOC emissions from Unit 14 and Unit 15 and CO emissions from Unit 14, as reported to IDEM in the emissions inventories, during the 2018-19 period are selected as Baseline Actual Emissions (BAE).

A December 2019 CO stack test for Unit 15 demonstrates a CO emission rate of 0.41 lb/MMBtu of heat input to the unit. NIPSCO used the coal combustion heat input for 2018 and 2019 for Unit 15 and the CO emission factor from the stack test to es imate actual CO emissions as BAE for this unit.

Appendix A Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name **NIPSCO - R.M. Schahfer Generating Station**
Source Address **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No. **073-47965-00008**
Significant Permit Modification No **073-48085-00008**
Reviewer **Hachem Ismaili Alaoui**

Actual Throughput for year 2023
MMCF/yr
115.0

	Pollutant							
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO	CO2e
Emission Factor in lb/MMCF	1.9	7.6	7 6	0.6	37.1 **see below	5 5	37.7	119,349
Potential Emission in tons/yr	0.11	0.44	0.44	0 03	2.13	0.32	2.17	6862.56

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.
CO2e from 40 CFR Part 98 Subpart A Table A-1 and Subpart C Tables C-1 and C-2.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Source Modification and Significant Permit Modification

Source Description and Location

Source Name:	**Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T 073-45762-00008**
Operation Permit Issuance Date:	**October 13, 2023**
Significant Source Modification No.:	**073-47965-00008**
Significant Permit Modification No.:	**073-48085-00008**
Permit Reviewer:	**Hachem Ismaili Alaoui**

Source Definition

This stationary source consists of an electric utility generating station with an on-site contractor that processes and moisture conditions fly ash:

(1) The electric utility generating station, Northern Indiana Public Service Company LLC, R.M. Schahfer Station, is the primary operation and is located at 2723 East 1500 North, Wheatfield, Indiana; and

(2) The fly ash processor, Headwaters Resources, Inc., is the supporting operation and is located at 2723 East 1500 North, Wheatfield, Indiana.

IDEM has determined that Northern Indiana Public Service Company LLC, R.M. Schahfer Station and Headwaters Resources, Inc., will be considered one source as defined by 326 IAC 2-7-1(22) based on contractual control. Therefore, the term “source” in the Part 70 documents refers to both Northern Indiana Public Service Company LLC, R.M. Schahfer Station and Headwaters Resources, Inc., as one source.

Separate Part 70 Operating permits will be issued to Northern Indiana Public Service Company LLC, R.M. Schahfer Station and Headwaters Resources, Inc., solely for administrative purposes.

This determination was initially made under Part 70 Operating Permit No. 73-23909-00040, issued on July 24, 2007.

Existing Approvals

The source was issued Part 70 Operating Permit Renewal No. 073-45762-00008 on November 13, 2023. There have been no subsequent approvals issued.

County Attainment Status

The source is located in Jasper County.

Pursuant to amendments to Indiana Code IC 13-17-3-14, effective July 1, 2023, a federal regulation that classifies or amends a designation of attainment, nonattainment, or unclassifiable for any area in Indiana under the federal Clean Air Act is effective and enforceable in Indiana on the effective date of the federal regulation.

Pollutant	Designation
SO_2	Unclassifiable or attainment effective April 9, 2018, for the 2010 primary 1-hour SO_2 standard. Better than national secondary standards effective March 3, 1978.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective August 3, 2018, for the 2015 8-hour ozone standard.
$PM_{2.5}$	Unclassifiable or attainment effective April 15, 2015, for the 2012 annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour $PM_{2.5}$ standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO_2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_x emissions are considered when evaluating the rule applicability relating to ozone. Jasper County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Jasper County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NOx emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Jasper County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a fossil fuel-fired steam electric power plant of more than 250 MMBtu/hour heat input, it is considered one (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1) or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is

invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Source Status - Existing Source

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions Prior to Modification (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[3]**	**Total HAPs**
Total PTE of Entire Source Including Fugitives*	**1067.83**	**32037.12**	**32035.79**	**190168.93**	**21781.26**	**100.14**	**1020.29**	**1876.29**	**2426.70**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."

[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.

[3]Single highest source-wide HAP (HCl)

*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant(s), PM, PM10, PM2.5, SO2, NOx, VOC, and CO, is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) This existing source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs.

(c) These emissions are based on the TSD of Part 70 Permit Renewal No. 073-45762-00008, issued on November 13, 2023.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed an application submitted by Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station on June 17, 2024, relating to the installation of four (4) natural gas-fired simple cycle combustion turbines, one (1) diesel emergency generator, and one (1) diesel emergency fire pump.

The following is a list of the new emission units and pollution control device(s):

(a) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(b) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(c) One (1) diesel emergency generator, Identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(d) One (1) diesel emergency fire pump, Identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Project Aggregation

Northern Indiana Public Service Company LLC, R.M. Schahfer Station submitted the following permit application to IDEM. When a major source for Prevention of Significant Deterioration (PSD) and/or Emission Offset (EO) submits an application for an amendment or modification, IDEM, OAQ reviews the permitting history of the source to determine if previous projects should be aggregated with the current project.

(1) Administrative Amendment No. 079-45452-00008 (issued on August 16, 2022)
Seeking approval to install Activated Carbon Injection (ACI) systems to control mercury emissions from two (2) pulverized coal-fired boilers identified as Unit 17 and Unit 18.

(2) Minor Source Modification No. 079-43419-00008 (issued on December 7, 2020)
Seeking approval to install a natural gas-fired temporary boiler, with a maximum heat capacity of less than or equal to 99.9 MMBtu per hour.

(3) Administrative Amendment No. 079-43478-00008 (issued on December 7, 2022)
Seeking approval to install a natural gas-fired temporary boiler, with a maximum heat capacity of less than or equal to 99.9 MMBtu per hour.

Each project was approved internally as a standalone project. The financial justification for the capital approval for each project was not dependent on any other past, present, or future capital projects at Northern Indiana Public Service Company LLC, R.M. Schahfer Station. Therefore, these separate projects will have no impact on one another from an operational or utilization standpoint.

Permit Level Determination – Part 70 Modification to an Existing Source

Pursuant to 326 IAC 2-1.1-1(12), Potential to Emit is defined as “the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical

or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	PTE Before Controls of the New Emission Units (ton/year)								
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[2]**	**Total HAPs**
Turbines 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	12.09	15.96
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	4.82	10.82
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	0.004	0.008
Emergency Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.001	0.002
Total PTE Before Controls of the New Emission Units:	**124.49**	**124.69**	**124.68**	**33.94**	**1206.60**	**135.83**	**1169.94**	**16.91**	**26.79**

[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[2]Single highest HAP (Formaldehyde).

Appendix A of this TSD reflects the detailed potential emissions of the modification.

(a) Approval to Construct

Pursuant to 326 IAC 2-7-10.5(g)(2), a Significant Source Modification is required because this modification is subject to 326 IAC 8-1-6.

Pursuant to 326 IAC 2-7-10.5(g)(4), a Significant Source Modification is required because this modification has the potential to emit PM/PM10/direct PM2.5, sulfur dioxide (SO2), nitrogen oxides (NOx), VOC at equal to or greater than twenty-five (25) tons per year.

Pursuant to 326 IAC 2-7-10.5(g)(6), a Significant Source Modification is required because this modification has a potential to emit equal to or greater than ten (10) tons per year of a single HAP and twenty-five (25) tons per year of any combination of HAPs.

Pursuant to 326 IAC 2-7-10.5(g)(7), a Significant Source Modification is required because this modification has a potential to emit equal to or greater than one hundred (100) tons per year of carbon monoxide (CO).

(b) Approval to Operate

Pursuant to 326 IAC 2-7-12(d)(1), this change to the permit is being made through a Significant Permit Modification because this modification does not qualify as a Minor Permit Modification or as an Administrative Amendment.

Permit Level Determination – PSD Emissions Increase

(a) Actual to Potential (ATP) Applicability Test
Since this project only involves the construction of new emissions units and/or emissions units considered new for this evaluation, an Actual to Potential (ATP) applicability test, specified in 326 IAC 2-2-2(d)(4), is used to determine if the project results in a Significant Emissions Increase.

(b) New Emissions Units Only
Pursuant to 326 IAC 2-2-1(t)(1), a new emissions unit is any emissions unit that is, or will be, newly constructed and that has existed for less than two (2) years from the date the emissions unit first operated.

The following proposed emissions unit(s) are considered as new emissions units for this evaluation.

(1) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, each with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

(2) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

(3) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

(4) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

(c) Baseline Actual Emissions
New Emissions Unit(s)
For a new emissions unit, the baseline actual emissions for purposes of determining the Emissions Increase that will result from the initial construction and operation of the unit shall equal zero (0) and thereafter, for all other purposes, shall equal the unit's potential to emit.

(d) Actual to Potential (ATP) Summary
An Actual to Potential (ATP) applicability test has been conducted the new emissions units and/or the emissions units considered new for this evaluation.

$ATP_{(new\ unit)} = PTE_{(new\ unit)} - Baseline\ Emissions_{(new\ unit)}$

See Appendix A of this Technical Support Document for detailed emission calculations.

New Emissions Units ATP (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Turbines 19A, 19B, 19C (ATP)	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Turbine 20 (ATP)	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Emergency Generator EDG1 (ATP)	0.24	0.29	0.28	0.01	7.96	1.54	4.20

New Emissions Units ATP (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Emergency Fire Pump FP1 (ATP)	0.03	0.18	0.18	0.17	0.54	0.11	0.47
Total	**61.31**	**124.69**	**124.68**	**33.94**	**1206.60**	**81.35**	**1169.94**
Significant Levels	25	15	10	40	40	40	100

The project emissions for PM, PM_{10}, $PM_{2.5,}$ NOx, VOC, and CO are each above the applicable PSD significant thresholds. Therefore, the project is a significant emissions increase for PM, PM_{10}, $PM_{2.5,}$ NOx, VOC, and CO.

The source performed a netting analysis, specified in 326 IAC 2-2-2(d)(1) and (d)(2), to demonstrate that the modification is not subject to PSD major review for the project PM, PM10, PM2.5, NOx, VOC, and CO emissions.

(e) Netting Applicability Test

The source performed a netting analysis, specified in 326 IAC 2-2-2(d)(1) and (d)(2), to demonstrate that the modification is not subject to PSD major review for the project PM, PM_{10}, $PM_{2.5,}$ NOx, VOC, and CO emissions.

For this netting analysis, the source has considered the project emissions increases described above (see ATP Summary), and identified contemporaneous increases and decreases associated with this project:

(f) Contemporaneous Emissions Decreases

The following emissions decreases are contemporanous with the proposed modification.

(1) One (1) cyclone coal-fired boiler, identified as Unit 14, with construction commenced in 1970 and commercial operation begun in 1976, with a design heat input capacity of 4,650 million Btu per hour (MMBtu/hr), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an activated carbon, Amended Silicates, or equivalent system for control of mercury emissions authorized in 2014, and an electrostatic precipitator (ESP) exhausting to stack 14. Unit 14 has a selective catalytic reduction (SCR) system, a reagent injection system, a flue gas desulfurization system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM).

(2) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 15, with construction commenced in 1974 and commercial operation begun in 1979, with a design heat input capacity of 5,100 million Btu per hour (MMBtu/hr), with low NOX burners (replaced in 2008-2009), combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an activated carbon, Amended Silicates, or equivalent system for control of mercury emissions authorized in 2014, and an electrostatic precipitator (ESP) with a flue gas conditioning (FGC) system for control of particulate matter, and exhausting to stack 15. Unit 15 has a selective non-catalytic reduction (SNCR) system, a reagent injection system, a flue gas desulfurization system, and has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM).

Note: *Unit 14 was shut down in July 2020 and removed from the permit in November 2023. Unit 15 was shut down in September 2021 and removed from the permit in November 2023. The period between the shutdown of Units 14 and 15 and the construction and operation of the new units (Turbines 19A, 19B, 19C, and 20, Engine EDG1, and Fire Pump FP1) will be within the contemporaneous period. Therefore, emissions decrease for PM, PM10, PM2.5, NOx, VOC, and CO due to the shutdown of Units 14 and 15 will accounted for in this project.*

(g) Contemporaneous Emissions Increases
The following emissions increases are contemporanous with the proposed modification.

(1) One (1) natural gas-fired temporary boiler, constructed in 2020, with a maximum capacity of less than or equal to 99.9 MMBtu per hour, using no control, and exhausting outdoors.

