Appendix A1: Materials Shared with Small Entity Representatives for the Pre-Panel Outreach Meeting held on December 14, 2022

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Agenda

EPA's SBAR Pre-Panel Outreach Meeting with Small Entity Representatives on Proposed Amendments to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

December 14, 2022, 1:00pm-3:30pm, Eastern time zone

Agenda

1:00 Welcome and Opening Remarks

- Bill Nickerson (EPA Small Business Advocacy Chair (SBAC) / Office of Policy)
- Penny Lassiter (Director, Sector Policy and Programs Division, EPA Office of Air and Radiation)
- David Rostker (Small Business Administration, Office of Advocacy)
- Sofie Miller (Office of Management and Budget, Office of Information and Regulatory Affairs)

1:15 SER Introductions

1:25 Presentation on Panel process (Bill Nickerson, EPA SBAC)

1:35 Presentation on Proposed Amendments to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (Office of Air Quality Planning and Standards)

2:05 Discussion Proposed Amendments to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

2:40 Break

2:50 Discussion (continued)

3:15 Closing session

- Closing remarks from EPA, SBA, and OMB
- Wrap up and next steps (what to expect next)

3:30 Adjourn

Panel Process Presentation

An Overview of the Small Business Advocacy Review (SBAR) Panel Process

December 2022

Office of the Administrator
Office of Policy
Office of Regulatory Policy and Management

Why does EPA convene an SBAR Panel?

The Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), requires agencies to:

“assure that small entities have been given an **opportunity to participate** in the rulemaking process” for any rule “which will have a **significant economic impact** on a substantial number of small entities.”

What is an SBAR Panel?

An EPA Small Business Advocacy Review (SBAR) Panel is made up of **four** managers from **three** federal agencies:

- EPA's Small Business Advocacy **Chair** (EPA's SBAC is from OP)
- A **manager** from the EPA program responsible for writing the rule

- The Small Business Administration's **Chief Counsel** for Advocacy

- The **Administrator** of the Office of Management and Budget's (OMB's) Office of Information and Regulatory Affairs (OIRA)

What does an SBAR Panel do?

The RFA tasks the Panel with **reviewing the material** the Agency has available concerning the rulemaking, and **collecting advice and recommendations** from small entity representatives (SERs) on issues related to the following **four** elements:

- Who are the small entities to which the proposed rule will apply?
- What are the anticipated compliance requirements of the upcoming proposed rule?
- Are there any existing federal rules that may overlap or conflict with the regulation?
- Are there any significant regulatory alternatives that could minimize the impact on small entities?

SERs Participation in the Pre-panel and Panel process

SERs are invited to 2 meetings: Pre-panel Outreach meeting and Panel Outreach meeting

- At each meeting, SERs participate in the discussion about how the rule might impact them and provide suggestions about how to minimize that impact.
- Panel Outreach meeting will focus on further refining SER advice and recommendations from the Pre-panel Outreach

SERs are invited to supplement the verbal meeting discussions with **written comments** (due 2 weeks after each meeting)

SER FAQ webpage https://www.epa.gov/reg-flex/frequent-questions-small-entities.

Where does the Panel process fit within the rulemaking process?

EPA's Pre-Panel Outreach Meeting with SERs → Panel Outreach Meeting with SERs → Panel Report to EPA's Administrator → Notice of Proposed Rulemaking → Public Comment Period → Final Rule

It is EPA's goal to host SBAR Panels well **before a proposed rule** is written so there is adequate time to incorporate Panel recommendations into senior management decision-making about the proposed rule

SER participation in the Pre-panel and Panel Outreach meetings **does not preclude** or take the place of participation in the normal public comment period at the time the rule is proposed

What does the Panel do with the information, advice, and recommendations from SERs?

The Panel prepares a Panel Report

- SER comments are **summarized**, and written comments are included as an appendix
- SER information, advice, and recommendations are **synthesized** into a set of Panel recommendations
- **Submitted** to the EPA Administrator
- Considered during senior-management decision-making **prior** to the issuance of the proposed rule
- Placed in the **rule's docket** when the proposed rule is published

Thank You

We realize that small entities make significant sacrifices to participate in this process

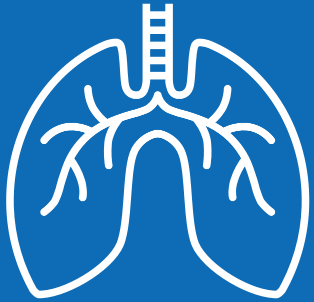
Thank you for taking time and effort away from your business or organization to assist the Panel in this important work

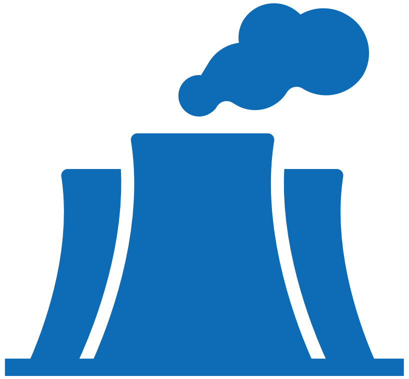
Contact Information for SBAC Staff

Lanelle Wiggins, RFA/SBREFA Team Leader
EPA Office of Policy
202-566-2372
wiggins.lanelle@epa.gov

Todd Coleman, RFA/SBREFA Team
EPA Office of Policy
202-564-1208
coleman.todd@epa.gov

Pre-Panel Rulemaking Presentation





Proposed Amendments to the New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

Office of Air and Radiation

SMALL ENTITY REPRESENTATIVE PRE-PANEL OUTREACH

DECEMBER 14, 2022

Today's Presentation

- Background
- Scope of the 2023 Proposal
- Other Federal Regulations
- Significant Alternatives
- Next Steps
- Contact Information

Background

Consultation with Small Entity Representatives

- EPA is interested not only in information, but also in advice and recommendations from the small entity representatives (SERs)
- This information will be used to develop a regulatory flexibility analysis, which becomes part of the record for the potential regulation
- Input requested:
  - Number of small entities potentially subject to the proposed amendments
  - Potential reporting, recordkeeping, and other compliance requirements of the proposed amendments
  - Identification of other relevant federal rules that may duplicate, overlap, or conflict with the proposed amendments
  - Any flexibilities or alternatives to the potential rule that accomplish the stated objectives and minimize significant economic impact of the proposed amendments on small entities
- Please refer to the Appendix for a list of questions

SERs and the Regulatory Process

- Seeking information on how the options presented might affect your business or organization
  - Provide specific examples of impacts
  - Provide cost data, if available
- Seeking input on regulatory alternatives that accomplish the objectives of the Clean Air Act (CAA)
  - Suggest other relevant control strategies, including data on their costs, effectiveness, and information on how to ensure compliance
  - Regulatory Flexibility Act (RFA) suggests flexibilities, such as exemptions, different compliance timetables, and simplified reporting requirements
- Effort to minimize duplication
  - Provide information on any potentially duplicative or contradictory federal, state, or local regulations

Power Sector Overview

Power Sector Overview

The U.S. power sector has been in transition since approximately 2005

Coal-fired electric generation has **decreased** from ~51% to ~20% of total

Natural gas-fired electric generation has **increased** 22%

- Includes stationary combustion turbines operating as base load electric generating units (EGUs) and as on-demand non-base load EGUs, supporting the grid during peak demand

Electric generation from renewables has **increased** ~11%

Electric Power Generation by Fuel Type

Fuel Type	1990	2005	2016	2017	2018	2019	2020
Coal	54.1%	51.1%	31.4%	30.9%	28.4%	24.2%	19.9%
Natural Gas	10.7%	17.5%	32.7%	30.9%	34.0%	37.3%	39.5%
Nuclear	19.9%	20.0%	20.6%	20.8%	20.1%	20.4%	20.5%
Renewables	11.3%	8.3%	14.7%	16.8%	16.8%	17.6%	19.5%
Petroleum	4.1%	3.0%	0.6%	0.5%	0.6%	0.4%	0.4%
Other Gases[a]	+%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Net Electricity Generation (Billion kWh)[b]	*2,905*	*3,902*	*3,917*	*3,877*	*4,017*	*3,963*	*3,849*

+ Does not exceed 0.05 percent.

(a) Other gases include blast furnace gas, propane, and other manufactured and waste gases derived from fossil fuels.
(b) Represents net electricity generation from the power sector. Excludes commercial and industrial CHP generation.

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Recent Legislation

- **Bipartisan Infrastructure Law (BIL)** provides for significant investments in infrastructure and programs
- **Inflation Reduction Act (IRA)** provides for significant investments in clean energy technologies and supporting infrastructure
- Specific funds to potentially support addressing GHG emission reductions from EGUs include:

Significant tax credits benefitting technologies such as clean hydrogen and carbon capture, utilization, and storage	Department of Energy loan guarantee programs to provide a backstop for financing of pollution control equipment
U.S. Department of Agriculture programs to finance clean energy technologies with rural coops	EPA programs to capitalize private green banks and fund state-led greenhouse gas reduction plans

A1-22

GHG NSPS under CAA 111(b)

NEW, MODIFIED, AND RECONSTRUCTED SOURCES

CAA Section 111(b)

- For source categories that **cause or contribute significantly** to air pollution which may reasonably be anticipated to **endanger public health or welfare**, CAA section 111 requires EPA to establish standards of performance for new sources
- Standards must be set based on what is achievable through the application of the **best system of emission reduction (BSER)**
  - Cost (must not be "exorbitant," "greater than the industry can bear," or "unreasonable")
  - Non-air quality health and environmental impacts
  - Energy requirements
  - Control measures that have been adequately demonstrated

Regulatory History – GHG NSPS

2015: GHG NSPS set standards to limit carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating units (EGUs)

- 40 CFR part 60, subpart TTTT
- Established standards for fossil-fired stationary combustion turbines (generally firing natural gas) and for fossil-fired electric utility steam generating units (generally firing coal)
- Applies to new units or existing units that meet conditions for being modified or reconstructed
- Reflects the degree of emission limitation achievable through the application of BSER that EPA determined has been adequately demonstrated for each type of unit
  - NSPS for newly constructed and reconstructed combustion turbines based on efficient generation and the use of clean fuels
  - NSPS for newly constructed fossil fuel-fired steam generating EGUs (*i.e.*, utility boilers and gasification units) based on the use of a supercritical pulverized coal boiler and partial carbon capture, utilization, and storage (CCUS)

Industry Sectors and Their Small Business Size Definitions

RFA 603(b)(3): a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply

- It is uncertain how many new sources will be built and whether the entities that own them will be small entities
- Number of new sources:
  - Under this uncertainty about new source numbers, we consider the number of similar sources built in recent years
  - Since 2017, approximately 201 units came online or are planned, based on data in EPA's National Electric Energy Data System (NEEDS) database, which is available on-line at: https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6
    - This estimate is from filtering the NEEDS v621 database by the following criteria:
      - Online year = 2017 or later;
      - Plant Type = Combined Cycle or Combustion Turbine; and
      - Capacity = 25 MW or greater

Industry Sectors and Their Small Business Size Definitions

- Entities owning sources
  - It is uncertain whether the entities that build new sources will be small entities
  - Some entities that own existing sources are small entities
  - Some entities that own existing sources have NAICS codes specific to the Electric Power sector
    - NAICS codes in the Electric Power sector have size standards that range between 250 employees and 1,000 employees, depending upon the NAICS code
    - For example, NAICS 221112 *Fossil Fuel Electric Power Generation*, has a size standard of 750 employees
  - Some entities that own existing sources have NAICS codes unrelated to the Electric Power sector
    - These companies can have differing size standards, based either on number of employees or on annual receipts (in millions of dollars)

Scope of the 2023 Proposal

2023 Proposal

RFA 603(b)(4): a description of the projected reporting, recordkeeping and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record

- The proposal will include amendments to the new source performance standards for greenhouse gas emissions from stationary combustion turbine electric generating units
- While EPA may issue proposals for both new and existing sources, this Panel is focused only on the NSPS because it directly regulates small entities, while the proposed emission guidelines will only provide requirements to states

Stationary Combustion Turbines, Generally Natural Gas

Current Subcategorization

- Natural gas-fired base load combustion turbine
  - Combusts more than 90% natural gas, and
  - Supplies more than the site-specific electric sales threshold to the electric grid
    - Electric sales threshold is determined based on the design efficiency of the EGU
- Non-base load and non-natural gas-fired combustion turbines
  - Combustion turbines not meeting the natural gas-fired base load applicability criteria

Current Requirements

- New and Reconstructed
  - Natural gas-fired base load emissions standard (applies to all sizes): 1,000 pounds carbon dioxide per megawatt-hour on a gross-output basis
  - Non-base load: clean fuels input-based standard
- Modified
  - Did not set a standard

Applicability Dates

- Any stationary combustion turbine that commenced construction after January 8, 2014, or commenced reconstruction after June 18, 2014, and meets applicability requirements, is currently subject to 40 CFR part 60, subpart TTTT
- Any stationary combustion turbine that commences construction after the date of the proposed amendments, and that meets the applicability requirements would be subject to the amended requirements in 40 CFR part 60, subpart TTTT

Combustion Turbines Potential Applicability Considerations

- Current subcategorization for natural gas-fired combustion turbines is determined by electric sales (*i.e.*, capacity factor)
  - Distinction between base load and non-base load combustion turbines is a site-specific electric sales threshold which is based on the design efficiency of the EGU

Current Subpart TTTT Subcategorization	Considerations
Non-base load • Simple cycle EGUs < ~ 39-49% of potential electric sales • Combined cycle EGUs < ~55% of potential electric sales	• The vast majority of simple cycle EGUs are operating well below electric sales threshold • There are significant differences in the emission rates of intermediate load EGUs
Base Load • Electric sales greater than the site-specific electric sales threshold	• Combined cycle EGUs have demonstrated the ability to maintain efficiency at capacity factors of less than 55%

Draft White Paper

Spring 2022 - EPA released a draft white paper on GHG control technologies for combustion turbines, including efficient combustion, carbon capture, utilization, and storage, and hydrogen

Link to draft white paper: https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf

Combustion Turbines Potential Control Strategies and Costs

Clean Fuels

- Current input-based standards for non-base load stationary combustion turbines are based on the use of clean fuels (*e.g.*, natural gas and fuel oil)
- Low/no cost
- In the current rulemaking, EPA is considering maintaining a clean fuels input-based standard for non-base load stationary combustion turbines
  - The current clean fuels standard is primarily applicable to subcategories where it is challenging to establish an output-based standard

Combustion Turbines Potential Control Strategies and Costs

Efficient Generation

- Similarly sized combustion turbines have a range of design efficiencies
- Examples of additional efficient generation practices that can be applied in the bottoming cycle (heat recovery steam generator) portion of a combined cycle EGU to improve the overall efficiency:
  - Use of triple pressure with reheat
    - Currently only used in larger combined cycle EGUs
  - Use of supercritical steam conditions (instead of subcritical steam conditions)
    - Smallest supercritical steam turbines are ~200 MW
  - Supercritical carbon dioxide to replace the use of steam
    - Demonstrated at a compressor station in Alberta, Canada
- Any additional capital and maintenance costs of more efficient operation are generally recovered through reduced fuel costs

Combustion Turbines Potential Control Strategies and Costs

Co-firing Hydrogen

- Majority of new combustion turbines can co-fire some amount of hydrogen without modifications to the combustion system
- Multiple projects are demonstrating hydrogen co-firing and intend to increase co-firing levels as additional supply of "clean" hydrogen is available at reasonable costs
- Costs:
  - One of the Department of Energy's Hydrogen Shot goals is to reduce the cost of low-GHG hydrogen to $2 per kilogram by 2026 and $1 per kilogram by 2030
  - At a cost of $1/kg ($7.4/MMBtu) and a co-firing rate of 30% (by volume), hydrogen co-firing increases annual expenses by 10%; the avoided cost of CO_2 is approximately $80 per tonne

Combustion Turbines Potential Control Strategies and Costs

Carbon Capture, Utilization, and Storage (CCUS)

- Carbon capture systems can capture greater than 90% CO_2
- New and novel systems – such as NET Power – have been demonstrated and are moving to commercial operations
- Post-combustion CCUS derates a combined cycle EGU by 10%, increases the capital costs of a combined cycle EGU by 130%, and increases other operating costs by 60%
- Revenue from tax subsidies for sequestration can offset these capital costs and increases in operating costs

Reporting and Recordkeeping
(Current Requirements)

Reporting

- Quarterly electronic reports
- Subject to Acid Rain Program → Follow requirements under part 75, subpart G
- Not Subject to Acid Rain Program → Follow requirements under part 75, subpart G
- Capture CO_2 – follow requirements in part 98, subpart PP or subpart RR

Recordkeeping

- Subject to Acid Rain Program → Follow requirements under part 75, subpart F
- Not Subject to Acid Rain Program → Follow requirements under part 75, subpart F; at a minimum must keep records of:
  - Monitoring plan,
  - Operating parameters,
  - Stack gas volumetric flow rate,
  - Continuous moisture monitoring systems,
  - CO_2 concentration monitor systems or O_2 monitors used to calculate CO_2 concentration,
  - Oil flow meters,
  - Gas flow meters,
  - Continuous Emission Monitoring System (CEMS) and fuel flow meters quality-assurance, and
  - Data acquisition and handling system verification
- Applicable data recorded and calculations performed

Reporting and Recordkeeping

- Small entities subject to GHG NSPS are also subject to reporting and recordkeeping requirements
- Preparers of sources already subject to the reporting and recordkeeping requirements in part 75 would have minimal training requirements
  - Preparers for sources not already subject to reporting and recordkeeping requirements in part 75 would need to register and become familiar with the Emissions Collection and Monitoring Plan System (ECMPS)
    - Affected EGUs outside the contiguous United States may not already be subject to part 75
  - Instructions for ECMPS are available at:
    - https://www.epa.gov/airmarkets/reporting-data-using-ecmps and
    - https://www.epa.gov/airmarkets/ecmps-reporting-instructions
- We do not anticipate significant revisions to the reporting and recordkeeping requirements

Other Compliance Requirements
(Current Requirements)

- Determine monthly average CO_2 emissions so that 12-operating-month rolling average can be obtained
- Operate and maintain each affected EGU, including associated equipment and monitors, in manner consistent with safety and good air pollution control practice at all times
- Maintain fuel use records and CO_2 emissions measurements
  - CO_2 CEMS (Alternative = Certified O_2 monitor)
  - Flow monitoring system, continuous moisture monitoring system (if measure CO_2 on dry basis)
  - May also determine hourly heat input rates and CO_2 emissions using prescribed methods
- Output basis standard
  - Watt meters to continuously measure and record hourly gross electric output or net electric output
  - For combined heat and power, continuously determine and record total useful thermal output
  - For process steam applications, continuously determine and record hourly steam flow rate, temperature, and pressure
- Heat-input basis standard
  - Determine total heat input using prescribed procedures

Other Compliance Requirements

- Small entities subject to GHG NSPS are also subject to compliance requirements
- Potential revisions to compliance requirements include:
  - Alternatives to sequestering captured CO_2 according to requirements in part 98, subpart RR
  - Procedures to determine useful thermal output

Other Federal Regulations

Other Federal Regulations

RFA 603(b)(5): an identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the proposed rule

- Other federal agencies have regulations that impact the power sector, but we have not identified any overlap or conflict with GHG NSPS
  - Department of Energy
  - Federal Energy Regulatory Commission

Significant Alternatives

Significant Alternatives

RFA 603(c): Each initial regulatory flexibility analysis shall also contain a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities. Consistent with the stated objectives of applicable statutes, the analysis shall discuss significant alternatives such as —

(1) the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;

(2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;

(3) the use of performance rather than design standards; and

(4) an exemption from coverage of the rule, or any part thereof, for such small entities.

Significant Alternatives

- Differing compliance or reporting requirements or timetables
  - The compliance and reporting requirements are aligned with part 75
  - Potential for subcategorization
    - EPA may distinguish (subcategorize) among classes, types, and sizes within categories of new sources
- Clarification, consolidation, or simplification of compliance and reporting requirements
  - The compliance and reporting requirements are aligned with part 75
- Use of performance rather than design standards
  - Subpart TTTT currently includes performance standards and not design standards
- Exemption from coverage of the rule, or any part thereof
  - The applicability of subpart TTTT currently includes an exemption for combined heat and power EGUs
    - It is easier for smaller EGUs to find thermal hosts and qualify for the exemption

Next Steps

Input Requested

- We would like to your input on:
  - Reporting and recordkeeping
  - Other compliance requirements
  - Other Federal regulations
  - Small business flexibilities
- Please refer to the Appendix for a list of questions

How to comment

- Please provide specific data, costs, and actionable information on your experience with GHG NSPS or these control technologies
  - Remember, you are the expert in your business!

❖ Send comments to Todd Coleman, coleman.todd@epa.gov

❖ Please send an email before submitting Confidential Business Information (CBI)

Preliminary Schedule

Milestone	Date
Convene SBAR Panel	January 2023
Panel Meeting	January 2023
Complete SBAR Panel	March 2023
Proposal Signature	Spring 2023

Contact Information

For More Information

Regulatory Questions

EPA Office of Air and Radiation
Email: PowerSectorGHG@epa.gov

SBAR Panel Questions

Todd Coleman
EPA Office of Policy
coleman.todd@epa.gov

202 564 1208

Link to Regulatory Website

https://www.epa.gov/stationary-sources-air-pollution/nsps-ghg-emissions-new-modified-and-reconstructed-electric-utility

Questions for Small Entity Representatives

Pre-Panel Outreach Small Entity Representative (SER) Questions for Discussion on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

The input and feedback EPA receives will be used to inform the Small Business Advocacy Review (SBAR) Panel Outreach meeting materials. The input will also be used to inform proposed amendments to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (EGU GHG NSPS).

For rules that may have a significant economic impact on a substantial number of small entities, the Regulatory Flexibility Act (RFA) requires agencies to evaluate regulatory alternatives that may minimize the burden on small entities expected to be regulated. The RFA notes that the regulatory alternatives must be consistent with the stated objectives of applicable statutes (i.e., the Clean Air Act (CAA)), and suggests significant alternatives such as:

- the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;
- the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;
- the use of performance rather than design standards; and
- an exemption from coverage of the rule, or any part thereof, for such small entities.

To that end, these informal questions on your work practices and your experiences with electric generating units (EGUs) are aimed at guiding our discussion today, and your later written feedback, towards ideas for minimizing the economic impact on your business while remaining within the constraints of the CAA. We are not seeking a structured response on each question; rather, we are interested in any feedback or details you can provide, and hope that these questions let you know what type of information would be most useful as we consider advice from the small entity representatives concerning this proposed action.

If you are interested in providing this or other information in writing, please see the contact information below.

We ask that you refrain from providing Confidential Business information (CBI) during the discussion or in email to EPA. If you choose to provide CBI, we will provide special instructions.

Contact Information:

Todd Coleman
Office of Regulatory Policy and Management
Office of Policy
Phone: (202) 564-1208
E-mail: coleman.todd@epa.gov

Overarching Topics

1. How do you anticipate any proposed amendments to the NSPS would affect your business? For example, would it impact the service you provide or perhaps require the hiring of additional staff?
2. Is there any information that would improve EPA's understanding of the number of small entities that may be affected by this proposed action?
3. What recommendations do you have for small business flexibilities that may reduce burden? In what way can these flexibilities be structured to better aid small entities in reducing potential burdens? Are there any specific flexibilities that would help your business?
4. What are the characteristics of a small business in your industry that make it different from a large business?
5. Do you anticipate any significant issues or circumstances not addressed in the materials provided?
6. Do you have any other feedback for EPA related to EGU GHG NSPS?

Reporting and Recordkeeping

1. What recommendations do you have for reducing the recordkeeping and reporting burden on small businesses?
2. Subpart TTTT currently has a 95 percent minimum data availability requirement. Some rules, like those in part 75, include provisions to be used when primary regulatory monitoring is unavailable or not properly operating. Should this rule include such provisions as an alternative to having periods of missing data and/or increase the minimum data availability?
   a. If so, what might be options for gap-filling that would serve to reduce those periods of missing data – redundant monitors, or higher than expected gap-filling values, operational shutdown until primary monitors online after a time period for gap-filling exceeded, or other?

Other Compliance Requirements

1. To determine the design efficiency of an EGU, subpart TTTT currently includes ASME PTC 22 Gas, ASME PTC 46 Overall Plant Performance, and ISO 2314 Gas turbines. Should the Agency consider other methods and/or specifically allow that operating data can be used to determine the design efficiency of existing EGUs (to determine the applicability for the existing source requirements)?
2. Subpart TTTT currently requires the use of calibration procedures in ANSI Standards No. C12.20 for measuring electrical output. Should the Agency consider alternate methods?
3. Subpart TTTT does not currently specify requirements for monitoring useful thermal output. What are practical, cost-effective ways to determine useful thermal output on an ongoing basis?
4. Is there an interest in using hydrogen (produced using a low-GHG technology), biomethane, and other types of non-conventional fuels as strategies to reduce GHG emissions?
   a. If so, how can low-GHG fuel use be differentiated, verified, monitored, and reported?
5. What are practical ways of measuring, monitoring, reporting, and verifying carbon dioxide sequestration or use in enhanced oil recovery?

6. What alternatives to existing quality assurance and quality control approaches exist for ensuring data can be collected properly, both initially and on an ongoing basis?
7. Do you anticipate any unique legal, administrative, or recordkeeping burdens associated with compliance with the proposed action?

Other Federal Regulations

1. Are there regulations from other federal agencies that apply to small entities that may overlap with this EPA action? Do you have suggestions on how to minimize conflicting requirements?

Power Sector

1. EPA's regulations will be proposed and finalized in the context of transition within the power sector, which makes it important to ensure that any regulatory approach captures the most current information about investment decisions in the sector. Are there any significant recent announcements or commitments to transitioning generation of which the Agency should be aware?
2. How does passage of the Inflation Reduction Act impact investments in the transitioning power sector?
3. How would an amended NSPS impact investments and new projects? For example, would they impact the selection of a particular combustion turbine design (*e.g.*, combined cycle or simple cycle) or the potential generating capacity of a new EGU?
4. Are there any sector-unique business or competitive issues that EPA should understand? Are there any specific business or competitive issues associated with your business?

Subcategory

1. Into which subcategory of the current NSPS are your affected EGUs classified (e.g., base load or non-base load)?
    a. Are there other potential subcategories that would be more appropriate for new EGUs? If so, please identify and document the basis for the recommendation.
2. What electric sales threshold (*i.e.*, capacity factor) is appropriate for simple cycle turbines intended to maintain grid reliability (*e.g.*, provide power during periods of peak electric demand)?
3. How can the Agency recognize the environmental benefit of intermediate load EGUs with lower emission rates?
4. At what annual capacity factor does the emission rate of combined cycle EGUs begin to increase?
5. At what annual capacity factor would you install a new combined cycle combustion turbine instead of a simple cycle combustion turbine?
6. How do you intend to use new simple cycle combustion turbines – peaking or intermediate load (max capacity factor)?
7. What types of simple cycle turbines are you considering – frame or aeroderivative?

Control Strategies

1. In Spring 2022, EPA released a draft informational white paper, titled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*. The white paper discussed the potential to mitigate GHG emissions with technologies such as efficient combustion; carbon capture, utilization, and storage (CCUS); and hydrogen (Link to draft white paper: https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf). What are your thoughts regarding how EPA should consider those technologies as the Agency develops amendments to the NSPS? Are there other technologies and/or factors EPA should consider?
2. What can you tell the Agency about the control strategies costs and emissions reduction effectiveness? Are there any other technical considerations EPA should be aware of?
3. Are the potential control strategies technically feasible for your facilities? Are they economically feasible for small entities? Would the potential control strategies increase labor costs? Do they impose more of a disadvantage to small entities than larger ones? If so, what type of control strategies might be more feasible for small businesses?

Appendix A2: Materials Shared with Small Entity Representatives for the Panel Outreach Meeting held on August 10, 2023

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Rulemaking Presentation A2-4

Agenda

Small Business Advocacy Review Panel Outreach Meeting with Small Entity Representatives on EPA's Proposed Amendments to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

August 10, 2023 -- 1:00pm-3:00pm (Eastern)

Agenda

1:00 Welcome and Opening Remarks

- Bill Nickerson (EPA Small Business Advocacy Chair (SBAC) / Office of Policy (OP))
- Penny Lassiter (Director, Sector Policy and Programs Division, EPA Office of Air and Radiation (OAQPS))
- David Rostker (Small Business Administration (SBA), Office of Advocacy)
- Sofie Miller (Office of Management and Budget (OMB), Office of Information and Regulatory Affairs)

1:15 SER Introductions

1:25 Presentation on Proposed Rule (OAQPS)

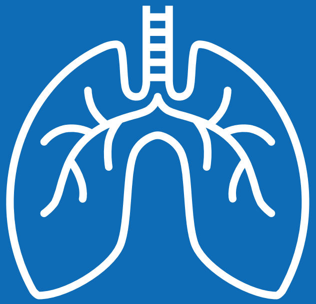
1:55 Discussion

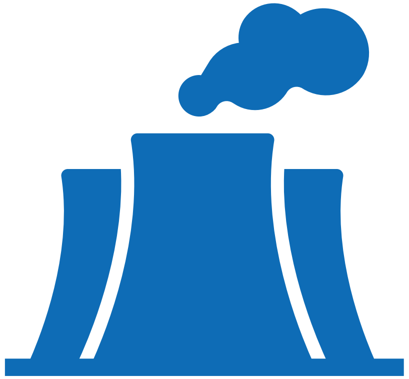
2:50 Closing Session

- Closing remarks from EPA, SBA, and OMB
- Wrap-up and next steps

3:00 Adjourn

Rulemaking Presentation





New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Proposed Rule

Office of Air and Radiation

SMALL ENTITY REPRESENTATIVE PANEL OUTREACH

AUGUST 10, 2023

Background

Consultation with Small Entity Representatives

- EPA is interested not only in information, but also in advice and recommendations from the small entity representatives (SERs)
- This information will be used to develop a regulatory flexibility analysis, which becomes part of the record for the potential regulation
- Input requested:
  - Number of small entities potentially subject to the potential rule
  - Potential reporting, recordkeeping, and other compliance requirements of the potential rule
  - Identification of other relevant federal rules that may duplicate, overlap, or conflict with the potential rule
  - Any flexibilities or alternatives to the potential rule that accomplish the stated objectives and minimize significant economic impact of the potential rule on small entities

SERs and the Regulatory Process

- Pre-panel outreach meeting was held on December 14, 2022
- Issues noted by SERS following the pre-panel outreach meeting included:
  - Maintaining grid reliability
  - Including optional compliance flexibilities such as rate-based or mass limits and emissions averaging
  - Subcategorizing units by capacity factor
  - Concerns with co-firing hydrogen and CCUS not being adequately demonstrated technologies
  - Considering tax credits when assessing cost reasonableness
- EPA worked to address these concerns in developing the proposed rule

How is this Panel process unique?

- Most SBAR Panels are conducted **prior to** publication of the NPRM for rules that may have a significant economic impact on a substantial number of small entities (SISNOSE)
- Given the data EPA had at the time of the NPRM publication, EPA certified the rule as not having a SISNOSE
- The rule as proposed in May 2023 includes information and options that indicate a potential for inability to meet the criteria for no SISNOSE
- Therefore, EPA may have to prepare a final regulatory flexibility analysis, so we convening this SBAR Panel **after** the NPRM published
- EPA will comply with all requirements of the RFA including:
  - Convening the Panel
  - Consulting with SERs
  - Panel Report
  - Publishing an Initial Regulatory Flexibility Analysis for public comment
- EPA plans to publish for notice and comment the regulatory flexibilities considered in the IRFA, and consider whether to finalize them in the final rule stage

Power Sector Overview

The U.S. power sector has been in transition since approximately 2005

Coal-fired electric generation has **decreased** from ~51% to ~20% of total share

Total share of natural gas-fired electric generation has **increased** 22%

- Includes stationary combustion turbines operating as base load electric generating units (EGUs) and as on-demand non-base load EGUs, supporting the grid during peak demand

Total share of electric generation from renewables has **increased** ~11%

Electric Power Generation by Fuel Type

Fuel Type	1990	2005	2016	2017	2018	2019	2020
Coal	54.1%	51.1%	31.4%	30.9%	28.4%	24.2%	19.9%
Natural Gas	10.7%	17.5%	32.7%	30.9%	34.0%	37.3%	39.5%
Nuclear	19.9%	20.0%	20.6%	20.8%	20.1%	20.4%	20.5%
Renewables	11.3%	8.3%	14.7%	16.8%	16.8%	17.6%	19.5%
Petroleum	4.1%	3.0%	0.6%	0.5%	0.6%	0.4%	0.4%
Other Gases[a]	+%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Net Electricity Generation (Billion kWh)[b]	*2,905*	*3,902*	*3,917*	*3,877*	*4,017*	*3,963*	*3,849*

+ Does not exceed 0.05 percent.

(a) Other gases include blast furnace gas, propane, and other manufactured and waste gases derived from fossil fuels.
(b) Represents net electricity generation from the power sector. Excludes commercial and industrial CHP generation.

Recent Legislation

- **Bipartisan Infrastructure Law (BIL)** provides for significant investments in infrastructure and programs
- **Inflation Reduction Act (IRA)** provides for significant investments in clean energy technologies and supporting infrastructure
- Specific funds to potentially support addressing GHG emission reductions from EGUs include:

Significant tax credits benefitting technologies such as clean hydrogen and carbon capture, utilization, and storage	Department of Energy loan guarantee programs to provide a backstop for financing of pollution control equipment
U.S. Department of Agriculture programs to finance clean energy technologies with rural coops	EPA programs to capitalize private green banks and fund state-led greenhouse gas reduction plans

GHG NSPS under CAA 111(b)

NEW, MODIFIED, AND RECONSTRUCTED SOURCES

Regulatory History – GHG NSPS

2015: GHG NSPS set standards to limit carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating units (EGUs)

- 40 CFR part 60, subpart TTTT
- Established standards for fossil-fired stationary combustion turbines (generally firing natural gas) and for fossil-fired electric utility steam generating units (generally firing coal)
- Applies to new units or existing units that meet conditions for being modified or reconstructed
- Reflects the degree of emission limitation achievable through the application of BSER that EPA determined has been adequately demonstrated for each type of unit
  - NSPS for newly constructed and reconstructed combustion turbines based on efficient generation and the use of clean fuels
  - NSPS for newly constructed fossil fuel-fired steam generating EGUs (*i.e.*, utility boilers and gasification units) based on the use of a supercritical pulverized coal boiler and partial carbon capture, utilization, and storage (CCUS)

2023 Proposal

RFA 603(b)(4): a description of the projected reporting, recordkeeping and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record

- EPA proposed revised new source performance standards for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs and for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification
- While EPA issued proposals for both new and existing sources, this Panel is focused only on the 111(b) NSPS because it directly regulates small entities, while the proposed emission guidelines will only provide requirements to states

CAA Section 111(b)

- For source categories that **cause or contribute significantly** to air pollution which may reasonably be anticipated to **endanger public health or welfare**, CAA section 111 requires EPA to establish standards of performance for new sources
- Standards must be set based on what is achievable through the application of the **best system of emission reduction (BSER)**
  - Cost (must not be "exorbitant," "greater than the industry can bear," or "unreasonable")
  - Non-air quality health and environmental impacts
  - Energy requirements
  - Control measures that have been adequately demonstrated

NSPS – Stationary Combustion Turbines

Proposing to update and establish more protective NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs that are based on highly efficient generating practices in addition to CCS or co-firing low-GHG hydrogen.

- **Applicability:** facilities that commence construction or reconstruction after May 23, 2023 (the date the proposal published in the Federal Register)

Three general subcategories of stationary combustion turbines

- Low load “peaking” combustion turbines
- Intermediate load combustion turbines
- Base load combustion turbines

For each subcategory, EPA is proposing a distinct “best system of emission reduction” (BSER) and standard of performance based on its evaluation of the feasibility, emissions reductions, and cost-reasonableness of available controls.