New Emissions Units ATP (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Project Emissions	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94

Contemporaneous Decreases (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Cyclone coal-fired boiler (Unit 14) and dry bottom pulverized coal-fired boiler (Unit 15)							
Baseline Actual Emissions	102.30	400.91	361.89	310.73	2166.44	82.31	4834.98
BAE	**-102.30**	**-400.91**	**-361.89**	**-310.73**	**-2166.44**	**-82.31**	**-4834.98**

Contemporaneous Increases (tons/year)							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**NO_X**	**VOC**	**CO**
Natural gas-fired temporary boiler installed in 2020							
Actual Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17
Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17

Net Emissions Increase (tons/year) "Project Emissions Accounting Test"							
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**
ATP for New Emissions Units	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94
Contemporaneous Increases	0.11	0.44	0.44	N/A	2.13	0.32	2.17
Contemporaneous Decreases	-102.30	-400.91	-361.89	N/A	-2166.44	-82.31	-4834.98
Project Net Emissions Increase	**-40.88**	**-275.77**	**-236.77**	**33.94**	**-957.71**	**-0.65**	**-3662.87**
Significant Levels	25	15	10	40	40	40	100
*PM2.5 listed is direct PM2.5.							

The source has opted to take limits in order to render the requirements of 326 IAC 2-2 not applicable to this modification.

See Technical Support Document (TSD) State Rule Applicability - Entire Source section, 326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset) applicability determination for more information regarding the limits.

(h) Conclusion
The Permittee has provided information as part of the application for this approval that based on net emissions increases test in 326 IAC 2-2-2 this modification to an existing major PSD stationary source will not be major because the Net Emissions Increase of each PSD regulated pollutant is less than the PSD significant levels levels (SO_2 emissions increases from the project

only is less than the significant emission rate)(i.e., the modification does not cause a Significant Net Emissions Increase).

PTE of the Entire Source After Issuance of the Part 70 Modification

The table below summarizes the after issuance source-wide potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of the Part 70 source and/or permit modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions After Issuance (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[3]**	**Total HAPs**
Total PTE of Entire Source Including Fugitives*	1129	32162	32160	190203	23004	184	2206	1896	2454
Title V Major Source Thresholds	NA	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."

[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.

[3]Single highest source-wide HAP (HCl)

*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing major PSD stationary source will continue to be major under 326 IAC 2-2 because at least one pollutant, PM, PM10, PM2.5, SO2, NOx, VOC, and CO has emissions equal to or greater than the PSD major source threshold.

(b) The facility is a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for any single HAP and/or equal to or greater than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA). However, the Permittee has announced retirement dates for the two coal-fired boilers at the facility as end of 2025. Startup of the new combustion turbines authorized in 2024 will occur after the retirement date of the two coal-fired boilers (Unit 17 and Unit 18). Therefore, the Permittee has requested enforceable limitations to be imposed on the entire source after the retirement of Unit 17 and Unit 18 but prior to the startup of the new combustion turbines authorized for construction in 2024. These emission limitations will restrict single HAP emission below ten (10) TPY and all HAPs emissions to less than twenty-five (25) TPY making this an area source of HAPs.

Federal Rule Applicability Determination

Due to the modification at this source, federal rule applicability has been reviewed as follows:

New Source Performance Standards (NSPS):

(a) The requirements of the New Source Performance Standard for Stationary Gas Turbines, 40 CFR 60, Subpart GG and 326 IAC 12, are not included in the permit for the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, because they are subject to 40 CFR 60, Subpart KKKK.

(b) The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the New Source Performance Standards for Stationary Combustion Turbines 40 CFR 60, Subpart KKKK and 326 IAC 12, because each of these gas turbines has a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour and they will be constructed after February 18, 2005.

The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 are subject to the following portions of Subpart KKKK.

(1) 40 CFR 60.4305
(2) 40 CFR 60.4315
(3) 40 CFR 60.4320(a)
(4) 40 CFR 60.4330(a)
(5) 40 CFR 60.4333
(6) 40 CFR 60.4340
(7) 40 CFR 60.4345
(8) 40 CFR 60.4350
(9) 40 CFR 60.4355
(10) 40 CFR 60.4365
(11) 40 CFR 60.4370(b)
(12) 40 CFR 60.4375
(13) 40 CFR 60.4380
(14) 40 CFR 60.4395
(15) 40 CFR 60.4400
(16) 40 CFR 60.4405
(17) 40 CFR 60.4410
(18) 40 CFR 60.4420
(19) Table 1 to Subpart KKKK of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, except as otherwise specified in 40 CFR 60, Subpart KKKK.

(c) The requirements of the New Source Performance Standard for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60, Subpart TTTT and 326 IAC 12, are not included in the permit for the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, because the construction of these turbines will commence after May 23, 2023.

(d) The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, 40 CFR 60, Subpart TTTTa and 326 IAC 12, because these units are stationary combustion turbines that will be constructed after May 23, 2023, each has base load rating greater than 250 MMBtu per hour of fossil fuel, and each serve generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the following portions of Subpart TTTTa.

(1) 40 CFR 60.5509a(a)
(2) 40 CFR 60.5515a
(3) 40 CFR 60.5520a
(4) 40 CFR 60.5525a
(5) 40 CFR 60.5535a
(6) 40 CFR 60.5550a
(7) 40 CFR 60.5555a

(8) 40 CFR 60.5560a
(9) 40 CFR 60.5565a
(10) 40 CFR 60.5580a
(11) Table 1 to Subpart TTTTa of Part 60
(12) Table 3 to Subpart TTTTa of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, except as otherwise specified in 40 CFR 60, Subpart TTTTa.

(e) The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 are subject to the New Source Performance Standards for 40 CFR 60, Subpart Stationary Compression Ignition Internal Combustion Engine and 326 IAC 12, because these units are stationary compression ignition (CI) internal combustion engines (ICE) and will commence construction after July 11, 2005.

The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 are subject to the following portions of Subpart IIII.

(1) 40 CFR 60.4200(a)
(2) 40 CFR 60.4205(b) and (c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4208
(6) 40 CFR 60.4209
(7) 40 CFR 60.4211(a), (c), and (f)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b) and (c)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219
(12) Table 2 to Subpart IIII of Part 60
(13) Table 5 to Subpart IIII of Part 60
(14) Table 8 to Subpart IIII of Part 60

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 except as otherwise specified in 40 CFR 60, Subpart IIII.

(f) The requirements of the New Source Performance Standard for Stationary Spark Ignition Internal Combustion Engines, 40 CFR 60, Subpart JJJJ and 326 IAC 12, are not included in the permit for the diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1, because these units are not stationary spark ignition internal combustion engines. They are stationary compression ignition internal combustion engines.

(g) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit for this proposed modification.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because these engines are considered new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engines (RICE) at an area source of hazardous air pollutants (HAP) because the Permittee has requested that the permit include emission limitations that will restrict single HAP emission below 10 tons

per year for single and the total HAPs emissions to less than 25 tons per year making this source an area source of HAPs prior to the first compliance date of this regulation.
The diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 will comply with following requirements of 40 CFR 63, Subpart ZZZZ.

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(c)
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the diesel-fired emergency generator EDG1 and diesel-fired emergency fire pump FP1 except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(b) The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are not subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY, which is incorporated by reference as 326 IAC 20-90, because these combustion turbines will be located at an "area source" of HAPs as of the first compliance date of the rule. The Permittee has proposed that prior to the first compliance date, which is the start of operation, for the new combustion turbines approved in 2024 for construction, the existing coal fired boilers (Unit 17 and Unit 18) will be shutdown making the facility an area source of HAPs. In addition, the Permittee has requested that the permit include emission limitations that will restrict single HAP emission below 10 tons per year for single and the total HAPs emissions to less than 25 tons per year making this source an area source of HAPs. This permit includes an enforceable condition that the operation of any of the new combustion turbines approved in 2024 for construction shall not start prior to the date of retirement of both coal fired boiler (Unit 17 and Unit 18) and appropriate emission limitations for source-wide HAPs emissions.

(c) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 63, 326 IAC 14 and 326 IAC 20 included for this proposed modification.

Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990 pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

(c) Pursuant to 40 CFR 64.2(b)(1)(iii), Acid Rain requirements pursuant to Sections 404, 405, 406, 407(a), 407(b), or 410 of the Clean Air Act are exempt emission limitations or standards. Therefore, CAM was not evaluated for emission limitations or standards for SO_2 and NO_X under the Acid Rain Program.

(d) Pursuant to 40 CFR 64.3(d), if a continuous emission monitoring system (CEMS) is required pursuant to other federal or state authority, the owner or operator shall use the CEMS to satisfy the requirements of CAM according to the criteria contained in 40 CFR 64.3(d).

The requirements of 40 CFR Part 64, CAM, are not applicable to any of the new units as part of this modification, since the new units do not have control devices.

Cross-State Air Pollutant Rule (CSAPR):

The USEPA has enacted the Cross State Air Pollutant Rule (CSAPR) which has replaced the Clean Air Interstate Rule (CAIR) effective January 1, 2015. Therefore, the Clean Air Interstate Rule (CAIR) expired on December 31, 2014. The Indiana Department of Environmental Management (IDEM) adopted the CAIR rule as State rule, 326 IAC 24-3. The Clean Air Interstate Rule (CAIR) Sulfur Dioxide Trading Program rule (326 IAC 24-2) and the Nitrogen Oxides Annual Trading Program (326 IAC 24-1) were repealed October 25, 2017. The final rule, The Clean Air Interstate Rule (CAIR) NOx Ozone Season Trading Program (326 IAC 24-3), was repealed on July 27, 2018. Therefore, The Clean Air Interstate Rule requirements have been removed from Section H and replaced with the requirements of 326 IAC 24 (Cross-State Air Pollution Rule (CSAPR) Programs)).

The preamble of the CSAPR regulations promulgated on August 8, 2011, states that the requirements established in the CSAPR trading program are applicable requirements that must be included in a source Title V permit pursuant to 40 CFR Part 70 and 71. The requirements of the Cross State Air Pollution Rules (CSAPR) apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and frame-type natural gas-fired combustion turbine, identified as Unit 20.

Transport Rule (TR) Trading Program Title V Requirements

The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and the frame-type natural gas-fired combustion turbine, identified as Unit 20, are subject to the requirements for the TR NOx Annual Trading Program, the TR NOx Ozone Season Trading Program, and the TR SO2 Group 1 Trading Program. The following tables summarize the unit specific monitoring provisions for this source:

Unit ID: 19A, 16B, 19C, and Unit 20					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	x	-------	-------	-------
NO_X	x	-------	-------	-------	-------
Heat input	-------	x	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2

Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

Cross-State Air Pollutant Rule (CSAPR):

The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and frame-type natural gas-fired combustion turbine, identified as Unit 20, are subject to the requirement of 326 IAC 21 which is incorporates the provisions of 40 CFR 72 through 40 CFR 78 for the purposes of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements for nitrogen oxide and sulfur dioxide emissions to demonstrate compliance with nitrogen oxides and sulfur dioxide emission reduction requirements.

State Rule Applicability - Entire Source

Due to this modification, state rule applicability has been reviewed as follows:

326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset)

PSD and Emission Offset applicability is discussed under the Permit Level Determination – PSD and Emission Offset section and the Permit Level Determination - PSD Emissions Increase and the Permit Level Determination - Emission Offset Emissions Increase section of this document. The source is located in an area that is either designated as attainment or unclassifiable for all pollutants. Therefore, Emission Offset provisions do not apply.

2024 Modification

In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits, shall limit the potential to emit of PM and VOC to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))

The provisions of 326 IAC 2-4.1 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997, unless the major source has been specifically regulated under or exempted from regulation under a NESHAP that was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act (CAA) and incorporated under 40 CFR 63. On and after June 29, 1998, 326 IAC 2-4.1 is intended to implement the requirements of Section 112(g)(2)(B) of the Clean Air Act (CAA).

The operation of the new combustion turbines (Units 19A, 19B, 19C, Unit 20), diesel-fired emergency generator (EDG1), and diesel-fired emergency fire pump (FP1) (approved in 2024 for construction) will emit equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs. This is because the entire source is limited to these levels by enforceable permit conditions. Therefore, 326 IAC 2-4.1 would not apply to the combustion turbines.

326 IAC 2-7-6(5) (Annual Compliance Certification)

The U.S. EPA Federal Register 79 FR 54978 notice does not exempt Title V Permittees from the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D), but the submittal of the Title V annual compliance certification to IDEM satisfies the requirement to submit the Title V annual compliance certifications to EPA. IDEM does not intend to revise any permits since the requirements of 40 CFR 70.6(c)(5)(iv) or 326 IAC 2-7-6(5)(D) still apply, but Permittees can note on their Title V annual compliance certifications that submission to IDEM has satisfied reporting to EPA per Federal Register 79 FR 54978. This only applies to Title V Permittees and Title V compliance certifications.

326 IAC 5-1 (Opacity Limitations)

This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1)

326 IAC 6-4 (Fugitive Dust Emissions Limitations)

Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)

This source is not subject to the requirements of 326 IAC 6-5, because the source has potential fugitive particulate emissions of less than twenty-five (25) tons per year.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)
Pursuant to 326 IAC 6.5-1-1(a), this source (located in Jasper County) is not subject to the requirements of 326 IAC 6.5 because it is not located in one of the following counties: Clark, Dearborn, Dubois, Howard, Marion, St. Joseph, Vanderburgh, Vigo or Wayne.

326 IAC 6.8 (Particulate Matter Limitations for Lake County)
Pursuant to 326 IAC 6.8-1-1(a), this source (located in Jasper County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

326 IAC 6.8 (Lake County: Fugitive Particulate Matter)
Pursuant to 326 IAC 6.8-10-1, this source (located in Jasper County) is not subject to the requirements of 326 IAC 6.8-10 because it is not located in Lake County.

326 IAC 24 (Cross-State Air Pollution Rule (CSAPR) Programs)
The source is subject to 326 IAC 24, because the requirements of 40 CFR Part 70 and 71 (Cross-State Air Pollution Rule (CSAPR)) apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, and frame-type natural gas-fired combustion turbine, identified as Unit 20. The requirements of Clean Air Interstate Rule (CAIR) have been repealed.

326 IAC 20 (Hazardous Air Pollutants)
Pursuant to SSM No. 073-47965-00008 and in order to render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA), upon permanent shutdown and decommission of the coal-fired boilers, identified as Unit 17 and Unit 18, and startup, as defined at 40 CFR 63.2, of the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, the Permittee shall comply with following limits:

(a) The combined total HAP emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and Emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined single HAP (formaldehyde) emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with these limits, combined with the potential to emit HAP from all other emission units at the source, shall limit the source-wide potential to emit single HAP to less than 10 tons per twelve (12) consecutive month period and the source-wide potential to emit total HAPs to less than 25 tons per twelve (12) consecutive month period, and shall render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA).

State Rule Applicability – Individual Facilities

Due to this modification, state rule applicability has been reviewed as follows:

Natural Gas-fired Simple Cycle Combustion Turbines 19A, 19B, 19C

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, are not subject to 326 IAC 6-2 because they are not indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, are exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, are not subject to 326 IAC 326 IAC 7-1.1 because each turbine has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each turbine has unlimited VOC potential emissions less than twenty-five (25) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

326 IAC 3-5 (Continuous Monitoring of Emissions)
Pursuant to 326 IAC 3-5-1(a), the requirements of 326 IAC 3-5 are applicable to the three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, because these turbines are required to perform continuous emission monitoring system(s) (CEMS) under 326 IAC 12 (40 CFR 60.334(b)).

Natural Gas-fired Simple Cycle Combustion Turbine Unit 20

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the frame-type natural gas-fired combustion turbine, identified as Unit 20, is not subject to 326 IAC 6-2 because it is not an indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The frame-type natural gas-fired combustion turbine, identified as Unit 20, is exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The frame-type natural gas-fired combustion turbine, identified as Unit 20, is not subject to 326 IAC 326 IAC 7-1.1 because its potential to emit (or limited potential to emit) of sulfur dioxide (SO2) are less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
The frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, is subject to the requirements of 326 IAC 8-1-6, because it was constructed after January 1, 1980, and its unlimited VOC potential emissions are equal to or greater than twenty-five (25) tons per year, and the frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, is not regulated by other rules in 326 IAC 8. Therefore, a Best Available Control Technology (BACT) analysis was required for the frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20 (see Appendix B of this TSD).

According to the BACT analysis contained in Appendix B of this TSD, IDEM, OAQ has determined that the following requirements represent BACT for the frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20:

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the frame-type natural gas-fired combustion turbine, identified as Unit 20, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the frame-type natural gas-fired combustion turbine, identified as Unit 20, since this unit is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

326 IAC 3-5 (Continuous Monitoring of Emissions)
Pursuant to 326 IAC 3-5-1(a), the requirements of 326 IAC 3-5 are applicable to the frame-type natural gas-fired combustion turbine, identified as Unit 20, because this unit is required to perform continuous emission monitoring system(s) (CEMS) under 326 IAC 12 (40 CFR 60.334(b)).

Diesel Emergency Generator EDG1 and Diesel Emergency Fire Pump FP1

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the diesel emergency generator EDG1 and the diesel emergency fire pump FP1 are not subject to 326 IAC 6-2 because they are not indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The diesel emergency generator EDG1 and the diesel emergency fire pump FP1 are exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The diesel emergency generator EDG1 and the diesel emergency fire pump FP1 are not subject to 326 IAC 326 IAC 7-1.1 because each unit has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the diesel emergency generator EDG1 and the diesel emergency fire pump FP1 were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each unit has unlimited VOC potential emissions less than twenty-five (25) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the diesel emergency generator EDG1 and the diesel emergency fire pump FP1, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the diesel emergency generator EDG1 and the diesel emergency fire pump FP1, since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to assure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

(a) The Compliance Determination Requirements applicable to this modification are as follows:

Testing Requirements:

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Testing or Date of Initial Valid Demonstration)**	**Pollutant/ Parameter**	**Frequency of Testing**	**Authority**
One (1) of Combustion Turbines Units 19A, 19B, and 19C	None	180*	NOx (45.90 lb/hr)	One-time	326 IAC 2-2-3 40 CFR 60, Subpart KKKK
			Formaldehyde (0.920 lb/hr)	One-time	326 IAC 2-4.1
Combustion Turbine Unit 20	None	180*	NOx (139.80 lb/hr)	One-time	326 IAC 2-2-3 40 CFR 60, Subpart KKKK
			Formaldehyde (1.10 lb/hr)	One-time	326 IAC 2-4.1
* No later than 180 days after startup of the emission unit or completion of the modification. Note: Testing should be during normal operation. Testing for these pollutants is not required during startup/shutdown events.					

Testing of the diesel emergency generator EDG1 and diesel emergency fire pump FP1 is not required because they are not required to comply with any applicable requirements.

Continuous Emissions Monitoring System (CEMS) Requirements:

Emission Unit	Type of Continuous Monitor (Pollutant Monitored)	Applicable Rule or Authority
Units 19A, 19B, 19C, and Unit 20	CEMS for NOx	326 IAC 3-5 326 IAC 2-7-6(1) & (6) 40 CFR 60, Subpart KKKK

Proposed Changes

As part of this permit approval, the permit may contain new or different permit conditions and some conditions from previously issued permits/approvals may have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes.

The following changes listed below are due to the proposed modification. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text (these changes may include Title I changes):

(1) Section A.2 has been updated to include the unit descriptions of the new units.

(2) Section D.0 has been added to the permit to include the HAPs limits for the entire source to be an area source of HAPs after the completion of this modification.

(3) Section D.13 has been added to the permit to outline the applicable requirements for the new combustion turbines.

(4) Sections E.6 and E.9 have been revised to include the applicable requirements for the new emergency generator (EDG1) and fire pump (PF1).

(5) Sections E.10, E.11, and E.12 have been revised to include the applicable requirements for the new combustion turbines Units 19A, 19B, 19C, and Unit 20.

(6) Section H has been revised to include the new combustion turbine Units 19A, 19B, 19C, and Unit 20.

(7) New reporting forms for the new combustion turbines (Units 19A, 19B, 19C, and Unit 20) have been added.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)]
[326 IAC 2-7-5(14)]

*****

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

*****

(~~d~~ **f**)

*****

(~~e~~ **g**)

*****

(~~f~~ **h**)

*****

(~~g~~ **i**)

(~~h~~ **j**)

(~~i~~ **k**)

*****

(~~j~~ **l**)

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected facility.]

*****

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]

Pursuant to SSM No. 073-47965-00008 and in order to render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA), prior to the startup, as defined at 40 CFR 63.2, of the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, the emergency generator EDG1, and emergency fire pump FP1, the Permittee shall comply with following:

(a) The combined total HAPs emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The combined single HAP (formaldehyde) emissions from the combustion turbines (Units 16A, 16B, 19A, 19B, 19C, and 20), temporary boiler, 334 HP diesel fire pump,

emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(c) The two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from service.

Compliance with these limits, combined with the potential to emit HAP from all other emission units at the source, shall limit the source-wide potential to emit single HAP to less than 10 tons per twelve (12) consecutive month period and the source-wide potential to emit total HAPs to less than 25 tons per twelve (12) consecutive month period, and shall render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA).

Compliance Determination Requirements

D.0.2 Compliance Determination for Combined Total HAP

In order to determine compliance with Condition D.0.1(a), the combined total HAP emissions from the entire source shall be determined using the following equation:

$$E_{THAP} = \sum_{i=1}^{12}\left(\sum_{n}\frac{EF_{n19} * HI_{19A} + EF_{n19} * HI_{19B} + EF_{n19} * HI_{19C} + EF_{nU20} * HI_{U20} + EF_{n16} * HI_{16A} + EF_{n16} * HI_{16B} + EF_{nTB} * NT_{TB} + EF_{n350FP} * DT_{350FP} + EF_{nFP1} * DT_{FP1} + EF_{nEDG1} * DT_{EDG1}}{2000}\right)$$

Where:

E_{THAP} = Combined total HAP emissions (tons/month)
HI_{19A} = Heat input from turbine Unit 19A (MMBtu/month)
HI_{19B} = Heat input from turbine Unit 19B (MMBtu/month)
HI_{19C} = Heat input from turbine Unit 19C (MMBtu/month)
HI_{U20} = Heat input from turbine Unit 20 (MMBtu/month)
HI_{16A} = Heat input from turbine Unit 16A (MMBtu/month)
HI_{16B} = Heat input from turbine Unit 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (gallons/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (gallons/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (gallons/month)
EF_{n19} = Emission factors (in lb/MMBtu) for every single HAP from Units 19A, 19B, and 19C
EF_{nU20} = Emission factors (in lb/MMBtu) for every single HAP from Unit 20
EF_{n16} = Emission factors (in lb/MMBtu) for every single HAP from Units 16A and 16B
EF_{nTB} = Emission factors (in lb/MMscf) for every single HAP from temporary boiler
EF_{n350FP} = Emission factors (in lb/gallon) for every single HAP from 350 HP diesel fire pump
EF_{nEDG1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency generator EDG1
EF_{nFP1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency fire pump FP1
i = Each calendar month within the twelve (12) consecutive month period
n = Every single HAP emitted by emission units included in the HAP limit

D.0.3 Compliance Determination for Combined Single HAP (Formaldehyde)

In order to determine compliance with Condition D.0.1(b), the combined single HAP (formaldehyde) emissions from the entire source shall be determined using the following equation:

$$\sum_{i=1}^{12} E_{Single\ HAP\ (Formaledyde)} = \frac{ER_{19} * HR_{19A} + ER_{19} * HR_{19B} + ER_{19} * HR_{19C} + ER_{U20} * HR_{U20} + EF_{16} * HI_{16A} + EF_{16} * HI_{16B} + EF_{TB} * NT_{TB} + EF_{350FP} * DT_{350FP} + EF_{FP1} * DT_{FP1} + EF_{EDG1} * DT_{EDG1}}{2000}$$

Where:

$E_{Single\ HAP\ (Formaldehyde)}$ = Single HAP (Formaldehyde) Emissions (tons/month)
ER_{19} = 0.920 lb/hr, emission rate for formaldehyde for turbines 19A, 19B, and 19C or value established in latest compliant stack test
ER_{U20} = 1.10 lb/hr, emission rate for formaldehyde for turbine Unit 20 or value established in latest compliant stack test
HR_{19A} = Number of operating hours per month for turbine 19A
HR_{19B} = Number of operating hours per month for turbine 19B
HR_{19C} = Number of operating hours per month for turbine 19C
HR_{U20} = Number of operating hours per month for turbine Unit 20
HI_{16A} = Heat input from turbine 16A (MMBtu/month)
HI_{16B} = Heat input from turbine 16B (MMBtu/month)
NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)
DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (hp-hr/month)
DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (hp-hr/month)
DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (hp-hr/month)
EF_{16} = 7.10E-04 lb/MMBtu, formaldehyde emission factor from AP-42 (Chapter 3.1 - Table 3.1-3)
EF_{TB} = 7.50E-02 lb/MMscf, formaldehyde emission factor from AP-42 (Chapter 1.4 - Table 1.4-3)
EF_{350FP} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*
EF_{EDG1} = 5.52E-07 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.4 - Table 3.4-3)*
EF_{FP1} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*
i = Each calendar month within the twelve (12) consecutive month period
*** Emission Factors in lb/hp-hr were calculated as follows: EF (lb/MMBtu) x 7,000 (Btu/hp-hr) x (1 MMBtu / 1,000,000 Btu)**

D.0.4 Testing Requirements [326 IAC 2-1.1-11]

In order to demonstrate compliance with Condition D.0.1 and to verify the emission rates for formaldehyde, not later than 180 days after the startup of the following emission units, the Permittee shall perform formaldehyde testing as follows:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	Formaldehyde (0.920 lb/hr)	One time
Frame type combustion turbine	Unit 20	Formaldehyde (1.10 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.0.5 Record Keeping Requirement

(a) To document the compliance status with Conditions D.0.1, the Permittee shall maintain monthly records in accordance with (1) and (3) below. Records maintained for (1) and (3) shall be taken as stated below and shall be complete and sufficient to establish compliance with the combined HAPs and single HAP emission limits established in Conditions D.0.1:

(1) Monthly combined total HAP emissions as calculated using the equation in Condition D.0.2.