NSPS – Stationary Combustion Turbines

Low load "peaking" combustion turbines BSER and standards:

BSER: lower emitting fuels (*e.g.*, natural gas, distillate oil)

Standards of performance: 120 – 160 pounds of carbon dioxide per one million British thermal units (lb CO_2/MMBtu (depending on the fuel used)

Intermediate load combustion turbines:

BSER has two components to be implemented in 2 phases:

- 1st component of BSER: Highly efficient generation
- 2nd component of BSER: Co-firing 30% (by volume) low-GHG hydrogen

Phases:

- **1st phase standards**: 1,150 lb CO_2 /MWh-gross—based on performance of a highly efficient natural gas-fired simple cycle turbine
- **2nd phase standards**: 1,000 lb CO_2 /MWh-gross—based on performance of a highly efficient natural gas-fired simple cycle turbine co-firing 30% (by volume) low-GHG hydrogen beginning in 2032
- Standards would be higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2 /MMBtu basis

NSPS – Stationary Combustion Turbines

Base load combustion turbines:

Several components to be implemented in several phases:

- 1st component of BSER for all sources: Highly efficient generation
- 2nd component of BSER for sources on the CCS pathway: 90% carbon capture and storage (CCS) by 2035
- 2nd and 3rd components of BSER for sources on the low-GHG hydrogen pathway: co-firing 30% (by volume) low-GHG hydrogen by 2032 and 96% by 2038

Phases:

1st phase standards: 770 – 900 lb CO_2 /MWh-gross, depending on the base load rating—based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine.

2nd phase standards for base load units on the CCS pathway: 90 – 100 lb CO_2 /MWh-gross, depending on the base load rating—based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine implementing 90% CCS by 2035.

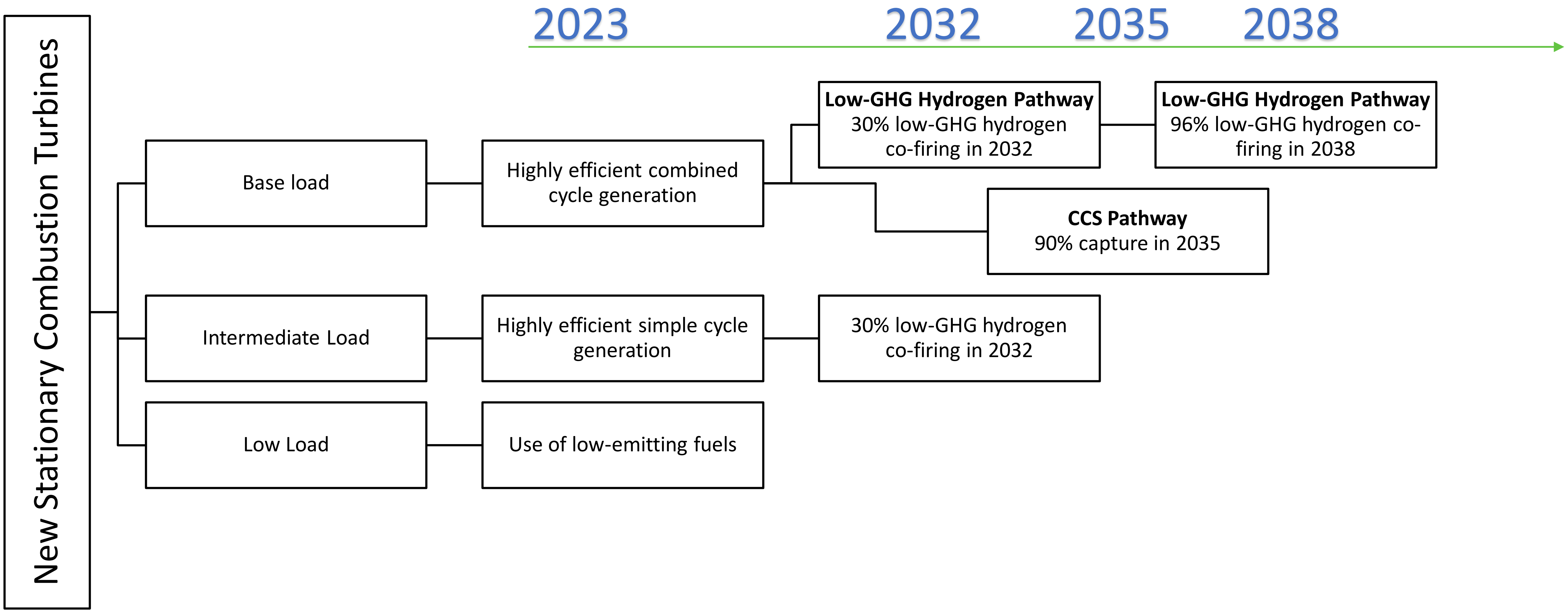
2nd phase standards for base load units on the low-GHG hydrogen pathway: 680 - 790 lb CO_2 /MWh-gross, depending on the base load rating—based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine co-firing 30% (by volume) low-GHG hydrogen by 2032.

3rd phase standards for base load units on the low-GHG hydrogen pathway: 90 – 100 lb/CO2/MWh-gross, depending on the base load rating—based on 96% (by volume) low-GHG hydrogen by 2038.

* Standards are higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2 /MMBtu basis.

Proposal for New Stationary Combustion Turbines

- Three subcategories: base load, intermediate load, low load
- Base load units have two pathways: 90% CCS in 2035 or 96% low-GHG hydrogen in 2038



Small Business Analysis

Industry Sectors and Their Small Business Size Definitions

RFA 603(b)(3): a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply

- This rule applies to owners and operators of fossil fuel-fired combustion turbines that commence construction or reconstruction after May 23, 2023, and fossil fuel-fired steam generating facilities that commence modification after May 23, 2023
- While it's uncertain how many new sources will be built and whether the entities that own them will be small entities, EPA relied on historical data to identify small entities that own the types of units that would be affected by this rulemaking
- We assume that the share of future builds built by small entities projected under compliance modeling remains consistent with the historical share and that the same entities that own units historically continue to do so going forward. We then apply a "cost-to-sales" test in order to determine if SISNOSE occurs
- Historical data used to determine number of new sources built, and the number built by small entities:
  - Since 2017, approximately 201 units came online or are planned, based on data in EPA's NEEDS database
  - EPA determined ownership information for these facilities based on data from Ventyx, S&P and publicly available data
    - Of the 52.8 GW of NGCC units built since 2017, 8% were built by seven small entities
    - Of the 7.2 GW of NGCT units built since 2017, 10% were built by four small entities

Projected Impact of the Proposed Rule on Small Entities in 2035

- EPA calculated the compliance costs for the projected capacity additions and compared these to the revenues for the affected small entities for 2035 (the year in which costs of the rule peak)
- EPA estimates NGCT additions and dispatch are higher as a result of reductions in existing coal-fired EGU capacity and generation. As a result, economic NGCT additions experience negative compliance costs in 2035
- EPA estimates economic NGCC additions dispatch at lower levels relative to the baseline when the second phase of the NSPS is active. As such, they experience positive compliance costs
- EPA did not find compliance costs exceeded 1% of revenues for any of the affected ultimate parent companies

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost ($2019 millions)	Number of Small Entities with Compliance Costs >=1% of Generation Revenues
Municipal	0	0	0
Private	6	11	0
Co-op	1	2	0
Total	**7**	**13**	**0**

- EPA estimated the annual net compliance cost to small entities to be approximately $13 million in 2035

Potential Impact of Final Rule on Small Entities

- While EPA certified no SISNOSE for the proposed NSPS, EPA solicited comment on:
  - A second component of the BSER of co-firing hydrogen for low-load combustion turbines
  - A lower first component of the BSER emissions standard for intermediate load combustion turbines
  - A second component and third component of the BSER for intermediate load combustion turbines based on a higher percentage of hydrogen co-firing
  - Separate BSER determinations for simple cycle and combined cycle intermediate load combustion turbines
  - Moving up the timing of the second component of the BSER for intermediate load combustion turbines
  - Lower the electric sales threshold for base load combustion turbines
- EPA estimated the average delivered natural gas price was $2.76/MMBtu in 2030 and $2.05/MMBtu in 2035, and estimated the delivered hydrogen price in phase two (starting in 2032) was $3.70/MMBtu
- Imposing additional hydrogen co-firing requirements on turbines, or imposing these requirements earlier, would likely result in higher dispatch costs (and lower revenues) to affected units, and could change the no SISNOSE finding

Compliance Requirements

Reporting and Recordkeeping

Reporting

- Quarterly electronic reports
- Follow requirements under part 75, subpart G
- Capture CO_2 – follow requirements in part 98, subpart PP or subpart RR

Recordkeeping

- Follow requirements under part 75, subpart F; including recordkeeping requirements which might include:
  - Monitoring plan,
  - Operating parameters,
  - Stack gas volumetric flow rate,
  - Continuous moisture monitoring systems,
  - CO_2 concentration monitor systems or O_2 monitors used to calculate CO_2 concentration,
  - Oil flow meters,
  - Gas flow meters,
  - Continuous Emission Monitoring System (CEMS) and fuel flow meters quality-assurance, and
  - Data acquisition and handling system verification
- Applicable data recorded and calculations performed

Reporting and Recordkeeping

- Small entities subject to GHG NSPS are also subject to reporting and recordkeeping requirements
- Preparers of sources already subject to the reporting and recordkeeping requirements in part 75 would have minimal training requirements
  - Preparers for sources not already subject to reporting and recordkeeping requirements in part 75 would need to register and become familiar with the Emissions Collection and Monitoring Plan System (ECMPS)—a new online version of ECMPS will be published in early 2024
    - Affected EGUs outside the contiguous United States and that are not subject to the Mercury and Air Toxics Standards rule may not be subject to part 75
  - Instructions for ECMPS are available at:
    - https://www.epa.gov/airmarkets/reporting-data-using-ecmps and
    - https://www.epa.gov/airmarkets/ecmps-reporting-instructions

Other Compliance Requirements

- Determine monthly average CO_2 emissions so that 12-operating-month rolling average can be obtained
- Operate and maintain each affected EGU, including associated equipment and monitors, in manner consistent with safety and good air pollution control practice at all times
- Maintain fuel use records and CO_2 emissions measurements
  - CO_2 CEMS (Alternative = Certified O_2 monitor)
  - Flow monitoring system, continuous moisture monitoring system (if measure CO_2 on dry basis)
  - May also determine hourly heat input rates and CO_2 emissions using prescribed methods
- Output basis standard
  - Watt meters to continuously measure and record hourly gross electric output or net electric output
  - For combined heat and power, continuously determine and record total useful thermal output
- Heat-input basis standard
  - Determine total heat input using prescribed procedures

Other Compliance Requirements

- Small entities subject to GHG NSPS are also subject to compliance requirements
- Potential revisions to compliance requirements include:
  - Procedures to determine useful thermal output

Other Federal Regulations

Other Federal Regulations

RFA 603(b)(5): an identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the proposed rule

- Other federal agencies have regulations that impact the power sector, but we have not identified any overlap or conflict with GHG NSPS
  - Department of Energy
  - Federal Energy Regulatory Commission
  - Pipeline and Hazardous Materials and Safety Administration

Significant Alternatives

Significant Alternatives

RFA 603(c): Each initial regulatory flexibility analysis shall also contain a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities. Consistent with the stated objectives of applicable statutes, the analysis shall discuss significant alternatives such as —

(1) the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;

(2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;

(3) the use of performance rather than design standards; and

(4) an exemption from coverage of the rule, or any part thereof, for such small entities.

Significant Alternatives

- EPA is interested in your perspective on these potential control strategies and input on regulatory alternatives that still accomplish the objectives of the Clean Air Act
  - Other relevant control strategies, including data on their costs, effectiveness, and information on how to ensure compliance
  - Subcategorization
  - Flexibilities such as exemptions, different compliance timetables, and simplified reporting requirements

Next Steps

How to comment

- As a follow up to the discussion during the panel outreach meeting, please provide written comments by August 24, 2023
  - To the extent possible, please provide specific data, costs, and actionable information on your experience with TTTT or these control technologies
  - Remember, you are the expert in your business!

❖ Send comments to Lanelle Wiggins, wiggins.lanelle@epa.gov

❖ Please send an email before submitting Confidential Business Information (CBI)

Preliminary Schedule

Milestone	Date
Convene SBAR Panel	July 2023
Panel Meeting	August 2023
Complete SBAR Panel	September 2023
Publish Request for Public Comment	October 2023
Final Rule Signature	Spring 2024

For More Information

Regulatory Questions

Lisa Thompson
EPA Office of Air and Radiation
Email: thompson.lisa@epa.gov

SBAR Panel Questions

Lanelle Wiggins
EPA Office of Policy
wiggins.lanelle@epa.gov

Link to Regulatory Website

https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power

Appendix

Cost and performance assumptions for new turbines

IPM DOCUMENTATION (TABLE 4-12)

Table 4-12 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in v6

	Combined Cycle - Single Shaft	Combined Cycle - Multi Shaft	Combustion Turbine - Industrial Frame	Combustion Turbine - Aeroderivative	Advanced Nuclear	Small Modular Reactor	Ultra-supercritical Coal without CCS
Size (MW)	418	1083	237	105	2156	600	650
First Year Available	2028	2028	2028	2028	2028	2028	2028
Lead Time (Years)	3	3	2	2	6	6	4
Availability	87%	87%	93%	93%	90%	90%	85%
Vintage #1 (2028)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	1,007	891	638	1,051	5,823	6,399	3,454
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #2 (2030)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	977	864	616	1,016	5,620	6,176	3,334
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #3 (2035)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	905	800	568	936	5,140	5,650	3,050
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #4 (2040)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	845	747	527	869	4,733	5,205	2,810
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #5 (2045)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	789	698	490	807	4,355	4,792	2,587
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #6 (2050-2055)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	732	648	452	746	3,973	4,374	2,361
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46

Further Resources

- Technical Support Document: Hydrogen in Combustion Turbine Electric Generating Units
- Technical Support Document: Simple Cycle Stationary Combustion Turbine EGUs
- Technical Support Document: Greenhouse Gas Mitigation Measures – Carbon Capture and Storage for Combustion Turbines

Hydrogen Costs

REGULATORY IMPACT ANALYSIS

CHAPTER 3 – COMPLIANCE COSTS, EMISSIONS, AND ENERGY IMPACTS

- Hydrogen is an exogenous input to the model, available at affected sources at a delivered cost of $1/kg under the baseline, and at a delivered cost of $0.5/kg in years when the second phase of the proposed NSPS is assumed to be active
- These costs are inclusive of $3/kg subsidies under the IRA
- The second phase of the proposed NSPS is assumed to provide investment certainty to produce hydrogen for use in power sector applications, resulting in lower realized costs
  - Some entities project the delivered costs of electrolytic low-GHG hydrogen to range from $1/kg H2 to $0/kg, given tax subsidies and grant programs
  - DOE's "Pathways to Commercial Liftoff: Clean Hydrogen" report reflects delivered costs of electrolytic low-GHG hydrogen range from $0.70/kg to $1.15/kg for power sector applications
  - Studies are demonstrating more efficient and less expensive techniques to produce low-GHG electrolytic hydrogen and tax credits and market forces are expected to accelerate innovation and drive down costs

Appendix B1: Written Comments Submitted by Small Entity Representatives following the Pre-Panel Outreach Meeting on December 14, 2022

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American Public Power Association (APPA)

AMERICAN PUBLIC POWER ASSOCIATION™
Powering Strong Communities

2451 Crystal Drive
Suite 1000
Arlington, VA 22202-4804
202-467-2900
www.PublicPower.org

January 9, 2023

Mr. Todd Coleman
U.S. Environmental Protection Agency
Office of Policy
1200 Pennsylvania Ave. N.W.
Washington, D.C. 20460

Re: American Public Power Association's Small Business Advocacy Review Panel Comments on Environmental Protection Agency's Pre-Proposal for Greenhouse Gas Emissions New Source Performance Standards for Electric Generating Units

Dear Mr. Coleman:

On December 14, 2022, the U.S. Environmental Protection Agency (EPA or Agency) convened its first meeting with small entity representatives (SERs) of the Small Business Advocacy Review (SBAR) panel on the Proposed Amendments to the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (GHG NSPS). The American Public Power Association (APPA) appreciates the opportunity to participate as a SER in this important stakeholder outreach.

APPA is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 96,000 people they employ. APPA participates on behalf of its members collectively in EPA rulemakings and other Clean Air Act (CAA or Act) proceedings that affect the interest of public power utilities. APPA has a clear interest in these forthcoming rulemakings, as well as other rulemakings that address carbon dioxide (CO_2) emissions and other greenhouse gas (GHG) emissions from the electric power sector. APPA is uniquely qualified to participate as a SER and comment on EPA's proposed GHG NSPS amendments because most APPA members are considered "small businesses" or "small governmental jurisdiction" under the Regulatory Flexibility Act.

<u>Public Power Utilities Are Unique within the Power Sector</u>

Public power utilities are not-for-profit entities of state and local government and have a responsibility to provide affordable, reliable, and resilient power to their customers. Public power utilities finance new power generation projects by issuing long-term bonds or loans, and these costs can be significant to small communities. Power plant costs, which include financing, construction, maintenance, and operating costs, are one of the key factors affecting electricity prices, which have increased on average by 15 percent between September 2021 and September

2022.[1] As a result, every decision that requires a substantial capital investment requires long-term planning and careful deliberation. Regulatory certainty is paramount for any small public power utility to invest hundreds of millions of dollars to construct new base-load natural gas combined cycle (NGCC) turbines that could operate with carbon capture, utilization, and storage (CCUS) or co-fire with hydrogen. Investment in developing technologies, such as CCUS and co-firing with hydrogen, still present technological, operational, and geographical challenges for the power sector. Small public power utilities are not equipped to assume this level of risk if the goal is to provide affordable, reliable, and resilient power to our customers.

Systems of Emissions Reduction Must Be Adequately Demonstrated

Advancements in CCUS and combustion turbines (CTs) co-firing with hydrogen fuel are promising; however, co-firing hydrogen and CCUS is not adequately demonstrated throughout the power sector as the best system of emission reduction (BSER). The two technologies are not widely accessible to power utilities due to their cost, limited availability, and associated infrastructure concerns. In particular, the application of CCUS technology on CTs requires significant upfront capital investment and involves increased operating and maintenance expenses that public power utilities cannot bear.[2]

The Inflation Reduction Act (IRA) amended Section 45Q of the Internal Revenue Code, increasing the tax credits available for carbon sequestration. CCUS projects in service after December 31, 2022, may receive a credit of $85 per ton of CO_2 disposed of in a secure geologic formation for storage, and projects using enhanced oil recovery receive $60 per ton if utilized in a qualifying manner. The credit may *only* be taken if the facility can capture at least 18,750 tons per year and have at least a 75 percent capture design capacity of the unit's baseline carbon dioxide production.[3] If the technology does not work, the facility is not eligible for the tax credit to offset the significant project costs. Public power utilities can ill afford to assume such risk.

In addition, CCUS and co-firing with hydrogen technologies are only available in select areas of the country due to their limited applicability and associated infrastructure needs. For example, implementing CCUS technology requires specific geologic features that allow for permanent sequestration of the captured CO_2 emissions. However, those features are not found nationwide.[4] As a result, to inject the captured CO_2 and receive federal tax subsidies, many utilities would need access to pipelines that can carry CO_2 to areas with storage capabilities. Similarly, hydrogen fuel is not accessible in many areas of the United States due to a lack of generation facilities or pipelines to carry hydrogen fuel from generation facilities to power plants. To either enable the use of CCUS technology or co-fire CTs with hydrogen fuel, nationwide networks of

[1] U.S. Energy Information Administration, Electric Power Monthly, Table 5.6.A., Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, September 2022 and 2021, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?=epmt_5_6_a.
[2] APPA has reviewed the FEED studies on Panda Sherman's plant and the Elk Hills plant, which estimated that capital investments of $477 million and $748 million would be needed, respectively.
[3] Pub. L. No 117-169, §13104(c).
[4] The U.S. Geological Survey, "National Assessment of Geologic Carbon Dioxide Storage Resources—Summary," Fact Sheet 2013–3020 Version 1.1, (September 2013).

new pipelines would need to be constructed because there are limits to repurposing existing natural gas pipelines to transport CO_2 or hydrogen.[5]

The lack of such infrastructure imposes significant constraints and concerns for utilities to implement either technology. The construction of pipelines and storage facilities has the potential to impact communities, invoke overwhelming community opposition, and permit difficulties. We are already seeing these concerns in many Louisiana parishes where the local governments have passed ordinances to stop companies from constructing CO_2 pipelines or conducting feasibility studies for CO_2 sequestration.[6] If these conflicts continue to develop in other regions, it will considerably impair many utilities' efforts to implement CCUS technology.

NSPS for Combustion Turbines

EPA must recognize and propose compliance flexibilities that support the power sector's transition to lower and non-emitting forms of power generation. NGCC and simple cycle turbines provide reliable baseload generation and serve as backup for intermittent renewable generation. EPA should not make the construction of these new units overly burdensome or expensive to hamper the energy transition.

We believe efficient combustion based on modern, efficient NGCC technology remains the most viable emissions control option. We encourage EPA to retain NGCC technology as the BSER for base-loaded combustion turbines.

Subcategorization Creates Compliance Flexibility

During the SBAR meeting, EPA discussed the possibility of creating an intermediate load subcategory for CTs. APPA and its members would like to learn more from EPA about the possible creation of an intermediate load subcategory. In theory, an intermediate load subcategory may provide more flexibility for utilities that wish to operate non-baseload CTs with greater frequency as a load-following resource as more intermittent renewable generation comes online. In addition, an intermediate subcategory may allow utilities to adapt for an electric grid of the future.

Conclusion

APPA appreciates the opportunity to submit these comments. Public power utilities have a responsibility to provide electricity that is affordable, reliable, and resilient to their communities. As a result, the implementation of CCUS technology or co-firing hydrogen fuel in CTs is a long-term project that necessarily requires careful deliberation and planning. As EPA undertakes the process to amend the GHG NSPS, we ask that the Agency consider these unique perspectives of public power utilities.

If you have questions regarding these comments, please contact Carolyn Slaughter, Director of Environmental Policy, at CSlaughter@publicpower.org or (202) 467-2900.

[5] Congressional Research Service, "Pipeline Transportation of Hydrogen: Regulation, Research, and Policy," Report number R46700, (March 2021).
[6] https://carbonherald.com/livingston-paris-puts-a-year-long-moratorium-on-co2-injection-wells/

National Rural Electric Cooperative Association (NRECA)

The National Rural Electric
Cooperative Association

Comments on

Proposed Amendments to the New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

Submitted Electronically in response to the Small Entity Representative Pre-Panel Outreach

to:

The Environmental Protection Agency

via

Todd Coleman, coleman.todd@epa.gov

January 9, 2023

by

Rae E. Cronmiller
Environmental Counsel
4301 Wilson Boulevard, EU 11-249
Arlington, VA. 22203-1860

(703) 907-5791 / rae.cronmiller@nreca.coop

I. Electric Cooperatives: Small Entities and unique characteristics

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) Small Entity Representative Pre-Panel Outreach on Proposed Amendments to the New Source Performance Standards (NSPS) for Greenhouse Gases (GHG) Emissions from New, Modified and Reconstructed Stationary Sources: Electric generating units.

NRECA is the national service organization for America's Electric Cooperatives. The nation's member-owned, not-for-profit electric cooperatives constitute a unique sector of the electric utility industry, providing reliable, affordable, and responsible electricity is the shared commitment of NRECA's members. The association represents nearly 900 not-for-profit rural electric utilities that provide electric service to approximately 42 million consumers in 48 states or 13% of the nation's population. The electric cooperatives provide electric service in 83% of the nation's counties that collectively covers 56 percent of the U.S. landmass, as the map at the end these comments depict.

For over 80 years, electric cooperatives have responded to the needs of their communities and adapted to changes in policy in meeting that commitment. We believe policymakers must continue to balance realism with aspiration, recognizing that any energy transition to less carbon emitting electric generation overall will require additional time and technology and must be inclusive of all energy sources to maintain the reliability and affordability that is the cornerstone of American energy security.

All co-ops share an obligation to serve their members by providing reliable and affordable electric service. This obligation is not without challenges. Electric co-ops serve 92 percent of the nation's persistent poverty counties, and the sparsely populated and primarily residential communities powered by electric co-ops are often the most expensive, hardest to serve areas of our country. Electric co-ops proudly shoulder the responsibility of bringing electricity to these communities. Data from the U.S. Energy Information Administration (EIA) show that rural electric cooperatives serve an average of 8 consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line. In other utility sectors, the averages are 32 customers and

$79,000 in annual revenue per mile of line.[1] Due to those geographically driven differences, 63% of rural electric cooperative members pay higher residential electric rates than customers of neighboring electric utilities. Higher rates impede the economic recovery of rural communities and can even challenge their viability. These facts make it especially important for electric cooperatives to keep their electric rates affordable and avoid any unnecessary rate increases brought about by imprudent regulatory policy.

NRECA's member electric cooperatives include sixty-three electric generation and transmission cooperatives (G&Ts) that generate and transmit power and 832 distribution cooperatives that distribute electric power to cooperative electric consumers. The G&Ts are owned by the distribution cooperatives they serve. Some distribution cooperatives receive power directly from other generation sources within the electric utility sector. Overall, the cooperative distributed electric generation fuel mix includes 19% from renewable generation and over 32% from natural gas fired generation, which is now the dominant fuel source for the cooperative distributed electric generation. Importantly, all but three of NRECA's member cooperatives are "small entities" under the Regulatory Flexibility Act, 5 U.S.C. §§ 601-12, as amended by the Small Business Regulatory Enforcement Fairness Act.

II. Electric Cooperatives' specific interests in this rulemaking

The nation's electric grid increasingly will depend on natural gas generation as a reliable "firm power" source of base load and intermediate load generation with the continuing transition to a less carbon intense grid. These "firm power" functions cannot be fulfilled by renewable energy sources such as wind and solar. These facts, combined with the increasing electrifying of other sectors of the economy, are anticipated to require a three-fold expansion of the transmission grid and up to 170% more electricity supply by 2050, according to the National Academies of Sciences.[2] More electricity demand and more renewable energy will place enhanced requirements on the electric grid and increase measures to enhance grid reliability. In this regard efforts to address greenhouse gas (GHG) mitigation must not jeopardize a resilient and reliable electric grid

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[1] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861; Platts UDI Directory of Electric Power Producers and Distributors, 2017.

[2] National Academies of Sciences, Engineering, and Medicine. 2021. *Accelerating Decarbonization of the U.S. Energy System.* Washington, DC: The National Academies Press. https://doi.org/10.17226/25932.

that affordably keeps the lights on and is the cornerstone of America energy security and economy.

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. Section 215 of the Federal Power Act (16 U.S.C. Section 824o) is the legal basis for FERC's oversight of NERC. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people.

NERC's 2022 Long-Term Reliability Assessment[3] mirrors many of our concerns over future electric reliability. The conclusions and recommendations in the executive summary[4] include:

- Manage the pace of older traditional generator retirements until solutions are in place to continue essential reliability services that include avoiding the loss of necessary sources of system inertia
- Consider the impacts of electrification may have on future electric demand
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons
- As retiring conventional generation is being replaced with large amounts of wind and solar planning considerations must adapt with more attention to essential reliability services

Electric generation from natural gas combustion turbines is needed now, and more will be needed in the future to serve these vital needs of maintaining grid reliability and affordability. While this section 111 rulemaking cannot resolve growing concerns over future grid reliability, it could

[3] Report can be found at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf

[4] Id. At 6-7

serve as an impediment to alleviate these concerns for example by proposing a system of emission reduction that is too costly or one that cannot be implemented broadly throughout the country or one for which necessary infrastructure to achieve a performance standard is lacking.

III. Comments on specific issues and questions

- CCUS or clean hydrogen are not a best system of emission reduction (BSER) within the context of section 111. Technologies for these strategies lack necessary associated infrastructure, are too costly, and are not available nationwide. CCUS remains woefully undemonstrated for gas combustors and is not at the same technology development as CCUS for coal-fired generation, where, among other shortcomings, the necessary infrastructure is also lacking.
- NSPS should include peaking, baseload, and intermediate subcategories. NRECA anticipates generation needs for new units will likely change as more and more renewable generation is brought online and existing coal-fired generation is retired. Unit required dispatch could go from peaking to intermediate peaking again over its lifetime. Likewise, unit shifting generation needs could require a unit go from baseload to intermediate back to baseload. The subcategories and requirements should accommodate these kinds of anticipated need changes over a unit's lifetime.
- In addition to above-described subcategory flexibility, the rule should allow compliance flexibility including rate-based or mass limits such as tons/year.
- The rule should allow emissions average as an optional compliance tool
- Combined Cycle with heat recovery stream generation (HRSG) unit with triple pressure with reheat has been commercially applied to very large units but for smaller units, higher unit costs and compromised thermal efficiency, as compared to that of larger units, presents challenges. Presently there are no demonstrations on smaller units.
- Supercritical Steam- There is no commercial application of supercritical steam application on a HRSG unit. Simply put, the "driving force" to generate such steam conditions in a HRSG unit is not potentially compelling as the case maybe for a coal-fired boiler. Thus far there is no commercial demonstrations of supercritical steam application on a HRSG unit
- Supercritical CO_2 in lieu of steam as the working fluid "demonstrated at compressor station", as EPA describes, is not adequately demonstrated technology for section 111 nationwide application. In fact, it has not been demonstrated at any commercial scale.

Extremely high temperature metallurgy as required for an expansion turbine is an ongoing materials science challenge, and the required materials are not proven for commercial duty

- Financial benefits such as tax credits should not be used as a factor to demonstrate reasonable cost of a technology necessary for defining a best system for section 111 application. Financial benefits calculation requires numerous assumptions that may not prove to be accurate, such as the anticipated assumed utilization of the unit as opposed to design capacity upon which the financial benefits may be linked, the assumed timing of the financial benefits, and the presumed intent of the Congress to sustain the benefits for the duration included in the original enacting legislation.

IV. NRECA response to the draft White Paper

A. Section 111(b) regulations and the White Paper should facilitate needed new natural gas generation, not impede it.

As the comments above have stressed, electric generation from natural gas combustion turbines is needed now, and more will be needed in the future to serve these vital needs of maintaining grid reliability and affordability. EPA's draft White Paper addressing gas-fired combustion turbine GHG mitigation technologies, when finalized, must not result in a tool that could be used or easily construed to delay, impede, or prevent the development of much needed natural gas combustion turbine generation to support a reliable and affordable electricity from the grid. Our principal concern is that the draft falls woefully short in fulfilling its main intent "to assist states and local air pollution control agencies, tribal authorities and regulated entities in their consideration of technologies and measures that may be implemented to reduce GHG emissions from stationary combustion turbines." Draft White Paper, page 1.

It is noteworthy that EPA views the draft White Paper, presumably when finalized, as merely providing a "context" for Federal Clean Air Act (CAA) permit development under the Prevention of Significant Deterioration (PSD) program Best Available Control Technology (BACT) assessment, and it "may be useful to EPA" in developing CAA Section 111 New Source Performance Standards (NSPS) best system of emission reduction. Id. Under these CAA programs, any proposed GHG mitigating technology or measure as applied to an NSPS category or a BACT assessment would necessarily undergo regulatory scrutiny addressing the many factors the CAA requires before arriving at a prudent technology or measure. Such scrutiny includes accessing the actual commercial viability, adequate technology demonstration, and a reasonable cost of the technology or measure.

The draft White Paper, however, provides no background or explanation of the additional considerations needed for a reasonable and prudent commercial technology application to a source that would assist a state or local permitting agency in evaluating whether it would be appropriate to consider any of the draft White Paper's technologies or methods in any applicability technology or process determination. If, as EPA states, the White Paper's principal use is to inform state and local permit agencies of GHG mitigation technologies for EGU combustion turbine application, it must be significantly revised consistent with these comments.

Additionally, the draft White Paper needs to appropriately describe the stage of development for each of the emerging and possibly available technologies included in the White Paper. Merely citing planned projects, application of the technologies to other types of units or citing units in other industrial sectors, or citing limited application in an electric utility setting, as the draft White Paper does, easily could lead to false conclusions by local regulators that in fact a given technology is commercially available, adequately demonstrated, or otherwise applicable for a given EGU combustion turbine.

B. CCUS or hydrogen blending are not BSER for Section 111 application

While promising technologies both Carbon Capture Utilization and Storage (CCUS) and hydrogen blending for gas combustion turbines requires, among other advances, vast new developments in infrastructure to allow broad geographic applicability needed to demonstrate best systems of emission reduction (BSER). For CCUS both pipelines and sequestration fields would be to be developed in addition to addressing significant water requirements and mitigating enormous cost of control issues. For hydrogen blending, needed infrastructure to transport and store "clean hydrogen" presents insurmountable obstacles for present day BSER application. Indeed, the existing pipeline infrastructure for transporting natural gas for commercial, industrial, electric utility, and home use is structurally and technically inadequate for transporting hydrogen for blending.[5] While the concept of Hydrogen Hubs shows promise for future application, that infrastructure on a geographic basis in not available today and may not be for years.

The draft White paper includes projects undergoing design exercises on NGCC units. It also details the status of these projects. They are all presently Front-End Engineering Design (FEED) studies that are the first prerequisites to a full-scale demonstration test. In addition to these four projects, DOE in late 2021 announced funding for additional design studies, also as a first step to demonstration tests. These additional studies are also not mentioned in the draft White Paper. These projects engage the Calpine Deer Park Energy Center in Texas, the Calpine Delta Energy Center in California, and a unit to be selected by GE Gas Power for which to design a CCUS process. These are design studies, and additional work must be completed prior to successful demonstration of the technology.[6] Hopefully successful technology demonstrations will eventually lead to lead to commercialization of CCUS on NGCC. The draft White Paper should also stress that at a minimum, commercialization, and technical feasibility is achieved only when a process successfully operates over a wide range of varied sites, and ambient conditions, as well as having a supplier who can provide a performance guarantee.

In summary, the draft White Paper should be revised to appropriately describe the state of technology development in all the technologies identified, especially where a given technology is not clearly already commercialized for EGU combustion turbine application. When used according to its portended purpose the White Paper should provide the reader with accurate and reliable information on the various available methods and technologies including the status of commercialized development and associated costs for application to EGU combustion turbines. Accordingly, the White Paper would need to be updated periodically to correctly represent changes including both setbacks and advancements in technologies and methods, as well as updates on costs of application.

[5] See California Public Utilities Commission Final Report, Hydrogen Blending Impacts Study at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

[6] See 26 U.S.C. § 48A(g); also 42 U.S.C. §§ 13573(e), 13574(d), 15962(i) EPA may not consider demonstration projects that receive assistance from various federal programs "adequately demonstrated" for the purposes of NSPS, PSD and LAER application.

C. The draft White Paper should be rewritten to address the following specific issues and concerns related to source permitting

The comments above express our concerns with the draft's failure to adequately describe in technical terms the status of technology development for each GHG mitigation technology listed. In addition, the white paper should address the following concepts and concerns:

- Each technology should be categorized based on stage of development potentially applicable to the EGU combustion turbines. Due to the potential inherent differences between EGU combustion operation and combustion turbine operation within the other industrial sectors, it cannot be presumed that a technology even reasonable perfected and possibly even commercialized in one sector has achieved that status for EGU application.

- Each technology should describe its potential application that would be consistent with the purpose and need of the EGU combustion turbine. For example, if an EGU combustion turbine application is for intermittent generation to support existing renewable generation, it would make little sense to consider an Energy-Output Integrated Renewables option described in Section5.6.2. of the drift White paper to complement the combustion turbine. In the context of Section 111 NSPS, the best system of emission reduction cannot effectively "redefine the source." The white paper should make clear that in all permitting cases the GHG reduction technology must be consistent with source objective, purpose, and design.