(2) Monthly combined single HAP (formaldehyde) emissions as calculated using the equation in Condition D.0.3.

(3) The dates of shutdown for each unit listed in Condition D.0.1(c).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.0.6 Reporting Requirements

A quarterly summary of the information to document the compliance status with D.0.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1(35).

*****

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.13.1 PSD Minor Limit for PM and VOC [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 157-47442-00044, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits shall limit the potential to emit PM and VOC to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008.

D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), the Permittee shall minimize VOC emissions from the frame-type natural gas-fired combustion turbine, identified as Unit 20, using the Best Available Control Technology (BACT), which has been determined to be the following:

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

Compliance Determination Requirements [326 IAC 2-7-5(1)]

D.13.3 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for Nox, not later than 180 days after the startup of the following emission units, the Permittee shall perform NOx testing on the following emission units:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	NOx (45.90 lb/hr)	One time
Frame type combustion turbine	Unit 20	NOx (139.80 lb/hr)	One time

utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.13.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the natural gas-fired combustion turbines Units 19A, 19B, 19C, and 20, shall be calibrated, maintained, and operated for measuring NOx, which meet all applicable performance specifications of 326 IAC 3-5-2.

(b) All continuous emissions monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60, Subpart KKKK.

D.13.5 Compliance determination for PM and VOC

(a) To determine the compliance status with Condition D.13.1(a), the following equation shall be used to determine combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20 using the equation shown below for each:

$$E_{PM} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{PM} = Total PM emissions (tons/month) form the combustion turbine Units 19A, 19B, 19C, 20

ER_N = 4.90 lb/hr PM emission rate in normal operation for Units 19A, 19B, and 19C or 11.6 lb/hour PM emission rate in normal operation for Unit 20, or value established in latest stack tests

$ER_{(SU/SD)}$ = 4.90 lb/event, PM emission rate in startup/shutdown events for Units 19A, 19B, and 19C or 11.60 lb/event, PM emission rate in startup/shutdown events for Unit 20

***Evt* = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle**

***H* = Number of hours of normal operation for the month for Units 19A, 19B, 19C, and 20**

***i* = Each calendar month within the twelve (12) consecutive month period**

n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

(b) To determine the compliance status with Condition D.13.1(b), the following equation shall be used to determine the combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20:

$$E_{VOC} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{VOC} = Total VOC emissions (tons/month) from the combustion turbine Units 19A, 19B, 19C, 20

ER_N = 5.40 lb/hr, VOC emission rate in normal operation for Units 19A, 19B, and 19C, or 6.50 lb/hr VOC emission rate in normal operation for Unit 20, or value established in latest stack test.

$ER_{(SU/SD)}$ = 1.40 lb/event, VOC emission rate in startup/shutdown events for Units 19A, 19B, and 19C, or 101.00 lb/event, VOC emission rate in startup/shutdown events for Unit 20

Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle

H = Number of hours of normal operation for the month for Units 19A, 19B, 19C, and 20

i = Each calendar month within the twelve (12) consecutive month period

n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

D.13.6 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.13.7 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Permittee shall record the output of the continuous monitoring system (lb/hr) and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligation with regard to the records required by this condition.

D.13.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.13.1, the Permittee shall maintain monthly records in accordance with (1) and (2) below. Records maintained for (1) and (2) shall be taken as stated below and shall be complete and

sufficient to establish compliance with the PM and VOC emission limits established in Condition D.13.1:

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.6(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13.6(b).

(b) The number of startup and shutdown events per month.

(c) The number of minutes for each startup event and each shutdown event.

(d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.13.9 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1 (35).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1 (35).

D.13.10 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.13.1 shall be submitted not later than thirty (30) days after the end of the quarter being

reported. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

*****

SECTION E.6 NSPS

Emissions Unit Description:

*****

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

*****

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

*****

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 60.4200(a)
(2) 40 CFR 60.4205(b) and (c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4208
(6) 40 CFR 60.4209
(7) 40 CFR 60.4211(a), (c), and (f)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b) and (c)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219

(12) Table 2 to Subpart IIII of Part 60
(13) Table 5 to Subpart IIII of Part 60
(14) Table 8 to Subpart IIII of Part 60

*****

SECTION E.9 NESHAP

Emissions Unit Description:

*****

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a maximum capacity of 327 horsepower, and exhausting to stack FP1.

[Under 40 CFR Part 60, Subpart IIII this unit is an affected facility.]
[Under 40 CFR Part 63, Subpart ZZZZ this unit is an affected source.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-89]

*****

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585
(3) 40 CFR 63.6590(c)(7)
(4) 40 CFR 63.6595(a)(7)
(5) 40 CFR 63.6665
(6) 40 CFR 63.6670
(7) 40 CFR 63.6675

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 63.6580
(2) 40 CFR 63.6585(c)
(3) 40 CFR 63.6590(a)(2)(iii) and (c)(1)

*****

SECTION E.10 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.10.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart KKKK.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.10.2 New Source Performance Standards for Stationary Combustion Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart KKKK (included as Attachment I to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.4305
(2) 40 CFR 60.4315
(3) 40 CFR 60.4320(a)
(4) 40 CFR 60.4330(a)
(5) 40 CFR 60.4333
(6) 40 CFR 60.4340
(7) 40 CFR 60.4345
(8) 40 CFR 60.4350
(9) 40 CFR 60.4355

(10) 40 CFR 60.4365
(11) 40 CFR 60.4370(b)
(12) 40 CFR 60.4375
(13) 40 CFR 60.4380
(14) 40 CFR 60.4395
(15) 40 CFR 60.4400
(16) 40 CFR 60.4405
(17) 40 CFR 60.4410
(18) 40 CFR 60.4420
(19) Table 1 to Subpart KKKK of Part 60

*****

SECTION E.11 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

E.11.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart TTTTa.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart TTTTa (included as Attachment J to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.5509a(a)
(2) 40 CFR 60.5515a
(3) 40 CFR 60.5520a
(4) 40 CFR 60.5525a
(5) 40 CFR 60.5535a
(6) 40 CFR 60.5550a
(7) 40 CFR 60.5555a
(8) 40 CFR 60.5560a
(9) 40 CFR 60.5565a
(10) 40 CFR 60.5580a
(11) Table 1 to Subpart TTTTa of Part 60
(12) Table 3 to Subpart TTTTa of Part 60

*****

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.506), (40 CFR 97.606)

ORIS Code: 994

*****

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a maximum heat input capacity of 519 MMBtu per hour, each using CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR Part 60, Subpart KKKK these units are affected facilities.]
[Under 40 CFR Part 60, Subpart TTTTa these units are intermediate mode affected facilities.]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR Part 60, Subpart KKKK this unit is an affected facility.]
[Under 40 CFR Part 60, Subpart TTTTa this unit is an intermediate mode affected facility.]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

*****

H.10 Description of TR Monitoring Provisions

*****

Unit ID: 19A, 16B, 19C, and Unit 20					
Parameter	**Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)**	**Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D**	**Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E**	**Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19**	**EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E**
SO_2	-------	**X**	-------	-------	-------
NO_X	**X**	-------	-------	-------	-------
Heat input	-------	**X**	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOx Annual Trading Program) and 97.530 through 97.535 (TR NOx Ozone Season Trading Program) and 97.630 through 97.635 (TR SO2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program) and 97.535 (TR NOx Ozone Season Trading Program) and 97.635 (TR SO2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program) and 97.530 through 97.534 (TR NOx Ozone Season Trading Program) and 97.630 through 97.634 (TR SO2

Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Emission Units: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: PM Emissions
Limit: Shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	PM Emissions (tons)	*PM Emissions (tons)*	*PM Emissions (tons)*
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Emission Units: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: VOC Emissions
Limit: Shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	VOC Emissions (tons)	*VOC Emissions (tons)*	*VOC Emissions (tons)*
	This Month	Previous 11 Months	12 Month Total

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: **Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, Indiana 46392**
Part 70 Permit No.: **T 073-45762-00008**
Emission Units: **Source-wide**
Parameter: **Combined Total HAP Emissions**
Limit: **Shall be less than 25 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month**

QUARTER:_____ **YEAR:_____**

Month	Column 1	Column 2	Column 1 + Column 2
	Total HAP Emissions (tons)	***Total HAP Emissions (tons)***	***Total HAP Emissions (tons)***
	This Month	**Previous 11 Months**	**12 Month Total**

☐ **No deviation occurred in this quarter.**
☐ **Deviation/s occurred in this quarter.**
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Emission Units: Source-wide
Parameter: Combined Single HAP (Formaldehyde) Emissions
Limit: Shall be less than 10 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	Single HAP (Formaldehyde) Emissions (tons)	***Single HAP (Formaldehyde) Emissions (tons)***	***Single HAP (Formaldehyde) Emissions (tons)***
	This Month	**Previous 11 Months**	**12 Month Total**

☐ **No deviation occurred in this quarter.**
☐ **Deviation/s occurred in this quarter.**
Deviation has been reported on: _____

Submitted by: _____

Title / Position: _____

Signature: _____

Date: _____

Phone: _____

*****

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on June 17, 2024

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 073-47965-00008. The operation of this proposed modification shall be subject to the conditions of the attached proposed Significant Permit Modification No. 073-48085-00008.

The staff recommends to the Commissioner that the Part 70 Significant Source Modification and Significant Permit Modification be approved.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073 47965 00008
Significant Permit Modification No: 073 48085 00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled Potential to Emit (tons/year)											
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51 784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	69,589	16,006	16,006	95,079	9,383	46.91	390.95	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	69 589	16 006	16 006	95 079	9 383	46.91	390.95	3 768 728	1211.34	938.28	HCl
Turbine 16A	41.92	41.92	41.92	21.49	2 032	13.34	520.78	705 653	7.90	4.51	Formaldehyde
Turbine 16B	41.92	41.92	41.92	21.49	2,032	13.34	520.78	705,653	7.90	4.51	Formaldehyde
Turbine 19A 19B and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	--	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	--	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**139393**	**32227**	**32225**	**190236**	**24056**	**259**	**3010**	**9001592**	**2466**	**1877**	**HCl**

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Limited Potential to Emit (tons/year)

Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	GHGs	Total HAPs	Worst Single HAP	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	521	16,006	16,006	95,079	10,425	47	391	3,768,728	1211.34	938.28	HCl
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	--	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	--	10.82	4.82	Formaldehyde
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**1129**	**32162**	**32160**	**190203**	**23004**	**184**	**2206**	**7912502**	**2454**	**1896**	**HCl**

Limited Potential to Emit After Removal of Boilers Unit 17 and Unit 18 (tons/year)

Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	GHGs	Total HAPs	Worst Single HAP	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	51,784	0.81	0.77	Hexane
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	161,108	2.01	1.03	Formaldehyde
Turbine 19A, 19B, and 19C	61.04	71.72	71.72	13.24	595.38	79.70	710.10	--	15.96	12.09	Formaldehyde
Turbine 20		52.50	52.50	20.52	602.99		455.17	--	10.82	4.82	Formaldehyde
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	100.97	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	850.56	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94.33	2.22E-03	6.75E-04	Benzene
Total	**81.46**	**147.29**	**147.28**	**44.19**	**2153.22**	**90.02**	**1424.50**	**375045.75**	**<25**	**<10**	**Formaldehyde**

Appendix A: Emission Calculations
Modofication Summary

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled PTE of New Units (ton/yr)										
	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	Total HAPs	Single HAPs	
Turbine 19A, 19B, and 19C	71.72	71.72	71.72	13.24	595.38	70.28	710.10	15.96	12.09	Formaldehyde
Turbine 20	52.50	52.50	52.50	20.52	602.99	63.91	455.17	10.82	4.82	Formaldehyde
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20	0.008	0.004	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.002	0.001	Benzene
Total	***124.49***	***124.69***	***124.68***	***33.94***	***1206.60***	***135.83***	***1169.94***	***26.79***	***16.91***	**Formaldehyde**