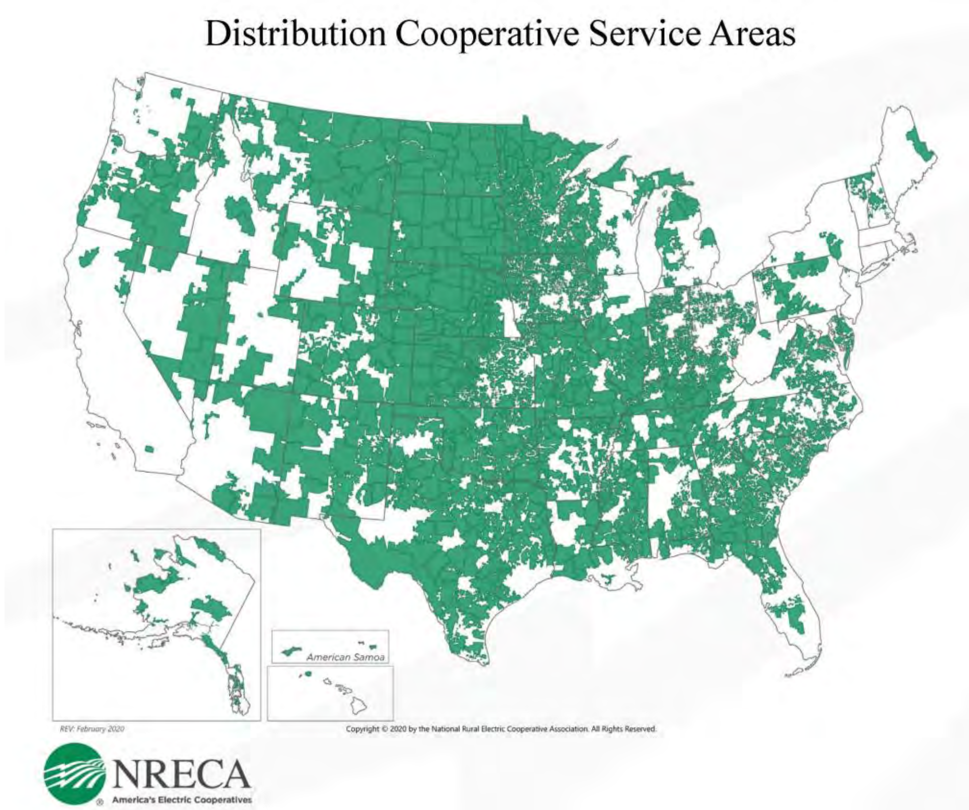
- Each technology should incorporate guidelines for qualifying and quantifying GHG reductions. For example, the draft White Paper correctly points out in the Hydrogen Section in 5.9 that among the different processes producing hydrogen, the selected one largely determines the amount of GHG emissions mitigation associated with the application of that technology to a combustion turbine. In some cases, GHG emissions associated with the way in which hydrogen is produced can negate any GHG reduction benefits directly associated with using that hydrogen at an EGU combustion turbine. Thus, the draft White Paper should provide appropriate guidelines for evaluation of GHG emissions associated with all technologies associated with a potential combustion turbine GHG reduction option.

- The top-down PSD BACT process notwithstanding, each technology or method description should enable readers to delineate the potential technological applicability to units that are new versus existing units that may be undertaking major modifications. Options at existing units may be more limited due to the physical layout, physical location, and design constraints, and these factors must be considered.

- The draft White Paper must recognize that existing infrastructure capabilities including electric transmission availabilities and supply chain limitations may dictate new unit locations, limiting the potential applicability of some of the options discussed in the draft White Paper, such as hydrogen co-firing, carbon sequestration or pipeline transmission to sequestration. The infrastructure needed to support some of the White Paper's options may not be available at existing sites or new source sites where location may be dictated by source purpose, need, and necessary infrastructure (*e.g.*, transmission capacity). Further, even if a given location my support a GHG reduction option, if the materials or services are not available on a timely basis to utilize that option consistent with source purpose and need, that option should be eliminated.

- The draft White Paper should provide some discussion of the costs and economic feasibility of each of the included technologies and methods. This should include a discussion of the costs and feasibility in relation to the application of the technologies reviewed to new versus existing sources. The discussion also should address any non-air quality health and environmental impacts (benefits and detriments) and energy requirements associated with the technologies under consideration.

- The draft White Paper should recognize that the location of a source is dictated by the generation need and existing transmission capabilities. A given source location may present space constraints or geographical factors that effectively negate availability of wind or sun that make co-locating the combustion turbine with renewable generating infeasible, whereby such renewable constraints would not alter the need for base or intermediate load electric generation in the region.



Western Farmers Electric Cooperative (WFEC)

Western Farmers Electric Cooperative

Comments on
Proposed Amendments to the New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

Submitted Electronically in response to the Small Entity Representative Pre-Panel Outreach

to:
The Environmental Protection Agency
via
Todd Coleman, coleman.todd@epa.gov

January 9, 2023

by

Laura Finley
Staff Attorney
3000 S. Telephone Road
Moore, OK 73160

(405) 402-0091 / laura.finley@wfec.com

Pre-Panel Outreach Small Entity Representative (SER) Questions for Discussion on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

Overarching Topics

1. How do you anticipate any proposed amendments to the NSPS would affect your business? For example, would it impact the service you provide or perhaps require the hiring of additional staff?
   - WFEC anticipates hiring additional consultants with specialized expertise as well as potentially hiring an engineering firm to determine options for compliance.

2. Is there any information that would improve EPA's understanding of the number of small entities that may be affected by this proposed action?
   - Energy Information Administration (EIA) data, Internal Revenue Service (IRS) data, and/or possibly National Rural Electric Cooperative Association (NRECA) datasets can provide the EPA with a better estimate of the number of small entities that may be affected by this proposed action.

3. What recommendations do you have for small business flexibilities that may reduce burden? In what way can these flexibilities be structured to better aid small entities in reducing potential burdens? Are there any specific flexibilities that would help your business?
   - Align recordkeeping and reporting requirements with already existing requirements.

4. What are the characteristics of a small business in your industry that make it different from a large business?
   - Small businesses have a lean structure with minimal staff. WFEC specifically is a not-for-profit organization whose aim, rather than making a profit for investors, is to keep electricity rates low for our members.

5. Do you anticipate any significant issues or circumstances not addressed in the materials provided?
   - None identified at this time.

6. Do you have any other feedback for EPA related to EGU GHG NSPS?
   - None identified at this time.

Reporting and Recordkeeping

1. What recommendations do you have for reducing the recordkeeping and reporting burden on small businesses?

   - Make reporting requirements consistent with existing reporting requirements (quarterly reporting in EDRs or semi-annual 60.7(c) reports similar to other NSPS reporting requirements for electric generating units (EGU). Energy assessments/equipment tune-ups inspections similar to NESHAP Subpart DDDDD and/or NESHAP Subpart UUUUU).

2. Subpart TTTT currently has a 95 percent minimum data availability requirement. Some rules, like those in part 75, include provisions to be used when primary regulatory monitoring is unavailable or not properly operating. Should this rule include such provisions as an alternative to having periods of missing data and/or increase the minimum data availability?
   a. If so, what might be options for gap-filling that would serve to reduce those periods of missing data – redundant monitors, or higher than expected gap-filling values, operational shutdown until primary monitors online after a time period for gap-filling exceeded, or other?
      - Requiring an operational shutdown due to monitor downtime will negatively impact grid reliability. During severe cold weather events, sample lines can freeze even with appropriate freeze protection, which will cause monitor downtime. In severe weather events with high winds and sub-zero temperatures, repair of sample lines can be a significant safety concern until conditions improve. In these conditions, redundant monitors would not be beneficial. Since PMA is calculated based on operational hours of the unit, a PMA of 95% can be reached in as little as 24 hours based an annual average. Part 75 missing data substitution procedures would be preferred over any shutdown requirements for PMA percentages.

Other Compliance Requirements

To determine the design efficiency of an EGU, subpart TTTT currently includes ASME PTC 22 Gas, ASME PTC 46 Overall Plant Performance, and ISO 2314 Gas turbines. Should the Agency consider other methods and/or specifically allow that operating data can be used to determine the design efficiency of existing EGUs (to determine the applicability for the existing source requirements)?

- EPA should allow the use of operating data and energy balance calculations for efficiency determinations as much as possible. Additionally, EPA could survey existing users with like units for existing design efficiency determination methodologies. Allowing existing, accepted methodologies is preferred.

1. Subpart TTTT currently requires the use of calibration procedures in ANSI Standards No. C12.20 for measuring electrical output. Should the Agency consider alternate methods?
   - Same comment as above.

2. Subpart TTTT does not currently specify requirements for monitoring useful thermal output. What are practical, cost-effective ways to determine useful thermal output on an ongoing basis?
   - Energy balance calculations would be practical and cost-effective. Installing a thermocouple grid in the stack would be costly to do and to maintain.
   - Additional costs hit small companies hard, especially those that are not-for-profit. Why does EPA want this monitored? Is this only for cogeneration and/or combined cycle units?

3. Is there an interest in using hydrogen (produced using a low-GHG technology), biomethane, and other types of non-conventional fuels as strategies to reduce GHG emissions?
   [What about H2, biomethane, or other non-conventional fuel impacts on NOx, SO2, PM, and HAPs emissions as well as impacts to heat rates? The use of a mixture of treated landfill gas and PQNG significantly reduced the heat rate at another plant and could not be used during startup.]
   - WFEC is not looking at any non-conventional fuels. As a small, not-for-profit entity, it is challenging to find the manpower and capital to conduct research and development on unproven technologies.

   a. If so, how can low-GHG fuel use be differentiated, verified, monitored, and reported?
      Fuel flow monitoring/reporting, similar to fuel and heat input reporting in Part 75.

4. What are practical ways of measuring, monitoring, reporting, and verifying carbon dioxide sequestration or use in enhanced oil recovery?
   - To WFFEC knowledge, carbon dioxide sequestration is not an economically or technologically feasible control strategy for EGU. A search of the RACT/BACT/LAER Clearinghouse indicated that carbon sequestration was not a control strategy employed by any facilities with an SIC Code of 4911 from January 1, 2012 through December 31, 2022.

5. What alternatives to existing quality assurance and quality control approaches exist for ensuring data can be collected properly, both initially and on an ongoing basis?
   - Consistent QA/QC requirements with Part 60 or Part 75 would be preferable. Alternatives may be requested and can be approved within a certain timeframe of submittal to the EPA, similar to alternative monitoring allowances in other Subparts. WFEC suggests EPA keep things consistent as opposed to creating new approaches.

6. Do you anticipate any unique legal, administrative, or recordkeeping burdens associated with compliance with the proposed action?
   - There are no control strategies proven to be technically or economically effective at reducing CO2 emissions. Measuring and calculating efficiency information would require additional calculations and configurations to be implemented between existing DAHS and plant control systems, which would be a unique and an additional requirement.

Other Federal Regulations

1. Are there regulations from other federal agencies that apply to small entities that may overlap with this EPA action? Do you have suggestions on how to minimize conflicting requirements?

   - GHG Mandatory Reporting Rule (40 CFR 98), NSPS Subpart GG/KKKK/TTTT, and/or 40 CFR Part 75 could have conflicting requirements. Reliability standards/requirements from FERC/NERC/RTOs could conflict as well. The RTO in our area (Southwest Power Pool or “SPP”) frequently dispatches simple cycle units rather than more efficient technology such as cogeneration and combined cycle units. The RTOs dictate operations. Any efficiency requirements should consider the reliability requirements and dispatch methodologies of RTOs. Keeping requirements consistent with currently applicable standards will minimize conflicting requirements.

Power Sector

1. EPA's regulations will be proposed and finalized in the context of transition within the power sector, which makes it important to ensure that any regulatory approach captures the most current information about investment decisions in the sector. Are there any significant recent announcements or commitments to transitioning generation of which the Agency should be aware?
   - ➢ Transitioning power requires more flexibility of units: cycling units more, simple instead of combined cycles. In the SPP area, renewables are the new base load. Combined cycles ramp at 3 MW/minute and have shorter startup times of 1 to 2 hours, as compared to 9 MW/minute ramp and 10 minute start times for simple cycles. The market is not picking up combined cycle units as often so their relatively high efficiency matters less and less.

2. How does passage of the Inflation Reduction Act impact investments in the transitioning power sector?
   - ➢ Tax incentives are now available for not-for-profit electric cooperatives.

3. How would an amended NSPS impact investments and new projects? For example, would they impact the selection of a particular combustion turbine design (*e.g.*, combined cycle or simple cycle) or the potential generating capacity of a new EGU?
   - ➢ Proposed projects are impacted by RTO dispatch behaviors. RTO reliability requirements should be considered if a certain generation technology is given an advantage/preferential treatment in the proposed rule. Also see comment in 1 above.

4. Are there any sector-unique business or competitive issues that EPA should understand? Are there any specific business or competitive issues associated with your business?
   - ➢ EPA must understand RTO dispatch preferences and strategies. Renewables are the new baseload in certain areas of the country (SPP dispatch area). There are regional differences in the way the grid is operated based on the volume of renewables available in that region.

Subcategory

1. Into which subcategory of the current NSPS are your affected EGUs classified (e.g., base load or non-base load)?

   - ➢ Our current generation would be considered non-base load, and any new generation that WFEC builds would most likely also be non-base load, i.e. capacity factors less than 20% based on SPP dispatch methods.

   a. Are there other potential subcategories that would be more appropriate for new EGUs?

- ➢ Combined cycles would most likely fall into an intermediate subcategory (around 30% capacity factor).
- ➢ Non-base load 0-20%; Intermediate 20%-55%; and Base load 55% +.

2. What electric sales threshold (*i.e.*, capacity factor) is appropriate for simple cycle turbines intended to maintain grid reliability (*e.g.*, provide power during periods of peak electric demand)?
   - ➢ Is EPA asking what percentage of the RTO fleet should be peaking? Or are they asking what capacity factor is a peaking unit maintaining grid reliability? Or are they asking how many renewables are sustainable in the RTO before the grid is unreliable? In SPP, grid reliability is a moving target based on renewable availability.

3. How can the Agency recognize the environmental benefit of intermediate load EGUs with lower emission rates?
   - ➢ In the SPP region, everything is dependent on the wind. The target mix of simple, combined, and renewables needs to be optimized. The more we rely on variable generation, the more we must lean on flexible less efficient units (simple cycle) as back up.
   - ➢ Arguably 30% variable generation is optimal. But the EGUs have zero control over dispatch order. A national energy plan would allow EPA to recognize the environmental benefit of intermediate load EGUs.

4. At what annual capacity factor does the emission rate of combined cycle EGUs begin to increase?
   - ➢ Turbines are designed to be run at 100% load, and the less they are started and stopped, the lower the emissions. Combustion is less efficient at lower loads. It also depends on which pollutant you are looking at. Below 80% is where you start to see emissions really start to increase.

5. At what annual capacity factor would you install a new combined cycle combustion turbine instead of a simple cycle combustion turbine?
   - ➢ Based off economics (return on investment), anything over 55% capacity factor. Again, this is based upon the region in which WFEC provides power because we this area of the country has so much wind generation.

6. How do you intend to use new simple cycle combustion turbines – peaking or intermediate load (max capacity factor)?
   - ➢ Simple cycle units are all WFEC plans to install due to SPP dispatch preferences. The only thing the market wants is peaking units (again, in our region). Which units are run is based on many factors, not just the cost of fuel.

7. What types of simple cycle turbines are you considering – frame or aeroderivative?
   - ➢ WFEC is considering both.

Control Strategies

1. In Spring 2022, EPA released a draft informational white paper, titled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*. The white paper discussed the potential to mitigate GHG emissions with technologies such as efficient combustion; carbon capture, utilization, and storage (CCUS); and hydrogen (Link to draft white paper: https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf). What are your thoughts regarding how EPA should consider those technologies as the Agency develops amendments to the NSPS? Are there other technologies and/or factors EPA should consider?

   - These strategies are not proven to be technically or economically effective control strategies. Based on WFEC's understanding, this White Paper was not intended to be the basis for rulemaking. EPA has not responded to comments on the white paper. It should not be relied upon. That said, installation of wind and solar onsite is possible if a site has the space.

2. What can you tell the Agency about the control strategies costs and emissions reduction effectiveness? Are there any other technical considerations EPA should be aware of?
   - Based on our understanding, there are no currently available technically or economically feasible control strategies for CO2.To WFFEC knowledge, carbon dioxide sequestration is not an economically or technologically feasible control strategy for EGUs. A search of the RACT/BACT/LAER Clearinghouse indicated that carbon sequestration was not a control strategy employed by any facilities with an SIC Code of 4911 from January 1, 2012 through December 31, 2022. However, combustion efficiency calculations via energy balance or confirmed by energy assessments and/or tune-ups/inspections is possible.

3. Are the potential control strategies technically feasible for your facilities? Are they economically feasible for small entities? Would the potential control strategies increase labor costs? Do they impose more of a disadvantage to small entities than larger ones? If so, what type of control strategies might be more feasible for small businesses?
   - Based on our understanding, there are no currently available technically or economically feasible control strategies for CO2. In the RACT/BACT/LAER clearinghouse, none of the control strategies from the white paper were listed; only efficient combustion and low carbon fuels for EGUs at facilities with an SIC Code of 4911 from January 1, 2012 through December 31, 2022. For small entities, the cost for installing carbon sequestration is prohibitive. Additionally, methods for ensuring CO2 is removed and not allowed to reenter the atmosphere have not been demonstrated as effective. Larger entities are able to enter into agreements with universities or other institutions for experimental treatment possibilities. As a not-for-profit, WFEC is limited in its ability to implement unproven treatment methods.

Appendix B2: Written Comments Submitted by Small Entity Representatives following the Panel Outreach Meeting on August 10, 2023

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American Public Power Association (APPA)

AMERICAN PUBLIC POWER ASSOCIATION™
Powering Strong Communities

2451 Crystal Drive
Suite 1000
Arlington, VA 22202-4804
202-467-2900
www.PublicPower.org

August 24, 2023

Via electronic correspondence at Wiggins.Lanelle@epa.gov

U.S. Environmental Protection Agency
Office of Policy
Ms. Lanelle Wiggins
RFA/SBREFA Team Leader
1200 Pennsylvania Ave N.W.
Washington D.C. 20460

RE: American Public Power Association Comments for the Small Business Advocacy Review Panel: New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule, Docket ID No. EPA–HQ–OAR–2023–0072

I. Introduction.

American Public Power Association (APPA or the Association) appreciates the opportunity to participate in the Environmental Protection Agency's (EPA) Small Business Advocacy Review Panel (SBAR) for the above-referenced Proposed Rule.[1] Many of our members are small entities that operate power generation plants that are subject to the Proposed Rule. The Association and its members have a strong interest in participating in the SBAR process and presenting the substantial economic impacts of this rulemaking on our members.

APPA is a trade association composed of not-for-profit, community-owned utilities that provide electricity to 2,000 towns and cities nationwide. APPA protects the interests of the more than 49 million people that public power utilities serve, and the 96,000 people they employ. Our association advocates and advises on electricity policy, technology, trends, training, and operations. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power.

APPA and our members have and continue to be dedicated to clean air in our communities and the protection of the environment. Our members have made significant investments to reduce emissions and comply with the suite of air regulations that EPA has

[1] New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule, 88 Fed. Reg. 33,240 (May 23, 2023).

promulgated over the last ten years. Many members continue to pay for those environmental compliance investments through loan obligations. The financial burden of the Proposed Rule creates further strain on these entities. APPA members have a significant stake in the ability to construct new generation, but the Proposed Rule poses substantial reliability and financial solvency hurdles.

Gas-fired power generators have become critical to maintaining the reliability of the power grid as the share of intermittent generation resources has grown. Grid reliability concerns have been echoed by grid operators, electric utilities, and regulatory authorities, who note that the flexibility and dispatchability characteristics of gas-fired generators will be important to balance the grid amid the energy transition. However, APPA is concerned that EPA's Proposed Rule could drive many of our members into premature retirement if not all the hurdles associated with developing the infrastructure needed to support carbon capture and sequestration (CCS) and hydrogen are not resolved in a timely manner.

Several of our small public power utility members are considering or are executing plans to add new natural gas-fired combined cycle (NGCC) and natural gas-fired simple cycle (NGCT) combustion turbines that would be subject to the Proposed Rule. APPA has consulted with several members who are investigating the potential to add new combustion turbines (CTs) that would fall into the proposed new source performance standards for low-load and intermediate-load subcategories and are considering major modifications.[2] These members face challenges with meeting EPA's abbreviated timeline to build on-site dispatchable generation prior to the anticipated retirements due to the proposed emission guidelines for coal-fired electric generating units (EGUs) under Clean Air Act Section 111(d). Swiftly launching and financing a project for CCS or hydrogen technologies is virtually impossible, considering the lack of infrastructure, economics, and developmental nature of both technologies. The Inflation Reduction Act (IRA) offers some opportunities to build renewable generation but fails to provide any level of support for the construction of new, dispatchable replacement generation.

APPA appreciated the opportunity to engage with EPA and other small entities representatives (SERs) on August 10, 2023. Our members wish to continue discussions on small entity impacts of the Proposed Rule. APPA joins with other small entities to request EPA to make its final SBAR report publicly available for comment. EPA should acknowledge the true cost impacts on small entities. APPA asks EPA to take the following actions:

- Reconsider its best system of emission reduction (BSER) approach for new generation based on reliability and financial consequences to the power sector as a whole and to small entities in particular;
- Adopt reasonable BSER strategies that are achievable across the nationwide fleet, which do not place small entities at a disadvantage;
- Decline to proceed with infeasible and unavailable technologies, such as CCS and hydrogen co-firing, as BSER;
- Revise timeframes to accommodate all sources and SER concerns;

[2] Holland Board of Public Works, Indiana Municipal Power Agency (IMPA), and Oklahoma Municipal Power Authority (OMPA).

- Consider the cumulative financial impact of EPA's suite of environmental regulations on smaller utilities; and
- Evaluate flexible options for small entities, including those that provide relief for smaller gas-fired units, peaking units, and combined heat and power operations.

EPA should provide this relief in a forthcoming supplemental notice of proposed rulemaking and then incorporate it into the final rule next spring. APPA provides the following specific comments as a supplement to our more detailed comments in the Proposed Rule's docket.[3]

II. EPA's screening analysis underestimates costs to the public power sector by a large magnitude.

This SBAR process has been highly unusual. APPA urges EPA to fulfill its obligation to consider the significant impacts of the Proposed Rule on small businesses. The Small Business Regulatory Enforcement Fairness Act (SBREFA) amended the Regulatory Flexibility Act (RFA) to require agencies, such as EPA, to consider the impacts of regulations on small business entities. Small entities include not-for-profit organizations, governmental bodies, and public power. A Small Business Advocacy Review (SBAR) panel is convened[4] with a public comment opportunity *prior to* publishing a proposed rule.[5] The SBAR process can only be skipped if the agency certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities.[6]

With respect to the Proposed Rule, EPA performed its small business entity analysis and certified that the Proposed Rule will not have a significant economic impact on a substantial number of small entities. EPA's screening analysis found that there would not be a substantial number of affected small entities that would experience annual compliance costs in excess of 1% based on the cost-to-revenue or cost-to-sales test.[7] EPA did not proceed with the SBAR process on this basis. Later, EPA decided to re-engage small entities in the August 10 SBAR panel, although EPA still has not acknowledged the significant economic impact on a substantial number of small entities, nor has EPA revised the original screening analysis. APPA and other entities have had only a brief comment period and limited discussions with EPA, as opposed to past rulemakings that involved a complete SBAR process with multiple meetings.[8] Further engagement and recognition of small entity impacts is necessary and warranted.

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[3] APPA Comments on the Proposed Rule, https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0566/attachment_1.pdf
[4] 5 U.S.C. § 609(b).
[5] 5 U.S.C. § 603.
[6] 5 U.S.C. § 605(b).
[7] EPA, "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," May 2023 at 5-5 – 5 11, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.
[8] *See, e.g.,* SBAR Panel: Federal Plan for Regulating Greenhouse Gas Emissions from Electric Generating Units, Final Report at 5, https://www.epa.gov/sites/default/files/2015-10/documents/report-sbar-panelreport-cppfip.pdf ("The Panel conducted three meetings/teleconferences with SERs on May 8th, 14th and 19th 2015. To help SERs prepare for the meetings, EPA sent materials to each of the SERs via email on May 1st 2015. A list of the materials

At the heart of the Proposed Rule's SBAR process is EPA's flawed business impact screening analysis. EPA's analysis is defective in several ways, resulting in low-ball estimates of the financial impacts on small entities. First, EPA considered only the costs of building new generation under proposed Section 111(b) and turned a blind eye to Section 111(d) expenses that include steep environmental project costs and unit shutdowns to comply. Even, hypothetically, if the RFA does not require the consideration of small entity costs Section 111(d), EPA cannot step away from the inextricable link between the two portions of the Proposed Rule, the dual threat of the requirements on an individual small entity, and the overwhelming rise in new generation builds that the public power sector must undertake within the next ten years.

The technologies identified as BSER under the new source performance standard (NSPS) leave small entities with no other choice but to try to replace prematurely retired dispatchable baseload units in some way. New generation or power purchases are the options at hand. Again, EPA's screening analysis misses the mark. EPA assumed that "as a proxy for the future gas capacity built by small entities," small entities would continue to build the same share of future capacity additions projected by its integrated planning model (IPM) over the forecast period. EPA's screening analysis uses historical data and planned builds since 2017 to determine the future universe of NGCC and NGCT additions.[9] This flawed premise assumes that the next ten years will be "business as usual" for new generation demands from small entities. By using past data, EPA disregards that many smaller entities have existing coal and large gas assets.[10] Through Section 111(d), EPA signs up these entities for CCS (coal/gas), hydrogen co-firing (larger CTs), or retirements. New generation builds must replace this capacity at great expense. Small entities of the past were not subjected to this generation crisis. Therefore, past data is not a barometer for the number of small entity future projects. This approach vastly undercounts the sheer number of small entities affected by Section 111(b). APPA asks EPA to revise the cost impact estimates by considering the actual cumulative impacts of the entire regulation (Section 111(b) and Section 111(d)) on small entities. The methodology should properly assess the actual share of new generation that small entities will be pursuing if the rules are finalized as proposed. A holistic Section 111 approach would be consistent with EPA's past acknowledgment during the Clean Power Plan rulemaking that the Section 111(d) BSER selection may create small business entity impacts.[11]

EPA should also reconsider its cost tally for new generation. It underestimates new generation costs by focusing primarily on the principal costs of compliance with Section 111(b). This insular view does not properly account for the overwhelming cost impacts on small entities. EPA must consider, at a minimum, the following costs: (1) the cost-prohibitive option to

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shared with SERs before and during the Panel outreach meeting is contained in Appendix A. EPA presented an overview of the SBREFA process, an explanation of the planned rulemaking, and technical background. EPA asked the SERs to provide written comments by May 28th 2015.").

[9] RIA at 5-6, https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0007

[10] *See* APPA, 2023 Public Power Statistical Report, *https://www.publicpower.org/system/files/documents/2023-Public-Power-Statistical-Report.pdf* at 4 (All 2021 generation nation-wide for coal assets totaled 21% in MW/hrs, while public power totaled 29.9% MW/hrs from coal assets).

[11] SBAR Panel: Federal Plan for Regulating Greenhouse Gas Emissions from Electric Generating Units, https://www.epa.gov/reg-flex/documents-sbar-panel-federal-plan-regulating-greenhouse-gas-emissions-electric-generating

purchase power for generation in lieu of building new generation; (2) the cost and challenges involved in financing new generation; and (3) the complete cost of installing new generation, including transmission interconnection fees,[12] gas-line and hydrogen infrastructure expenses, and other ancillary costs of CCS and hydrogen projects.

III. The Proposed Rule places unique cost and reliability burdens on small entities that must be considered.

A. Small public power utilities must invest in new baseload generation to deliver reliable and affordable power.

Public power entities have a responsibility to the communities they serve, as their core mission, to supply reliable, affordable and sustainable power. Public power utility customers have lower electricity rates and have shorter outages. Owning generation is essential to this end.

Public power entities cannot shoulder expensive power purchases. Unpredictable market conditions are becoming more frequent as the market becomes more volatile due to regional transmission organizations (RTOs)/independent system operators (ISOs) experiencing generation shortfalls. In addition, extreme weather events have caused recent exorbitant market purchase prices. For example, the PJM Interconnection region market prices during Winter Storm Elliott in December 2022 exceeded $4,000/MWh at one point during the storm when there was no sunlight to power solar resources. Public power entities and their communities cannot absorb this type of cost.

Winter Storm Uri demonstrated that the financial strain of power purchases on small entities is not illusory. During the storm, commodity price volatility occurred due to capacity deficits. The city of Denton, Texas incurred $140 million in above budget storm costs.[13] The city had to devise a long-term financing solution to avoid default. The unanticipated large expenses affected the city's overall financial position and caused the credit rating agency, Fitch Ratings, to assign a Rating Negative Watch to the series 2017 utility system revenue bonds issued by the city. Fitch Ratings expected the storm-related costs to weaken the city's leverage profile, which also resulted in downgrading the city's rating. Lower ratings may cause interest rates to rise, making it more difficult to borrow money.[14]

During Winter Storm Uri, Brazos Electric Power Cooperative (Brazos) incurred $2.1 billion in power purchase invoices to the Electric Reliability Council of Texas Inc. (ERCOT). Brazos asserted that the bill for the week-long storm was about three times its total power cost for 2020. The cooperative argued that ERCOT failed to follow protocols for setting contractually required emergency rates, and the Public Utilities Council of Texas mandated that it

[12] Small entities must shoulder large transmission upgrade costs for interconnection of intermittent resources. Renewable generation requires more transmission capability to safely handle peak generation highs (e.g., when the sun is shining). RTOs charge large interconnection costs to support the necessary transmission upgrades to support renewables. These costs must be factored into EPA's analysis.

[13] *See* FitchRatings, :Fitch Maintains Rating Watch Negative on Denton, TX's Utility System Revenue Bonds, May 11, 2021, https://www.fitchratings.com/research/us-public-finance/fitch-maintains-rating-watch-negative-on-denton-tx-utility-system-revenue-bonds-11-05-2021

[14] https://www.garlandtx.gov/DocumentCenter/View/1298/Fitch-Electric-Rating-PDF

follow emergency orders during the storm. Ultimately, the cooperative settled with ERCOT to pay $1.89 billion of that cost. Brazos had to declare bankruptcy and sell its gas-fired generation portfolio, totaling around 2,200 MW of capacity, to cover the tab.[15]

The danger of relying on unhedged power purchases to serve consumer demand is not even permissible in some regions. For example, Indiana utilities must have in place sufficient capacity and not acquire more than 15% of their total summer and winter unforced capacity needs from capacity markets. Also, this requirement expands to year-round in 2026.[16] The requirement assures "reliable electric service to Indiana customers and assists with providing planning reserve margin requirements and other federal reliability requirements."[17] RTOs, themselves, mandate members to meet planning reserve margin requirements to sustain a stable grid. Many state public service commissions also do not condone utility behavior that causes exposure to the whims of the market to meet demand requirements.[18]

Load-serving entities, like public power utilities in the Midcontinent Independent System Operator (MISO) market, must supply capacity as well as energy. Capacity accreditation for non-dispatchable generation must be considered to replace thermal generation. MISO's new non-dispatchable generation has a much lower accredited generation capacity than the fossil resources being replaced. MISO recently stated that they anticipate a 2.1 gigawatt (GW) accredited capacity shortfall.[19] Market volatility deters small entities from relying on the markets as a capacity resource.

Even during normal peak seasons (winter and summer, depending on geography), public power entities must have sufficient generation to meet their needs. Otherwise, additional load requirements must be met by power purchases. As it stands, public power entities are not able to construct new generation in compliance with the Proposed Rule in the amount of time that EPA has proposed, irrespective of the costs of that generation. As a result, entities are reliant on any extra reserves on the grid to absorb the loss. As noted in our comments filed in the docket, many RTOs/ISOs already project shortfalls.[20] This Proposed Rule is likely to further stretch remaining reserves on the system by forcing dispatchable generation retirements. Even if there is power to

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[15] S&P Global, Market Intelligence (Nov. 17, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/court-approves-brazos-electric-reorganization-plan-orders-1-89b-ercot-payment-73110977; Reuters, "Brazos Electric gets initial go-ahead for $1.4 bln energy bill settlement" Sept. 13, 2022, https://www.reuters.com/legal/litigation/brazos-electric-gets-initial-go-ahead-14-bln-energy-bill-settlement-2022-09-13/

[16] Indiana Code § 8-1-8.5-13(g)(2)(ii).

[17] Indiana Code § 8-1-8.5-13(g)(1)(ii).

[18] *See, e.g.,* Kentucky PSC Order, Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To The Extraordinary Fuel Charges Incurred By Kentucky Power Company In Connection With Winter Storm Elliott In December 2022, Case No. 2023-00145 (June 23, 2023). The KPSC rejected a Kentucky utility's request for rate recovery for $11.5 million in power purchase costs during Winter Storm Elliott. The PSC found that the utility failed to meet its legal obligation to provide adequate, efficient and reasonable service by knowingly having inadequate generation to hedge its market exposure.

[19] S&P Global Market Intelligence, Midcontinent ISO, states eye possible 2.1 GW capacity shortfall in 2025, July 17, 2023.

[20] APPA Comments on the Proposed Rule at 4-5, https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0566/attachment_1.pdf; *see also* NERC, 2023 State of Reliability Overview (June 2023), https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Overview.pdf

be purchased, the prices would rise significantly as demand for a dwindling pool of power rises. The increase in prices will impact small entities more significantly because (1) small entities are less likely to have duplicative generation resources to call upon; (2) small entities need more time to build new generation due to financing challenges not faced by investor-owned utilities (IOUs); and (3) small entities are more cost sensitive. The costs to build new generation technologies are directly passed on to public power customers as our members do not have the benefit of rate recovery. EPA should consider these specific cost and financing considerations that more heavily impact this sector.

Transmission constraints further limit the ability to utilize energy markets. For example, in certain areas of the country, transmission systems are networked versus point-to-point; thus, limiting a utility's ability to add new load. In addition, transmission line upgrades would be necessary to allow more than a limited number of local generation assets to provide electricity. Energy cannot be purchased from other sources to import into the electric system because the transmission constraints present delivery problems into these pockets. The design limits of transmission lines and substation equipment cannot be exceeded. Constrained geographic areas further highlight how shutting down generation prior to replacement will jeopardize reliability. Power purchases do not solve the problem if there is no power to be purchased or the transmission lines are insufficient to electrify an area.

Given these market and transmission realities, public power entities are presently evaluating their capacity needs, current generation capacities, the impacts of the Proposed Rule on these assets, and how to resolve future generation deficits. The Proposed Rule places extreme pressure on meeting these needs from a timing and financial perspective. Public power entities must look to replace forced retirements with dispatchable power. A recently built subpart TTTT 550 MW NGCC costs $ 380,000,000.[21] The $380 million doesn't include the costs to produce permit and transport hydrogen needed to comply with EPA's BSER hydrogen pathway, which would be additive. CCS is only slightly more affordable. These project costs are extraordinary and burdensome for smaller entities that cannot look to investors to raise capital. With baseload generation out of reach, the Proposed Rule's subcategories force smaller entities to evaluate less expensive options, such as simple cycle units in the low load category. However, small entities find the Proposed Rule's 20% capacity factor restriction debilitating, as it caps new replacement generation from these assets. Constructing multiple low load simple cycle units is cost prohibitive for small entities, unlike IOUs. APPA asks EPA to consider the Proposed Rule from the perspective of small entities that are forced to retire existing generation without a cost-feasible replacement solution at hand.

B. Costs to build new generation directly affect communities served by public power

Public power entities are particularly rate sensitive. New generation project costs must be directly passed onto public power customers without the benefit of rate recovery. The

[21] Comments submitted by Cooperative Energy, https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0691 at 3.

Proposed Rule's greenhouse gas pathways require an unprecedented financial investment to pursue CCS and/or hydrogen technologies. These costs would be passed onto end users, including those in disadvantaged communities. These residential customers would be more heavily impacted as the ability to afford electricity declines. Persistent poverty communities would face health and safety concerns without electricity to heat and cool homes, particularly during extreme winter and summer temperatures.

As new electric generation resources, especially renewable resources, are developed, new transmission facilities may be required, and the uses of the electric transmission grid will evolve with the change in resource mix. Rising transmission costs are a major concern for many APPA members. Increased transmission investment in recent years has resulted in substantial increases in transmission rates in some regions, and this trend is expected to continue. This concern is especially relevant to public power customers in disadvantaged communities, who pay a higher percentage of their income to cover power bills. Electric rates are generally formulated to recover the cost of delivering electricity. Therefore, any environmental rules (like the one proposed here) applicable to electric generators will result in additional costs being passed through to electric ratepayers.

Beyond transmission upgrades, the Proposed Rule requires the construction of new pipeline infrastructure to implement BSER. Natural gas pipelines and hydrogen pipelines must be constructed to support the Proposed Rule's selections. Communities served by our members are likely to see these impacts. EPA has recognized pipeline construction concerns in its environmental justice outreach meetings prior to release of the Proposed Rule.[22] EPA did not offer an immediate solution except to turn community-specific concerns over to states for engagement. APPA requests that EPA reconsider the impacts on these citizens.

EPA has the flexibility to consider the hardships on economically disadvantaged communities and small entities. Increased energy costs, transmission upgrade costs, and infrastructure encroachment are concrete effects on the disproportionately impacted communities that should be further evaluated.

C. Financing high dollar new generation projects presents substantial challenges for small entities.

Small entities are hard-pressed to finance new generation projects due to the initial investment required, particularly one of the magnitude required to meet the BSER imposed by the Proposed Rule. Since public power entities do not have investors to raise capital, they typically rely on the operating income to perform projects or invest in new generation assets. Many municipalities, especially our smaller members, have limited emergency funds to purchase power in the event the generating asset is offline for a long period of time. This financing structure hinges on the availability of the generating unit. If the Proposed Rule shuts down a key

[22] 88 Fed. Reg. at 33,399 ("The EPA recognizes, however, that facility- and community-specific circumstances, including the existence of cumulative impacts affecting a community's resilience or where infrastructure buildout would necessarily occur in an already vulnerable community, may also exist.").

municipal unit before replacement occurs, then the municipality's ability to provide power to its citizens is severely handicapped.

To finance large projects, municipalities must have revenue-producing assets to use as leverage to secure a loan or bond. Again, retaining existing generation is essential as collateral. Sometimes, a municipality has already leveraged the asset to perform another large environmental project, such as the installation of an air pollution control device or a large coal combustion residuals project. In these circumstances, the municipality may wait for the maturity of existing loans or bonds before further indebting the entity. Additional time is needed to spread out large expenditures.

Furthermore, the Proposed Rule forces small entities to strand existing generation units prior to their end of life. These entities must continue to pay on loans or bonds for retired assets without the income stream that the assets would have generated. On top of this hardship, these small entities must navigate a path to purchase or build replacement generation. EPA must consider this untenable situation.

To date, EPA's answer to challenging financial scenarios is the Inflation Reduction Act (IRA). The IRA presents our members with helpful opportunities, and implementation efforts have recently begun. However, EPA must recognize that IRA tax incentives are only available for renewable generation. Small entities seeking to replace dispatchable generation cannot rely on the IRA. Even for intermittent renewable generation, the IRA simply has not matured to the point in which EPA can assume that it will fund replacement generation. For public power utilities, rural electric cooperatives, and other tax-exempt entities to make use of IRA's refundable direct pay tax credit regime, domestic content requirements must be met unless the project qualifies for certain waivers. As a result, implementation of these requirements and waivers will ultimately drive fundamental decisions about asset ownership and even the basic economics of a facility, not simply the credit amounts for which the project might otherwise qualify. EPA must recognize that the IRA is not a complete funding solution for small entities. While EPA and stakeholders recognize that intermittent renewable generation cannot completely replace baseload dispatchable fossil generation,[23] public power entities must secure financing for that new gas-fired generation, CCS, and hydrogen without access to IRA funds. EPA should depart from any unrealistic assumptions that the IRA will cause and support dramatic generation transitions in just seven years.

[23] EPA accounts for gas-fired generation increases by 2035, presumably for baseload purposes. EPA, Integrated Proposal Modeling and Updated Baseline Analysis: Memo to the Docket for New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal, July 7, 2023 (Docket ID No. EPA-HQ-OAR-2023-0072) at Table 12.

IV. The proposed compliance pathways and timeline for new combustion turbines is unworkable for small entities and should be adjusted to afford flexibility.

The BSER for affected baseload and intermediate load CTs are not feasible. While investor-backed utilities may have more leeway to experiment around the edges of hydrogen technology, this is not realistic for small entities. These projects are further frustrated by the lack of infrastructure that would need to be financed. APPA presented detailed comments and technical data in the Proposed Rule's docket regarding the inability of CTs to combust hydrogen at the levels contemplated by the Proposed Rule over an extended period of time.[24] EPA's BSER for new CTs is simply not adequately demonstrated.

Regardless, APPA considered how to make the requirements for constructing new CTs more practical for small entities. The only realistic improvements involve limiting the applicability of EPA's debilitating BSER selection to fewer CTs. APPA suggests that EPA could create additional subcategories by (1) unit size for the intermediate load category and (2) for peaking units, to carve out these types of CTs from hydrogen co-firing requirements. Presently, the Proposed Rule defines the Intermediate Subcategory as CTs with capacity factor greater than 20% but lower than the source-specific upper bound based on the CT design efficiency. Small entities would benefit from further subcategorization such that CTs on the smaller end of the subcategory range do not have to deploy a costly hydrogen co-firing project. In addition, peaking units should be afforded special consideration. Their quick start/stop capability compliments renewable generation and should not be disincentivized. These additional flexibilities would present more options for small entities that are only able to finance new CT builds without an expensive hydrogen project.

APPA also supports an exemption for smaller CTs. At present, the Proposed Rule only exempts Subpart TTTTa units with a base load rating greater than 260 GJ/h or 250 mmBtu/hr of fossil fuel, alone or in combination with any other fuel, and that serve a generator capable of selling more than 25 MW of electricity to a power distribution system. This exclusion covers only the smallest units. APPA suggests that this applicability language could be increased to apply to the construction of new smaller CTs that would add reliable generation to complement renewable generation. These small CTs should also be permitted to operate at a higher capacity factor to support the grid. This flexibility would provide small entities with a proven, financeable technology to rapidly replace retiring generation.

EPA proposes to narrow the definition of the low load CT category by lowering the electric sales threshold as compared to 40 CFR Subpart TTTT. APPA observes that this restriction hampers CTs that have ramping capability to support grid reliability. EPA should not narrow the band of CTs in the low load category. These simple cycle peaking units are essential for grid reliability. APPA supports a higher electricity sales threshold to provide small entities with more flexibility.

Finally, small entities require more time. EPA should consider relaxing the compliance deadlines for all new CT categories as applied to small entities via a new subcategory or

[24] APPA Comments on the Proposed Rule at 28, https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0566/attachment_1.pdf

exclusion. EPA should factor in additional time due to the financing structure of municipalities. However, APPA observes that existing generation deadlines are the most pressing. Coal-fired retirements should be delayed until entities can commission new generation, which should be built into the Proposed Rule. Obviously, timeline adjustments do not resolve the overall financial burden of the Proposed Rule.

To summarize, APPA reiterates its overarching concerns with EPA's BSER selection for CTs. In the spirit of dialogue, APPA offers the above-referenced suggestions for softening this BSER to provide small entities with several new options to build reliable, dispatchable generation.

V. The Combined Heat and Power (CHP) exemption should be retained and clarified.

The CHP exemption should be retained as a flexible option for small entities and match the CHP applicability threshold in the IRA. The Proposed Rule contains vague language that may lead to confusion or unintended consequences. The final rule should clearly state how it applies to natural gas with CHP. A CHP facility supplying the energy to a third-party thermal host should be able to subtract this annual thermal or electric output from the gross electric sales generated by the facility. EPA should specify that the electric output from the CHP/small boiler operation does not need to be directly (physically) supplied to the thermal host for use. Rather, if the CHP electric output is supplied to a transmission system and the thermal host uses power from that transmission system, then the CHP operation should be exempt. EPA should recognize the benefits of the CHP process that provide (1) redundant thermal supplies, (2) stable thermal electrical load to promote fuel purchases and local power quality, and (3) reliability provided by a locally connected and operating generation resource. These systems should be supported and offered flexibility from regulation.

VI. Conclusion.

Thank you for your consideration of these comments. The Association looks forward to working with EPA concerning this rulemaking and its small business implications. Should you have any questions regarding these comments, please contact Ms. Carolyn Slaughter (202-467-2900) or cslaughter@publicpower.org.

Sincerely,

Carolyn Slaughter

Carolyn Slaughter
Senior Director, Environmental Policy
American Public Power Association

East Kentucky Power Cooperative (EKPC)

Via electronic correspondence at Wiggins.Lanelle@epa.gov

Ms. Lanelle Wiggins
RFA/SBREFA Team Leader
Office of Policy
U.S. Environmental Protection Agency
1201 Constitution Avenue NW
Washington, DC 20004

RE: East Kentucky Power Cooperative, Inc.'s Comments on the Small Entity Representative Panel Outreach on the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule, Docket ID No. EPA–HQ– OAR–2023–0072

Dear Ms. Wiggins:

East Kentucky Power Cooperative, Inc. (EKPC) is pleased to provide comments and recommendations as a small entity representative (SER) on the above-referenced rule (the Proposed Rule). EKPC appreciated the opportunity to engage in the Small Entity Representative (SER) meeting on August 10, 2023. Thank you for considering the following for comments in response to EPA's request for feedback. For additional detail concerning select areas of these comments, EKPC refers to its comments filed in the docket for the Proposed Rule.[1]

I. High Level Summary of EKPC's SER Comments.

EPA requested feedback from small entities regarding any flexibilities or alternatives that could minimize significant economic impact of the Proposed Rule on small entities. After consideration, EKPC believes the most effective solution would be a revision to the best system of emission reduction (BSER) in the Proposed Rule for new and existing generating units. EKPC has thoughtfully considered and performed its own technical review of the chosen BSER. We conclude that carbon capture and sequestration (CCS) and hydrogen co-firing are not realistic options for EKPC and many other cooperatives as small entities. The technologies are experimental and, and even if they were feasible, the costs are indefensible, the mandates are overly burdensome and Rule's timelines could not be met. These options are the backbone of the Proposed Rule. Therefore, any ideas on flexibilities that EKPC could offer would not

[1] Comments of East Kentucky Power Cooperative, Inc. on the Proposed Rule, filed in the docket on August 8, 2023, https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0542

provide significant relief. We also respectfully ask EPA to refrain from implementing any of the more stringent options presented in the preamble for the same reasons.

If EPA revises the BSER, EKPC encourages EPA to consider the following items that are important to small entities, including cooperatives:

- Timeframes that can be met. EKPC appreciates EPA's consideration of the additional time needed for financing and outage planning.
- Exclusions for smaller new gas-fired units and peaking units: Smaller resources support renewable resources and are less expensive to build for small entities.
- Exclusions for all existing gas-fired units: The existing gas-fired fleet is essential for reliability and to complement renewable generation.
- Subcategory development for Cooperatives: All non-profit Cooperatives should be in a separate category since they serve rural America, in our case, rural Kentuckians, who are some of the poorest of the poor. By definition, rural Americans or in our case, Kentuckians, fit the definition of Environmental Justice, the disproportionately served.
- Fleet-wide generation averaging of emissions inside the fence: Develop a mechanism by which a fleet's average carbon dioxide emissions, whether by mass tons or rate, can be used to set BSER from a baseline year, such as 2005, to determine a percentage of reductions to be demonstrated by 2050. This would offer a mechanism by which States and stakeholders could develop an approvable plan by which EPA could review and approve.
- A mechanism for reliability relief: Key baseload generation should be allowed to operate until new replacement generation comes on-line. Additionally, should grid emergencies develop, cooperatives could use emergency conditions under the Clean Air Act Title V air permits as a safety valve. Once grid emergency relief occurs, the units could return to normal operating conditions or go offline as needed. This would provide grid reliability and flexibility to the operators and regional transmission organizations (RTOs).

EKPC encourages EPA to refrain from devising a trading program like the Good Neighbor Federal Implementation Plan (FIP) for GHGs. The FIP lacks the true features of a trading program because EPA does not provide enough allocations to meaningfully trade. Banks are also reduced, removing another flexibility. As a result, the program provides very little flexibility to sources, and allowance prices have skyrocketed. Small entities cannot afford high allowance prices, and they have fewer units to trade allowances within their own systems. Trading is not a workable flexibility, and this should be considered during this process.

II. Introduction.

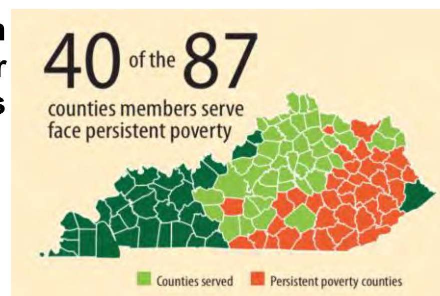
A. About EKPC.

EKPC is a not-for-profit owned, operated, and governed by its members which use the energy and services EKPC provides. The Owner-Member cooperatives to which EKPC provides energy supply 520,000 homes, farms, and businesses across 87 counties in Kentucky. EKPC's purpose is to generate electricity and transmit it to 16 Owner-Member cooperatives that distribute it to retail, end use consumers. EKPC provides wholesale energy and services to sixteen distribution cooperatives through baseload units, peaking units, hydroelectric power, solar, landfill gas to energy units transmitting power across the rural Kentucky areas via more than 2,900 miles of transmission lines.

EKPC's owner-members collective customer base is comprised predominantly of residential customers (93 percent). In 2019, 57 percent of EKPC's owner-member retail sales were to the residential class. The 2020 End-Use Survey results indicate electricity is the primary method for water heating and home heating.

EKPC is the voice for a substantial number of end users of electricity in its service territory that live in substantial poverty. These communities place a high value on affordable energy costs. EKPC's service territory includes rural areas with some of the lowest economic demographics in the United States. In these areas, families, literally, are faced with a regular choice between food, electricity and medicine. Of the eastern Kentucky counties that EKPC's owner-member cooperatives serve, 40 counties experience persistent poverty, as reported by the USDA.

Table, Kentucky Counties in EKPC's Owner-Member Service Areas



Many of these hardworking Americans have been plagued by unemployment from mines, trucking companies, restaurants and other businesses. The unemployment rate is 60% higher than the national average. They rely on government assistance to survive: Thirty to 54% of total income in most Eastern Kentucky counties comes from government assistance. Forty-two percent of these electricity users are elderly (65 years or older). Many are on fixed incomes and reside in energy-leaking mobile homes. Recent brutal cold weather has caused their monthly electric bills to skyrocket. EKPC has a strong interest in keeping energy affordable to assist its 16 Owner-Member cooperatives in serving people facing the harsh realities of today's economy.

EKPC and its Owner-Member cooperatives have a strong commitment to environmental excellence, which is underscored by a record of environmental over-compliance, investments in air control technology, and renewable diversification. EKPC has ensured that excellent air quality and clean water is sustained and has minimized and managed waste in accordance with and beyond regulatory minimums. EKPC is a leader in environmental stewardship in the Kentucky community.[2] In addition, EKPC has created a Strategic Sustainability Plan with goals and investments through 2035. EKPC developed, permitted and built the first renewable energy sources in Kentucky. Since that time, EKPC launched a 60-acre photovoltaic solar array in Winchester, Kentucky, and continues to utilize landfill gas generation assets and to support hydroelectricity (Wolf Creek and Laurel Dams) via Southeastern Power Administration (SEPA) contracts.

EKPC is an active participant in reducing its CO2 footprint, but renewables must be balanced with coal-fired, dual fueled natural gas-fired generation and small combustion turbine peakers for reliability. EKPC installed 60 acres or 10 gross MWs of solar array commissioned in 2017. Recent summer heat waves and winter freezes serve as stark evidence that renewable generation has operability and reliability constraints. Fossil generation plays an essential role in grid reliability until technology advances. While nuclear generation options are available, given cooperatives small balance sheets, small modular reactors are an option in the distant future likely beyond 2040 for such time for research and regulatory licensing certainty avails itself.

B. The EKPC Fossil Fuel-Fired Generating Fleet.

The Proposed Rule substantially affects EKPC. The following existing fossil fuel units are essential to EKPC's ability to provide power to rural Kentuckians. EKPC has no plans to retire any of these assets. Any retirement of these assets would be premature and costly.

- Spurlock Station. The station is located near Maysville, Kentucky on the Ohio River. It is EKPC's flag-ship plant. The closest natural gas pipeline is almost 40 miles from Spurlock Station. The electric generating units (EGUs) at the facility are:
  - Spurlock Unit 1 – is a wall-fired unit (344 MW)[3] that combusts bituminous coal. Unit 1 has cold side ESP, WFGD, Wet ESP, SCR and low-NOx burners to control particulate matter (PM), SO2, SO3 / H2SO4 mist, HAPs and NOx respectively, installed on or before April 2009.
  - Spurlock Unit 2 – is a tangential-fired unit (555 MW) that combusts bituminous coal. Unit 2 has a hot side ESP, WFGD, Wet ESP, SCR, low-NOx burners, and over-fire air to control PM, SO2, SO3 / H2SO4 mist, HAPs and NOx, respectively, installed on or before October 2008.
  - Spurlock Unit 3 – is a coal-fired circulating fluidized bed (CFB) unit (305 MW), which is designed to emit less NOx in the combustion

[2] *See* https://www.ekpc.coop/environmental-stewardship, for a description of our efforts.
[3] Spurlock Unit MW values are taken from the Consent Decree in *United States v. EKPC*, No. 04-34-KSF (E.D. Ky). MW values are provided for descriptive reference only and are only generally reflective of unit capabilities.

process. Unit 3 has a SNCR to control NOx, a dry FGD to control SO2/SO3, and a filter fabric baghouse to control PM and HAPs.
  - Spurlock Unit 4 – is a CFB unit (315 MW), which is designed to emit less NOx in the combustion process. Unit 4 has a SNCR to control NOx, a dry FGD to control SO2/SO3 and a filter fabric baghouse to control PM and HAPs.

- Cooper Station. The station is located near Burnside, Kentucky adjacent to Lake Cumberland. Cooper Station is a critical asset due to its location in rural, south-central Kentucky. Cooper Station serves a transmission-constrained area. The closest natural gas pipeline is almost 40 miles from Cooper Station. The EGUs at the facility are:

  - Cooper Unit 1 – is a wall-fired unit (124 MW)[4] that combusts bituminous coal. Unit 1 has low-NOx burners. It is tied into the Unit 2 dry FGD and pulse jet fabric filter to control SO2, HAPs and PM and shares a common stack with Cooper Unit 2.
  - Cooper Unit 2 – is a wall-fired unit (240 MW) that combusts bituminous coal. Unit 2 has a SCR and low-NOx burners, dry FGD and filter fabric baghouse to control PM, HAPs and SO2/SO3. It shares a common stack with Cooper Unit 1.

- Smith Station. The station, located near Winchester, KY, consists of natural gas-fired combustion turbines. Smith provides EKPC with nimble assets to quickly meet daily power demands and support renewable generation. EKPC has no plans to retire these units. EGUs at the facility are:

  - Smith Units 1-3 – are simple-cycle dual fuel, predominately natural gas-fired combustion turbines (115 MW each).[5] Units 1-3 use water injection to control NOx.
  - Smith Units 4-7 -- are simple-cycle dual fueled oil and gas-fired combustion turbines (114.91 MW each). The units have dry low-NOx burners.
  - Smith Units 9 and 10 -- are simple-cycle gas-fired combustion turbines (102 MW each). The units have SCRs to control NOx and reduce CO by use of catalytic oxidation.

- Bluegrass Station. The station, located near LaGrange, KY, consists of dual fueled natural gas-fired combustion turbines with diesel fuel as an emergency back-up. The units are essential to the region and served a key role in

[4] Cooper Unit MW values are taken from the Consent Decree in *United States v. EKPC*, No. 04-34-KSF (ED Ky). MW values are provided for descriptive reference only and are only generally reflective of unit capabilities.
[5] Smith Unit MW values are taken from the Title V permit for the facility. MW values are provided for descriptive reference only and are only generally reflective of unit capabilities.

preventing brown and blackouts in the Louisville region during Winter Storm Elliott last year.

- Bluegrass Units 1-3 – are simple-cycle gas-fired combustion turbines (208 MW each).[6] All three units have dry low-NOx burners.

III. EPA should re-evaluate and acknowledge the tremendous cost impacts to small entities.

EPA certified that the Proposed Rule will not have a significant economic impact on a substantial number of small entities. EPA's analysis has several flaws that should be corrected. The Regulatory Flexibility Act (RFA) requires agencies to consider the impacts of regulations on small business entities. Small entities include small not-for-profit organizations, such as cooperatives, and small governmental jurisdictions. Agencies must convene a Small Business Advocacy Review (SBAR) panel[7] and make available for public comment an initial regulatory flexibility analysis (IRFA) when publishing a proposed rule.[8] If the agency certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities, then no panel is needed.[9]

With respect to the Proposed Rule, EPA's screening analysis found that only a number of small entities would experience annual compliance costs in excess of 1% based on the cost-to-revenue or cost-to-sales test.[10] EPA certified no significant economic impact based on these results.

The screening analysis is in error in the following ways:

- The analysis does not include any costs to entities, such as EKPC, to comply with the Section 111(d) portion of the rule. In its analysis, EPA signed EKPC up for a CCS project at Spurlock Unit 1 and 2[11] – a massive multi-billion-dollar project. By ignoring those costs, EKPC turns a blind eye to the costs that disadvantaged communities must bear. In contrast, EPA found a small entity

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[6] Bluegrass Unit MW values are taken from the Title V permit for the facility. MW values are provided for descriptive reference only and are only generally reflective of unit capabilities.
[7] 5 U.S.C. § 609(b).
[8] *See* 5 U.S.C. § 603.
[9] *See id.* at § 605(b).
[10] EPA, "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," May 2023 at 5-5 – 5 11, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.
[11] IPM 3032 Baseline case, Table 7-1 (identifying 38 coal-fired units will adopt CCUS by 2032, including Spurlock Unit 1 and 2).

impact in the Clean Power Plan rulemaking under the same provision of the Clean Air Act.[12]

- The analysis undercounts the number of affected entities by failing to consider the baseload replacement needs of cooperatives with coal-fired assets, driven by Section 111(d), and instead, relies on historical data to project future generation projects.
- The analysis fails to consider all of the costs of the Section 111(b) portion of Proposed Rule to small entities

EPA should revise its screening analysis to properly account for the exorbitant costs of this Proposed Rule and acknowledge the true cost disproportionately impacts small entities. EPA should convene a SBAR panel. EPA should also incorporate alternatives for small entities in a forthcoming supplemental notice of proposed rulemaking and then into the final rule. Those alternatives should involve a revision of BSER.

IV. The Proposed Rule Causes Economic Hardship for Electric Cooperatives and the Disadvantaged Communities They Serve.

A. About Electric Cooperatives.

Electric cooperatives are a distinct portion of the utility sector. EKPC requests EPA's consideration of challenges specific to cooperatives. The electric cooperative network is composed of 831 distribution cooperatives. Cooperatives were built by and serve co-op members in the community with the delivery of electricity and other services. All but the three largest electric cooperatives qualify as "small businesses" under Small Business Administration standards. Cooperatives operate at cost and without a profit incentive. They are owned by the members they serve with no independent stockholders.

Cooperatives serve 42 million people in predominantly rural areas, including 92% of persistent poverty counties. The sector powers over 21 million businesses, homes, schools and farms in 48 states. Cooperatives sell most of their power to households rather than businesses, unlike investor-owned utilities (IOUs). Therefore, the costs of this Proposed Rule will be borne directly by hard-working Americans. Rate affordability is crucial for consumer-members at the end of the line.

Since the 1970s, the cooperative energy sector has been coal-heavy. In response to a Congressional mandate, electric cooperatives built approximately two-thirds of the coal-fired units in the electric cooperative fleet under the 1978 Powerplant and Industrial Fuel Use Act, prior to its repeal. The Act pushed electric cooperatives to build significant new "coal capable" baseload generation for self-generation to preserve natural gas supplies. Some cooperatives still have outstanding loan debt on these

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[12] SBAR Panel: Federal Plan for Regulating Greenhouse Gas Emissions from Electric Generating Units, Final Report, https://www.epa.gov/sites/default/files/2015-10/documents/report-sbar-panelreport-cppfip.pdf

investments. The premature closure of coal generating assets could lead to stranded assets, causing additional harm to the disproportionate that we serve.

B. Special Financing Considerations.

The Proposed Rule would require major capital investments in new generation and large retrofit projects for coal-fired generation. Cooperatives must raise an unprecedented amount of capital to fund these projects. The largest financier of cooperative capital projects is Rural Utility Service (RUS).[13] Cooperatives must be afforded time to pursue financing.

RUS financing is a multi-step process that includes the National Environmental Policy Act (NEPA) provisions that require an Environmental Impact Statement (EIS) and take at least 18–24 months longer than the Proposed Rule's projected time on the front end of the project.[14] The process begins with cooperatives submitting a detailed project work plan to RUS, including vendor estimates. RUS must approve the Work Plan.

RUS financing requires compliance with the NEPA, which significant time at the beginning of a large project. Environmental reviews require development of Environmental Reports (ER), Environmental Assessments (EA), or Environmental Impact Statements (EIS) depending on the complexity/scale of the project.[15] RUS reviews the EA or other appropriate environmental document and may require additional information, additions or revisions to the EA during the review process. Borrowers must wait for the conclusion of RUS's environmental review before taking any action on projects or obtaining RUS financial assistance.[16] Once RUS releases funds, the project engineering design and competitive bidding process may commence.

EKPC is a regular RUS borrower to finance environmental compliance and other projects. Other financing options have significantly higher interest rates. EKPC asks EPA to consider this additional 18 to 24 month financing time period in its timelines.

C. Cumulative cost impacts of EPA's suite of power sector rules on Small Entities should be considered.

[13] For more information about RUS and its essential role for the cooperative community, see https://www.rd.usda.gov/about-rd/agencies/rural-utilities-service (*visited June 3, 2022*) ("The Electric Program provides funding to maintain, expand, upgrade and modernize America's rural electric infrastructure. The loans and loan guarantees finance the construction or improvement of electric distribution, transmission and generation facilities in rural areas. The Electric Program also provides funding to support demand-side management, energy efficiency and conservation programs, and on-and off-grid renewable energy systems. Loans are made to cooperatives, corporations, states, territories, subdivisions, municipalities, utility districts and non-profit organizations.").

[14] New generation requires scoping and approval from the Board of Directors and submittal to the Kentucky Public Service Commission for a Certificate of Public Convenience and Necessity (CPCN) approving the project to move forward.

[15] *See* 7 CFR § 1970.8 (describing the extent of the environmental review).

[16] *See* 7 CFR § 1970.12.

EPA has recently proposed a substantial number of impactful environmental rulemakings that are targeted at the power sector. A few of these rules include: Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review; and Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments. Meanwhile, this proposed rulemaking involves five actions rolled into one.

Cooperatives have limited resources to finance multiple large environmental compliance projects. Cooperatives do not have investors to raise money. Large, capital-intensive projects are a substantial investment for smaller entities. EPA should consider the cumulative cost impacts of EPA's suite of power sector rules.

D. Cooperatives are disproportionately impacted as small generation systems.

Cooperatives have small generating systems, which limits compliance options for complex rules, such as the Proposed Rule. Since cooperatives do not have redundant assets, capacity shortfalls between Section 111(d) retirements and commissioning of new generation are more likely. Trading programs and averaging are often not useful for cooperative systems that have fewer units in these programs. Fewer units and plants to average or trade diminishes the flexibility of these programs, particularly when structured like the recent Good Neighbor FIP that restricts banking. Cooperatives also must plan around outages since there are fewer resources to make up the generation deficit.

E. The Section 111(b) BSER selections are more costly for cooperatives with transmission-heavy systems.

Hydrogen, natural gas, and CCS all require new infrastructure. When applied to electric cooperative systems, more lines must be built to accommodate large rural areas. Cooperatives have greater infrastructure needs. To power 56% of America's land mass, large spans of infrastructure are required. Rural areas are electrified by miles of transmission lines. This infrastructure must be developed over America's rural areas to ensure that the plants serving these cooperative service territories can install BSER to be compliant. Vast service territories make this task more time consuming and costly for cooperatives, particularly in areas in which the geology does not support CO2 storage. EPA should consider these larger small entity impacts.

F. EPA should consider the cost of stranded assets in its cost impact analysis for small entities.

The Proposed Rule requires utilities to strand generation assets even though they are still paying on environmental compliance financial obligations. In EKPC's case, the cooperative incurred substantial debt through 2049 to enable the installation of NOx and SO2 air pollution controls at its coal-fired units between 2007 and 2012. To achieve compliance with EPA's recent revisions to the CCR rule and ELGs, EKPC made substantial investments in a project at its Spurlock Station with financial obligations through 2050. Although EKPC should be rewarded and praised for these financial commitments to environmental compliance, the Proposed Rule unfairly and perversely penalizes EKPC for cleaning up its coal plants, reducing emissions and being proactive in the communities. EKPC must continue to pay on loans that finance past EPA-required compliance costs. EPA's small entity analysis must consider the hardship of placing debt on top of debt, as cooperatives move toward financing new generation projects. The ratepayers must finance EPA's changing political agendas, likely in the form of environmental compliance riders in our Public Service Commission regulated state.

V. Cooperatives serve disadvantaged communities that must bear higher energy costs due to the Proposed Rule.

Electric cooperatives sell the majority of their power to households rather than businesses. To this end, the Proposed Rule's greenhouse gas BSER would require an astronomical financial investment in CCS and/or hydrogen technologies. These costs would almost certainly be passed on to end users as environmental compliance costs. The economic harm to disadvantaged communities risks human health and welfare. Rural residential customers must be able to afford electricity to power rural Kentucky homes, especially during extreme winter and summer temperatures. Yet, the Proposed Rule has no direct health benefits flowing back to those communities from lowering greenhouse emissions.

In addition, the infrastructure required to implement BSER will impact rural and disadvantaged communities. Great expanses of natural gas pipelines and hydrogen pipelines must be commissioned to support BSER. Carbon dioxide transport pipeline infrastructure is also necessary to transport the CO2 to be beneficially used or sequestered. Communities are likely to see these impacts. Commenters have raised concerns regarding pipeline safety, particularly with respect to hydrogen transportation. EPA even acknowledged that pipeline construction concerns were raised in community engagement meetings regarding the Proposed Rule.[17] EPA did not offer a direct solution except to turn community-specific concerns over to states for engagement.

EKPC's owner-member cooperatives serve 40 of 87 eastern Kentucky counties that experience persistent poverty. EKPC asks EPA to reconsider the impacts on these citizens. EPA certainly has the flexibility to consider the hardships on economically disadvantaged communities and small entities, as it did in the context of the 2015

[17] 88 Fed. Reg. at 33399 ("The EPA recognizes, however, that facility- and community-specific circumstances, including the existence of cumulative impacts affecting a community's resilience or where infrastructure buildout would necessarily occur in an already vulnerable community, may also exist.").

Ozone NAAQS.[18] Increased energy costs and contending with infrastructure takings are concrete effects on these disproportionately impacted communities. Persistent poverty end users will not sustain a direct air quality benefit from this rule[19] but will be impacted by these negative consequences.

VI. Reliability is a large concern for small entities.

A. The Proposed Rule's new generation timelines do not permit new generation to be built in time to replace retiring generation.

Cooperatives are disproportionately impacted by the Proposed Rule due to fuel use. Cooperatives use a balanced fuel mix, which includes generation of electricity using coal at a higher percentage than other portions of the power sector.[20] Small entities that own small, coal-heavy systems must react to the BSER requirements of Section 111(d) but do not have enough time to build replacement generation. By setting BSER that small entities cannot achieve, the Proposed Rule shuts down small entity key generating resources. Without other units to gap-fill, cooperatives have few options.

Cooperatives need more time to pivot. A hypothetical new generation project to place replacement, dispatchable generation (gas) on the ground requires construction of a gas line, financing, RUS funds, permits, PJM interconnection, Public Service Commission approval, commencement of construction and commissioning. Multiple new generation projects would need to proceed concurrently to replace an entire plant, like Spurlock Station. It is not possible to compress this type of project into only six years (2024-2030).[21] Small entities would be hard-pressed financially to shoulder multiple projects concurrently.

EPA must provide cooperatives with time to build new generation before retirements occur. Entities, such as EKPC, do not have redundant generation assets to meet load. Therefore, generation will roll off of the grid creating reliability concerns in an already stressed electricity grid.

B. Transmission-constrained areas deserve special consideration.

Areas with transmission system limitations and energy market constraints risk power interruption if replacement generation cannot be put in place before retirements. RTOs must be involved to evaluate safety and reliability concerns. EKPC discusses the

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[18] *See, e.g.*, 87 Fed. Reg. 21842 ("I/M programs ensure that vehicles are operating according to EPA's vehicle emissions standards and adequately protecting public health. However, any Basic I/M program for the 2015 ozone NAAQS may present potential economic hardship and other concerns for low-income individuals of newly reclassified Moderate ozone nonattainment areas.").
[19] Proposed Rule at 33247, 33413.
[20] Cooperatives have a generation mix of 35% coal-fired assets based on 2021 data, which is greater than the national fuel use average. https://www.publicpower.org/system/files/documents/2023-Public-Power-Statistical-Report.pdf
[21] The compliance date for existing coal-fired units is January 1, 2030.

transmission needs and inadequacies in detail in its comments. The high-level message is that transmission systems require time and substantial costs to upgrade. Until that happens, assets in constrained areas are essential and cannot be retired by EPA.

EKPC-owned Cooper Station is in a transmission constrained area near Lake Cumberland in southern Kentucky. The grid in that area of Kentucky is primarily electrified by three generation sources: Cooper Station (Cooper), E.W. Brown Generating Station (Brown), and Wolf Creek Hydroelectric Plant (Wolf Creek). A total of 590 MW is needed between these three generation assets to serve this area of Kentucky during typical peak load conditions. Cooper Station is essential to maintain the combined 590 MW need for this area because the three generation assets cannot be offline at the same time without creating customer interruptions. Present infrastructure options restrain generation from other assets to contribute significant power to this area.

The Proposed Rule would substantially reduce capacity in this area (namely, the coal-fired assets of Cooper Station and Brown) causing a dire situation. The transfer of energy into areas served by Cooper and Brown, without exceeding the design limits of transmission lines and substation equipment, is not presently possible.

In summary, EPA should consider the costs and timing of projects that solve transmission constraints. Transmission and market realities are complicated, local issues that are not adequately considered by the Proposed Rule. A Reliability Mechanism would assuage this concern. Key assets for reliability should be allowed to continue operation until new generation can be built or transmission lines upgraded.

VII. The Proposed Rule's BSER proposal is not adequately demonstrated or cost effective for small entities.

The BSER selected for new and existing units is not adequately demonstrated.[22] Hydrogen co-firing and CCS are rampant with technical issues and infrastructure inadequacies. The timelines presented in the Proposed Rule cannot be met. BSER (CCS) for EKPC's six operating coal-fired units cannot be achieved at these locations by the date of approval of the Kentucky Section 111 state plan or January 1, 2030.[23] CCS and hydrogen co-firing for new gas assets are also not feasible. CCS is also not cost effective for EKPC's coal-fired fleet.[24]

The Proposed Rule's alternatives only leave generators the option of installing multiple low-load CTs as baseload generation to avoid CCS or hydrogen, which is highly impractical, expensive, and may even emit more CO2 than one baseload gas-

[22] EKPC refers to the extensive comments on BSER in the docket and in EKPC's own comments.
[23] Proposed Rule at 498.
[24] NRECA engages in a thorough discussion of CCS costs in the *Analysis of Post Combustion CO_2 Capture Costs in EPA's Proposed Power Plant Greenhouse Gas Emissions* Rule, attached to the NRECA comments.

fired new unit. CCS and hydrogen co-firing should not be included as feasible options until they are deployment-ready nationwide. Further, EPA should weigh cost and any non-air quality health and environmental impact and energy requirements. Co-benefits should not diminish the real time dollars that compliance would require.

VIII. EPA should consider the cost impacts of power purchases that make up generation gaps if capacity is short.

EKPC's current dispatchable generation resources are fundamental to serving its load on a reliable basis. EKPC is a winter peaking system serving heating resource load to rural residential consumers. EKPC's existing generation fleet covers forecasted winter loads based on projections. Extra reserves are limited. To make up deficits, power purchases would be required. With so such generation coming off-line by 2030-2032, reserves are likely to be limited on the PJM system based on the Proposed Rule. Any available power on the market is expected at large power purchase prices as supply becomes limited and demand increases.

EKPC prepared pricing estimates to demonstrate the exorbitant cost of power purchases from the market. Notably, these examples do not include pricing that is anticipated to escalate due to the Proposed Rule:

- On June 13, 2022, if EKPC had to purchase power from the PJM market to replace Cooper Station (Cooper Units 1 and 2) for one day of lost generation, the market cost would total $2.6 million. Of that total, Cooper Unit 1's lost capacity would cost $850,000 to purchase off the PJM market, while Cooper Unit 2 would cost the remainder ($1.7 million).
- On December 23, 2022, PJM prices experienced during Winter Storm Elliott exceeded $4,000/MWh when there was no sun to power solar resources. EKPC's generation fleet was on-line and over-performed as compared to its commitment to provide capacity to the PJM region. EKPC calculated the hypothetical cost to replace generation from EKPC's existing generating plants as if the Proposed Rule retired them. The total cost would have been over $135 million for two days of extreme cold. These costs would be passed along to EKPC's rate payers, if approved by the KPSC. These disadvantaged communities cannot and should not have to bear this tremendous burden.