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Contemporaneous Emissions Decreases

Existing Emission Units (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Unit 14 and Unit 15							
Baseline Actual Emissions	102.30	400.91	361.89	310.73	2166.44	82.31	4834.98
Baseline period 2018-2019							
BAE	***-102.30***	***-400.91***	***-361.89***	***-310.73***	***-2166.44***	***-82.31***	***-4834.98***

Contemporaneous Emissions Increases

Emissions (ton/yr)							
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Temporary Boiler Operation							
Actual Emissions	0.11	0.44	0.44	0.03	2.13	0.32	2.17
Period of emissions 2023							
BAE	***0.11***	***0.44***	***0.44***	***0.03***	***2.13***	***0.32***	***2.17***

New Emission Units (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C							
Potential Emissions	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*36.49*	*71.72*	*71.72*	*13.24*	*595.38*	*31.45*	*710.10*
ATP	***36.49***	***71.72***	***71.72***	***13.24***	***595.38***	***31.45***	***710.10***
Turbine 20							
Potential Emissions	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*24.56*	*52.50*	*52.50*	*20.52*	*602.99*	*48.25*	*455.17*
ATP	***24.56***	***52.50***	***52.50***	***20.52***	***602.99***	***48.25***	***455.17***
Emergency Generator EDG1							
Potential Emissions	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.24*	*0.29*	*0.28*	*0.01*	*7.69*	*1.54*	*4.20*
ATP	***0.24***	***0.29***	***0.28***	***0.01***	***7.69***	***1.54***	***4.20***
Emergency Fire Pump FP1							
Potential Emissions	0.03	0.18	0.18	0.17	0.54	0.11	0.47
Baseline Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Project Emissions Increase	*0.03*	*0.18*	*0.18*	*0.17*	*0.54*	*0.11*	*0.47*
ATP	***0.03***	***0.18***	***0.18***	***0.17***	***0.54***	***0.11***	***0.47***

Grey Cells are limited emissions

New Emissions Units Potential to Emit (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
Turbines 19A, 19B, and 19C	36.49	71.72	71.72	13.24	595.38	31.45	710.10
Turbine 20	24.56	52.50	52.50	20.52	602.99	48.25	455.17
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	1.54	4.20
Emergency Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47
ATP	***61.31***	***124.69***	***124.68***	***33.94***	***1206.60***	***81.35***	***1169.94***

Net Emissions Increase (ton/yr)							
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**
ATP for New Emission Units	61.31	124.69	124.68	33.94	1206.60	81.35	1169.94
Contemporaneous Increases	0.11	0.44	0.44	NA	2.13	0.32	2.17
Contemporaneous Decreases	-102.30	-400.91	-361.89	NA	-2166.44	-82.31	-4834.98
Net Emissions Increase	**-40.88**	**-275.77**	**-236.77**	**33.94**	**-957.71**	**-0.65**	**-3662.87**
Significance Threshold (tpy)	25	15	10	40	40	40	100

Unit 14 was shutdown in July 2020 and removed fom the permit in November 2023. Unit 15 was shutdown in September 2021 and removed from the permit in November 2023. The period between the shutdown/removal of Units 14 and 15 and the construction and operation of the new units (Turbines 19A, 19B, 19C, and 20, Engine EDG1, and Fire Pump FP1) will be within the contemporaneous peride. Therefore, emissions decrease for

PM and VOC should be subject to the 40% capacity factor limited to avoid being subject to PSD BACT analysis

Appendix A Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
99.9	1020	858.0

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1 9	7.6	7.6	0.6	37.1 **see below	5 5	37.7
Potential Emission in tons/yr	0.82	3 26	3 26	0.26	15 92	2.36	16.17

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.50E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	9.0E-04	5.1E-04	3.2E-02	0.77	1.5E-03	**0.81**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	2.1E-04	4.7E-04	6.0E-04	1.6E-04	9.0E-04	**2.4E-03**
Methodology is the same as above.					**Total HAPs**	**0.81**
The five highest organic and metal HAPs emission factors are provided above.					**Worst HAP**	**0.77**
Additional HAPs emission factors are available in AP-42, Chapter 1.4.						

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	51,478	0 99	0 94
Summed Potential Emissions in tons/yr	51,480		
CO2e Total in tons/yr	51,784		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0 64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A Emission Calculations
Coal Burning - Coal Boilers #17

Company Name NIPSCO - R.M. Schahfer Generating Station
Source Address 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No. 073-47965-00008
Significant Permit Modification No 073-48085-00008
Reviewer Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %		Weight %
Sulfur =	3.2	Ash =	8 90

Uncontrolled PTE	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89 0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0 06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0 60		
Uncontrolled Potential Emission in tons/yr	69 589	16 006	16 006	95 079	9 383	47	391
Limited Potential Emission in tons/yr	*521*				*10,425*		

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 17.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1yr * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1 5E-01	1 3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2 98E-03	1 29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2 01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8 81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/

Total HAPs	1211 34
Worst Single	938 3

Methodology
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24 93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #18

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)	Potential Throughput (ton/hr)
3967	11111	1.56E+06	1.79E+02

	Weight %		Weight %
Sulfur =	3.2	Ash =	8.90

Uncontrolled PTE

	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*	--	--	--	*10,425*	--	--

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 18.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1year * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/22)

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of C	Potential Throughput (ton/yr)
3967	11111	1560000

	Weight %		Weight %
Sulfur =	3.2	Ash =	8.90

Limited

	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7 (10A)	20.47 (2.3A)	3.6 *(38S)*	4.4	0.06	6.00
Potential Emission in tons/yr	524	16,006	2,852	3,475	47	4,691

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
VOC emission factor is from Table 1.1-19 (Total non-methane organic carbon).
Potential Throughput (tons/year) = Heat Input Capacity (MMBtu/hr) x 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x 8,760 hrs/yr
Emission Factors from AP-42, Chapter 1.1 for; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
Emission (tons/yr) = Throughput tons per year x Emission Factor (lb/ton) / 2,000 lb/ton
Emissions (lbs/MMBtu) = 10^6 Btu/MMBtu / Heat Content of Coal (Btu/lb) / 2000 lb/ton x Emission Factor (lb/ton)

Appendix A Emission Calculations
Natural Gas Combustion Only
Turbine 16A

Company Name **NIPSCO - R.M. Schahfer Generating Station**
Source Address **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No. **073-47965-00008**
Significant Permit Modification No **073-48085-00008**
Reviewer **Hachem Ismaili Alaoui**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450 0	1020	12452 9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/MMBtu	0 0066	0 0066	0 0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41 92	41.92	41.92	21.49	2032.32	13 34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Uncontrolled Emission Factor in lb/MMBtu * 2000hours/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1 2E-05	4 3E-07	7.10E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4 06E-01	8 26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4 0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2 03E-01	8 26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0 0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698 610	55	19	Limited Potential Emission in tons/yr	159 500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O
Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 200hours/yr /2000lb/ton

Appendix A Emission Calculations
Natural Gas Combustion Only
Turbine 16B

Company Name **NIPSCO - R.M. Schahfer Generating Station**
Source Address **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No. **073-47965-00008**
Significant Permit Modification No **073-48085-00008**
Reviewer **Hachem Ismaili Alaoui**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450 0	1020	12452 9	0 0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0 32	0 0021	0.0820
Uncontrolled Potential Emission in tons/yr	41 92	41.92	41.92	21.49	2032 32	13 34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor in lb/MMBtu * 2000hrs/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1 2E-05	4.3E-07	7.1E-04	6.4E-05	1.3E-04	2 9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4 51E+00	4 06E-01	8 26E-01	1 84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4 0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8 26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,653			CO2e Total in tons/yr	161,108		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu)*8760hrs/yr * 1ton/2,000 lb
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 2000hours/1 year * 1ton/2000lbs

Appendix A Emissions Calculations
Turbines 19A, 19B, and 19C

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

Projected Operation

Maximum Heat input per Turbine	519	MMBtu/hr
Output (gross)	55	MW
Number of Turbines:	3	
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)
Number of SU/SD	4	events per day
CT operation	1,460	events/year
Startup duration for CT*	0.17	hour
Shutdown duration for CT**	0.15	hour
Heat input during events***	73.60	MMBtu/event
Worst case sulfur in NG	0.50	gr/100 cf
SO2 emission factor	0.002	lb/MMBtu

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 turbines)
PM	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM10	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
PM2.5	4.90 lb/hr	4.90 lb/event	60.99 tons/yr	10.73 tons/yr	71.72 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	12.92 tons/yr	0.32 tons/yr	13.24 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	571.29 tons/yr	24.09 tons/yr	595.38 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	67.21 tons/yr	3.07 tons/yr	70.28 tons/yr
CO	50.70 lb/hr	36.10 lb/event	631.04 tons/yr	79.06 tons/yr	710.10 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 Turbines)
PM	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
PM10	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
PM2.5	4.90 lb/hr	4.90 lb/event	25.75 tons/yr	10.73 tons/yr	36.49 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	5.46 tons/yr	0.32 tons/yr	5.78 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	241.25 tons/yr	24.09 tons/yr	265.34 tons/yr
VOC	5.40 lb/hr	1.40 lb/event	28.38 tons/yr	3.07 tons/yr	31.45 tons/yr
CO	50.70 lb/hr	36.10 lb/event	266.48 tons/yr	79.06 tons/yr	345.54 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72 2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors	***Unlimited HAP Emissions***	***Limited HAP Emissions***	
Hexane	2.50E-04 lb/MMBtu	1.70 tons/yr	0.68 tons/yr	
1,3-Butadiene	4 3E-07 lb/MMBtu	0.00 tons/yr	0.00 tons/yr	
Acetaldehyde	4.00E-05 lb/MMBtu	0.27 tons/yr	0.11 tons/yr	
Acrolein	6.40E-06 lb/MMBtu	0.04 tons/yr	0.02 tons/yr	
Benzene	1.20E-05 lb/MMBtu	0.08 tons/yr	0.03 tons/yr	
Ethylbenzene	3.20E-05 lb/MMBtu	0.22 tons/yr	0.09 tons/yr	
Formaledyhyde	0.920 lb/hr	12.09 tons/yr	4.84 tons/yr	
Napathalene	1.30E-06 lb/MMBtu	0.01 tons/yr	0.00 tons/yr	
PAH	2.20E-06 lb/MMBtu	0.02 tons/yr	0.01 tons/yr	
Proplene Oxide	2 90E-05 lb/MMBtu	0.20 tons/yr	0 08 tons/yr	
Toluene	1 30E-04 lb/MMBtu	0.89 tons/yr	0 35 tons/yr	
Xylene	6.40E-05 lb/MMBtu	0.44 tons/yr	0.17 tons/yr	
	Total HAP Emissions	**15.96 tons/yr**	**6.38 tons/yr**	
	Single Worst HAP Emission	**12.09 tons/yr**	**4.84 tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) 1.77E-03
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Appendix A Emissions Calculations
Turbine 20

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

Projected Operation

Maximum Heat input per Turbine	2416	MMBtu/hr
Output (gross)	247	MW
Number of Turbines:	1	
Annual capacity factor	40.0%	based on capacity factor restriction applicable to the turbines per 40 CFR 60, Subpart TTTTa (40 CFR 60.5580a)
Number of SU/SD	2	events per day
CT operation	730	events/year
Startup duration for CT	0.35	hour
Shutdown duration for CT	0.25	hour
Heat input during events	564	MMBtu/event
Worst case sulfur in NG	0.50	gr/100 cf
SO2 emission factor	0.002	lb/MMBtu

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52 50 tons/yr
PM10	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
PM2.5	11.60 lb/hr	11.60 lb/event	48.27 tons/yr	4.23 tons/yr	52.50 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	20.11 tons/yr	0.41 tons/yr	20.52 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	581.71 tons/yr	21.28 tons/yr	602.99 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	27.05 tons/yr	36.87 tons/yr	63.91 tons/yr
CO	51.10 lb/hr	664.50 lb/event	212.63 tons/yr	242.54 tons/yr	455.17 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
PM10	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
PM2.5	11.60 lb/hr	11.60 lb/event	20.32 tons/yr	4.23 tons/yr	24.56 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	8.47 tons/yr	0.41 tons/yr	8.88 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	244.93 tons/yr	21.28 tons/yr	266.21 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	11.39 tons/yr	36.87 tons/yr	48.25 tons/yr
CO	51.10 lb/hr	664.50 lb/event	89.53 tons/yr	242.54 tons/yr	332.07 tons/yr