EKPC Generating Stations	December 23, 2023	December 24, 2023
Spurlock Station	$25M	$34M
Cooper Station	$6.5M	$9M
Smith Station	$17M	$23M
Bluegrass Station	$10M	$13M

Any power purchase decision that EKPC makes would be subject to review and approval by the Kentucky Public Service Commission (KPSC) for rate recovery. KPSC recently exercised its authority to reject a decision by another Kentucky utility that did not have adequate generation during Winter Storm Elliott and had to purchase power.[25] The KPSC denied a request for rate recovery for $11.5 million in power purchase costs. The KPSC found that the utility did not meet its legal obligation to provide adequate, efficient and reasonable service. The costs and uncertain rate recovery highlight the dangers of being capacity short and subjecting a not-for-profit cooperative to unhedged market exposure. EPA should recognize that power purchases are off-the-table for small entities and its customers.[26]

IX. Conclusion.

Thank you for your consideration of these comments regarding the impacts on EKPC as a small entity. EKPC looks forward to working with the Agency in the greenhouse gas rulemaking process for the power sector. Should you have any questions regarding these comments, please contact Jerry Purvis at 859.744.4812 or jerry.purvis@ekpc.coop

Sincerely,

Jerry Purvis

Jerry Purvis, VP Environmental Affairs,
East Kentucky Power Cooperative

[25] Kentucky PSC Order, Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To The Extraordinary Fuel Charges Incurred By Kentucky Power Company In Connection With Winter Storm Elliott In December 2022, Case No. 2023-00145 (June 23, 2023).

[26] During Winter Storm Uri, Brazos Electric Power Cooperative declared bankruptcy due to costs incurred from power purchases from the Electric Reliability Council of Texas Inc. (ERCOT). The cooperative settled with ERCOT to pay $1.89 billion of the total cost but had to sell its gas-fired generation portfolio, totaling around 2,200 MW of capacity. S&P Global, Market Intelligence (Nov. 17, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/court-approves-brazos-electric-reorganization-plan-orders-1-89b-ercot-payment-73110977; Reuters, "Brazos Electric gets initial go-ahead for $1.4 bln energy bill settlement" Sept. 13, 2022, https://www.reuters.com/legal/litigation/brazos-electric-gets-initial-go-ahead-14-bln-energy-bill-settlement-2022-09-13/

Golden Spread Electric Cooperative (GSEC)

From:	Ruth Calderon
To:	Wiggins, Lanelle
Cc:	Cronmiller, Rae E.
Subject:	Comments of Golden Spread Electric Cooperative: Small Business Advocacy Review Panel Outreach meeting on EPA"s proposed EGU GHG NSPS rule
Date:	Thursday, August 24, 2023 6:16:54 PM
Attachments:	GSEC 111b _111d comments 8-8-23 FINAL (1).pdf

Good evening Lanelle,

Please find attached, Golden Spread Electric Cooperative's, inc. ("Golden Spread") comments on the Environmental Protection Agency's ("EPA") Small Entity Representative Panel Outreach for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units ("Proposed Rule").

Golden Spread also incorporates by reference the comments submitted by the National Rural Electric Cooperative Association ("NRECA"), of which Golden Spread is member.

As discussed in its attached comments, Golden Spread is a non-profit generation and transmission cooperative ("G&T") owned by its 16-member rural electric distribution cooperatives ("Members"). Golden Spread's corporate goal is to supply low cost, reliable wholesale power to its Members' who supply retail service to approximately 318,000 meters serving Member-consumers (i.e., members of a cooperative and retail electric customers) in the South Plains, Edwards Plateau, and Panhandle regions of Texas (covering 24 percent of the state), portions of Southwestern Kansas and Southeastern Colorado, and the Oklahoma Panhandle.

By joining together and owning their own wholesale power supplier (i.e., G&T), Golden Spread's Members' and the communities they serve are able to achieve more control over pricing and planning of their power supply needs.

Over the past 18 years, Golden Spread invested more than a billion dollars to build and maintain primarily quick start gas (dispatchable) generation to serve its Members' power supply needs. This quick start generation supports the vast renewable generation in the region and allows Golden Spread to hedge the cost of serving its Members' loads while mitigating volatile price spikes.

As a G&T cooperative, Golden Spread recovers all of its costs from its Members who recover their costs from their Member-consumers. Ultimately, it is the communities served by Golden Spread's Members (i.e., Member-consumers) who will bear any costs to Golden Spread from the Proposed Rule.

As discussed in the attached comments, Golden Spread requests that EPA reconsider its analysis on the proposals impacts on small cooperative entities by objectively considering the following factors:

- Impacts of the operating ceiling proposed by EPA for "low load" natural gas-fired combustion turbines of 20% after accounting for:
    - o the essential role and need for simple cycle units to support renewables,

particularly in areas with high renewable development; and

  - the cost impacts to small cooperative entities who will be required to invest in additional, incremental generating capacity should its needs exceed the 20% operating limit.

- Impacts of all costs associated with the use of clean hydrogen in geographic areas where significant water is unavailable.

Please let me know if you have any questions,

Ruth Calderon
Legislative, Regulatory and Policy Manager
Golden Spread Electric Cooperative, Inc.
PO Box 9898
Amarillo, TX 79105-5898
Phone: (806) 349-5205
Mobile: (806) 681-5788
rcalderon@gsec.coop

Golden Spread
Electric Cooperative, Inc.
A Touchstone Energy® Cooperative

GSEC Attachment – NPRM comments

Golden Spread
Electric Cooperative, Inc.
A Touchstone Energy™ Cooperative

August 8, 2023

Submitted by Federal eRulemaking Portal:

EPA Docket Center
U.S. Environmental Protection Agency
U. S. EPA Mail Code: 28221T 1200 Pennsylvania Ave. NW Washington, DC 20460
https://www.regulations.gov

Attn: Docket ID No. EPA–HQ–OAR– 2023–0072

Dear Administrator Regan,

Golden Spread Electric Cooperative, Inc. ("Golden Spread") appreciates the opportunity to submit these comments on EPA's Proposed Rule published at 88 Fed. Reg. 33240 (May 23, 2023). Golden Spread also supports and incorporates by reference the comments submitted by the National Rural Electric Cooperative Association ("NRECA"), of which Golden Spread is a member.

I. EXECUTIVE SUMMARY

Key points of Golden Spread's comments include:

- The Proposed Rule would significantly interfere with Golden Spread's mission to reliably provide responsibly generated and reasonably priced electric service to its member distribution cooperatives, which serve consumers largely located in rural areas and who are often affected by poverty. This outcome is not only inconsistent with the nation's climate change policy, but also President Biden's Executive Order 13985, *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government*, which identifies "persons who live in rural communities" and those "otherwise adversely affected by persistent poverty" as deserving of special attention by Federal policymakers.

- The operating ceiling for "low load" natural gas-fired combustion turbines ("CTs") should be set at 33%, retaining the current regulatory ceiling. Mandating a lower ceiling, such as the 20% included in the Proposed Rule, will disrupt the essential role CTs play in supporting the reliable operation and growth of renewables-powered energy sources (e.g., wind and solar). Golden Spread has strategically invested in natural-gas fired "fast start" simple cycle units ("NGSC") to support the abundant and growing wind generation capacity in its service area. A rule aimed at reducing greenhouse gas emissions must not create barriers to the necessary use of NGSC units to support the reliable operation and integration of renewable energy resources.

- Co-firing CTs with hydrogen, or carbon capture and sequestration ("CCS") of greenhouse emissions from CTs, is not the "best system of emission reductions" ("BSER") for CTs on the scale and schedule proposed by EPA. The Proposed Rule also does not adequately consider technical issues such as the impact of hydrogen co-firing on CT reliability, the water intensity of these technologies that limits their applicability in drought-stricken areas such as those served by Golden Spread, and the engineering and energy inefficiencies associated with CCS.

- The proposed allowance for low load CTs to exceed the applicable threshold in the case of "system emergencies" has no value unless generators are not exposed to allegations of violations of other applicable air emission standards (via either regulation or permit).

- EPA has not substantially complied with the public notice and comment provisions of the Administrative Procedure Act ("APA"). EPA has not provided the public with sufficient time to comment on the Proposed Rule, making significant changes to the administrative record during the public comment period without meaningful public disclosure, and suggesting in late-added materials that it might make potentially major changes to requirements in the published Proposed Rule (e.g., changing the applicability of the Proposed Rule from a unit basis to a plant-wide basis, which would have massive economic and technical consequences, an outcome that Golden Spread opposes). Any material change to the Proposed Rule, particularly its applicability provisions, must be accomplished through an amended proposal for public comment that includes a revised technical, economic, and environmental analysis that fully evaluates and justifies the proposed changes.

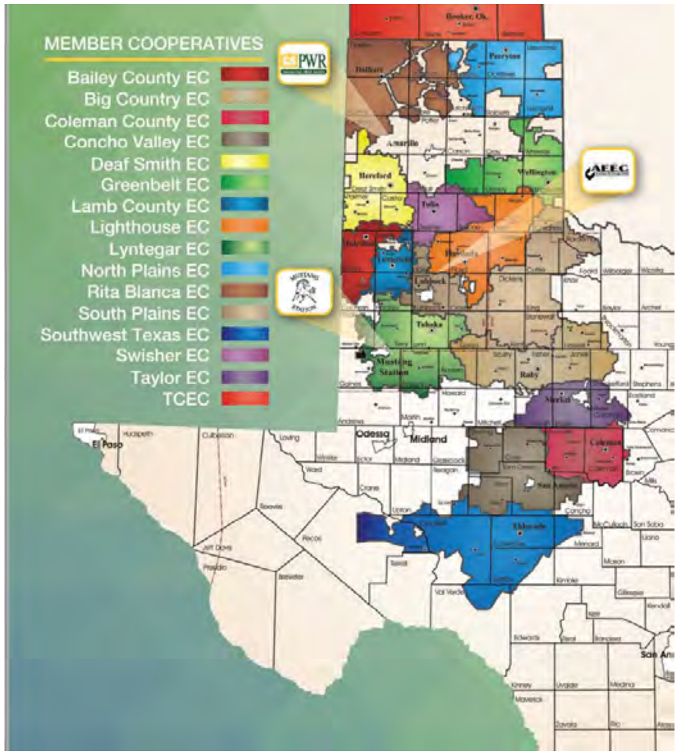
Golden Spread urges EPA to take these comments into account to fashion a final rule that is based on the facts, supports the responsible generation of reliable and affordable energy, and recognizes the critical role of natural gas generated power in ensuring a reliable electric grid with significant renewable energy penetration.

II. GOLDEN SPREAD'S GENERATION RESOURCES ARE USED TO SERVE RURAL COMMUNITIES AND ARE LOCATED IN AREAS WITH SUBSTANTIAL RENEWABLE RESOURCES.

A. <u>Overview of Golden Spread and its Member Cooperatives</u>

Golden Spread is a non-profit electric generation and transmission ("G&T") cooperative headquartered in Amarillo, Texas. Its purpose is to supply reliable wholesale electric power at the lowest feasible cost to its 16 non-profit distribution cooperative members ("Member Cooperatives" or "Members") while abiding by all applicable regulatory requirements. Golden Spread Members provide power to approximately 318,000 retail electric meters serving Member-Consumers (i.e., members of a cooperative and retail electric customers) located over an expansive area, including the South Plains, Edwards Plateau, and Panhandle regions of Texas (covering 24 percent of the state), portions of Southwestern Kansas and Southeastern Colorado, and the Oklahoma Panhandle. Golden Spread owns and operates power plants in both the Electric Reliability Council of Texas ("ERCOT") and the Southwest Power Pool ("SPP"). Figure 1 shows the location of Golden Spread's electric generating units and its Member Cooperatives' service territories.

Figure 1. Golden Spread Electric Generating Units and Members' Service Territories



B. <u>Federal Policy Supporting Electric Cooperatives</u>

Non-profit electric cooperatives such as Golden Spread and its Member Cooperatives are part of the essential infrastructure of rural America. They have played a central role in rural economic development since passage of the Rural Electrification Act ("REA") in 1936 which provided funding for rural electrification. Before the REA, electricity was commonplace in cities but not so in rural areas. Rural America was largely ignored as the focus was on more densely populated areas with higher expected revenues. The REA gave rise to the non-profit, community owned and operated electric cooperative model that is still the backbone of many rural communities today. Now with over 42 million customers nationwide, non-profit electric cooperatives have generated the electricity that has powered the economic development of rural America and supported a way of life and standard of living admired the world over.

The central role of rural America in Federal policy is recently reflected in President Biden's Executive Order ("EO") 13985 of January 20, 2021, *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government*.[1] EO 13895 expressly identifies "persons who live in rural communities" as deserving of specific attention by Federal policymakers to ensure equitable treatment, including specific direction that Federal agencies consult and engage with underserved communities.

[1] 86 Fed. Reg. 7009 (Jan. 25, 2021).

Nationally, cooperatives serve 92% of the nation's persistent poverty counties,[2] and the sparsely populated and primarily residential communities powered by electric cooperatives are often the country's most expensive, hardest-to-serve areas. Of the 79 counties served by Golden Spread Members, 58 are entirely or in part designated as a disadvantaged community.[3]

EPA should heed long-standing policies supporting affordable and reliable rural electrification, as well as EO 13985's directive, and ensure equitable treatment of rural electric cooperatives and the communities they serve in the final rule. The elements of the Proposed Rule that would decrease reliability, curtail the use of renewable energy, significantly increase the use of water, and increase the cost of electricity are inconsistent with EO 13985.

C. Golden Spread Members Serve An Area With High Wind Generation And Increasing Solar Energy Development.

As shown in Figures 1 and 2 below, Golden Spread Members serve a region with high wind and solar energy resources. This region has seen significant growth in renewable development in recent years. In Texas' ERCOT region, 28% of the energy generated in 2021 came from wind and solar (more than twice the national percentage). This penetration increased to 31% in 2022.[4] In SPP, 37.5% of the generation produced in 2022 came from wind.[5]

As a state, Texas leads the nation in wind-powered electricity generation, producing more than one-fourth of the nation's total wind power.[6] Texas generates about 66% more than Oklahoma, the second highest generating state.[7] In the first quarter of 2023, the installed wind capacity in Texas was 40,555 MW, representing 28% of the total installed wind capacity in the country.[8] Texas also has the second largest percentage share of total utility-scale solar electricity generation at 15%.[9]

Wind generation development in Texas and the region is not expected to slow down. Forces driving the growth of wind generation facilities in Texas include favorable wind resources and

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2 National Rural Electric Cooperative Association. Electric Co-op Facts and Figures. April 13, 2023.

3 U.S. Climate Resilience Toolkit: Climate and Economic Justice Screening Tool. Available at: [Climate and Economic Justice Screening Tool | U.S. Climate Resilience Toolkit](https://toolkit.climate.gov/tool/climate-and-economic-justice-screening-tool) (https://toolkit.climate.gov/tool/climate-and-economic-justice-screening-tool#:~:text=The%20Climate%20and%20Economic%20Justice,are%20faced%20with%20significant%20burdens.)

4 ERCOT. Fuel Mix Report: 2023. Available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.ercot.com%2Ffiles%2Fdocs%2F2022%2F02%2F08%2FIntGenbyFuel2022.xlsx&wdOrigin=BROWSELINK.

5 Southwest Power Pool 2022 Annual Report. Available at: https://storymaps.arcgis.com/stories/18725105e46943b5bfe7c77202a4737d

6 DOE's Office of Energy Efficiency & Renewable Energy. U.S Installed and Potential Wind Power Capacity and Generation. Available at *https://windexchange.energy.gov/maps-data/321*

7 *Id.*

8 *Id.*

9 U.S. Energy Information Administration . Solar explained: Where solar is found. Available at: *https://www.eia.gov/energyexplained/solar/where-solar-is-found.php*

land availability. Texas has twice the amount of wind power capacity than the state with the second highest wind power capacity potential.[10]

Figure 2. NREL U.S Annual Average Wind Speed at 30 m, February 21, 2012

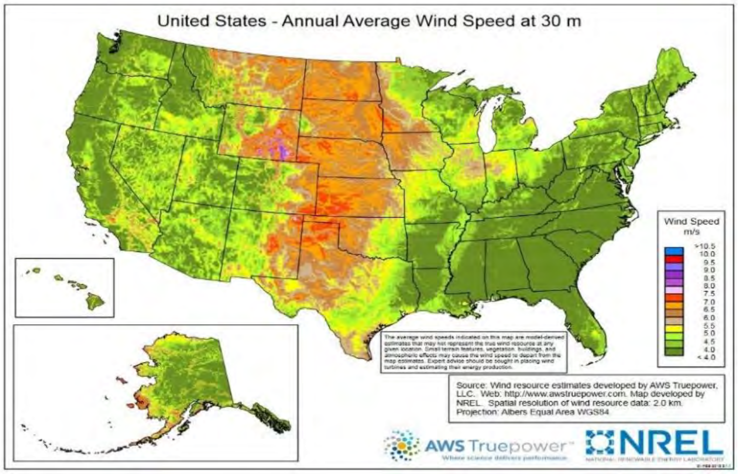
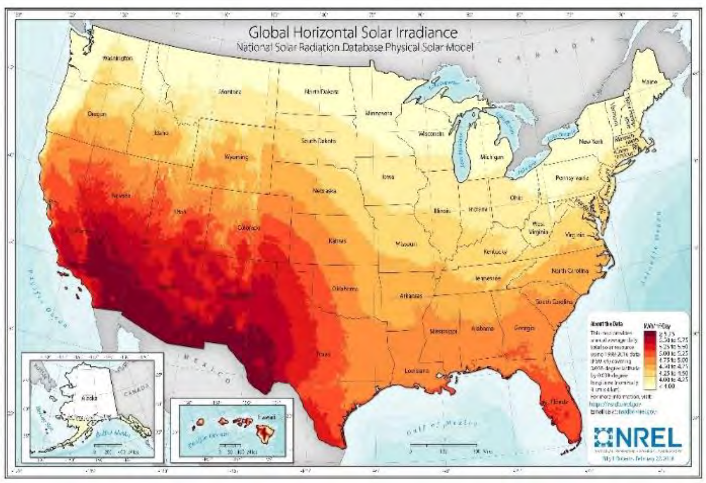


Figure 3. NREL Global Horizontal Solar Irradiance, February 22, 2018



With an expected increase in the reliance on wind energy, the risk of sudden losses of generation necessarily rises with it. Because wind power has a significant role in the region's power generation portfolio, which is anticipated to only increase, alternative generation resources must be in place to maintain grid stability and serve load when weather conditions are not conducive to wind energy production. While steps have been taken to mitigate the risk of intermittent resources like wind, there are startling recent reminders of what can happen when the wind does not behave as one might

10 Department of Energy. U.S. Installed and Potential Wind Power Capacity and Generation. Available at: https://windexchange.energy.gov/maps-data/321

expect.[11] The risk of sudden losses of generation necessarily rises with the expansion of renewables. Therefore, non-wind energy sources must be available to quickly make up for the loss in wind energy production to maintain the continued viability and growth of renewables and grid reliability. As discussed below, NGSCs play an essential role in reliably integrating renewable generation.

D. Golden Spread Has Limited Water Resources.

While the region in which Golden Spread operates has abundant wind, solar, and land resources, water resources are limited. The region has historically suffered from persistent drought conditions and surface water is scarce due in part to low precipitation as shown in Figure 4. Additionally, the Ogallala Aquifer, which underlies much of the High Plains region where Golden Spread operates, is critical to the economy of the area. For example, approximately 95 percent of the groundwater withdrawn from the Aquifer is used for agricultural irrigation. That, combined with long-term drought conditions, makes the availability of water a critical factor in the design and operation of energy infrastructure in the area. The NGSC units operated by Golden Spread offer significant water efficiency advantages over other resources including natural gas combined-cycle ("NGCC") units. Indeed, one of the reasons CCS and hydrogen co-firing are not technically or economically feasible for Golden Spread is because of water paucity.

Figure 4 Annual Precipitation from 1961 to 1990 by National Atlas of the United States

E. Golden Spread's Electric Generating Resources

Over the past 20 years, Golden Spread has invested more than one billion dollars to build and maintain generation to serve its Member Cooperatives' growing demand and need for electric power supply needs. Due in part to the high wind and solar penetration (and potential for more) in its service area, Golden Spread has pursued a strategy to invest primarily in natural-gas fired "fast start" NGSC as the best resource to support the growing renewable generation and limited water resources in the region.

[11] NERC Quick Reference Guide: Inverter-Based Resource Activities. June 2023. "Panhandle Wind Disturbance" and "2022 Odessa Disturbance." Available at: https://www.nerc.com/pa/Documents/IBR_Quick%20Reference%20Guide.pdf.

Golden Spread's assets include (1) a NGCC unit[12] and three NGSC units[13] located at its Mustang Station in Denver City, Texas; (2) 18 reciprocating internal combustion engines ("RICE") and three fast-starting NGSC units[14] located at its Antelope Elk Energy Center ("AEEC") in Abernathy, Texas; and (3) 34 wind generators located at Golden Spread Panhandle Wind Ranch near Wildorado, Texas. The approximate location of these electric generating units is shown in Figure 1 on page 3 of these Comments. Golden Spread does not own or operate any coal or oil-fired electric generating units. As part of its corporate goal to meet its Members' energy needs, Golden Spread regularly evaluates whether and when it needs to develop new resources.

III. EPA'S PROPOSAL TO DECREASE THE OPERATING THRESHOLD FOR LOW LOAD UNITS FROM 33% TO 20% IS NOT SUPPORTED BY THE ADMINISTRATIVE RECORD AND WOULD ADVERSELY AFFECT THE RELIABILITY OF THE GRID AND INTEGRATION OF RENEWABLE GENERATION.

EPA's proposal to artificially limit low load combustion turbines (i.e., NGSCs) to a 20% capacity factor has no basis in the record and ignores their continuing importance to the reliability and efficiency of the nation's grid, particularly given the increase in renewable energy development. NGSC units play an important and established role in the support of intermittent renewable generation because of their "fast start" and ramping capabilities. That role is anticipated to become more critical as wind generation is increasing at unprecedented levels throughout the country, particularly in wind rich regions like Texas.

Contrary to EPA's analysis in its *Simple Cycle CT Technical Support Document* ("EPA NGSC TSD"),[15] the important role of NGSCs in the integration of renewable generation is not "hypothetical" and "unclear."[16] A potential flaw in EPA's assessment appears in part to be because the EPA NGSC TSD evaluates NGSCs on a generic fleetwide basis and does not accurately consider the significant variability of renewables penetration in different regions. The critical role that NGSCs play in making the growth of renewables possible is not only reflected in Golden Spread's direct experience but has also been widely discussed on a national level.

As recognized by the Energy Information Administration ("EIA")—the agency responsible for providing impartial energy information to promote sound policy making—and is unambiguous about the role played by NGSCs to support renewables:

> "Electric grid operators can use SCGT [simple cycle gas turbine] power plants to respond quickly to fluctuating demand for electricity. The need for more electric grid support during the day is growing as the share of electricity generation from intermittent renewables grows. SCGT power plants can meet demand if there is a lull in wind or solar output. SCGT power plants can best provide grid support because they can produce

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[12] 463 MW unit subject to 40 CFR Part 60, Subparts GG and Db.

[13] 152 to 158 MW units subject to 40 CFR Part 60, Subpart KKKK.

[14] 191 to 195 MW units subject to 40 CFR Part 60, Subpart TTTT.

[15] *Simple Cycle CT Technical Support Document*, U.S. EPA (March 2023), Docket ID No. EPA-HQ-OAR-2023-0072.

[16] EPA Simple Cycle Stationary Combustion Turbine EGUs Technical Support Document at pp. 7-8.

> electricity quickly to immediately fill gaps in electricity output on the grid, and they can ramp down just as quickly. Other natural gas-fired electricity generators, such as CCGT or steam boiler plants, can take two to three times longer than SCGT power plants to start and ramp up to full load."[17]

EPA also incorrectly assumes that the role of natural gas-fired generation will decrease over the next 10 to 20 years, even as significantly more renewables are anticipated to come online, more coal units are retired, and electricity demand increases (particularly with the planned replacement of internal combustion engines with electric vehicles). EPA offers no factual support for these assumptions. Indeed, the EIA data discussed by EPA in its proposal contradicts EPA's conclusion as it shows that natural gas utilization has continued to increase as more renewables come one line[18]:

> "Moreover, the share of fossil generation supplied by coal-fired EGUs [electric generating units] fell from 46 percent in 2010 to 23 percent in 2021 while the share supplied by natural gas-fired EGUs rose from 23 to 37 percent during the same period. In absolute terms, coal-fired generation declined by 51 percent while natural gas-fired generation increased by 64 percent. This reflects both the increase in natural gas capacity as well as an increase in the utilization of new and existing gas-fired EGUs."[19]

EPA's NGSC TSD also incorrectly seems to attribute any increases of NGSC capacity factors to variables such as changes in natural gas prices, ignoring their growing role in supporting intermittent renewable generation. Again, those conclusions are contradicted both by Golden Spread's direct experience as well as by EIA who acknowledges the role of NGCC in support of intermittent renewable energy. EIA states, for example, that the average monthly capacity factor for NGSC units has grown annually since 2020 and that it surpassed 20% for two consecutive summer months in 2022.[20]

Though EPA's proposal does not evaluate NGSCs' essential role in supporting renewables, EPA nonetheless concedes that such backups are necessary. Without acknowledging that certain sources currently provide backup to intermittent resources (e.g., NGSCs), EPA speculates that necessary backup in the future will be provided by battery storage. This speculation is not supported by the administrative record. First, the use of NGSCs as the primary backup for renewables continues to grow. Second, the record does not demonstrate that technically adequate and cost-effective battery storage will be available in the volumes necessary by the deadlines established by EPA.

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17 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Available at: https://www.eia.gov/todayinenergy/detail.php?id=55680#:~:text=Electric%20grid%20operators%20can%20use,generation%20from%20intermittent%20renewables%20grows

18 88 Fed. Reg. at 33278 ("As discussed in section IV.F.2 of this preamble and in the accompanying RIA, the post-IRA 2022 reference case projects that natural gas-fired combustion turbines will continue to play an important role in meeting electricity demand. However, that role is projected to evolve as additional renewable and non-renewable low-GHG generation and energy storage technologies are added to the grid.").

19 88 Fed. Reg. at 33256.

20 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Available at: https://www.eia.gov/todayinenergy/detail.php?id=55680

The North American Electric Reliability Corporation ("NERC") recently laid out the necessary interdependence between natural gas electric generating units and renewables, and the growing but still insufficient role of battery storage, as a "key finding" in its "2022 State of the Reliability Report."[21] NERC observed that CTs were "necessary balancing resources for reliable integration of the growing fleet of variable renewable energy resources," noting the importance of ensuring "uninterrupted delivery of natural gas to these balancing resources, particularly in areas where penetration levels of renewable generation resources are highest."[22] NERC has also raised concerns regarding the aggregate impact of inverter based (i.e., batteries) resources, noting that it was analyzing "large-scale grid disturbances involving common mode failures in inverter-based resources that, if not addressed, could lead to catastrophic events in the future," and that "the aggregate impact of these resources must be considered when developing policies, regulations, and requirements."[23] In its 2022 Report, NERC concluded:

> "Until storage technology is fully developed and deployed at scale, natural-gas-fired generation will remain essential to providing the grid's rapidly increasing flexibility needs. Improvements in the mutual understanding of electricity and natural gas interdependencies enable operators in both industries to enhance reliability across energy delivery systems and reduce end-use customer exposure to energy shortfalls during extreme weather events."[24]

NERC's report demonstrates the complexity of this interdependence, the importance of planning and coordination by those with the experience and authority to manage the grid, and the consequences to consumers if these issues are not successfully managed.

The Proposed Rule does not consider the full gravity, complexity, and importance of the grid capacity, reliability, and affordability issues described by NERC that will be affected by this rulemaking. EPA is not merely proposing CO_2 emission standards. Rather, it is proposing a rule that will significantly affect the structure and operation of the grid, including the interdependency of key elements of the grid necessary to provide reliable and affordable electricity to the public, based on assumptions about the availability, interoperability and affordability of power generation and storage technology about which it has little expertise or experience. In so doing, EPA is stepping over its traditional jurisdictional lines and venturing into the "major question" zone on which it foundered in *West Virginia vs. EPA*.[25]

NGSC units are an integral and critical element of the efficient use of renewable energy, precisely the type of resources EPA seeks to significantly expand with this rulemaking. Restricting the use of NGSC units by imposing an artificial 20% capacity limit will disrupt the relationship between

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21 NERC. 2022 State of Reliability Report. July 2022. Available at: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

22 *Id*. at p. viii.

23 NERC. Inverter-Based Resource Performance Issues. March 14, 2023. Available at: NERC Alert IBR Performance (https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf).

24 NERC. 2022 State of Reliability Report. July 2022. P. 45. Available at https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

25 *West Virginia v. EPA*, 142 S.Ct. 2587 (2023).

natural gas and renewable electric generating units, may actually be limiting renewable generation, and in some cases increase—not decrease—emissions due to curtailment of renewables.

IV. GOLDEN SPREAD OPPOSES EPA'S BSER DETERMINATION FOR NATURAL GAS COMBUSTION TURBINES.

A. Hydrogen Co-firing And CCS Are Not BSER For Natural Gas Combustion Turbines.

EPA acknowledges that there is no commercial scale electric generating unit in the United States currently operating with CCS technology or co-firing with so-called "green hydrogen" in any meaningful volumes. Nonetheless, EPA asserts that both of these commercially unproven and undemonstrated technologies (in the power generation sector) are BSER.

EPA's imposition of these technologies with the expectation that they will designed, installed, and operating by 2035[26] does not meet the criteria established by *Portland Cement v. Ruckelshaus,* which allows EPA to consider technologies that "may fairly be projected for the regulated future, subject to "the restraints of reasonableness," without "crystal ball speculation," and dependent on a showing of "achievability."[27] The Supreme Court observed, in the recent seminal case on Section 111(d), that "has been adequately demonstrated…imposes meaningful constraints" including that the "best system has a "proven track record."[28]

It is undisputed that there is no "proven track record" of CTs implementing CCS or hydrogen co-firing in any meaningful way, nor does the administrative record contain the necessary evidence or data to make EPA's assumptions any more than "crystal ball speculation."[29] EPA must not impose such speculative and draconian controls in the face of well-established data demonstrating that the nation's grid is already stressed, stresses that will increase as coal-fired units continue to shut down, while at the same time the demand on the grid is projected to increase.

Golden Spread adopts in full the detailed comments of the NRECA on the technical and economic challenges and barriers to the installation and operation of CCS and "green" hydrogen co-firing at CTs on the schedule proposed by EPA, and will not repeat those here. In addition, Golden Spread has specific knowledge regarding the infeasibility of CCS for its NGCCs.

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26 The initial 2035 deadline is deceiving. As a practical matter, the technology must be designed, proven and available long before 2035 if the investments are to be made and the engineering and construction completed, such that when the switches are turned on in 2035 electricity will continue to be reliably and efficiently delivered in the quantities demanded by the public.

27 *Lignite Energy Council v. U.S. EPA,* 198 F.3d 930, 934 (D.C. Cir. 1999) (citing *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973)).

28 *West Virginia v. EPA*, 142 S.Ct. at 2629 (Kagan dissenting).

29 For example, EPA relies on Duke Energy's 2022 Climate Report to support the proposition that only hydrogen-burning peaking CTs will be constructed after 2040. 88 Fed. Reg. at 33255, n. 72. However, Duke's report provides absolutely no data or technical basis to support this assumption. EPA also cites NextEra's Energy Zero Carbon Blueprint, which contains similar aspirational projections regarding the future use of hydrogen to fuel natural gas power plants, but these projections are not accompanied by economic, technical and environmental data and studies. Aspirational projections contained in corporate strategy documents that are unsupported by any data or meaningful technical or economic evaluation are not evidence of a "proven track record" for purposes of establishing BSER.

Golden Spread's Mustang NGCC facility was the subject of a CCS feasibility study conducted by the University of Texas and funded in part by the Department of Energy.[30] In 2022 this study concluded that CCS was not feasible at the Mustang Station because, among other things, the limited availability of water and the high percentage of renewables in Golden Spread's service area. The study concluded that the "ideal site" factors for installing CCS at a CT facility included a service area with low renewables, CTs operating at a high capacity, and plentiful water. Thus, CCS is not a feasible option in Golden Spread's service area precisely because the already high penetration of renewables supported by Golden Spread's CTs. Regardless of the technology EPA speculates might be available, some of these decisive factors will never change for Golden Spread: water will not be plentiful (and continued drought is more likely), and the significant reliance on renewals is only going to increase, not decrease.

The technical and cost barriers set forth in NRECA's comments and demonstrated in the Golden Spread Mustang study apply with even greater force to NGSCs, such as Golden Spread's, that operate in regions with high renewable generation. The technical and cost barriers set forth in NRECA's comments and demonstrated in the Golden Spread Mustang study apply with even greater force to NGSCs, such as Golden Spread's, that operate in regions with high renewable generation and limited water availability. Thus, EPA's proposal to impose CCS (or hydrogen co-firing) on any NGSC that exceeds 20% capacity, or that batteries will be available to replace NGSCs on the scope and scale contemplated in the Proposed rule, is not BSER.

B. <u>Restricting The Availability Of Low Load NGSCs Will Have Adverse Environmental, Reliability, And Efficiency Consequences.</u>

Restricting the availability of low load NGSCs will force operators to rely on less efficient alternatives that could result in curtailments of renewable power and even increased emissions (relative to expectations). "Intermediate" load NGSCs will not fill that gap because EPA's proposed BSER (combinations of CCS and hydrogen co-firing), which is not economically or technically feasible for CTs generally, is even more infeasible for peaking NGSCs that run at less than 33% capacity. Thus, if low load NGSCs are restricted to units operating at less than 20% capacity, the primary practical alternative will be NGCC units, which are not well suited to fill in for NGSCs.[31] EPA is also considering equipping intermediate load NGSCs with steam injection, in addition to the economically and technically infeasible CCS/hydrogen co-firing, which EPA concedes would in part transform them into NGCC units.[32]

NGCC units require approximately two and one half hours (or even longer) to be at full load and optimum heat rate, from a cold state, and the boiler is adversely impacted by frequent cycling. Therefore, NGCC units are not well suited to efficiently and consistently backup intermittent generation such as wind and solar. The frequent cycling and ramping up and down of NGCC units causes thermal stresses on plant equipment and components, which increases maintenance costs and decreases the overall efficiency of the unit. NGSC units equipped with heat recovery

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[30] University of Texas at Austin. Piperazine Advanced Stripper FEED Study. DE-FE0031844.

[31] As discussed elsewhere in these Comments and other public comments, EPA has not demonstrated that battery technology has a "proven track record" to be installed on the scope and schedule contemplated in this proposal to be a meaningful alternative to NGSCs and, if the use of low load NGSCs is significantly diminished, to NGCCs.

[32] 88 Fed. Reg. at 33324, n. 490.

steam generators ("HRSG") for purposes of steam injection face similar complexities.

NGCC units can practically supplement intermittent energy sources only if they are brought on-line and held at a minimum load on stand-by because they cannot start quickly from a cold state. However, doing so can limit the amount of renewable electricity generated, resulting in an overall increase in emissions. This result is because it is necessary at times to curtail wind generation, for example, due to excess generation, so that resources with slower start times (e.g., NGCC units or intermediate load NGSCs with steam injection) can stay online at minimum output and dispatched, to be readily available when the wind drops off. When NGCC units are operating, at any capacity, their power must and will be dispatched according to grid operating rules and protocols. As a result, if there is excess generation, dispatching power from NGCCs operating at stand-by capacity requires that power from some other source, e.g., wind, be curtailed.

This relationship between demand and available renewable generation capacity, coined the "duck curve" by CAISO, was first unveiled by NREL in 2008 and has been exacerbated by the increase in renewables capacity.[33] This phenomenon is not unique to California and is increasingly occurring in other parts of the country such as Texas and around the world where intermittent generation from renewables is increasing compared with generation from conventional sources.