Methodology:
Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72 2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Pollutants	Emission Factors	***Unlimited HAP Emissions***	***Limited HAP Emissions***	
Hexane	2.50E-04 lb/MMBtu	2.65 tons/yr	1.06 tons/yr	
1,3-Butadiene	4 3E-07 lb/MMBtu	0.00 tons/yr	0.00 tons/yr	
Acetaldehyde	4.00E-05 lb/MMBtu	0.42 tons/yr	0.17 tons/yr	
Acrolein	6.40E-06 lb/MMBtu	0.07 tons/yr	0.03 tons/yr	
Benzene	1.20E-05 lb/MMBtu	0.13 tons/yr	0.05 tons/yr	
Ethylbenzene	3.20E-05 lb/MMBtu	0.34 tons/yr	0.14 tons/yr	
Formaledyhyde	1.10 lb/hr	4.82 tons/yr	1.93 tons/yr	
Napathalene	1.30E-06 lb/MMBtu	0.01 tons/yr	0.01 tons/yr	
PAH	2.20E-06 lb/MMBtu	0.02 tons/yr	0.01 tons/yr	
Proplene Oxide	2 90E-05 lb/MMBtu	0.31 tons/yr	0.12 tons/yr	
Toluene	1 30E-04 lb/MMBtu	1.38 tons/yr	0 55 tons/yr	
Xylene	6.40E-05 lb/MMBtu	0.68 tons/yr	0.27 tons/yr	
	Total HAP Emissions	**10.82 tons/yr**	**4.33 tons/yr**	
	Single Worst HAP Emission	**4.82 tons/yr**	**1.93 tons/yr**	Formaldehyde

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) 4 55E-04
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.80%)

Appendix A: Emission Calculations
Gypsum Material Handling System
Radial Stackers

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Parameter		Value	Units	Source / Basis
New stacker throughput capacity	=	220	tons/hour	For each stacker. Information from the S&L Study 3-29-2012
New maximum throughput per stacker	=	1,927,200	tons/year	Based on 8,760 hours/year
Number of Stackers for Replacement	=	2		
Number of drop pont per stacker	=	1	Number	One drop point from stacker to pile
Moisture Content (M)	=	4.80	%	Conservative estimate
Annual Mean Wind speed (U)	=	10.00	mph	From RMS Calculations for Material Handling Emissions
PM Particle size multiplier (kP)	=	0.740	dimensionl	Ref. 1
PM10 Particle size multiplier (kP)	=	0.350	dimensionl	Ref. 1
PM2.5 Particle size multiplier (kP)	=	0.053	dimensionl	Ref. 1
PM Emission Factor	=	0.00171	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM10 Emission Factor	=	0.00081	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM2.5 Emission Factor	=	0.00012	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1

PTE Calculation Results

	PTE (TPY)		
Emission Unit	PM	PM10	PM2.5
Stacker 7MX04G-RS	1.65	0.78	0.12
Stacker 8MX04G-RS	1.65	0.78	0.12
Total	3.30	1.56	0.24

References:
1. EPA AP-42 Chapter 13.2.4; 11/2006.

Methodology:

PM/PM10/PM2.5 PTE (TPY) = New maximum throughput per stacker (tons/year) * Emission Factor (lb/ton/drop) * 1ton/2000lbs

Appendix A Emission Calculations
Unit 17 & Unit 18
Activated Carbon Injection Grid

Company Name **NIPSCO - R.M. Schahfer Generating Station**
Source Address **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No. **073-47965-00008**
Significant Permit Modification No **073-48085-00008**
Reviewer **Hachem Ismaili Alaoui**

Parameter		Value	Units	Source / Basis
Unit 17 AC Throughput Annual	=	365	tons/year	Design basis[1]
Unit 18 AC Throughput Annual	=	365	tons/year	Design basis[1]
PM Emission Factor	=	100%	fraction	AC particles in the 15 to 25 micrometer range[2]
PM10 Emission Factor	=	100%	fraction	Assumed 100% fractures to PM10[3]
PM2.5 Emission Factor	=	100%	fraction	Assumes 100% fractures to PM2.5[3]
Control Efficiency	=	99.75%	Use of ESP & Wet Scrubber[4]	

PTE Calculation Results

	PTE, Controlled					
	Unit 17 (TPY)			Unit 18 (TPY)		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
ACI Stack Emissions	0.91	0.91	0 91	0.91	0.91	0 91

[1] Design basis establishes injection rate of ~2,000 pounds per day per unit.

[2] Activated Carbon Injection for Mercury Control on Industrial Coal-Fired Boilers Richard Miller Vice President Business Development ADA Environmental Solutions Co-Chairman ICAC Mercury Committee.

[3] Conservative assumption as worst case scenario.

[4] ESP design efficincies approximately 99.5%. Conservatively assumed that wet scrubber will achieve 50% additional reduction.

Appendix A: Emission Calculations
Fugitive Dust Emissions - Unpaved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Unpaved Roads at Industrial Site
The following calculations determine the amount of emissions created by unpaved roads, based on 8,760 hours of use and AP-42, Ch 13.2.2 (11/2006).

Vehicle Information (provided by source)

Type	Maximum number of vehicles	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	264	0.050	0.0	2.6
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	264	0.050	0.0	2.6
		Totals	**0.3**		**6.6**			**0.0**	**5.1**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.05 miles/trip

Unmitigated Emission Factor, Ef = k*[(s/12)^a]*[(W/3)^b] (Equation 1a from AP-42 13.2.2)

	PM	PM10	PM2.5	
where k =	4.9	1.5	0.15	lb/mi = particle size multiplier (AP-42 Table 13.2.2-2 for Industrial Roads)
s =	4.8	6.0	6.0	% = mean % silt content of unpaved roads (AP-42 Table 13.2.2-1 Iron and Steel Production)
a =	0.7	0.9	0.9	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)
W =	23.5	23.5	23.5	tons = average vehicle weight
b =	0.45	0.45	0.45	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [(365 - P)/365] (Equation 2 from AP-42 13.2.2)
Mitigated Emission Factor, Eext = E * [(365 - P)/365]
where P = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.2-1)

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	6.51	2.03	0.20	lb/mile
Mitigated Emission Factor, Eext =	4.37	1.36	0.14	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.01**	**0.00**	**0.00**

Methodology

Total Weight driven per day (ton/day)	= [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip)	= [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day)	= [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip)	= SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip)	= SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Mitigated PTE (Before Control) (tons/yr)	= (Maximum one-way m les (miles/yr)) * (Mitigated Emission Factor (lb/mile)) * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr)	= (Mitigated PTE (Before Control) (tons/yr)) * (1 - Dust Control Efficiency)

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particulate Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Paved Roads at Industrial Site
The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	1056	0.200	0.0	10.2
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	1056	0.200	0.0	10.2
		Totals	**0.3**		**6.6**			**0.1**	**20.4**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.20 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	23.5	23.5	23.5	tons = average vehicle weight
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	2.177	0.435	0.1069	lb/mile
Mitigated Emission Factor, Eext =	1.998	0.400	0.0981	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.02**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (Before Control) (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = [Mitigated PTE (Before Control) (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

One (1) diesel fire pump 350 HP

Output Horsepower Rating (hp)	350.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	175,000

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.0022	0.0021	0.0310	0 0025	0.0067
Potential Emission in tons/yr	0.19	0.19	0.19	0.18	2.71	0.22	0.58

*PM and PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs***
Emission Factor in lb/hp-hr****	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8.26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.71E-04	2.51E-04	1.75E-04	2.39E-05	7.23E-04	4.70E-04	5.67E-05	1.03E-04

***PAH = Polyaroma ic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.37E-03**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Green House Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	1.01E+02	4.05E-03	8.10E-04

Summed Potential Emissions in tons/yr	**1.01E+02**
CO2e Total in tons/yr	**1.01E+02**

Methodology
Emission Factors are from AP42 (Supplement B 10/96), Tables 3.3-1 and 3.3-2
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Poten ial Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O
Potential Emission ton/yr x N2O GWP (298).

Appendix A Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)
Emergency Engine EDG1

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

Output Horsepower Rating (hp)	2922.0	NSPS Subpart IIII Emission Standards based on a: 2007 model year emergency engine
Output Horsepower Rating (kw)	2178.9	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	1,461,000	
Potential Throughput (kw-hr/yr)	1,089,468	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2 *(.00809S)*	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		4.01E-04	3.89E-04	1.21E-05			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				6.40	1.28	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0 29	0.28	0.01			
Based on g/kw-hr Emission Factor	0.24				7 69	1.54	4.20
Potential Emission in tons/yr	**0.24**	**0.29**	**0.28**	**0.01**	**7.69**	**1.54**	**4.20**

*The PM10 and PM2 5 emission factors for are from AP-42 Table 3.4-2. The PM10 emission factor is the sum of filterable PM10 and condensable particulate. The PM2.5 emission factor is the sum of filterable particulate less than 3 um and condensable particulate. Emission factors in lb/hp-hr were calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3 3-1 and 3.4-1).
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5 52E-08	1.48E-06
Potential Emission in tons/yr	3 97E-03	1.44E-03	9.87E-04	4.03E-04	1.29E-04	4 03E-05	1.08E-03

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Potential Emission of Total HAPs (tons/yr)	**8.05E-03**	
Worste Single HAP	**3.97E-03**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.16E+00	6.35E-05	9.30E-06
Potential Emission in tons/yr	8.47E+02	4.64E-02	6.79E-03

Summed Potential Emissions in tons/yr	**8.47E+02**
CO2e Total in tons/yr	**8.51E+02**

Methodology
CO2 Emission Factor is from AP 42 (Supplement B 10/96) Table 3.4-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) based on 11/29/2013 federal GWPs= CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr

Appendix A Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)
Fire Pump FP1

Company Name	**NIPSCO - R.M. Schahfer Generating Station**
Source Address	**2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.	**073-47965-00008**
Significant Permit Modification No	**073-48085-00008**
Reviewer	**Hachem Ismaili Alaoui**

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

NSPS Subpart IIII Emission Standards based on a: 2009 model year emergency engine

Output Horsepower Rating (hp)	327.0	
Output Horsepower Rating (kw)	243.8	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	163 500	
Potential Throughput (kw-hr/yr)	121,922	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant						
	PM	PM10*	direct PM2.5*	SO2	NOx[1]	VOC[1]	CO
AP-42 Emission Factor in lb/hp-hr		0.0022	0.0022	0.00205			
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				4.00	0.80	3.5
Potential Emissions ton/year							
Based on AP-42 lb/hr Emission Factor		0.18	0.18	0.17			
Based on g/kw-hr Emission Factor	0.03				0.54	0.11	0.47
Potential Emission in tons/yr	**0.03**	**0.18**	**0.18**	**0.17**	**0.54**	**0.11**	**0.47**

*PM2.5 emission factors are assumed to be equivalent to PM10 emission factors. No information was given regarding which method was used to determine the factor or the fraction of PM10 which is condensable.
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).

Hazardous Air Pollutants (HAPs)

	Pollutant							
	Benzene	Toluene	Xylene	1,3-Butadiene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	6.53E-06	2.86E-06	2.00E-06	2.74E-07	8 26E-06	5.37E-06	6.48E-07	1.18E-06
Potential Emission in tons/yr	5.34E-04	2.34E-04	1.63E-04	2 24E-05	6.75E-04	4.39E-04	5.29E-05	9.61E-05

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.22E-03**	
Worste Single HAP	**6.75E-04**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3 3-1 and 3 3-2.
Output Horsepower Rating (kw) = Output Horsepower Rating (hp) * (0.7457 kw/hp)
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Throughput (kw-hr/yr) = [Output Horsepower Rating (kw)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] * [ton/2,000 lbs]
Potential Emission (tons/yr) = [Potential Throughput (kw-hr/yr)] * [Emission Factor (g/kw-hr)] * [lb / 453.592 g] * [ton/2,000 lbs]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	9.40E+01	3.78E-03	7.57E-04

Summed Potential Emissions in tons/yr	**9.40E+01**
CO2e Total in tons/yr	**9.43E+01**

Methodology
CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential

Appendix A: Emission Calculations
Unit 14 & Unit 15 Actual Emissions

Company Name: NIPSCO - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-47965-00008
Significant Permit Modification No: 073-48085-00008
Reviewer: Hachem Ismaili Alaoui

Baseline Actual Emissions for Contemporaneous Changes

	2018 Emissions (ton/yr)		2019 Emissions (ton/yr)		BAE* (ton/yr)		Total
Pollutant	Unit 14	Unit 15	Unit 14	Unit 15	Unit 14	Unit 15	
PM	43.9	59.8	64.2	36.8	54.0	48.3	**102.3**
PM10	139.9	301.1	142.7	218.2	141 3	259.6	**400.9**
PM2.5	119.3	284.2	112.5	207.9	115 9	246.0	**361.9**
SO2	163.4	211.4	115.0	131.7	139 2	171.5	**310.7**
NOx	760.2	1,668.6	676.5	1,227.7	718 3	1448.1	**2166.4**
VOC	50.4	41.5	41.8	31.0	46.1	36.2	**82.3**
CO	232.8	5,262.4	192.4	3,982.3	212.6	4622.3	**4835.0**

* BAE: Baseline Actual Emissions

Emissions reported in the site emissions inventories

	2018	2019	
Unit 15 coal heat input	25,545,640	19,331,471	MMBtu
CO factor for Unit 15	0.41	lb/MMBtu	
CO stack test for Unit 15 - December 3, 2019			

	2018	2019	BAE	
Unit 15 CO emissions	5,262.4	3,982.3	4,622.3	TPY

Notes
PM, PM10, PM2.5 NOx, and VOC emissions from Unit 14 and Unit 15 and CO emissions from Unit 14, as reported to IDEM in the emissions inventories, during the 2018-19 period are selected as Baseline Actual Emissions (BAE).