As explained by ERCOT's Independent Market Monitor:

> "The prediction of the future shape of this curve once a large quantity of solar has entered has been referred to as the "duck curve" or, in Texas, the "dead armadillo curve." This curve indicates that conventional [thermal] resources will have to ramp rapidly each evening as the sun goes down and the solar resources' output falls sharply. Similarly, shifting weather patterns can cause wind output to fall rapidly and the timing of these decreases can be difficult to predict."[34]

Kenan Ogelman, Vice President of Commercial Operations in ERCOT, has stated:

> "The basic way to envision it is that load is still rising in the evening as people are returning home and increasing their electricity usage, but solar is dropping, so there is a need for a rapid increase in production of electricity. The contingency reserve service is designed to fill that need by having units capable of responding in 10 minutes or less to meet the additional demand."[35]

Thus, if the Proposed Rule is finalized as proposed and new NGSCs would have to operate at less than 20% of capacity, operators would be forced to keep less-flexible alternatives, such as NGCCs,

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[33] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Available at: *https://www.eia.gov/todayinenergy/detail.php?id=56880*

[34] Potomac Economics, 2021 State of the Market Report for the ERCOT Electricity Markets at 2 (May 2022) ("2021 SOM Report"). Available at: https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-theMarket-Report.pdf.

[35] State Energy Plan Advisory Committee, Report to the 87th Legislature, September 1, 2022 P. 58, available at: State Energy Plan Advisory Committee Report - Final.docx (competitivepower.org) p. 57 (https://competitivepower.org/wp-content/uploads/2022/09/State-Energy-Plan-Advisory-Committee-Report-Signed-Final.pdf).

running and available to prepare for the loss of solar and wind in the evening, as illustrated by the "duck curve." Using these alternatives that are less flexible than low load NGSCs has the unintended consequence of forcing curtailments of renewable energy and potentially increasing CO_2 emissions.

For NGCCs to effectively serve as back up and support for large amounts of renewable capacity, they must be kept at minimum load since they do not have the ability to start up quickly from a cold state. At minimum load, fuel is still being spent and energy is still being produced. This scenario can result in overall higher emissions since the renewable energy that could have otherwise served load with zero associated emissions must be curtailed to make room for NGCC.[36] Thus, in areas with high wind capacity (such as the region served by Golden Spread), reducing the availability of low load NGSC turbines and relying more on NGCCs can decrease generation by renewables and cause an increase, rather than a decrease, of expected CO_2 emissions. The fast-start flexibility provided by NGSC turbines on a grid-wide basis results in greater integration of renewable resources into the grid.

NGSC units that are available to quickly and economically operate at capacities greater than 20% are an essential part of operating an electric grid with significant renewable energy penetration and will be for the foreseeable future. NGCCs (and intermediate load NGCCs) are not economically or environmentally suitable alternatives to low load NGSCs. Further, the record does not support EPA's assumption that this role can be technically or economically assumed by battery power on anything approaching the scale and schedule contemplated in the Proposed Rule.

C. New NGCCs And Co-firing Of Hydrogen Are Not Feasible In Water Scarce Regions.

Incentivizing development of new water-intensive technologies such as NGCC, steam injected NGSCs,[37] or hydrogen co-firing is particularly problematic in water-starved areas such as Texas. In parts of the country with arid climates that are particularly susceptible to drought conditions, excessive reliance on these technologies may not be feasible or a desirable option. As is the case with Texas, these are also often regions with ample wind and solar resources.

The lack of rain and insufficient surface water in the geographic areas served by Golden Spread's Members have required reliance on the Ogallala Aquifer, which lies beneath the same area. EPA's adoption of a rule encouraging the development of more NGCC (or steam injected NGSCs) units to replace the use of NGSC units, would result in a large increase in water use. If EPA adopts such an approach, it will have serious implications to surface water and groundwater supply and can carry significant risks to the reliability of the grid. As discussed below, co-firing with hydrogen is even more demanding on water resources.

This impact to already scarce water resources in many areas, including Texas, is an issue that EPA is required to consider in the promulgation of an NSPS standard. Section 7411 of the Clean Air Act requires that EPA consider "any nonair quality health and environmental impacts" when promulgating a "standard of performance." In particular, the D.C. Circuit Court in *Sierra Club*

[36] Docket ID: EPA-HQ-OAR-2013-0495. Comments of Golden Spread Electric Cooperative. March 18, 2019. Available at: Regulations.gov

[37] The EPA solicited comment on the use of steam injection on intermediate load combustion turbines. 88 Fed. Reg. at 33324.

v. Costle stated that the NSPS Best System of Emission Reduction ("BSER") must reflect and balance other environmental considerations such as water usage.[38]

NGSC units are more water efficient than NGCC units, an important factor in wind generation areas such as Texas and the Southwest, where water is a scarce and sometimes decreasing resource. NGCC is a relatively water-intensive technology that can consume hundreds of millions gallons of fresh water per year. An NGCC power plant can consume more than 270 gallons per MWh of cooling water on an annual basis, whereas a NGSC unit typically consumes only 41 gallons per MWh.[39]

For Golden Spread, the water level in the local aquifers near AEEC has declined over the last several years and is becoming scarce. Consequently, technology evaluations must consider the future availability and value of water among the various selection criteria. Considering Golden Spread's need for operational flexibility to startup and shutdown multiple times daily, and water resource availability issues, the selection of additional NGCCs may not be technically feasible.

NGSC units equipped with steam injection are water intensive, as they effectively incorporate water-based steam technology into their operation. This makes them similarly unsuitable for arid regions of the country, regions which frequently have high potential for renewable energy.

Hydrogen production and related co-firing is also a water and energy intensive process as described by EPA in its proposal:

> "New combustion turbine models designed to combust hydrogen, and those potentially being retrofit to combust hydrogen, may be co-located with electrolyzers that produce the hydrogen the facility will use. In such instances, water scarcity could be exacerbated in some areas by the freshwater demands of electrolytic hydrogen production, which could pose a particular challenge for vulnerable communities. As such, electrolyzer siting will need to take water availability into account."[40]

Modeling tools made available by turbine manufacturers illustrate both the water and energy intensity of hydrogen co-firing for NGSCs. One of these models calculates that co-firing a 190 to 200 MW NGSC with 90% hydrogen would consume approximately 33,000 gallons and 35 MW of parasitic load per hour, while co-firing with 30% hydrogen would use

[38] 657 F.2d 298 (D.C. Cir. 1981) ("For example, an efficient water intensive technology capable of 95 percent removal efficiency might be "best" in the East where water is plentiful, but environmentally disastrous in the water-scarce West where a different technology, capable of only 80 percent reduction might be "best." . . . The standard is, after all, a national standard with long-term effects.").

[39] Alternative cooling technologies that have been considered for NGCCs (e.g., air cooled condensers, or ACC), but they result in significant efficiency losses and decreased in net output. According to a study conducted by EPRI, "dry cooling imposes a heat rate and lost-capacity penalty on a plant that can range up to 25% during the hottest hour of the year and exceed 8% for over 1,000 hours at a hot, arid site. On an annual basis, plant output is reduced by about 2%."[39] Thus, the ACC equipped NGCC plant will burn more fuel and generate more air emissions to produce the same net power produced by a NGCC unit using a traditional evaporative cooling tower. Furthermore, demand for energy typically peaks during hot temperatures, so this loss of efficiency would be significant and more pronounced.

[40] 88 Fed. Reg. at 33414.

approximately 5,158 gallons and 5.5 MW of parasitic load per hour.[41] Putting this in context, at an approximately 50% capacity factor—without hydrogen co-firing—such a unit might typically consume approximately 6.1 million gallons per year of water. The same unit with 30% hydrogen co-firing would increase its water consumption to approximately 23.5 million gallons per year, and 90% hydrogen co-firing would require approximately 150 million gallons per year.

While EPA acknowledges that the water consumption associated with co-firing hydrogen may be an issue for vulnerable communities, the only solution EPA proposes is the potential future use of sea water,[42] which is not an option for regions such as Golden Spread's service area. Hydrogen co-firing itself does not have a proven track record for CTs, and the feasibility and affordability of widespread use of reclaimed seawater to support hydrogen co-firing in the energy generation sector has not been demonstrated by EPA in the administrative record.

V. THE PROPOSED ALLOWANCE FOR SYSTEM EMERGENCIES MUST BE CLARIFIED OR REVISED.

EPA's proposal includes a provision that exempts electricity sold during a "system emergency" from counting towards applicable subcategorization capacity thresholds (e.g., the 20% threshold for low capacity CTs). EPA states that this allowance is necessary to maintain system reliability and minimize overall costs by not imposing the CCS/hydrogen co-firing requirements when CTs exceed the 20% cap due to emergencies. This exemption will not achieve its intended goal and cannot be depended on as a tool to ensure system reliability, particularly when combined with EPA's proposal to decrease the low-capacity threshold to 20%, a limit which is inconsistent with the use of NGSCs as an integral element of the renewable energy infrastructure.

The exemption would preclude a low load unit from being categorized as intermediate or peaking unit due solely to increased capacity use during a system emergency. However, this exemption does not protect an operator from other potential associated air emission violations that might occur during a system emergency.

Under EPA's proposal, for example, a new "low load" simple cycle would be permitted to operate at no more than 20% capacity factor. Such an air permit would also establish maximum allowable emissions for other pollutants (e.g., NOx, SOx, particulates) based on that same enforceable 20% cap. If the unit operates at 23% capacity one year, with 5% of that capacity attributable to system emergencies, the unit would still be classified as a low load unit for purposes of the greenhouse gas emission standards established by this rulemaking. However, the generator would have potentially violated its permitted emissions of other pollutants which were based on the permitted 20% capacity factor. EPA's proposed exemption for purposes of regulating greenhouse gas emissions will not provide operators any protection from enforcement actions associated with excess emissions of other pollutants emitted during such a system emergency.

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41 GE Gas Power: Hydrogen and CO2 Emissions Calculator. Accessed August 2023. Available at: https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines/hydrogen-calculator

42 *Id.*

The proposed exemption would also decrease rather than enhance grid reliability. Regional Transmission Organizations and Independent System Operators use a market tool called a Reliability Unit Commitment ("RUC") to require an electric generating unit to participate in the wholesale market during operating reserve supply shortage. Generators are required to respond to an RTO/ISO's RUC instructions.[43] Golden Spread's units regularly receive RUC instructions aimed at maintaining grid stability and reliability. However, at the same time, Golden Spread will not dispatch a unit if there is a potential for an air permit violation, putting the company in an impossible position. Golden Spread assumes that other generators have similar policies. The combination in the Proposed Rule of an incorrect 20% cap on low-capacity units, and the mirage of an exemption from that cap for system emergencies, will not provide operators with regulatory relief nor the grid with reliability.

EPA can correct this problem by maintaining the current 33% capacity limit such that the likelihood of exceeding the low-capacity threshold is significantly decreased, and clarifying and modifying the system emergency exemption such that system emergency allowances provide meaningful protection applicable to all air emission limits, not just greenhouse gas limits.

VI. THE PROPOSED RULE'S APPLICABILITY MUST BE ON A GENERATING UNIT, NOT PLANT-WIDE, BASIS.

The discussion of applicability of the standards to existing CTs in the Proposed Rule, and the economic and environmental projections associated with it, is based on individual generating unit capacity, with 300 MW being the primary cut-off size for existing CTs. However, without any meaningful public notice, EPA on June 7, 2023, after the commencement of the public comment period, submitted an undated memorandum into the docket titled *Integrated Proposal Modelling and Updated Baseline Analysis – Memo to the Docket*. Within the Memo, EPA included the following statement:

> "[W]hile the proposed rulemaking applied that threshold on a unit-level basis, and all of the modeling performed to date does the same, comments from stakeholders to date have led the EPA to also consider applying the threshold on a plant-level basis. EPA is considering the appropriate MW threshold for such a plant-level approach and whether such an approach should also include a unit-level MW threshold."[44]

Thus, while EPA concedes that the Proposed Rule and all its modeling to date has been based on unit-level applicability decisions, it nonetheless states that it is considering an entirely different plant-level approach to applicability that is not part of the Proposed Rule. This change likely would constitute a massive expansion of the final rule, significantly increasing the number of existing CTs that would be subject to the rule. This expansion would require additional analysis by EPA to determine how many existing natural gas power plants are composed of CTs with under 300 MW capacity that would not be subject to the rule as proposed but would be subject to the rule if capacity were evaluated on a plant-wide basis.

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43 In SPP, for example, a RUC is defined as: SPP process to assess resource and Operating Reserve adequacy for the Operating Day, commit and/or de-commit resources as necessary, and communicate resource commitments or de-commitments to the appropriate Market Participants, as necessary.

44 Memo to the Docket at p. 5.

Finalizing a plant-level approach to bring existing CTs into a final rule would violate the APA. EPA admits that it did not propose such an applicability test, and that none of its modeling to date evaluated this approach. This concept is revealed in a few sentences in an undated *Memo to the Docket* focusing on technical modeling issues filed with no meaningful public notice after the public comment period opened. EPA has not made any specific proposal that the public can evaluate or on which it can comment. Since EPA has not modeled a plant-wide applicability approach, it does not know the economic or environmental consequences of such an approach, or whether it is feasible. Such a significant change in any final rule, based on a few sentences in an undated memo to the docket about modeling filed in the docket after the commencement of the comment period, could not reasonably be considered a "logical outgrowth" of the Proposed Rule.

Golden Spread opposes the concept of making applicability determinations in this rulemaking for existing CTs on a plant-wide basis. However, if EPA is considering such an approach, it must re-propose the rule with a specific proposal on the applicability issue, and accompany that proposal with the necessary economic, technical, and environmental data and modeling supporting the proposal. To do otherwise would violate the APA.

VII. CONCLUSION

If EPA moves forward with the Proposed Rule, Golden Spread urges EPA to do the following:

- Retain the existing capacity factor of 33% for CTs as the threshold for low-load CTs.
- Decline to impose CCS and "green" hydrogen co-firing as BSER for CTs, particularly for NGSCs.
- Revise the "system emergency" capacity allowance to provide meaningful regulatory and enforcement protection to generators.
- Decline to adopt a plant-wide approach to applicability determinations.

Golden Spread urges the EPA to consider the critical and integral role that NGSCs serve in the existing and growing renewable power infrastructure. It is not reasonable to evaluate and regulate NGSCs on a generic and nationwide basis as power generation units (i.e., the "average NGSC" across the nation) without regard to the varying roles that NGSCs play in the grid. The extent to which the grid depends on renewable energy, and thus the significance of the contribution of NGSCs, varies considerably around the country. Failing to take these variabilities into account will obscure the crucial and growing role NGSCs play in the renewables infrastructure, and result in regulatory outcomes inconsistent with EPA's stated goal of increasing the nation's reliance on renewable energy. Thus, EPA should give significant weight to Golden Spread's Comments, based on its experience in a vast geographic service area where renewable generation penetration is the highest in the country (twice the national average), and whose NGSCs play an integral role in supporting this success story.

Golden Spread appreciates the opportunity to submit input on the Proposed Rule. Should you have any questions please contact Ruth Calderon, Legislative, Regulatory & Policy Manager at rcalderon@gsec.coop or (806) 349-5205.

Minnekota Power Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312

Phone 701.795.4000
www.minnkota.com

August 24, 2023

<u>Via electronic correspondence at Wiggins.Lanelle@epa.gov</u>

Ms. Lanelle Wiggins
RFA/SBREFA Team Leader
Office of Policy
U.S. Environmental Protection Agency
1201 Constitution Avenue NW
Washington, DC 20004

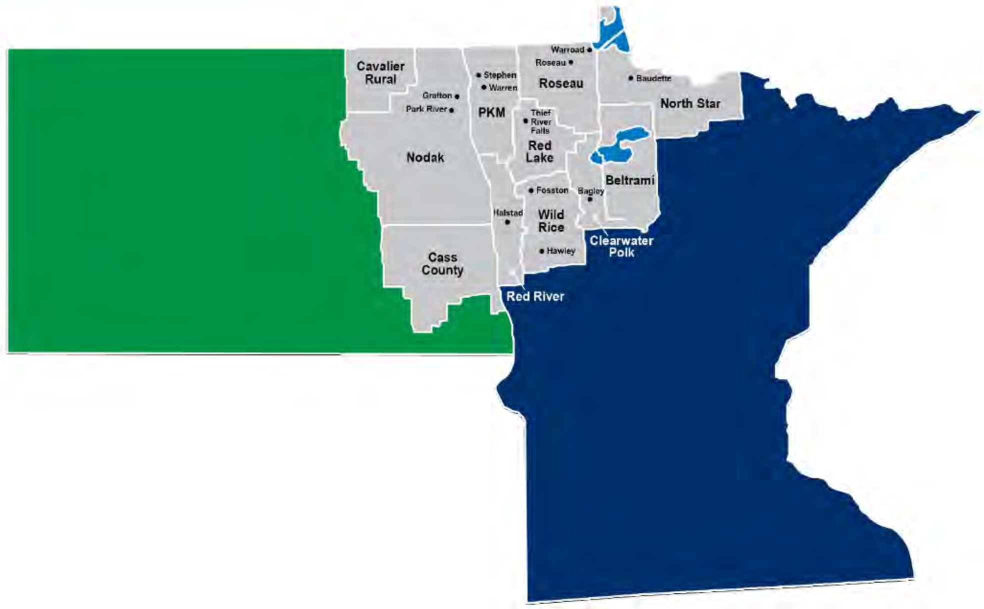
RE: Minnkota Power Cooperative, Inc.'s Comments on the Small Entity Representative Panel Outreach on the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule, Docket ID No. EPA–HQ– OAR–2023–0072

Dear Ms. Wiggins:

Minnkota Power Cooperative, Inc. appreciates the opportunity to provide input and recommendations on the above-referenced rule (the Proposed Rule) as a small entity representative. Minnkota offers the following for comments for consideration in the EPA's analysis of the Proposed Rule's impacts on small entities and in response to EPA's request for feedback. For reference, Minnkota attaches its detailed comments for this Proposed Rule as Attachment A, which are also filed in the docket.

I. Background on Minnkota and the Joint System.

Minnkota is a wholesale electric generation and transmission (G&T) cooperative headquartered in Grand Forks, North Dakota. Minnkota provides wholesale electric service to 11 retail distribution cooperatives, which are the members and owners of Minnkota, serving approximately 152,000 retail customers in a 34,500-square-mile area across northwestern Minnesota and eastern North Dakota. This service area is depicted by the map below:



Member-systems are cooperative associations made up of residential, commercial, and industrial consumers within a contiguous geographic area. They provide retail electric service to their own member consumers through wholesale purchases of capacity and energy from Minnkota, which is delivered through the member-systems' electrical distribution facilities. Minnkota has wholesale power contracts with each of the 11 member systems through December 31, 2058.

Minnkota also serves as operating agent for Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, Minnesota. NMPA is a municipal power agency serving 12 municipal utilities—ten located in northwestern Minnesota and two in eastern North Dakota. NMPA's 12 municipal utilities serve the electrical requirements of approximately 15,800 customers.

Minnkota and NMPA effectively form a Joint System through:

a. Operating agreements and joint ownership of transmission facilities
b. Generation and Western Area Power Administration (WAPA) allocations that are collectively utilized to serve the Joint System capacity and energy requirements.
c. Obligations to conform to MISO's Resource Adequacy requirements.

The largest generating resources in the Joint System are the coal-fired Milton R. Young (MRY) Station and Coyote Station, hydropower WAPA allocations, and full or partial shares of the wind output from the Langdon, Ashtabula, and Oliver III wind farms.

Some details of the Joint System's resource mix include:

a. MRY is a two-unit, lignite coal-fired power plant located near the town of Center, North Dakota. Minnkota owns and operates Young 1 (250 MW) and operates Young 2 (455 MW) on behalf of its owner, Square Butte Electric Cooperative.
b. Coyote Station (427 MW) is a lignite coal-fired mine mouth facility located near Beulah, North Dakota. NMPA owns 30% of Coyote Station (128 MW), and Minnkota acts as NMPA's agent for scheduling capacity and energy. Otter Tail Power owns 35% of Coyote Station and is the plant's operating agent. The other co-owners are Montana-Dakota Utilities and NorthWestern Energy.

Minnkota Power COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312

Phone 701.795.4000
www.minnkota.com

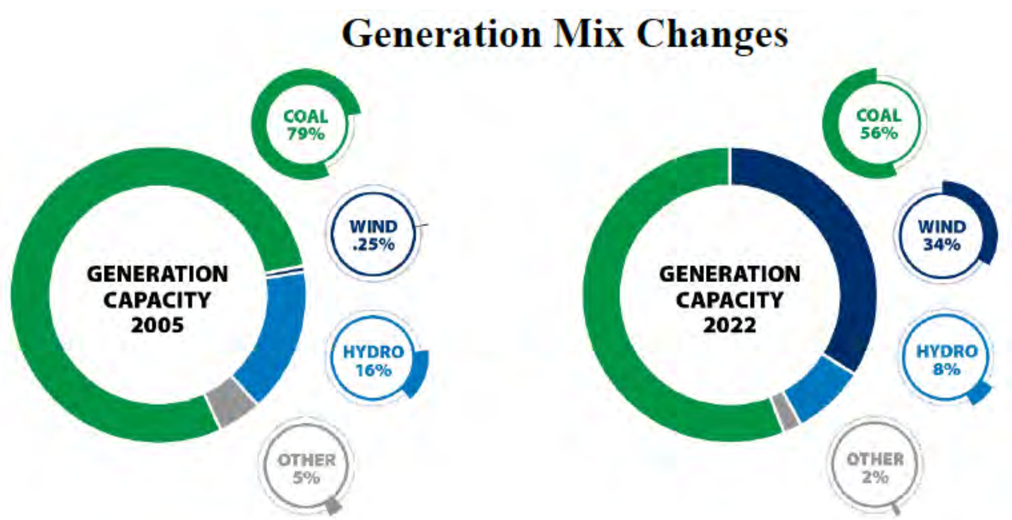
c. Langdon, Ashtabula, and Oliver III wind are all located in North Dakota. In total, Minnkota has rights to the output of 457 MW of wind (in nameplate capacity).

d. Minnkota and eight NMPA municipals have WAPA firm power allocations. Minnkota's WAPA allocation provides firm capacity and energy to the Joint System of 72.6 MW and 358,303 MWh per year. NMPA's allocations provide firm capacity and energy to the Joint System of 40.6 MW winter/36.2 MW summer and 174,311 MWh per year.

e. Minnkota's Infinity Wind Program consists of two 900 kW wind turbines, one located near Valley City, North Dakota, and one located near Petersburg, North Dakota. Both turbines commenced operation in 2002, and both produce about 2,800 MWh annually.

f. Smaller-sized resources include:
   i. Thief River Falls owns and operates a 500 kW hydro plant that has been in operation since 1927.
   ii. Minnkota leases 10 diesel generating units for Cass County Electric Cooperative, which have a total capacity rating of 18.28 MW.
   iii. Three of the NMPA municipal members, Thief River Falls, Grafton, and Halstad, have diesel generators leased to Minnkota, which total 13.54 MW.

In 2022, the Joint System's capacity mix was mostly coal (56%) and wind (34%). This is depicted on the right-side of the "Generation Mix Changes" figure below. This is in stark contrast to the left-side of the figure, which shows that in 2005, the Joint System was about 80% coal and just 0.25% wind.



Minnkota is sponsoring the development of a carbon capture and storage (CCS) project called Project Tundra, estimated to capture 95% of carbon dioxide (CO_2) emissions processed from Young 2 and Young Unit 1. Project Tundra would result in about 450 MW of near-zero carbon power produced with limited or no increase in cost. The Project is expected to commence operation in 2028.

Regarding its transmission infrastructure, the Joint System operates and maintains more than 3,340 miles of transmission line and 252 substations, including a recently-completed 250-mile, 345 kV transmission line between Center, North Dakota and Grand Forks, North Dakota. The Joint System is composed on small cooperative and municipal entities, all of which are substantially impacted by the Proposed Rule.

To comply with the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), EPA must consider the impacts of regulations on small business entities. Small entities include not-for-profit cooperatives, governmental bodies, and public power. EPA performs a screening analysis to determine if a rulemaking has a significant economic impact on a substantial number of small entities. EPA's screening test examines whether small entities would experience annual compliance costs in excess of 1% based on the cost-to-revenue or cost-to-sales test.[1] A Small Business Advocacy Review (SBAR) panel is convened[2] with a public comment opportunity prior to publishing a proposed rule.[3] EPA may skip the SBAR process if EPA certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities.[4]

For the Proposed Rule, EPA's screening analysis found that only a minimal number of small entities would experience annual compliance costs in excess of 1%. EPA did not proceed with the SBAR process on this basis and still has not acknowledged the significant economic impact on a substantial number of small entities nor has EPA revised the original screening analysis. Minnkota has had only a short comment period and one belated meeting with EPA.[5] Minnkota wishes to further engage with EPA to discuss small entity impacts and collaborate concerning compliance flexibility options.

To date, EPA prepared a small entity screening analysis that was not designed to effectively determine the impacts of the Proposed Rule on small entities. Minnkota requests EPA conduct a resource adequacy analysis on rural G&Ts to accurately assess the full impact of the Proposed Rule on small entities because the factors which impact these entities must primarily be driven by adequacy, reliability and economic considerations. Each of these factors has a direct impact on small entities and their consumers, rural Americans.

II. Number of small entities potentially subject to the potential rule.

Any existing coal-fired source under Section 111(d) that cannot implement CCS is left with the option of curtailment of the existing generation to reduce emissions or co-fire with low-GHG fuels. The latter option may result in re-permitting the unit to switch fuel combusted, based on the definition of a "modification to a major existing source." The unit would then be subject to the Section 111(b) NSPS.

While each entity would be required to perform its own independent resource adequacy analysis, all small entities owning existing units subject to the Section 111(d) would be implicated under a similar fact pattern. Those small entities are potentially impacted by the proposed Section 111(d) standards and should be included in the analysis of the economic impact of the Section 111(b) rule on small entities.

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[1] EPA, "Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," May 2023 at 5-5 – 5 11, https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

[2] 5 U.S.C. § 609(b).

[3] 5 U.S.C. § 603.

[4] 5 U.S.C. § 605(b).

[5] *See, e.g.,* SBAR Panel: Federal Plan for Regulating Greenhouse Gas Emissions from Electric Generating Units, Final Report at 5, https://www.epa.gov/sites/default/files/2015-10/documents/report-sbar-panelreport-cppfip.pdf For the CPP, EPA conducted 3 meetings and a comment period.

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EPA's screening analysis vastly underestimated the number of small entities affected by the Proposed Rule.[6] EPA evaluated only the costs of building new generation under proposed Section 111(b). The two portions of the Proposed Rule – Section 111(b) and (d) are interwoven and create a dual threat to any individual small entity that must contend with prematurely retiring assets due to infeasible and costly BSER retrofits and then must replace that generation. EPA must take into account the new generation builds that cooperatives must commission to meet demand.

III. Compliance Requirements of the Proposed Rule.

A. BSER Options and Timelines in the Proposed Rule are not feasible.

The Proposed Rule's CCS assumptions about operations, equipment capabilities and timing are inaccurate. Based on Minnkota's project development experience with CCS on a coal-fired unit, CCS has not been proven, even as a pre-demonstration project, at the size needed to treat the flue gas of a large coal-fired EGU. With respect to natural gas units, CCS has not been demonstrated in practice at all, regardless of scale. Minnkota refers to the comments filed in the docket for further discussion and support regarding this immature technology.[7] Minnkota's comments also provide timeline details that show how EPA's timeline is unreasonably short, irrespective of necessary small entity timing flexibilities. Sequestration is also not demonstrated nationwide. The Proposed Rule's timelines to permit and construct a well site is unattainable and inconsistent with UIC Class VI well requirements and timelines. EPA must revise and reconsider its optimistic suppositions about cost, project schedule, operational flexibility, and regional viability of CCS. At present, CCS is not a viable new generation project strategy for small entities to pursue.

The Proposed Rule's hydrogen technology BSER is similarly premature. EPA has not presented information to show that new generation is able to co-fire hydrogen at the percentages proposed. While EPA identifies certain non-power sector combustion turbines that can combust up to 100 percent hydrogen, it remains illusory whether power sector CTs of any size can achieve higher co-firing rates of 96% by 2038. The future availability of low-GHG hydrogen is theoretical based on the information available at present. Hydrogen transport and storage infrastructure is not in place, nor is there evidence that it will be available prior to the compliance deadline. Minnkota supports these conclusions by reference to detailed technical discussions concerning hydrogen co-firing prepared by its trade association partners, located in the docket.[8] Like CCS, small entities cannot pursue hydrogen co-firing until that technology is proven, infrastructure is in place, timelines are adjusted, and low-GHG hydrogen is attainable.

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[6] The EPA screening analysis assumed that small entities would continue to build the same share of future capacity additions projected by IPM over the forecast period. Cooperatives are more heavily impacted by the Proposed Rule because cooperatives still have a generation mix of 35% coal-fired assets based on 2021 data. https://www.publicpower.org/system/files/documents/2023-Public-Power-Statistical-Report.pdf

[7] Technology Readiness Level (TRL) projects are defined as "system prototype demonstration in an operational environment." TRL 7 projects have results from testing a prototype system in an operational environment but the technology has not been proven to work in its final form and under expected conditions to achieve TRL 8 status. TRL 9 projects are proven in the operating environment.

[8] NRECA GHG Comments, https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0072-0770

For these reasons, small entities seeking to build new generation are relegated to the Proposed Rule subcategories that do not require CCS or hydrogen for compliance. This reality places a significant chilling effect on the ability to build new generation. Cooperatives are faced with limited choices to replace generation that EPA has proposed to effectively retire.

B. Particularized small entity concerns with implementation of the compliance requirements of the Rule.

Overall, labor shortages, manufacturing, and supply chain issues have not returned to normal since the COVID pandemic. In rural and more isolated areas of the country, fewer labor resources are available. Manufacturing and labor shortages were not considered in the impact to small business economic analysis, these are very real threats to the timeline for compliance.

Cooperatives, such as Minnkota, rely on coal-fired generation to power rural communities. MRY is a mine-mouth plant. The lignite mine on-site provides jobs to local community members, promoting economic stability in the community since the 1970s. The Proposed Rule is designed to shutdown coal by putting unachievable BSER in place, even impacting utilities like Minnkota that are ahead on CCS deployment. Small mining communities will be impacted and must be considered in EPA's analysis.

IV. Renewable Interconnection Costs and RTO Limitations Cap Deployment

The Proposed Rule relies on IPM assumptions that renewable generation will take the place of resources that Section 111(d) effectively retires. EPA must consider RTO limitations on renewable generation, which may be more limited than EPA assumes. MISO is 4% away from hitting 30% penetration of renewable energy, which MISO determined will make managing the system more challenging without significant transmission upgrades. Transmission upgrades are costly and take time to implement, and interconnection queue delays are impacting project development timelines. It has taken 50 years for the country to develop the current transmission system. It is not surprising that there are limits to how quickly the system can be transformed and upgraded.

EPA must consider the substantial renewable interconnection costs on small entities. The EPA also needs to consider the timeline for implementation and compliance to ensure it is achievable. The economic analysis of the proposed Section 111(b) rule assumes generation shifting from dispatchable resources to intermittent resources that require upgrade to downstream transmission infrastructure (substation and line rebuilds) or shifting to controls that cannot be divorced from significant upstream transmission infrastructure development (Pipelines and storage facilities). Costs to support such a shift in the form of current limitations of the grid were not adequately recognized in the analysis.[9]

A major limiting factor for renewable generation deployment (because of the intermittent nature of them) is the cost for interconnection.[10] DOE reports that in MISO and PJM projects have seen a doubling of

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[9] See A. Larson, "Interconnection Constraints Threaten Success of Clean Energy Projects," at https://www.powermag.com/interconnection-constraints-threaten-success-of-clean-energy-projects/ (last accessed August 20, 2023).

[10] Interconnection costs refer to those costs associated with interconnecting an energy generator or storage project to the grid, including investments at the point of interconnection and any broader network upgrades needed to accommodate the addition of the new project's capacity. See DOE Interconnection Innovation e-Xchange, "Tackling High Costs and Long Delays for Clean Energy Interconnection," at https://www.energy.gov/eere/i2x/articles/tackling-high-costs-and-long-delays-clean-energy-interconnection (last accessed August 20, 2023).

5301 32nd Ave S
Grand Forks, ND 58201-3312

Phone 701.795.4000
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project costs between 2019 and 2021.[11] For those that remain in queue they are seeing an even higher cost increase with MISO tripling and PJM adding an 800% cost increase in the past two years. These increases in cost are due to the significant addition of capacity needed because of the intermittency of renewables, which is to say that deployment of renewable energy requires overbuilding the energy to cover for the intermittency in the resources. To obtain adequate capacity factors to serve load, generators need to secure two times the load need for wind, a generous capacity factor of 50%, and four times for solar, again generous capacity factor of 25%. A contributing factor is that the transmission system is already at or near capacity, which will require more to be built to accommodate the added generation. In other words, even if the dispatchable generation is subtracted, it is two-to-one or four-to-one replacement because of the intermittency of renewables and still requires increased transmission capacity. The flood of projects is bogging down the interconnection queue, straining the transmission system, driving up costs and delaying projects. Further, the resource planning outcome for many small entities may include development of a combustion turbine for a portion of any retired generation as the most economically optimal plan when examining the cost of interconnection and the exposure to market volatility. The reality of the transmission system limitations must be considered in the analysis of the economic impact of the Proposed Rule. EPA must also consider the costs to small entities of commissioning and installing renewable generation. The Proposed Rule shifts the generation mix to renewables, but the lower overall capacity factor of solar and wind assets requires small entities to make a larger capital investment to meet its obligation to serve the same load. EPA should consider the impacts of these costs on small entities.

V. Cost and Financing Considerations for Resource Development

A. Hydrogen and CCS Challenges

Hydrogen production and proliferation on a 2030 to 2050 timeline requires a substantial amount of renewable energy to be deployed for electrolytic low-GHG hydrogen and will further require $85-$215 billion capital infusion across the midstream (distribution and storage) and end use infrastructure for low carbon energy production. [12] The analysis ignores the timeline for break even in 2040 or later for firm power generation using hydrogen due to "blending limits, end use and pipeline infrastructure, lower energy density,…[and] sensitivity to future natural gas price."[13] Again, the realities of resource development time horizon and substantial cost of infrastructure on the transport and end-user should have been more clearly and accurately accounted for the analysis of hydrogen combustion as a compliance mechanism in the Proposed Rule. Small entities have fewer resources to dabble in low-GHG hydrogen experimentation and build infrastructure. Timeline pressure is more acute for small entities due to financing consideration or the inability to raise money more quickly through investors.

CCS requires a level of infrastructure similar to hydrogen, transport needs to be considered as well as storage infrastructure. For example, Project Tundra, at an average of 4 million metric tons per year, requires 20,000 acres of storage for a 20 year operating life. This is for storage that is efficient and with

[11] Proposed generator projects are studied for their impacts on the transmission grid while in queue. *Id.*
[12] DOE "Pathways to Commercial Liftoff: Clean Hydrogen" at chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf (accessed last August 20, 2023).
[13] *Id.* At p.44.

top tier characteristics for permeability and porosity. Two to three Class VI wells would be required to account for the capacity. Other geology may not have favorable characteristics and would require more injection wells and sites which will increase the overall CAPEX and OPEX of the projects. On average Class VI injection wells cost in 2020 dollars $6-7M per well. Again, these investments are more difficult for small entities to shoulder, even assuming that all sites could bear the costs of multiple injection wells for CCS, which is quite theoretical.

B. The Cost of Replacement Generation for Cooperatives

If enough dispatchable assets are not available, cooperatives risk market exposure. Market exposure is also not a viable solution. Due to the financial risk associated with relying too heavily on energy markets, Minnkota and other cooperatives must meet energy requirements from owned or power purchase agreement resources to the extent practicable.

Replacement dispatchable generation is essential for reliability. Many small entities are evaluating the installation of some combustion turbine resource in its optimal future resource mix in response to the Proposed Rule. A new baseload combined cycle CT would cost roughly $1.4 million/MW, which to replace 100% of the MRY (700MW) but stay under the 20% capacity factor trigger Intermediate BSER (hydrogen co-firing) then Minnkota would have to raise $5.25 billion in capital to replace on a megawatt per megawatt basis. [14]

Based on the modeling done by EPA, the price for energy from a combustion turbine will become less competitive as a result of renewable penetration in the market, indicating this will occur over the next 5 years. If this is the case, cooperative members would have to carry the investment risk because cooperatives would be required to assume a downside base case with an amortizing schedule for the capital cost over a shorter term. In short, combustion turbine generation would result in an increase to member rates that the analysis must take into consideration.

Minnkota participates in the MISO market, which North American Electric Reliability Corporation (NERC) has documented to have an "elevated" potential for insufficient operating reserves in above-normal conditions.[15] As the market becomes more volatile due to generation shortfalls, pricing is more volatile. In addition, extreme weather events may cause steep market purchase prices. As an example, on December 23, 2023, MISO had a four-hour capacity/pricing event during winter storm conditions. Natural gas assets went offline unexpectedly due to the inability to secure fuel and/or personnel unavailability due to the storm. The capacity event was unplanned, as reflected by day ahead pricing that showed these resources as available. Minnkota responded with approximately 450-500 MW of load relief. The cooperative's dispatchable coal-fired assets operated at full capacity during the event. In just four hours, Minnkota would have had the following market exposure if the following coal assets had not been available (RT Impact Column).

Young #1

[14] For a CT unit the size of MRY that would comply with EPA's BSER hydrogen pathway a levelized cost could be upwards of $12.5 billion which would need to be refined based upon a study of capital cost estimates, O&M estimates and a 30-year proforma to determine. The high estimate assumes the possibility (which Minnkota has not been able to find evidence of) that combined cycle CT can co-fire at 96% hydrogen as proposed EPA. Much of the cost is attributed to the substantial amount of storage necessary to run at a baseload capacity factor.

[15] NERC, 2023 Summer Reliability Assessment, May 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf (NERC 2023 Summer Assessment) at 7-8.

5301 32nd Ave S
Grand Forks, ND 58201-3312

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Day	DA Avg. YNG1 LMP	RT Avg. YNG1 LMP	DA Impact	RT Impact
23-Dec	$48.80	$303.16	($269,394.40)	($1,673,452.40)
Young #2				
Day	**DA Avg. YNG2 LMP**	**RT Avg. YNG2 LMP**	**DA Impact**	**RT Impact**
23-Dec	$49.16	$300.59	($442,458.75)	($2,705,272.50)
Coyote				
Day	**DA Avg. CYT LMP**	**RT Avg. CYT LMP**	**DA Impact**	**RT Impact**
23-Dec	$49.07	$298.84	($150,749.44)	($918,023.68)

The day ahead (DA) pricing is identified in the chart as a comparison. DA values show the anticipated impact of having these assets offline. However, the real time (RT) impact illustrates the pricing escalation for *only four hours*. Small entities cannot absorb such a large expense. They must own generating assets to hedge. This example illustrates why small entities must not have a gap between retiring dispatchable resources and new generation coming on-line.

Brazos Electric Power Cooperative (Brazos) members were exposed to approximately $1.89 billion in electric rate charges for week-long winter storm Uri in February 2021. Brazos incurred $2.1 billion in power purchase invoices to the Electric Reliability Council of Texas Inc. (ERCOT). Brazos settled with ERCOT for a cost reduction.[16] As a result, Brazos filed for bankruptcy to protect its member cooperatives. Brazos and ERCOT reached settlement, which left Brazos winding down its generation business, including sale of its 2,200 MW gas-fired generation portfolio, to fund the settlement distributions, avoiding hardship to some of its ratepayers.[17]

Importantly, the regulatory response must a refocused regulatory approach to valuing enhancement measures. Regulating authorities, such as RTOs/ISO, must define critical infrastructure to identify and recognize the value of resilient infrastructure. The Brazos bankruptcy provides a key example of the value of conventional thermal dispatchable generation in the transmission system. Renewables have an

[16] S&P Global, Market Intelligence (Nov. 17, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/court-approves-brazos-electric-reorganization-plan-orders-1-89b-ercot-payment-73110977; Reuters, "Brazos Electric gets initial go-ahead for $1.4 bln energy bill settlement" Sept. 13, 2022, https://www.reuters.com/legal/litigation/brazos-electric-gets-initial-go-ahead-14-bln-energy-bill-settlement-2022-09-13/

[17] See ERCOT, "Proposed Brazos and ERCOT Bankruptcy Settlement", at https://www.ercot.com/about/legal/brazos (accessed on August 20, 2023); S&P Global, Market Intelligence (Nov. 17, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/court-approves-brazos-electric-reorganization-plan-orders-1-89b-ercot-payment-73110977; Reuters, "Brazos Electric gets initial go-ahead for $1.4 bln energy bill settlement" Sept. 13, 2022, https://www.reuters.com/legal/litigation/brazos-electric-gets-initial-go-ahead-14-bln-energy-bill-settlement-2022-09-13/

important market role, but the grid will lose the resiliency without a diversified generation mix. Small entities are the most exposed due to smaller generation systems and lack of investor funding.

C. Financing Challenges and Grants for Cooperatives

1. Cooperative Loans

Hydrogen, CCS and renewables costs and deployment timeline were enhanced by federal incentive programs since the small entity economic impact analysis referenced the BIL and the IRA as "offsetting or mitigating opportunities" for small entities compliance. As non-profits, cooperatives lack access to capital compared to investor-owned utilities. EPA's small business analysis and deployment timelines must account for additional time to obtain financing or grant funds. The largest financier of cooperative capital projects is Rural Utility Service (RUS). RUS has historically served cooperatives, with the mission of electrifying and maintaining critical infrastructure in rural America.[18] Other financing options may be available for certain types of projects, but the interest rates are significantly higher. Cooperatives are nonprofits and their end-users of electricity are in rural communities sensitive to rate increases. Minnkota is a regular RUS borrower.

In Minnkota's experience, EPA must factor in at least an additional 18 months to obtain financing on top of the Proposed Rule's projected timelines to allow cooperatives to obtain financing for new generation and/or large retrofit projects. Infrastructure and transmission projects will be needed to support these projects.

RUS financing is time consuming because it is a multi-step process. Project development prior to construction requires an RUS-approved work plan. The Plan has a project justification for the projected dollars to be spent with third-party vendors cost estimates, design, and operational specifications. Projects must undergo National Environmental Policy Act (NEPA) review. The environmental review requirements are set forth by NEPA, which require all federal agency actions or approvals go through a standardized environmental review process to evaluate what effect their proposed actions (projects) would have on the environment.[19] Borrowers must wait for the conclusion of RUS's environmental review before taking any action on projects or obtaining RUS financial assistance.[20] Once RUS releases funds, the project engineering design and competitive bidding process may commence. EPA must take the financing process into account in the timelines for small entities.

2. Bipartisan Infrastructure Law and Inflation Reduction Act Incentives

Cooperatives have long been unable to take advantage of clean energy tax credits since they have no tax liability. The IRA offered the Empowering Rural America (New ERA) program which helps rural electric cooperatives (small entities) finance the development of the next set of generation resources. There are $9.7B in grants funds available and 62 generation and transmission cooperatives (G&T) that may qualify for funding under the program. The program provides that no one G&T can get more than $970M.

Grants are not available to build dispatchable generation, only renewable generation. Renewable generation does not shield our membership from exposure to intermittency of the resources, in North

[18] For more information about RUS and its essential role for the cooperative community, see https://www.rd.usda.gov/about-rd/agencies/rural-utilities-service

[19] *See* 7 CFR § 1970.8 (describing the extent of the environmental review).
[20] *See* 7 CFR § 1970.12.

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5301 32nd Ave S
Grand Forks, ND 58201-3312

Phone 701.795.4000
www.minnkota.com

Dakota and Northwestern Minnesota winters that see negative 30 through 100+ Fahrenheit weather. Thus, our members would be exposed to energy market risk or reliability concerns.

One of the programs available under new ERA provides grants for purchase, build, or deployment of renewable energy, zero-emission systems, carbon capture storage systems, or to purchase renewable energy—The $970M is limited to 25% cost share for any one project. If we were to build to own new assets with $970M that would require a G&T to raise an additional $3B as a cost-share match. In any case the financing debt service will ultimately be carried by our membership. Even if Minnkota pursued this strategy to replace 750 MW (U1 and U2 total MW), the capacity values of wind would require the construction of, or a PPA to cover, at least 1500 MW. If we were looking at solar that would be 3,000 MW. Two hundred MW of wind or solar is about $500M CapEx proposition. To replace our 750MW of generation with wind or solar we would be looking at between $3.75B-$7.5B in capital required. That figure just accounts for new generation and is not inclusive of standard asset costs of the MRY Unit 1 and Unit 2 and does not account for the interconnection and transmission upgrades required. The grant ceiling and total funds are clearly not sufficient to fund new generation projects of the magnitude proposed by EPA.

3. Stranded Assets are not addressed by loans or grants.

The Proposed Rule completely ignores the direct member rate-payer impact on rural Americans resulting from stranded assets in the form of baseload generation prematurely shutting-down and the cost of new resource planning costs. The cost of decommissioning both units at the MRY roughly $30M, (~$13M U1 and ~$25M U2), this is not inclusive of the debt held on the system which includes these generating resources. If we had to curtail generation members would have to carry more debt coverage on a kwh basis to account for debt being shifted to transmission assets.

The New ERA offers a restructure of RUS debt currently held to a 0% interest rate. However, the savings have to be used towards renewables instead of member rates to triage the impact of resource replacement. Minnkota would need to invest on a two-to-one or four-to one basis for renewables to replace the energy and capacity of the MRY. Therefore, the ERA does not provide relief.

VI. Any flexibilities or alternatives to the potential rule that accomplish the stated objectives and minimize significant economic impact of the potential rule on small entities.

Minnkota considered EPA's request for flexibilities or alternatives to offer to small entities. Considering the experimental nature of the BSER chosen for the Proposed Rule, flexibilities do little to address what Minnkota believes are fatal technical and legal flaws. Therefore, Minnkota suggests that EPA reconsider its BSER approach based on reliability and financial consequences to small entities. EPA should choose feasible and available technologies and adopt timelines that are achievable by all power sector sources. Regardless, Minnkota considered the following flexibility options:

- More flexible timeframes to accommodate all sources and small business concerns: More flexible timelines would help small entities with financing, resource shortfalls, and labor shortages. We observe that a more flexible timeline is only helpful if the BSER can be feasibility implemented on any timeline;

- New subcategories, such as for small units or peaking units: Excluding units from BSER would help will reliability but only avoids the larger problem of a feasible BSER for new generation.
- A stronger reliability relief mechanism: A mechanism is needed to ensure that critical resources will not be hampered by the CO2 limitations that EPA proposed. More critically, baseload generation should be permitted to operation unless there is sufficient time to bring new replacement generation on-line. The gap is generation is a significant reliability concern and potential for business-ending power purchases, such as the Brazos example.
- Trading for compliance: A trading program is only helpful if EPA provides enough allocations to allow sources to meaningfully trade, which has not been EPA's policy of late. In the most recent program example, the Good Neighbor Federal Implementation Plan (FIP), EPA has reduced allowance pools so substantially that the program provides very little flexibility and allowance prices have skyrocketed. Small entities cannot afford high allowance prices and have fewer units to trade allowances within their own systems.

Finally, EPA should refrain from implementing any of the more stringent options presented in the preamble. The options presented by the Proposed Rule are already unworkable.

VII. Conclusion

Thank you for your consideration of these comments. Minnkota looks forward to engaging with the Agency concerning this rulemaking. Should you have any questions regarding these comments, please contact Shannon Mikula at 701.795.4211 and smikula@minnkota.com.

Sincerely,

Shannon R. Mikula

Shannon R. Mikula, Environmental Manager
Special Projects Counsel

Enclosure.

Minnekota Attachment – NPRM Comments

Minnkota Power Cooperative
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312

Phone 701.795.4000
www.minnkota.com

August 8, 2023

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2023-0072
1200 Pennsylvania Avenue, NW
Washington, DC 20460

RE: Comments from Minnkota Power Cooperative, Inc. on New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule, 88 Fed. Reg. 33240, Docket ID No. EPA-HQ-OAR-2023-0072

Minnkota Power Cooperative, Inc. (Minnkota) appreciates the opportunity to provide comments on EPA's proposed rule entitled "New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (the Proposed Rule).

Minnkota is a not-for-profit electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. We are comprised of 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota, and serve some 160,000 member cooperative rate-payers. Minnkota also serves as the operating agent for Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, MN. Since our formation in 1940, Minnkota has been committed to delivering safe, reliable, affordable and environmentally-responsible energy to its member owners.

Minnkota is proud of our extensive decarbonization efforts, including a renewable portfolio that comprises 42% of our current generation resources. Additionally, in 2015, Minnkota undertook the role as lead sponsor of a carbon capture and sequestration project (CCS) adjacent to the Milton R. Young Station (Young Station) to treat the flue gas from the facility's two cyclone lignite-fired coal units, located near the town of Center, North Dakota. Consequently, Minnkota, as the owner-operator of Young Station, has a strong interest in commenting and finds itself in an unusual position in relation to the Proposed Rule.

Although Minnkota strongly supports investment in CCS technology, the Proposed Rule overstates the technologies current and future capabilities as well as the timeline in which CCS can feasibility be deployed. Other aspects of the Proposed Rule pose new, grave reliability concerns stimulating additional premature retirements and further compounding the existing dispatchable generation shortage. As a small, cost-sensitive cooperative, Minnkota urges EPA to consider the perspective of utilities with fewer generating assets.

Though Minnkota is better positioned than most, even Project Tundra would not fully comply with EPA's mandate as presented. We encourage EPA to act on the following requests:

- Wholly revise and reconsider its BSER approach for new and existing generation;
- Adopt reasonable BSER strategies achievable at the unit;
- Decline to proceed with technologies not available to all EGUs, such as carbon capture and sequestration and hydrogen co-firing, as BSER for existing coal-fired and new and existing natural gas-fired units;
- Decline to adopt illegal source redefining, such as fuel-switching (coal to natural gas), as BSER;
- Choose timeframes that accommodate all sources and small business concerns;
- Evaluate grid reliability impacts of its proposal, taking into account the rapid resource transitions, lessons learned from recent generation curtailments, generation scarcities, and transmission constraints that IPM does not cover;
- Adopt a safety valve with two prongs: (1) One that may be used, generally, to buffer key fossil resources from retirement; and (2) Another that operating resources may avail themselves of in emergency circumstances to operate temporarily above GHG emissions limits or capacity factor restrictions;
- Revise and simplify Section 111(d) state plan requirements to remove content burdens, engagement duplicity, and allow for meaningful remaining useful life and other factors (RULOF) consideration; and
- Consider the cumulative financial impact of EPA's suite of environmental regulations on nonprofit, smaller utilities.

Thank you for your consideration of the following more detailed comments. Minnkota looks forward to engaging with EPA concerning this Proposed Rule. Should you have any questions regarding these comments, please contact Shannon Mikula at 701.795.4211 and smikula@minnkota.com.

Sincerely,

Shannon R. Mikula

Shannon R. Mikula, Environmental Manager
Special Projects Counsel

Enclosure.

Minnkota Power Cooperative, Inc.

Comments on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule, Docket ID No. EPA–HQ– OAR–2023–0072

I. Introduction.

Minnkota Power Cooperative (Minnkota) appreciates the opportunity to comment on the Proposed Rule. Minnkota finds itself in an unusual position in relation to this Proposed Rule.[1] Minnkota is proud of our extensive decarbonization efforts, including renewables that comprise 42% of our current generation resource portfolio. Additionally, in 2015, Minnkota undertook the role as lead sponsor of a carbon capture and sequestration project (CCS) adjacent to the Milton R. Young Station (Young Station) to treat the flue gas from the facility's two lignite-fired coal units. With countless hours of dedicated work and investment, the CCS project, known as Project Tundra, is close to becoming a feasible option to further reduce Minnkota's carbon footprint. Minnkota is proud of the work completed to-date to explore promising carbon capture technology, but we also remain very concerned about the ability to achieve the unrealistic timelines and standards set forth in this rule.

Reliability has and always will be essential to Minnkota and our member owners' mission. Federal agencies, lawmakers, and regional transmission organizations (RTOs) have articulated fears of a reliability crisis. In May, the Federal Energy Regulatory Commission (FERC) spoke before the Senate Committee on Energy and National Resources on this topic. Commissioner Christie testified:

> The United States is heading for a reliability crisis. I do not use the term "crisis" for melodrama, but because it is an accurate description of what we are facing. I think anyone would regard an increasing threat of system-wide, extensive power outages as a crisis. In summary, the core problem is this: Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the addition of intermittent resources, primarily wind and solar, but the far too rapid subtraction of dispatchable resources, especially coal and gas.[2]

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[1] The "Proposed Rule" refers to the rulemaking entitled, "The New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 88 Fed. Reg. 33240 (May 23, 2023).
[2] Testimony of Commissioner Mark Christie, FERC Commissioner, to the Senate Committee on Energy and National Resources, May 4, 2023, https://www.energy.senate.gov/services/files/1D618EDD-7CED-4BC5-8F09-C8F0668FE608 .

The math does not add up. Dispatchable generation is retiring faster than replacement resources are coming online. In the MISO[3] region where Minnkota resides, the dearth of dispatchable resources is well-documented and places the entire region on a heightened capacity shortage alert. Electricity demand is on the rise, but EPA's suite of new environmental regulations will handcuff the ability of utilities to meet that demand. Minnkota has joined with industry peers and the State of North Dakota to express our deep concern over the implications of the Proposed Rule. While EPA did not respond, we remain ready to engage in that discussion, particularly given the critical nature of the impacts.[4]

Minnkota is a not-for-profit electric cooperative and small business entity that powers rural communities in eastern North Dakota and northwestern Minnesota. These communities depend on Minnkota to provide cost-effective electricity to sustain rural residences, businesses, schools, and farms. Cooperatives have also sounded the reliability alarm. The cooperative trade association, National Rural Electric Cooperative Association (NRECA), recently underscored the reliability crisis in our country and called for new government regulations to cease "forcing the disorderly closure of always-on power plants in favor of renewables" to prevent demand from exceeding supply during critical times.[5]

Although Minnkota strongly supports investment in CCS technology, the Proposed Rule overstates its current and future capabilities and the timeline in which CCS can feasibility be deployed. Other aspects of the Proposed Rule pose new, grave reliability concerns, stimulating more premature retirements and further compounding the existing dispatchable generation shortage. As a small, cost-sensitive cooperative, Minnkota urges EPA to consider the perspective of utilities with fewer generating assets. The Proposed Rule places a proportionally greater strain on cooperatives. Even though Minnkota is better positioned than most, even Project Tundra would not fully comply with EPA's mandate.

Furthermore, this Proposed Rule is actually *five* regulatory actions that EPA has compiled together as one vast and complex rulemaking. The complexity of this rulemaking is striking, including hundreds of pages of backup documents, many of which have reference attachments. Numerous stakeholders requested that EPA extend the public comment period for this impactful suite of greenhouse gas regulations. EPA provided only 15 additional days. A 75-day comment period is completely insufficient for Minnkota to examine the impacts of EPA's proposal on its existing fleet and consider how new generation would be built. The Proposed Rule presents a myriad of technical issues concerning the feasibility and timing of EPA's proposed best system of emissions reduction (BSER) that require outside technical support. Minnkota has a small

[3] MISO stands for "Midcontinent Independent System Operator."
[4] Remarks of Senator Cramer from North Dakota to the Senate Environment and Public Works Committee on the Nomination of Joseph Goffman, March 1, 2023.
[5] NRECA, Along Those Lines: Raising the Alarm on Grid Reliability," June 22, 2023 (podcast with Jim Matheson, CEO of NRECA, and David Tudor, CEO of Associated Electric Cooperative), https://www.electric.coop/along-those-lines-raising-the-alarm-on-grid-reliability

environmental staff, as do many not-for-profit cooperatives. EPA has completely inundated staff with other rulemakings during the same time period as the Proposed Rule. In fact, during the 75-day comment period for this proposal, Minnkota had to consider and comment on three other rulemakings specifically targeted at the power sector and substantially impacting our fleet:

- Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category that ended May 30;
- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review that ended June 23; and
- Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments that ended July 17.

EPA's refusal to grant an extension for this Proposed Rule has put Minnkota at a severe disadvantage to place meaningful comments into the record and to fully examine the impacts of the proposal on our ability to deliver affordable and reliable electricity to our members. We ask EPA to re-open the comment period for an additional 45 days, at a minimum, past the current deadline of August 8.

Minnkota is a member of the Lignite Energy Council (LEC) and the National Rural Electric Cooperative Association (NRECA). Minnkota supports the comments of these groups and incorporates their comments and technical support by reference.

Minnkota summarizes its requests related to this rulemaking, as follows:

- Wholly revise and reconsider its BSER approach for new and existing generation;
- Adopt reasonable BSER strategies achievable at the unit;
- Decline to proceed with technologies not available to all EGUs, such as carbon capture and sequestration and hydrogen co-firing, as BSER for existing coal-fired and new and existing natural gas-fired units;
- Decline to adopt illegal source redefining, such as fuel-switching (coal to natural gas), as BSER;
- Choose timeframes that accommodate all sources and small business concerns;
- Evaluate grid reliability impacts of its proposal, taking into account the rapid resource transitions, lessons learned from recent generation curtailments, generation scarcities, and transmission constraints that IPM does not cover;
- Adopt a safety valve with two prongs: (1) One that may be used, generally, to buffer key fossil resources from retirement; and (2) Another that operating resources may avail themselves of in emergency circumstances to operate temporarily above GHG emissions limits or capacity factor restrictions;

- Revise and simplify Section 111(d) state plan requirements to remove content burdens, engagement duplicity, and allow for meaningful remaining useful life and other factors (RULOF) consideration; and
- Consider the cumulative financial impact of EPA's suite of environmental regulations on nonprofit, smaller utilities.

We appreciate EPA's consideration of our more detailed comments herein and look forward to future engagement on these matters.

II. Background.

A. Minnkota Power Cooperative

Minnkota Power Cooperative is a not-for-profit electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. Minnkota provides wholesale electric energy to 11 member-owner distribution cooperatives located in eastern North Dakota and northwestern Minnesota. Minnkota also serves as the operating agent for the Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, MN.

Minnkota is the operator and a partial owner of the Milton R. Young Station (Young Station), a two-unit, cyclone lignite coal-fired power plant located near the town of Center, North Dakota. Minnkota owns and operates Unit 1, while also operating Unit 2 on behalf of Square Butte Electric Cooperative. Square Butte is owned by the same 11 member-owner cooperatives associated with Minnkota and shares the same management. Minnkota has no plans to retire the Young Station, which is the key generation asset of the cooperative. Minnkota's electric generation portfolio also includes renewable energy purchased primarily from three North Dakota wind farms, and hydroelectricity purchased from the Garrison Dam in central North Dakota. In all, renewables and hydroelectric power comprise 42% of Minnkota's nameplate generation capacity. Minnkota exists as a not-for-profit cooperative for the sole purpose of meeting the generation and transmission needs of our distribution cooperative member owners.

Minnkota and its project partners are pursuing construction of a CCS project adjacent to the Young Station known as Project Tundra. It will be North America's largest CCS facility when it commences operation. The project will treat the flue gas of Units 1 and 2 to reduce and capture CO2 emissions. The project is designed to capture CO2 at a rate of about 95% of the treated flue gas from either unit at the Station, with the CO2 stored more than a mile underground.[6] The project will be two and a half times the size of the Petra Nova project.

[6] Project Tundra, About, https://projecttundrand.com/about.

III. The Proposed Rule Disproportionally Affects Electric Cooperatives and the Rural Communities They Serve.

A. EPA has not adequately considered the impacts of the Proposed Rule on the Cooperative Community.

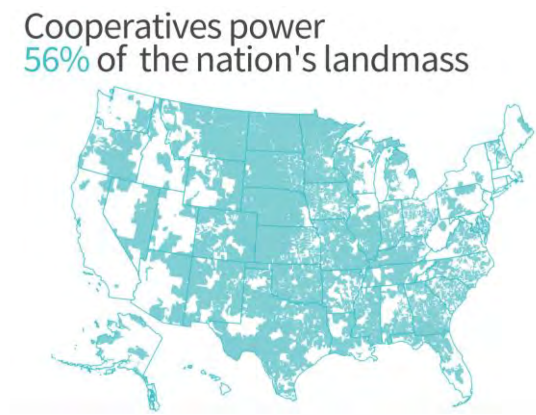
EPA must consider the specific and important challenges of not-for-profit, consumer-owned electric cooperatives as a distinct portion of the utility sector. Cooperatives require time and resources to meet the requirements posed by the Proposed Rule. For this reason, Minnkota requests EPA's consideration of challenges specific to cooperatives.

1. Background: Electric Cooperatives.

(a) *The Electric Cooperative Portion of the Power Sector*.

The electric cooperative network is composed of 831 distribution cooperatives. They were built by and serve co-op members in the community with the delivery of electricity and other services. All but the three largest electric cooperatives qualify as "small businesses" under Small Business Administration standards.

Cooperatives serve 42 million people predominantly rural areas, including 92% of persistent poverty counties. The sector powers over 21 million businesses, homes, schools and farms in 48 states. Cooperatives sell most of their power to households rather than businesses, unlike investor-owned utilities (IOUs). They operate at cost and without a profit incentive. They are owned by the members they serve with no independent stockholders. Rate affordability is crucial for consumer-members at the end of the line. Costs are borne across a base of fewer consumers and by families that already spend more of their limited incomes on electricity than do comparable municipal-owned or IOU customers. Data from the U.S. Energy Information Administration show that cooperatives serve an average of eight consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line.



Today, Cooperatives rely on a diverse energy mix. From 2010 to 2021, cooperatives more than tripled their renewable capacity from 3.9 gigawatts to more than

13 gigawatts. Co-ops added over 900 MW of new renewable capacity in 2022. More than two-thirds of the electricity delivered by cooperatives comes from low- or zero-carbon sources. Cooperatives are committed to the environment. Our portion of the power sector has reduced SO2 emissions 82% from 2005 to 2021, while NOx emissions reduced 68%.[7]

(b) *History and Mission of Electric Cooperatives to Serve Rural America*.

In the 1930s, nine out of ten rural homes did not have electric service. Rural economies were exclusively dependent on agriculture. In 1933, President Roosevelt promoted the electrification of these rural areas. On May 11, 1935, Roosevelt signed Executive Order No. 7037 establishing the Rural Electrification Administration (REA), now the Rural Utilities Service (RUS), an arm of the Department of Agriculture. REA provided financing of cooperative projects. In 1937, the REA drafted the Electric Cooperative Corporation Act. The Act created a model to enable states to form and operate of not-for-profit, consumer-owned electric cooperatives. By 1953, more than 90 percent of U.S. farms had electricity. Today, 99 percent of the nation's farms have service. This success was made possible by locally-owned rural electric cooperatives that got their start by borrowing funds from REA to build lines and provide service on a not-for-profit basis.

Since the 1970s, the cooperative energy sector has been coal-heavy. In response to a Congressional mandate, electric cooperatives built approximately two-thirds of the coal-fired units in the electric cooperative fleet under the 1978 Powerplant and Industrial Fuel Use Act, prior to its repeal. The Act pushed electric cooperatives to build significant new "coal capable" baseload generation for self-generation to preserve natural gas supplies. Some cooperatives still have outstanding loan debt on these investments, in part due to the cost of environmental retrofits to meet evolving regulations such as Regional Haze.

(c) *Electric Cooperatives have special financing considerations that increase project timeframes.*

The Proposed Rule would require major capital investments in new generation and large retrofit projects for coal-fired generation. Transmission projects are also likely to support new generation. EPA's small business analysis and deployment timelines must account for additional time to obtain financing. The largest financier of cooperative capital projects is RUS. RUS has historically served cooperatives, with the mission of electrifying and maintaining critical infrastructure in rural America.[8]

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[7] https://www.electric.coop/electric-cooperative-fact-sheet

[8] For more information about RUS and its essential role for the cooperative community, see https://www.rd.usda.gov/about-rd/agencies/rural-utilities-service (*visited June 3, 2022*) ("The Electric Program provides funding to maintain, expand, upgrade and modernize America's rural electric infrastructure. The loans and loan guarantees finance the construction or improvement of electric distribution, transmission and generation facilities in rural areas. The Electric Program also provides funding to support demand-side management, energy efficiency and conservation programs, and on-and

Obtaining RUS financing is a multi-step process. During project development and prior to construction, the cooperative's project engineering team must prepare initial scoping and draft a project justification for the projected dollars to be spent. This process involves reaching out to third-party vendors to confirm cost estimates, design, and operational specifications. RUS must approve the Work Plan.

RUS financing requires compliance with the National Environmental Policy Act (NEPA), which adds additional time at the beginning of a large project. The U.S. Department of Agriculture (USDA) regulates actions financed by RUS requiring environmental review. The environmental review requirements are set forth by NEPA, which require all federal agency actions or approvals go through a standardized environmental review process to evaluate what effect their proposed actions (projects) would have on the environment. Environmental reviews require development of Environmental Reports (ER), Environmental Assessments (EA), or Environmental Impact Statements (EIS) depending on the complexity/scale of the project.[9]

The environmental review process and timelines depend upon the scope of the project and ultimately what project documents RUS will request that the cooperative submit; however, a large control device project is likely to trigger an EA.[10] RUS reviews the EA or other environmental document and may require additional information, additions or revisions to the EA during the review process. Ultimately, RUS adopts the EA at the conclusion of the review process. RUS then publishes a public notice of the availability of the EA. The public notice and comment process commences, which would involve notice of the issuance of a Finding of No Significant Impact (FONSI), if RUS makes this finding.[11] Borrowers must wait for the conclusion of RUS's environmental review before taking any action on projects or obtaining RUS financial assistance.[12] Once RUS releases funds, the project engineering design and competitive bidding process may commence.

While other financing options may be available for certain types of projects, the interest rates are significantly higher. Cooperatives are nonprofits and their end-users of electricity are in rural communities sensitive to rate increases. For these reasons, Minnkota is a regular RUS borrower to finance environmental compliance and other projects.

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off-grid renewable energy systems. Loans are made to cooperatives, corporations, states, territories, subdivisions, municipalities, utility districts and non-profit organizations.").

[9] *See* 7 CFR § 1970.8 (describing the extent of the environmental review).

[10] For reference, *see* Environmental Assessments for other cooperative projects located on the RUS website: https://www.rd.usda.gov/resources/environmental-studies/assessments. Projects include transmission line, renewable generation, and fossil generation.

[11] RUS outlines the environmental review process in detail on its website and provides a step-by-step flowchart of the process. We provide a link to this information for EPA's reference for inclusion into the record: https://openei.org/wiki/RAPID/Roadmap/9-FD-h

[12] *See* 7 CFR § 1970.12.

In Minnkota's experience, EPA must factor in at least an additional 18 months *on top of the Proposed Rule's projected time* to allow cooperatives to obtain financing for new generation and large retrofit projects for coal-fired generation. Infrastructure and transmission projects will be needed to support these projects.

2. Rural Communities require affordable energy to thrive.

Electric co-ops sell the majority of their power to households rather than businesses. Keeping rates affordable is especially important for consumer-members at the end of the line. Environmental compliance decision-making demands balancing the air quality benefit on a rural community against the associated compliance costs (energy cost). The Proposed Rule cites no direct health benefits from lowering greenhouse emissions. To justify the rule, EPA finds that reducing greenhouse gases will have indirect benefits to environmental justice communities that face the impacts of climate change. EPA also bootstraps alleged co-benefits regarding other pollutants – highlighting reductions in ambient levels of PM 2.5 and ozone exposure.[13] EPA must recognize that the justification for the Proposed Rule primarily relies on benefits that are indirect and theoretical to the communities ultimately footing the bill. In comparison, increased energy costs are concrete. EPA should factor in the cost impacts of this Proposed Rule on rural communities.

3. The specialized needs of electric cooperatives must be considered.

The Proposed Rule overburdens the cooperative community in the following specific ways:

- Difficulty absorbing and/or raising money for the unprecedented number of environmental compliance rulemakings proposed by the Biden Administration. Cooperatives do not have investors from which to raise money. Large, capital-intensive projects are a substantial investment for smaller entities. Inflation Reduction Act (IRA) funds are not necessarily available to bridge the financial gaps. EPA's rulemaking "asks" result in an unprecedented financial burden that falls in a short time period between now and 2030, and for cooperatives will imply substantial rate increases to comply.
- Smaller generating systems have fewer compliance options when faced with multi-faceted, complex rules, such as the Proposed Rule. With fewer units in operation to leverage to meet power generation needs, cooperative systems are not as nimble as larger IOU systems that have varied baseload assets. IOUs have more assets to meet generation demands while complying with the Proposed Rule. Trading programs and averaging are often not useful for cooperative systems that have fewer units in these programs. With fewer units and plants to average or trade, these solutions place cooperatives at a disadvantage. In addition, while units are in outage for compliance projects, cooperatives have fewer resources to make up the generation deficit, and would be subject to potentially high-cost replacement energy.

[13] Proposed Rule at 33247, 33413.

- Cooperatives have greater infrastructure needs. To power 56% of America's land mass, large spans of infrastructure is required. Rural areas are electrified by miles of transmission lines. The Proposed Rule calls for brand new infrastructure for hydrogen and CO2 transportation, separately. This infrastructure must be developed over America's rural areas to ensure that the plants serving these cooperative service territories install BSER to be compliant. Vast service territories make this task more challenging for cooperatives, particularly in areas in which the geology does not support hydrogen or CO2 storage.
- Insufficient time to pursue project financing for projects to retrofit existing generation to comply with the proposal, or in lieu, to build new generation to bridge the gap. Environmental compliance requires time for project planning, man-power, and financing. Cooperatives cannot simply raise funds through investors. Project financing is needed through RUS or, if affordable, private resources.
- Coal-heavy cooperatives are disproportionately impacted. Cooperatives with small systems that rely on coal are placed in an impossible position. The Proposed Rule shuts down the coal by failing to provide enough time to construct CCS projects. Without other non-coal units to gap-fill, these cooperatives have few options.

Minnkota requests that EPA factor in the impacts of the Proposed Rule on cooperatives. A generalized cost analysis is inadequate. The Regulatory Impact Analysis should specifically account for impacts on this subset of the utility sector.

III. EPA's BSER proposal is not adequately demonstrated.

EPA's determinations of BSER for new and existing EGUs are far beyond the boundaries of CAA Section 111 or even what EPA has promulgated under Section 111 in the past. The Proposed Rule sets GHG emissions standards for fossil fuel-fired coal, oil, and natural gas generating units. EPA requires units, depending on category and fuel burned, to deploy CCS or low-GHG hydrogen combustion. EPA's determination of the "best system of emissions reduction" must be adequately demonstrated to comply with Congress's mandate.

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (considering the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been *adequately demonstrated*.

Courts have drawn EPA's boundaries for selecting BSER. As a fundamental principle, EPA's BSER decision must be the result of "reasoned decisionmaking."[14] The BSER technology must not be a "purely theoretical or experimental" means of controlling air pollution.[15] EPA's task is to make a projection based on existing technology subject to the "restraints of reasonableness and cannot be based on 'crystal ball' inquiry." This determination is partially based on the time in which the technology will be available.[16] While a standard can be predictive, courts look at EPA's record for evidence to determine whether it is achievable in the expected time frames.[17]

Minnkota's trade association partners have undertaken extensive studies of EPA's BSER – CCS and hydrogen co-firing. Minnkota endorses these studies and adds its perspective, particularly with respect to navigating CCS on existing coal-fired generation. Minnkota confidently joins industry's position that EPA has chosen a BSER that is not adequately demonstrated and certainly not attainable within the deployment timelines that EPA has recommended.

A. CCS is not adequately demonstrated.

1. The Proposed Rule's record is insufficient to support CCS as BSER.

Minnkota shares EPA's enthusiasm for the promise of a CCS as an effective method of reducing carbon emissions. Our cooperative has specialized knowledge to comment on the Proposed Rule given the time spent since 2015 on project development to bring CCS to the Young Station.

Minnkota has reviewed EPA's justifications that CCS is adequately demonstrated. The record is insufficient to support this claim. EPA identifies only a small list of projects and includes a project rife with technical issues, a non-operating project, and a small pilot project:

- SaskPower Boundary Dam Unit 3 (110 MW lignite-fired unit in Saskatchewan, Canada), the only currently operating project of the three.
- Petra Nova capture facility (240 MW capture at Parish Generating Station in Texas)
- Plant Barry (25 MW capture in Mobile, Alabama)[18]

To be adequately demonstrated, both the carbon capture and the storage aspects of the proposal must be addressed. With respect to carbon capture itself, EPA

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[14] *National Asphalt Pavement Ass'n v. Train*, 539 F.2d 775 (D.C. Cir. 1976) (citing *Essex Chem. Corp. v. Ruckelshaus*).
[15] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973) (citing Senate Report).
[16] *Id.* at 391-92.
[17] *See, e.g., Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981) (considering vendor information that stated the SO2 standard was achievable and overlooking data shortcomings, such as limited test information).
[18] Proposed Rule at 33293.

proposes full-scale installations achieve 90 percent capture rates with cost estimates based on recent coal fleet average capacity of 400 MW. However, EPA identifies only a small list of CO_2 capture projects.[19] None of the cited projects have demonstrated successful operation and capture on a scale than would be deployed to accommodate larger power generating units in the country.