A December 2019 CO stack test for Unit 15 demonstrates a CO emission rate of 0.41 lb/MMBtu of heat input to the unit. NIPSCO used the coal combustion heat input for 2018 and 2019 for Unit 15 and the CO emission factor from the stack test to es imate actual CO emissions as BAE for this unit.

Appendix A Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name **NIPSCO - R.M. Schahfer Generating Station**
Source Address **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No. **073-47965-00008**
Significant Permit Modification No **073-48085-00008**
Reviewer **Hachem Ismaili Alaoui**

Actual Throughput for year 2023

MMCF/yr
115.0

	Pollutant							
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO	CO2e
Emission Factor in lb/MMCF	1.9	7.6	7 6	0.6	37.1 **see below	5 5	37.7	119,349
Potential Emission in tons/yr	0.11	0.44	0.44	0 03	2.13	0.32	2.17	6862.56

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission factors for NOx at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.
CO2e from 40 CFR Part 98 Subpart A Table A-1 and Subpart C Tables C-1 and C-2.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Indiana Department of Environmental Management
Office of Air Quality

TSD Appendix B
Best Available Control Technology (BACT) Analysis Determination

Source Background and Description

Source Name:	**Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T073-45762-00008**
Operation Permit Issuance Date:	**November 13, 2023**
Significant Source Modification No.:	**073-47965-00008**
Significant Permit Modification No.:	**073-48085-00008**
Permit Reviewer:	**Hachem Ismaili Alaoui**

Background Information

Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station owns and operates a stationary electric utility generating station located at 2723 East 1500 North, Wheatfield, Indiana 46392. The source is currently operating under Part 70 Operating Permit Renewal No. T073-45762-00008, issued on November 13, 2023. This source is major under Prevention of Significant Deterioration (PSD) and a minor source of Hazardous Air Pollutants (HAPs) under Section 112 of the Clean Air Act.

Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station submitted an application on June 17, 2024 proposing to construct three (3) aero-derivative natural gas-fired simple cycle combustion turbines, one (1) frame-type natural gas-fired simple cycle combustion turbine, one (1) diesel emergency generator, and one (1) diesel emergency fire pump.

Requirement for Best Available Control Technology (BACT)

The requirements of 326 IAC 8-1-6 (New Facilities, General Reduction Requirements) applies to facilities located anywhere in the state that were constructed on or after January 1, 1980, which have potential volatile organic compounds (VOC) emissions greater than 25 tons per year, and which are not otherwise regulated by other provisions of 326 IAC 8 rule, and requires the reduction of VOC emissions using Best Available Control Technology (BACT).

The proposed one (1) frame-type natural gas-fired simple cycle combustion turbine has potential VOC emissions of greater than 25 tons per year and is therefore subject to this rule.

Pursuant to 326 IAC 8-1-6, the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), has performed the following Best Available Control Technology Review (BACT) review for the following frame-type natural gas-fired simple cycle combustion turbine:

(a) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum heat input capacity of 2,416 MMBtu per hour, using CEMS for NOx emissions, using no controls, and exhausting to stack 20.

Summary of the Best Available Control Technology (BACT) Process

IDEM, OAQ conducts BACT analyses in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

Also, in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, BACT analyses take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

VOC BACT: Frame-type Natural Gas-fired Simple Cycle Combustion Turbine (Unit 20) Determination

In combustion of natural gas in combustion turbines, VOC emissions occur as a result of incomplete combustion of carbon-based fuels. The primary factors influencing VOC formation are temperature and residence time within the high temperature environment of the combustor. Variations in fuel carbon content have relatively little effect on overall VOC emissions. Generally, the effect of the combustion zone temperature and residence time on VOC emissions generation is the opposite of their effect on NOx emissions generation. Higher combustion zone temperature and residence times lead to more complete combustion and lower VOC emissions, but higher NOx emissions. The formation of VOC emissions is also dependent on the loading of the turbine. A gas turbine operating under full load experiences greater fuel efficiency than lesser loads and reduces the generation of VOC emissions.

Two basic techniques for controlling VOC emissions from combustion turbines were discussed in this BACT: post-combustion control, which includes the installation of an oxidation catalyst to oxidize VOC to CO2 and good combustion practices.

Step One: Identify All Potentially Available Control Technologies

The following potentially available control technologies were identified for controlling VOC emissions from the reactor system:

(a) Oxidation Catalyst

Catalytic oxidation is an add-on control technology that is commonly used to reduce VOC emissions in conjunction with its target pollutant CO. The catalysts are typically made of a precious metal and operate at temperatures in a relatively narrow range of 650°F to 1,000°F. No reactant is used with an oxidation catalyst. As with CO, VOC compounds will react with residual O2 in the presence of a catalyst to form CO2 and water vapor. The performance of an oxidation catalyst system is dependent on the specific VOC constituents present in the combustion turbine exhaust. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, backpressure loss to the system, catalyst life, susceptibility to poisoning by fine particles in the exhaust gas which reduces the catalyst's effectiveness, and potential collateral increases in emissions of PM10 and sulfuric acid mist.

(b) Good combustion practices

Good combustion practices are a method of controlling VOC emissions from combustion turbines. Maintaining optimum combustion efficiency and/or implementing appropriate maintenance procedures are examples of good combustion practices.

Step Two: Eliminate Technically Infeasible Control Options

To be considered technically feasible, a control technology must either be successfully demonstrated on a unit or, if not demonstrated, then be "available and applicable". A technology is considered "available" if it can be obtained by the applicant through commercial channels. An available technology is considered "applicable" if it can reasonably be installed and operated on the unit in question.

The feasibility of each of the potentially applicable control options identified is evaluated below.

(a) Oxidation Catalyst

The frame-type simple cycle combustion turbine (Unit 20) has a potential VOC emission exceeds 25 tons per hour threshold. However, only 22% of the potential VOC emissions occur during the normal operation of the combustion turbines, where add-on an oxidation catalyst would be effective in reducing VOC emissions. Typically, oxidation catalyst systems are not effective at controlling VOC emissions from combustion turbines during startup or shutdown events as the exhaust temperature is outside the optimum operating range. The following table presents a conservative VOC cost effectiveness evaluation for the proposed frame-type combustion turbine for the purpose of BACT for use of oxidation catalyst. Detailed VOC BACT cost effectiveness calculations are included in Appendix C.

Parameter	Oxidation Catalyst
Total capital requirement	$7,900,000
Annual O&M cost	$33,000
Catalyst replacement annual coat	$32,571
Capital recovery annual cost	$581,296
Total annual cost	$646,867
Uncontrolled VOC emissions (tons/yr)	48.26
Controlled VOC emissions (tons/yr) Assumed VOC control efficiency of 90% for normal operation and 50% for SU/SD (conservative assumptions)	19.57
VOC control cost effectiveness (per ton of VOC)	$22,550

The capital cost associated with the installation of an oxidation catalyst on the frame-type combustion turbine is estimated to be $7.9 million. The capital cost of the oxidation catalyst system includes the catalyst housing, duct work, control systems and balance of plant equipment. An equipment life of 20 years and an interest rate of 4 percent are assumed resulting in a capital recovery factor of 0.07. The annual capital recovery cost is calculated as $581,296. The annual operating cost associated with the oxidation catalyst system is approximately $65,571 per year (Annual O&M cost + Catalyst replacement annual cost). The annual operating costs include catalyst replacement, energy impacts, operating personnel, and maintenance. A catalyst life of five years is assumed.

The resultant cost effectiveness associated with the use of the oxidation catalyst is $22,550 per ton of VOC controlled resulting in negative economic impacts. Installation of an oxidation catalyst will also have negative energy and environmental impacts as well. These will include increased pressure drop through the combustion turbine exhaust resulting in decreased electricity generation and disposal requirements of catalyst material. Based on the energy, environmental, and economic impacts, the installation of an oxidation catalyst is not a technically feasible option as VOC BACT for the proposed frame-type combustion turbine.

(b) Good combustion practices

Good combustion practices are essential for the operation and life-span of the proposed combustion turbine and will be implemented. The proposed combustion turbine will only combust natural gas as fuel. Therefore, good combustion practices and clean fuels are technically feasible for this combustion turbine. Among the natural gas-fired simple-cycle combustion turbines listed in the RBLC, the majority all listed natural gas-fired combustion turbines concluded that the use of good combustion practices was representative of BACT.

Step Three: Rank Feasible Technologies

The remaining technically feasible options for controlling VOC emissions from the reactor system are as follows (listed in descending order of most technically feasible):

(1) Oxidation Catalyst.

(2) Good combustion Practices.

Step Four: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 15.110 (Natural Gas Fired Large Simple Cycle Combustion Turbines – Peaking Units). The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number and Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO – R.M. Schahfer Generating Station	073-47965--00008	N/A	One (1) Frame-type Simple Cycle Combustion Turbine (Unit 20) (2,416 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 6.50 lb/hr during normal operation **Emission Limit 2:** 101.0 lb/event during startup 101.0 lb/event during shutdown
FPEC, LLC (Freestone Peakers Plant)	TX173582 June 13, 2024	TX-0975	Simple Cycle Gas Turbines (221.00 MW)	**Control Method:** Good combustion **Emission Limit 1:** 2.0 ppmvd @ 15% O2 **Emission Limit 2:** 0
Tenaska Roan's Prairie Partners (TRPP), LLC Roan's Prairie Generating Station	114698 PSDTX1378 September 22, 2014	TX-0696	Two Simple Cycle Turbines (600.00 MW)	**Control Method:** Good combustion practices **Emission Limit 1:** 1.4 ppmvd @ 15% O2 (For GE) **Emission Limit 2:** 1.0 ppmvd @ 15% O2 (for Siemens)

The capital cost associated with the installation of an oxidation catalyst on the frame-type combustion turbine is estimated to be $7.9 million. The cost effectiveness of this BACT option is over about $22,550 per ton VOC controlled. The recent BACT determinations for VOC in RBLC for natural gas-fired simple combustion turbines – peaking units utilize good combustion practices.

Step Five: Select BACT

Based on a review of the recent VOC BACT determinations for similar facilities and the cost analysis discussed in the above for the installation of an oxidation catalyst, IDEM has established the following as BACT for volatile organic compounds (VOC) for the proposed frame-type simple cycle combustion turbine (Unit 20):

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during normal operation shall not exceed 6.50 pounds per hour.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Ed Pierce
Northern Indiana Public Service Company LLC RM Schahfer Generating Station
2755 Raystone Dr
Valparaiso, IN 46383

DATE: February 4, 2025

FROM: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
TV Significant Permit Modification
073-48085-00008

This notice is to inform you that a final decision has been issued for the air permit application referenced above.

Our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person. In addition, the Notice of Decision has been sent to the OAQ Permits Branch Interested Parties List and, if applicable, the Consultant/Agent and/or Responsible Official/Authorized Individual.

The final decision and supporting materials are available electronically; the original signature page is enclosed for your convenience. The final decision and supporting materials available electronically at:

IDEM's online searchable database: https://www.in.gov/apps/idem/caats/ . Choose Search Option **by Permit Number**, then enter permit 48085

and

IDEM's Virtual File Cabinet (VFC): https://www.in.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, or have difficulty accessing the documents online, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Visit **on.IN.gov/survey** or scan the QR code to provide feedback.
We appreciate your input!

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

February 4, 2025

TO: Jasper County Public Library Wheatfield Public Library

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: **Northern Indiana Public Service Company LLC RM Schahfer Generating Station**
Permit Number: **073-48085-00008**

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library 1/13/2025

Visit on.IN.gov/survey or scan the QR code to provide feedback.
We appreciate your input!

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

February 4, 2025
Northern Indiana Public Service Company LLC RM Schahfer Generating Station
073-48085-00008

To: Interested Parties

This notice is to inform you that a final decision has been issued for the air permit application referenced above. This notice is for informational purposes only. You are not required to take any action.

You are receiving this notice because you asked to be on IDEM's notification list for this company and/or county; or because your property is nearby the company being permitted; or because you represent a local/regional government entity.

The enclosed Notice of Decision Letter provides additional information about the final permit decision.

The final decision and supporting materials are available electronically at:

IDEM's online searchable database: https://www.in.gov/apps/idem/caats/. Choose Search Option by Permit Number, then enter permit 48085

and

IDEM's Virtual File Cabinet (VFC): https://www.in.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit.

Please Note: *If you would like to be removed from the Air Permits mailing list, please contact Joanne Smiddie-Brush with the Air Permits Administration Section at 1-800-451-6027, ext. 3-0185 or via e-mail at JBRUSH@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
Final Interested Parties Cover Letter 1/13/2025

Visit on.IN.gov/survey or scan the QR code to provide feedback.
We appreciate your input!

Mail Code 61-53

IDEM Staff	JLSCOTT 2/4/2025 Page 1 of 2 Northern Indiana Public Service Company LLC RM Schahfer Generating Station 073-48085-00008 Final		
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**

AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Ed Pierce Nor hern Indiana Public Service Company LLC RM Sch 2755 Raystone Dr Valparaiso IN 46383 (Source CAATS) via UPS									
2		Kurt Sangster Vice President of Operations Northern Indiana Public Service Company LLC RM Sch 2755 Raystone Dr Valparaiso IN 46383 *(RO CAATS)*									
3		Ms. Lana Gawronski 9296 N 900 W DeMotte IN 46310 *(Affected Party)*									
4		Mr. Aaron Webster 7149 W 1000 N DeMotte IN 46310 *(Affected Party)*									
5		The Echterling Residence 9180 W 950 N DeMotte IN 46310 *(Affected Party)*									
6		Current Resident 548 N Oak Dr Plymouth IN 46563 *(Affected Party)*									
7		Mr. Lawrence A Vanore Sommer & Barnard Ackerson 1 Indiana Square, Ste 3500 Indianapolis IN 46204-5198 *(Affected Party)*									
8		State Representative District 16 PO Box 1 Rensselaer IN 47978 *(Legislator)*									
9		Jasper County Commissioners 115 W Washington St Rensselaer IN 47978 *(Local Official)*									
10		Jasper County Health Department 910 S Sparling Ave #1 Rensselaer IN 47978-9132 *(Health Department)*									
11		Mr. Donald Speacht, Jr 11751 N CR 500 E San Pierre IN 46374 *(Affected Party)*									
12		The Banks Family 11846 N CR 100 E Wheatfield IN 46392 *(Affected Party)*									
13		Ms. Kay Asher 4036 Heritage Dr N Wheatfield IN 46392 (Affected Party)									
14		Ms. Maryann Desalvo 10145 N 200 E Wheatfield IN 46392 *(Affected Party)*									
15		Victor & Cleone Downing 1333 E 1225 N Wheatfield IN 46392 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

FACSIMILIE OF PS Form 3877

Mail Code 61-53

IDEM Staff	JLSCOTT 2/4/2025 Page 2 of 2 Northern Indiana Public Service Company LLC RM Schahfer Generating Station 073-48085-00008 Final		
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**

AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Deborah PO Box 307 Wheatfield IN 46392 (Affected Party)									
2		George & Joyce Gourko 2039 S 9th St Lafayette IN 47905 *(Affected Party)*									
3		Mr. Scott Helton PO Box 307 Wheatfield IN 46392 *(Affected Party)*									
4		Mr. Bob Hetrick 10274 N 200 E Wheatfield IN 46392 *(Affected Party)*									
5		Ms. Monica Jones 9250 N 100 W Wheatfield IN 46392 *(Affected Party)*									
6		Michael & Kathleen Teiron 4073 E 425 N Wheatfield IN 46392 *(Affected Party)*									
7		Robert & Barbara Witvoet 14240 N SR 49 Wheatfield IN 46392 *(Affected Party)*									
8		Sharon Williams 22745 Frederick Rd Steger IL 60475 *(Affected Party)*									
9		Darlene & Scott Holmes 9161 N 900 W Demotte IN 46310 *(Affected Party)*									
10		Mr. Kenny Haun PO Box 280 Rensselaer IN 47978 *(Affected Party)*									
11		Tom & Gail Clark 1186 E CR 1250 N Wheatfield IN 46392 *(Affected Party)*									
12		Wheatfield Town Council 170 S Grace St Wheatfield IN 46392 *(Local Official)*									
13		Jasper County Public Library - Wheatfield 350 S Bierma St Wheatfield IN 46392 (Library)									
14		Save the Dunes 444 Barker Rd Michigan City IN 46360 *(Affected Party)*									
15		La Porte County Herald-Dispatch 422 Franklin St, Ste B Michigan City IN 46360 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

FACSIMILIE OF PS Form 3877

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 102
MISO Attachment Y Response to NIPSCO

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 Environmental Management
100 North Senate Avenue, 12th Floor
Indianapolis, IN 46204

RE: Northern Indiana Public Service Company
R. M. Schahfer Generating Station
NPDES Permit No. IN 0053201
Notice of Planned Participation under 40 CFR 423

Dear Ms. Clark Mettler:

This letter serves as Notice of Planned Participation under 40 CFR 423 – Effluent Limitations Guidelines (ELG) for the Electric Power Generating Point Source Category. Under the Reporting and Recordkeeping Requirements of 40 CFR 423.19(h), Northern Indiana Public Service Company, LLC (NIPSCO) is hereby notifying the permitting authority that absent a directive to remain open, NIPSCO plans to cease combustion at Units 17 and 18 at the R. M. Schahfer Generating Station by December 31, 2025, and qualify for the reduced requirements for combustion residual leachate (CRL) under the ELG Rule. This notice includes the following information, in accordance with 40 CFR 423.19(h)(2) – i.e., the 2034 subcategory:

Electric generating units intended to achieve the permanent cessation of coal combustion:

RESPONSE: Units 17 and 18 at NIPSCO's R. M. Schahfer Generating Station.

Expected date that each electric generating unit is projected to achieve permanent cessation of coal combustion:

RESPONSE: Absent a directive to remain open, NIPSCO remains on track to cease coal combustion at Schahfer's remaining two coal units by December 31, 2025.

Whether the date above represents a retirement or a fuel conversion:

RESPONSE: Retirement

Whether each retirement or fuel conversion has been approved by a regulatory body:

RESPONSE: On January 31, 2023, NIPSCO filed an Attachment Y Suspension Notice with the Midcontinent Independent System Operator (MISO) indicating retirement of Units 17 and 18 at R. M. Schahfer Generating Station by December 31, 2025. On February 3, 2023, MISO approved the Attachment Y Suspension Notice. This documentation is enclosed with this letter.

What the relevant regulatory body is:

RESPONSE: Midcontinent Independent System Operator (MISO).

Include a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs:

RESPONSE: In Indiana, utilities are required to submit Integrated Resource Plans (IRPs) to the Indiana Utility Regulatory Commission (IURC) every 3 years. While IRPs are submitted to the IURC as part of a legislative process, they are not regulatory filings where formal "approval" is granted. NIPSCO's 2024 IRP documents the planned retirement of Schahfer Units 17 and 18 by December 31, 2025.

Please see NIPSCO's 2024 IRP here:

https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf

Certification of electric generating unit (EGU) cessation under 40 CFR 257.103(b) or other documentation supporting that the EGU will permanently cease the combustion of coal by December 31, 2034:

RESPONSE: Please see the enclosed Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of Coal-Fired Boilers by a Date Certain Addendum 2 cover letter. Please also see the associated Addendum 2 report, filed with the U.S. Environmental Protection Agency pursuant to §257.103(f)(2) here:

https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-groundwater-moniitoring-and-corrective-action/rm-schahfer-generating-station-wda-part-a-addendum-2-summer-2022.pdf?sfvrsn=d2e31151_3

Timeline to achieve the permanent cessation of coal combustion (include interim milestones and the projected dates of completion):

RESPONSE:

January 31, 2023	Attachment Y Suspension Notice Submitted to MISO
February 3, 2023	Attachment Y Suspension Notice Approved by MISO
June 22, 2023	Submittal of Notice of Planned Participation under 40 CFR 423.19(g)
June 4, 2024	Annual Progress Report Submitted to the Indiana Department of Environmental Management (IDEM)
October 29, 2025	Annual Progress Report Submitted to the Indiana Department of Environmental Management (IDEM)
October 29, 2025	Submittal of Notice of Planned Participation under 40 CFR 423.19(h)
December 31, 2025	Absent a Directive to Remain Open, NIPSCO Remains On Track to Retire Schahfer's Remaining Two Coal Units By This Date

NIPSCO
A NiSource Company

Certification Statement that the facility is in compliance the applicable limitations or standards for FGD wastewater in 423.13(g) or (g)(2)(ii) or (iii) or 423.16(e)(1) or (2):

RESPONSE: NIPSCO is in compliance with all applicable limitations for FGD wastewater.

Certification Statement that the facility is in compliance the applicable limitations or standards for bottom ash transport water in 423.13(k)(1) or (k)(2)(i) or (iii) or 423.16(g)(1) or (2):

RESPONSE: NIPSCO is in compliance with all applicable limitations for bottom ash transport water.

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

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
R. M. Schahfer Generating Station Demonstration Addendum Cover Letter Summer 2022

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
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]

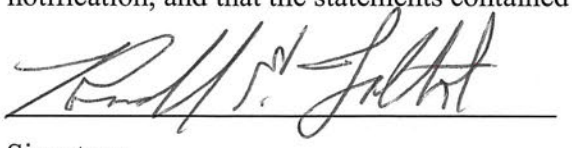
[ ] Rescind the current notice to SuspendThe facility is further described as follows:

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

Contact Information

Title: SVP Electric Operations

Email: rtalbot@nisource.com

Date: 1/20/23

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

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

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

August 16, 2022

Submitted via email

Mr. Michael Regan, Administrator US EPA
1200 Pennsylvania Avenue, N.W.
Mail Code 5304-P
Washington, D.C. 20460

Re: Northern Indiana Public Service Company LLC
RM Schahfer Generating Station, Wheatfield, IN
Demonstration – Addendum 2, Pursuant to 40 CFR Part 257.103(f)(2)

Dear Administrator Regan:

Northern Indiana Public Service Company LLC (NIPSCO LLC) is providing the enclosed *Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of Coal-Fired Boilers by a Date Certain* Addendum 2 (Demonstration Addendum 2) for approval by the United States Environmental Protection Agency (US EPA). Approval of NIPSCO LLC's 257.103(f)(2) Demonstration by the US EPA will allow NIPSCO LLC to continue use of the Waste Disposal Area ash pond (WDA) in operation at the RM Schahfer Generating Station located in Wheatfield, IN (RMSGS, Site), after April 11, 20221. This approximately 80-acre pond will complete closure no later than October 17, 2028, as provided in the enclosed Demonstration Addendum #2.

This Demonstration Addendum 2, provides a new date of permanent cessation of coal-fired boilers at the RMSGS and NIPSCO's continued commitment to cease operation and complete closure the WDA no later than October 17, 2028, as stipulated in 257.103(f)(2)(iv)(B). Furthermore, to meet the requirements of 40 CFR § 257.103(f)(2), Demonstration Addendum 2 supplies information updated since November 2020 (i.e., the date Demonstration Addendum 1 was prepared) with respect to groundwater monitoring and corrective action activities at RMSGS.

As explained and justified herein, cessation of coal-fired generation at RMSGS will now be December 31, 2025, providing nearly three years to a) complete boiler shutdown processes, some of which are expected to generate significant volumes of CCR and non-CCR waste streams, b) reduce and/or eliminate other ongoing influent streams, c) optimize the closure plan and gain regulatory agency approval for the WDA closure approach, and d) complete closure construction. Following cease receipt

of WDA waste streams (Q2 2026), NIPSCO estimates a timeframe of approximately two and a half years to achieve final closure of the WDA including the professional engineer's certification, thereby achieving final closure by September 17, 2028, and meeting the 40 CFR § 257.103(f)(2) deadline of October 17, 2028.

This Demonstration Addendum 2 in combination with Demonstration (Golder, October 2020) and Demonstration Addendum 1 (Golder, November 2020) meet the requirements of 40 CFR § 257.103(f)(2).

Following US EPA guidance, the enclosed Demonstration Addendum 2 was submitted via email to Richard Huggins, Frank Behan, Kirsten Hillyer and Lydia Anderson. I may be contacted at (219) 680-8628 or mturman@nisource.com with questions or comments.

Sincerely,

Maureen Turman

Maureen Turman
NiSource Director Environmental Policy and Sustainability

Enclosure

CC: Richard Huggins, US EPA
Frank Behan, US EPA
Kirsten Hillyer, US EPA
Lydia Anderson, USEPA