Only Petra Nova has operated at a coal-fired facility in the United States. That was only a slip-stream project, and CCS is not currently in operation there. While the Boundary Dam, Canada installation demonstrated more continuous operation, that project is on a single, small capacity unit that does not correlate to the capacities contemplated by the Proposed Rule. There are no known CCS projects on natural gas units.

With respect to the storage component of the process, Minnkota agrees with EPA's assessment that geologic sequestration of captured CO2 is available in certain parts of the country, such as in North Dakota. Yet, it is not available universally. EPA acknowledges this fact but fails to offer an effective, cost-reasonable solution. The likely outcome for less fortunate sites is unit shutdowns where compliance is not available.[20] As discussed in Section VI, EPA cannot legally choose non-operation as BSER.

The record is riddled with timing underestimates. In Minnkota's experience, the rigorous timeline offered by EPA cannot be met by sources that have not already begun CCS project development. For example, EPA projects just two to three years to characterize and permit a storage facility but neglects to consider difficulties in obtaining Class VI permits for storage facilities or, in the alternative, difficulties in permitting and installation of a pipeline, if on-site storage is unavailable.

2. <u>Minnkota's CCS project experience is not consistent with many of EPA's project assumptions</u>.

CCS technology is important to support economy-wide decarbonization. However, EPA makes assumptions about operations, equipment capabilities and timing that are inaccurate based on Minnkota's project experience. EPA must revise and reconsider its optimistic suppositions about cost, project schedule, operational flexibility, and regional viability of CCS.[21] Minnkota's experience with Project Tundra is instructive to this proposal. EPA's feasibility assumptions and timeline must also be reconsidered.

(a) Feasibility of Carbon Capture.

<u>Carbon capture is a pre-demonstration technology</u>. CCS is feasible but not adequately demonstrated. To be adequately demonstrated, CCS must be possible at

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[19] EPA, Spreadsheet of CCS facilities, EPA-HQ-OAR-2023-0072-0061_attachment 1
[20] EPA acknowledges that all areas of the country do not have geologic sequestration capabilities. Proposed Rule at 33298
[21] EPRI Comments, filed separately in this docket at Section 2.1 and 2.2.

all sites with existing coal-fired units, at all boiler-types, and at all loads. Minnkota's experience confirms this is not true. Of most significance, CCS has not been proven, even as a pre-demonstration project, at the size needed to treat the flue gas of a large coal-fired EGU.

Project Tundra is financed as a Technology Readiness Level (TRL) 7 project. TRL 7 projects are defined as "system prototype demonstration in an operational environment." TRL 7 projects have results from testing a prototype system in an operational environment but the technology has not been proven to work in its final form and under expected conditions to achieve TRL 8 status. TRL 9 projects are proven in the operating environment.

While BSER does not require pilot tests, evidence must be in the record to support CCS application at larger scales. The Young Station units are a 455 MW unit (Unit 2) and a 250 MW unit (Unit 1). The Tundra project only has capacity to treat 530 MW. Of consequence, the parasitic load of the project decreases the capacity of the units while the CCS system is operating due to electricity and steam requirements.

If carbon capture was demonstrated, Minnkota and its partners would not be able to finance Project Tundra as presently arranged. Project Tundra is requesting financing, in part, as a demonstration project through funds from the Department of Energy's (DOE) Office of Clean Energy Demonstrations (OCED). The Bipartisan Infrastructure Law enacted in December 2021 created the funding opportunity for *demonstration* projects.[22] Funding is not available for technologies that are proven at a commercial scale. To obtain funding from OCED, DOE looks at "technology readiness levels." It provides funds to projects that show advancing technology. The Project Tundra demonstration results from the bold investment to take CCS farther than before. The Project seeks to advance the technology readiness level of CCS by scaling up the technology (2.5x), applying it lignite, and showing successful operating in an extreme cold weather climate.

<u>Demonstration projects carry a perceived technology risk</u>. Minnkota has acknowledged and carefully calculated the technology risk, taking account of site-specific variables. A crucial assumption in Minnkota's calculus is that the Young Station units may operate and generate electricity *even if the CCS equipment has an outage.* In other words, if equipment issues arise – whether due to the CCS technology, equipment, increased scale, extreme temperatures, or variability in flue gas load – the CCS system may take a forced outage. Meanwhile, the Young Station units are able to generate electricity and emit flue gas through the current stack configuration while CCS is down and as it warms back up for service. Thus, the risk of equipment failure is much

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[22] DOE, OCED, OCED Funding Opportunity Exchange, https://www.oced-exchange-energy.gov/FAQ.aspx.

less impactful than if the entire Young Station must come offline for the entire duration of the CCS plant forced outage. In that event, Minnkota would be hedging its ability to meet generation needs on the CCS project equipment, a much different situation. The Proposed Rule would compel this result.

Carbon capture at a large-scale coal-fired unit or any natural gas unit has not been demonstrated. In fact, the Tundra project seeks to prove that large scale coal-fired application is possible. Project Tundra will be able to capture the CO2 emissions equivalent to a 530 MW unit.[23] Tundra's scale will be the largest capture system in the world and will employ the largest single train system that has been built by the project OEM. This large train is still not sufficient to cover EPA's anticipated scope, which in Minnkota's case would be 705 MW of flue gas. An additional CCS train would be necessary. This additional equipment would exponentially expand the project cost to only capture an additional 28% of load.

Carbon capture is not adequately demonstrated to continuously achieve a rate of 90% capture of CO2 based on a source-specific level of baseline emission performance. Project Tundra is designed to capture CO2 at a rate of about 95% from approximately 530 MW of the 734 MW produced at full load from a combination of Unit 2 and Unit 1 flue gas. The carbon capture process depends on a complex chemical reaction in the CCS absorber to strip the CO2 and capture it. Carbon capture efficiency will vary when the flue gas stream is at a lower load. Minnkota has no technical data or testing assurance that EPA's value of 90% capture can be achieved across varying unit loads. In addition, weather (seasonal temperature) impacts are anticipated to impact the CCS equipment function. No information is available to determine how the carbon capture rate may be affected. Based on Minnkota's understanding from project development, this demonstration project will help to fill in these gaps, which are presently unknowns. The Tundra project parameters were never dependent on achieving a specific capture rate continuously. Certainly, a margin for compliance would be required. EPA's aspirational 90% value is clearly speculative and unsupported. Further testing and vendor information is necessary to target an achievable capture percentage that could be applied to all unit sizes, project scales, weather conditions, pollution control trains, and load levels with a margin for compliance.

(b) Reliability Considerations.

The electrical and steam requirements of capture system is consequential. EPA should consider the practical consequences of CCS. The electrical and steam requirements of carbon capture systems will remove a significant amount of load from the grid. In Tundra's case, 205 MW from the Young Station units is needed to operate the adjacent CCS facility. In total, the CCS demand is about 31% of the Young Station's net capacity. This value is equivalent to retirement of a smaller generating

[23] The Project is designed to capture variable mixes of flue gas. At full load, the system will treat the flue gas of Young Unit 2 (a 455 MW unit) and 30% of the CO_2 emissions at Young Unit 1 (a 250 MW unit).

unit. The overall cumulative demand to serve multiple CCS facilities on the grid must be evaluated to determine the impacts on an already strained grid.

Forced outages due to CCS equipment failures will remove generation from the grid. At present, no regulatory requirements constrain the Young Station from operating if the CCS system experiences a malfunction or if MISO calls on the Young Station to run at full load, without a CCS-related derate, for grid stability. It is crucial to preserve the ability for units to function in must-run situations to abate a grid emergency. EPA must consider exemptions for CCS equipment malfunction events and for reliability needs.

(c) CCS Project Costs and Financing Limitations

CCS Projects are very expensive due to development, one-time capital costs, and ongoing operating costs. Project Tundra is estimated at a cost of approximately $1.4 billion.[24] The project will be financed by utilizing 45Q federal tax credits, which are currently $85 per ton of CO2 that is captured and stored in a geologic formation deep underground. Permitting is currently under way for an adjacent second CO2 storage site. If this federal subsidy were not in place, the project would not be economical. The extraordinary capital and annual operating costs of CCS are a statutorily-required consideration that EPA must factor into the analysis. These costs are even more substantial for smaller generators, such as cooperatives.

Financing options are essential but limited. CCS projects are only possible through multiple funding sources. Project Tundra will avail DOE funds, as well as assistance from the IRA. The state of North Dakota is providing a $250 million loan to assist the project. Private bank loans are more challenging to obtain for demonstration projects. A project of the scale needed to comply with the Proposed Rule would require even more funding. The increase in project cost just to treat the flue gas from both the Young Station units (28% more flue gas) would require a large sum of additional capital in addition to the IRA monies and the OCED grant to build a second CCS train and acquire more storage acreage.

(d) Sequestration Feasibility, Costs and other Considerations.

Many areas of the country do not have the geology to support sequestration. The Young Station happens to be placed on ideal geology for safely sequestering carbon. However, much study was necessary to arrive at this conclusion. In 2005, the Energy & Environmental Research Center (EERC) at the University of North Dakota started characterizing the geology within the state and targeting formations. It took the EERC over a decade just to characterize the geology. The graphical representation of the geology under the Young Station depicts the necessary elements for storage. Most sites do not have a deep porous rock layer to hold the CO2 and overlying cap rock layers will seal the CO2 in the storage zone.[25] Sites that do not have this geological

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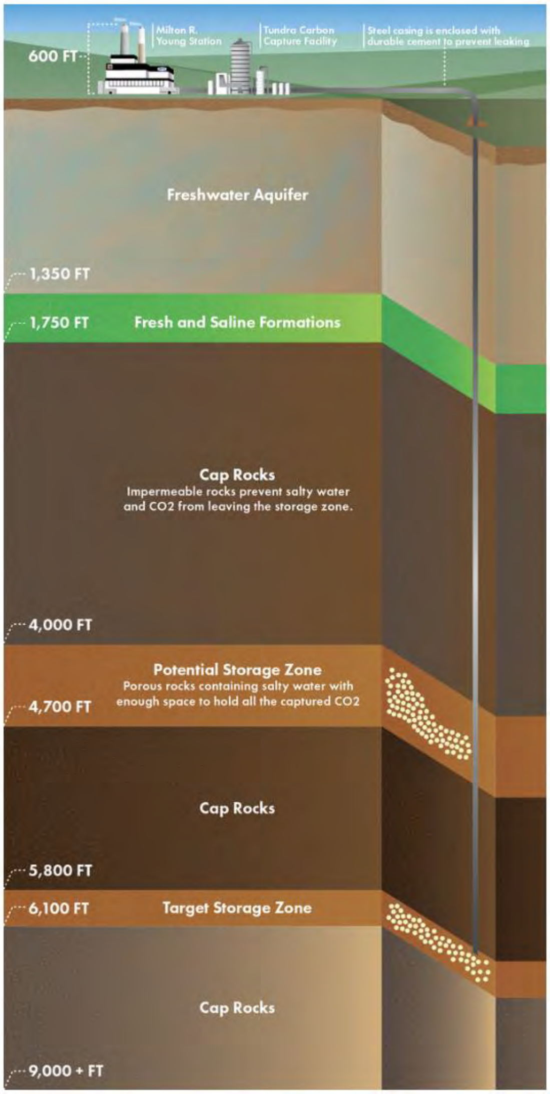
[24] https://www.projecttundrand.com/faq
[25] https://www.projecttundrand.com/co2-storage

setting must pump the extracted CO_2 to a storage area. Dedicated piping must be available, adding even more cost to the project.



<u>States with oil and gas frameworks, like North Dakota, will have a shorter timeline for exploring and permitting storage.</u> North Dakota has an oil and gas and mining regulatory framework to study sequestration geology and issue permits. Many states do not have any experience at all in this area. Time would be necessary to enable those states to develop a regulatory framework that supports sequestration and drilling and addresses ownership of pore space to lessen the possibility of future legal challenges for projects and permits.

<u>To obtain a Class VI permit to allow storage of CO_2 is an arduous data collection process</u>. A tremendous amount of information is needed. For example, EERC needed over a decade to characterize the geology. After that characterization, in 2020, Minnkota drilled two characterization wells to gather the necessary geologic data to support a permit application. This step was required to obtain a complete application.

<u>Class VI permits are expensive</u>. For Tundra, the storage permit cost upwards of $30 million. This cost is likely reduced because the work was performed during the COVID-19 pandemic lockdown when rig costs and labor were less expensive. In the future, the cost might be double, particularly when utilities are competing over limited drilling resources.

<u>Class VI permitting is a lengthy process</u>. North Dakota is one of only two states with primacy to issue Class VI permits. North Dakota engaged in two full sessions of state lawmaking to enact laws required for EPA to grant primacy. Sources in all other states must look to EPA to grant Class VI permits. At present, 33 permit applications are pending.[26] Even though some states are trying to attain primacy, that process is also time-consuming. If CCS becomes BSER, the backlog of pending applications is sure to increase.

[26] Hunton Andrews Kurth, Class VI Program Permit Tracker, https://www.huntonak.com/en/class-vi-program-permit-tracker.html.

(e) EPA's CCS Project Timeline is unrealistic.

EPA's proposed timeline requires CCS units to be fully operational by January 1, 2030. This time frame cannot be achieved. For Project Tundra, project development took almost nine years of study and engineering analysis necessary to support a final decision on construction, despite exceptional geology at the Young Station. Carbon capture FEED studies take a minimum of 18 months (6 months for Pre-FEED studies plus 12 months minimum for a FEED study). Only four to five vendors actually have the capability to launch CCS projects. Minnkota has identified only two of those vendors able to develop CCS operations at the scale of Tundra.

For Project Tundra, the OEM selected, Mitsubishi, has been studying the flue gas characteristics of the Young Station since 2015. These studies ensure successful capture solvent performance. Environmental permitting has played a significant factor in the project timeline. The CCS facility requires water permits, an air permit, and transmission changes at the plant (re-routing). Once FEED studies, permitting, and other project development work is complete, the actual construction timeline will take three to four years. Since equipment is fabricated off-site, it must be ordered to specifications well in advance. Delays are possible due to labor storages or supply chain issues. Minnkota projects that Tundra will come on-line in 2029.

Construction timelines are likely to impacted by the demand the Proposed Rule would place on the small number of vendors available to develop and construct CCS projects. In addition, supply chain issues are anticipated and will increase the time necessary to achieve commercial operation. Compressors, other large rotating equipment, and the power distribution equipment such as large transformers and primary control modules must be commissioned, built, and installed. The Proposed Rule would stimulate many new CCS projects for coal and gas that would flood the field at the same time. Suppliers are likely to be overwhelmed and unable to provide equipment without lengthy waits.

To obtain the Class VI permit for Project Tundra, four years were required to obtain the permit, including characterization of the geology for the permit application, completing the Class VI permit application, holding hearings, and obtaining the final permit. Minnkota anticipates that sites in states without a subsurface regulatory framework and primacy will require much more time.

The CO2 pipeline from the generating unit to the storage site requires additional time. Project Tundra did not require a long pipeline -- only a quarter mile pipeline from the CCS equipment to the injection site on plant property. For a longer pipeline, a permit would be needed. Minnkota estimates an additional 18-month process to permit the pipeline, without accounting for any potential challenges.

To summarize, Project Tundra would not be completed in the time EPA has proposed, had the project begun today. Even for Minnkota, the currently designed and financed CCS system does not meet EPA's requirements. In addition, Minnkota does not have adequate time to develop, finance, design, and build a new capture train to further increase the project scale. Without time to construct a second CCS train by 2030, Minnkota would have to derate Unit 1 until either a new train or new generation could be built. The loss of 175 MW at Minnkota's only fossil generation station is very significant for the cooperative's ability to serve its customers with reliable, affordable electricity.

B. Natural gas co-firing is not adequately demonstrated on all coal-fired unit types.

Natural gas co-firing is an available option for many existing coal-fired steam boilers with modification. The level of modification is dependent on boiler design and existing infrastructure. With respect to some steam boiler types, the ability to co-fire has not been demonstrated.

In other cases, the ability to co-fire exists but the required infrastructure does not. The cost of building an entirely new natural gas pipeline is timing consuming and expensive. The Young Station has no gas line within 20 miles of the plant. In addition, typically the cost of gas on a cost per megawatt basis is more than 50% greater than the cost of coal and possibly even higher to ensure firm delivery. Replacement of coal with natural gas would substantially increase fuel prices for Minnkota. Further exacerbating the situation, EPA presents co-firing as a temporary ten-year extension solution from 2030 to 2040. For cost and timing reasons, co-firing is not a viable gap-filling opportunity for Minnkota to address the remaining flue gas that the Tundra project cannot accommodate.

IV. The Proposed Rule places reliable and affordable power at risk while energy demands surge.

The Proposed Rule targets baseload generation. Fossil resources ensure the power grid remains stable and compliment renewable assets. Even EPA recognizes that renewable generation cannot substitute for the crucial role of baseload generation. A balanced generation mix is fundamental due to extreme weather events and increased demand as electrification efforts incrementally rise each year.

A. The Proposed Rule's impact analysis illustrates dramatic implications for coal-fired power.

The Proposed Rule would set in motion an unprecedented change in the electricity generation grid within a short time period. Costs and infeasibility of BSER would force retirements that have yet to be announced. EPA has no provision for the replacement of this generation with reliable baseload resources.

EPA projects generation transitions in its baseline analysis (Table 12), which do not even take into account that the infeasibility of BSER will force more generation offline.[27] In 2028, EPA projects that coal generation without CCS will total 100 GW. EPA estimates that the Proposed Rule will cause reductions in coal capacity without CCS to 44 GW in 2030 and to 0 GW in 2035. Only 9 GW of coal-fired generation, with CCS installed, survives at all in 2040. EPA projects that renewable generation will begin at a baseline of 315 GW in 2028 and finish with 877 GW in 2040. Other generation fuel sources – oil and natural gas -- show small increases by 2040. Such a massive resource transformation requires careful planning and adequate time for RTOs to ensure grid reliability. The retiring coal generation must be replaced with reliable, dispatchable generation.

Table 12 2028, 2030, 2035 and 2040 Projected U.S. Capacity by Fuel Type for the Updated Baseline and the Illustrative Integrated Proposal Scenario

	Year	Capacity (GW)		Percent Change from Updated Baseline
		Updated Baseline	Integrated Proposal	Integrated Proposal
Coal	2028	100	99	-1%
Coal with CCS		0	0	-
Coal with Gas co-firing		0	0	-
Natural Gas		463	468	1%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		0	0	-
Nuclear		96	96	0%
Hydro		102	102	0%
Non-Hydro RE		315	316	0%
Oil/Gas Steam		63	63	0%
Other		7	7	0%
Grand Total		1,146	1,151	0%
Coal	2030	60	44	-25%
Coal with CCS		9	12	29%
Coal with Gas co-firing		0	1	-
Natural Gas		454	462	2%
Hydrogen Co-firing		0	0	-
Natural Gas with CCS		7	4	-39%
Nuclear		92	92	0%
Hydro		104	104	0%
Non-Hydro RE		403	405	0%
Oil/Gas Steam		60	70	15%
Other		7	7	0%
Grand Total		1,196	1,200	0%
Coal	2035	33	0	-99%
Coal with CCS		11	12	13%
Coal with Gas co-firing		0	1	-
Natural Gas		460	446	-3%
Hydrogen Co-firing		0	42	-
Natural Gas with CCS		10	6	-45%
Nuclear		84	84	0%
Hydro		108	108	0%
Non-Hydro RE		667	664	0%
Oil/Gas Steam		59	68	14%
Other		7	7	0%
Grand Total		1,439	1,438	0%
Coal	2040	28	0	-99%
Coal with CCS		8	9	12%
Coal with Gas co-firing		0	0	-
Natural Gas		503	515	2%
Hydrogen Co-firing		0	12	-
Natural Gas with CCS		10	6	-45%
Nuclear		79	79	0%
Hydro		110	110	0%
Non-Hydro RE		868	877	1%
Oil/Gas Steam		59	67	14%
Other		7	7	0%
Grand Total		1,672	1,683	1%

Note: In this table, "Non-Hydro RE" includes biomass, geothermal, landfill gas, solar, and wind

Minnkota is in an enviable position as compared to other utilities. The Young Station has an ongoing CCS project and may even be included in EPA's estimates of surviving coal with CCS in 2040. However, Minnkota finds itself with serious concerns due to the Proposed Rule. As previously stated, with the present Tundra capture design, Minnkota would not be able to meet EPA's objectives in the Proposed Rule.

[27] EPA, Integrated Proposal Modeling and Updated Baseline Analysis: Memo to the Docket for New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal, July 7, 2023 (Docket ID No. EPA-HQ-OAR-2023-0072) at Table 12.

Minnkota has no replacement generation sufficient to cover the Young Station's capacity. Therefore, even Minnkota finds its generation resources in jeopardy.

B. MISO projects a high risk of generation shortfalls.

The MISO region is already in a precarious position, without regard to the shortfalls of generation that the Proposed Rule will cause. The North American Electric Reliability Corporation (NERC) performed a summer reliability assessment of all areas of the country, released in May 2023.[28] NERC reported the MISO region as an "elevated" potential for insufficient operating reserves in above-normal conditions, as depicted in Figure 1 from this report.

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

NERC notes that reserve margins are projected to manage normal summer peak demand. Other reliability factors cited in the analysis include fuel supply and infrastructure insufficiencies, restrictions due to the Good Neighbor Federal Implementation Plan (FIP), delays in interconnection of new generation, low replacement distribution transformer inventories, supply chain issues, and transmission congestion, among other factors.

Reliability concerns are present in other seasons. Many parts of North America are experiencing elevated temperatures in shoulder months (spring and fall) when owners and operators historically scheduled outages for maintenance. NERC warns utilities about potential capacity shortages and suggests that utilities take steps to mitigate, such as more conservative outage coordination periods.[29]

The existing stresses on the grid exist without the impacts of the Proposed Rule. With unachievable project timelines for existing generation, the Proposed Rule would cause unprecedented unit shutdowns without time to construct replacement generation. Generation shortfalls are not acceptable in cold climates, such as North Dakota, where residents depend on electricity to heat their homes. EPA must factor the precarious state of America's grid into its environmental compliance decisions.

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[28] NERC, 2023 Summer Reliability Assessment, May 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf (NERC 2023 Summer Assessment) at 7-8.

[29] NERC 2023 Summer Assessment at 8.

C. Power demands are on the rise in North Dakota.

In the first quarter of 2023, North Dakota was the top state in economic growth in the country at 12.4%, as measured by gross domestic product (GDP).[30] Economic prosperity is due to industry growth from mining, quarrying, oil and gas extraction. North Dakota has also seen gains in agriculture and forestry activities. These sectors are energy intensive industries, highly dependent on reliable power.[31] In fact, other areas of the MISO and Southwest Power Pool (SPP) footprint are seeing top tier economic growth. South Dakota and Nebraska also report substantial increases in GDP. All of these areas have an elevated risk of reliability concerns. This corridor of prosperity cannot weather more generation coming off-line. MISO already notes the dangers that EPA's environmental compliance agenda is causing the overall interconnected grid.[32]

Minnkota and its distribution cooperatives provide power to support economic development projects that provide transformational opportunities for the rural communities and residents they serve. Without reliable electricity, these opportunities cannot be realized. Unintentional consequences from the proposed regulatory changes will jeopardize the potential of creating highly skilled, highly compensated positions and careers.

Minnkota urges EPA to make responsible environmental compliance decisions in light of increased demand in its service area. Adequate baseload generation is needed to respond to increased demand. The Proposed Rule stands to deactivate grid resources.

D. Extreme weather events underscore the importance of a balanced generation mix, contrary to the Proposed Rule's policies.

Extreme weather events have been commonplace in both winter and summer. Recent weather events illustrate the importance of a balanced electricity grid during these circumstances that tax the grid. Recently, in the eastern part of the country, Winter Storm Elliott showed the imminent danger of grid emergencies and the need for reliability contingencies.

PJM, the RTO impacted by the storm released a report that identifies the causes of the emergency and significant generation shortfall. PJM concluded that the daily Appalachian gas production loss of approximately 30% of total northeast daily production caused a significant loss of gas supply for all downstream gas consumers, particularly larger, more efficient gas-fired power generation units that require supplies

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[30] U.S. Department of Commerce, Bureau of Economic Analysis, "Gross Domestic Product by State and Personal Income by State, 1st Quarter 2023," June 30, 2023, https://www.bea.gov/sites/default/files/2023-06/stgdppi1q23.pdf

[31] https://www.statista.com/statistics/1065144/north-dakota-real-gdp-by-industry/

[32] MISO identifies the FIP as a reliability driver. North Dakota is not subject to the FIP, but other states within the MISO interconnected grid are affected.

flowing at uniform and higher pipeline pressures to operate.[33] PJM reported that coal generation had fewer outages than gas generation. Wind resources performed well, but solar generation only met or exceeded its capacity expectations during a few hours each afternoon, which was not coincident with the peak electric demand periods.[34]

Focusing on Minnkota's geographic area, NERC observes that the reliability of MISO's portion of the grid hinges on the performance of wind generation. NERC states, "MISO can face challenges in meeting above-normal peak demand if wind energy output is lower than expected."[35] MISO itself predicted just enough capacity to serve its projected summer needs in a probable generation scenario.[36] Given the considerable hedge on wind energy, the Proposed Rule's push on the generation mix *away* from diversification is particularly disconcerting. By shutting down coal and minimizing the construction of new gas assets, renewable resources must save the day during a reliability crisis. Particularly in areas with extreme cold temperatures – like North Dakota – betting on the performance of wind and solar generation is an ill-advised gamble. A diversified generation portfolio is essential during emergency events. Where gas supplies fail, other resources, such as coal, must be available to assuage the crisis.

Taking these concerns and the weakened grid into account, Minnkota strongly supports a reliability safety valve for force majeure situations at a minimum.

VI. EPA's Section 111 proposal is illegal.

A. Congress did not delegate EPA the authority to re-shape the electricity sector.

EPA lacks the authority to promulgate the Proposed Rule – The far-reaching repercussions of the Proposed Rule exceed EPA's congressional grant of authority under CAA Section 111. A rule with such sweeping impacts on the entire energy sector must be promulgated under an express grant of authority.

Where Congress does not clearly express authority, an agency cannot regulate such significant matters. The federal agency must properly invoke a constitutionally enumerated source of authority to regulate an area. On this point, the Supreme Court provides: "We expect Congress to speak clearly" if it wishes to grant an executive agency authority over decisions "of vast economic and political significance."[37] The courts dub this concept the Major Questions Doctrine.

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[33] *Id.*
[34] *Id.*
[35] NERC 2023 Summer Assessment at 5.
[36] https://cdn.misoenergy.org/2023%20Summer%20Resource%20Assessment628978.pdf
[37] *Util. Air Regul. Grp. v. EPA*, 573 U.S. 302, 324 (2014) ("*UARG*"); *see also Alabama Assn. of Realtors v. Department of Health and Human Servs.*, 141 S.Ct. 2320 (2021) (Kavanaugh, J., concurring).

The Major Questions Doctrine rests on "two overlapping and reinforcing presumptions."[38] The first presumption is that Congress "intends to make major policy decisions itself." *Id.* Second, in making those decisions, Congress should default against delegating "major lawmaking authority." *Id.*

The Proposed Rule plainly falls within the boundaries of a major question. A question is "major," when the following factors are present: (1) the amount of money involved for regulated and affected parties and the overall impact on the economy, (2) the number of people affected, and (3) the degree of congressional and public attention to the issue.[39]

The Proposed Rule satisfies each of these factors:

- Exceptional financial impact on regulated parties and the United States economy as an "economically significant regulatory action" as defined by OMB, costing more than $100 million annually or will cause a material adverse effect on the economy;[40]
- Broad-reaching as to the number of entities affected (states, the utility sector, end users, small businesses, EGUs and all consumers of electricity; and
- Significant public attention of Congress, news outlets, states, and stakeholders[41]

The Proposed Rule will have transformative consequences on the entire energy economy and America's electricity grid. Reliable electricity is essential to support the entire economy. Electricity is an "essential" and foundational element of modern life.[42] The electric power industry is a "significant portion of the American economy." In comparison, the Supreme Court considered an attempted overhaul of the tobacco industry to be a major question.[43] The Proposed Rule will result in substantial modifications to the U.S. energy supply sector and significant grid reliability issues for 84 million Americans.

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[38] *U.S. Telecom Ass'n v. FCC*, 855 F.3d 381, 419 (D.C. Cir. 2017) (Kavanaugh, J., dissenting from denial of rehearing en banc).

[39] *Id.* at 422-23 (Kavanaugh, J., dissenting from denial of rehearing en banc); *see UARG*, 134 S.Ct. at 2443-44 (regulation would impose massive compliance costs on millions of previously unregulated emitters); *Gonzales v. Oregon*, 546 U.S. at 267 (physician-assisted suicide is an important issue subject to "earnest and profound debate across the country"); *Brown & Williamson*, 529 U.S. at 126-27, 133, 143-61 (FDA's asserted authority would give it expansive power over tobacco industry, which was previously unregulated under the relevant statute); *MCI Telecommunications Corp. v. Am. Telephone & Telegraph Co.*, 512 U.S. 218, 230-231, (rate-filing requirements are "utterly central" and of "enormous importance" to the statutory scheme).

[40] *See https://www.reginfo.gov/public/jsp/Utilities/faq.myjsp*

[41] *See, e.g.,* House Committee on Energy and Commerce, Environment Hearing: "Clean Power Plan 2.0: EPA's Latest Attack on America's Electric Reliability," June 6, 2023, https://www.youtube.com/watch?v=IxJDm_QvRzI

[42] *Puerto Rico v. Franklin Cal. Tax-Free Tr.*, 136 S. Ct. 1938, 1950 (2016).

[43] *Brown & Williamson*, 529 U.S. at 159.

Section 111 did not delegate power to EPA to restructure the energy sector. In the instant rulemaking, EPA has selected a BSER that is so stringent, expansive, and infeasible that effectively shuts down coal and erects hurdles for operation of gas-fired generation. The Proposed Rule will force the country's generation mix away from fossil fuels, especially coal, by 2032 or sooner. The Supreme Court has recognized the limits of EPA's powers in *West Virginia*. The Supreme Court recently stated in the context of Section 111:

> Capping carbon dioxide emissions at a level that will force a nationwide transition away from the use of coal to generate electricity may be a sensible "solution to the crisis of the day." *New York v. United States*, 505 U.S. 144, 187, 112 S.Ct. 2408, 120 L.Ed.2d 120 (1992*). But it is not plausible that Congress gave EPA the authority to adopt on its own such a regulatory scheme in Section 111(d). A decision of such magnitude and consequence rests with Congress itself, or an agency acting pursuant to a clear delegation from that representative body.* The judgment of the Court of Appeals for the District of Columbia Circuit is reversed, and the cases are remanded for further proceedings consistent with this opinion.[44]

EPA opted not to heed the Supreme Court's direction, adopting the most aggressive and transformative rule of our time. The Court's view on Section 111(d) is precise, describing it as "the previously little-used backwater."[45] In that portion of the CAA, Congress would not have conferred upon EPA the authority to decide "how much coal-based generation there should be over the coming decades."[46] Congress's decisions to pass on an extensive greenhouse gas regulatory program further supports the Court's conclusion as to EPA's authority.[47]

As presented in these comments, the Proposed Rule's objectives and future impacts are undisputable and bold. EPA fashions coal-fired generation categories based on retirements. It attaches unquestionably expensive and infeasible requirements to non-sunsetting units as the only path away from retirement. By placing unachievable technologies, coal-fired units are set up to fail. In this way, EPA substantially overreaches the guiderails of its Section 111 power to summarily erase the coal-fired fleet. EPA even takes a further step by inflicting an unachievable BSER on larger gas-fired units. EPA must withdraw this expansive proposal. Major questions are triggered by stepping into energy markets and imposing a substantial monetary impact on the United States. economy. The CAA does not grant EPA this expansive authority.

B. EPA has overreached into the jurisdiction of other agencies charged with managing the country's energy resources.

EPA's expansive Proposed Rule illegally broadens its agency jurisdiction and intrudes into the delegated space of other agencies and entities that regulate energy policy, energy transmission, and electricity rates. FERC regulates interstate energy

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[44] *West Virginia v. EPA*, 142 S.Ct. 2587, 2616 (2022) (emphasis added).
[45] *Id.* at 2613.
[46] *Id.*
[47] The Court cited Clean Power Plan-type CAA amendments that Congress rejected. *Id.* at 2614.

policy. FERC has delegated its authority to ensure grid reliability to the North American Electric Reliability Corporation (NERC). As part of the Energy Policy Act of 2005, Congress gave FERC the responsibilities of protecting the reliability and cybersecurity of the Bulk-Power System through the establishment and enforcement of mandatory reliability standards. FERC regulates the transmission and wholesale sale of electricity in interstate commerce. A FERC goal is "facilitating the development of the electric infrastructure needed for the changing resource mix."[48]

In addition, DOE sets energy policy. Energy Information Administration (EIA), part of DOE, develops generation mix projections to inform DOE and assist with its goals. The Proposed Rule has a direct bearing on grid reliability, which is under the purview of these agencies. Energy markets across multiple jurisdictions will see shutdowns, capacity limitations, and uneven cost burdens, particularly as to utilities and states, like North Dakota, using coal-heavy fuels. Compliance with this rule will have a direct and continuing hold over the energy market through implementation, or at least 2040, with long-lasting indirect impacts from a revolutionized energy conversion. It is beyond EPA's scope and expertise to meddle in energy policy.

These actions lean into FERC's jurisdiction and its delegated authority to NERC. EPA is operating outside its jurisdiction. The dangers of two agencies instituting policy over energy and reliability is problematic. For instance, EIA develops generation mix projections in pursuit of its goals.[49] At the same time, EPA is running IPM models to make the same projections. Preliminary analyses of EPA's model already revealed improper unit retirement projections and undue emphasis on the IRA's financial incentives.[50] These models are completely separate efforts and often do not agree.

Congressional authorizations prevent agency overlapping by designating the agency in charge. EPA must leave energy policy to others. Its BSER selections should allow for all fuel-types to thrive to result in a balanced generation mix. FERC, DOE, and others can then shape the nation's policies per Congress's design.

C. The framework of the Proposed Rule is contrary to CAA Section 111.

The Proposed Rule's structure contradicts the CAA and its Section 111 in several meaningful ways. New source performance standards must be achievable at the unit, usually in the form of an emission limitation. Here, EPA designs a rule with a technology that is not adequately demonstrated (CCS for coal units) or other alternatives based on reduction of capacity factors or retirements. Turning a unit "off" or derating a unit, is not an acceptable BSER – nor has it ever been. EPA should not base coal-fired unit retirement categories on retirement as compliance, nor should Young Unit 1 have to take derates to avoid noncompliance with unrealistic time frames.

[48] See FERC Strategy Plan for Fiscal Years 2022-2026, Mar. 28, 2022 at https://www.ferc.gov/media/ferc-fy22-26-strategic-plan.
[49] EIA, Annual Energy Outlook 2023, https://www.eia.gov/outlooks/aeo/narrative/index.php#ExecutiveSummary
[50] *See* NRECA Comments and technical support, filed separately in the docket.

Inconsistent availability of BSER to all sources nationwide is not consistent with Section 111. Adequately demonstrated BSER must be dependable and effective to all individual sources at a reasonable cost.[51] EPA may extrapolate but only to a limited degree. In this case, BSER is unequally available. While some geographic areas of the country can support carbon storage, others do not have that option available. Infrastructure is also inconsistent. EPA must re-think its BSER selection and choose a technology that can be uniformly applied.

Natural gas co-firing for intermediate coal-fired units is also not appropriate as BSER for several reasons. First, EPA attempts to address GHG emissions by transforming a coal unit into a natural gas unit. Section 111 does not permit or require "redefining a source" as BSER. In addition, natural gas is not available to all coal-fired units, or it is cost prohibitive to run new gas pipelines to those areas. EPA piles on by only allowing sources to operate until 2040 by conducting a project to co-fire with natural gas. The cost metrics simply do not work to gain only eight more years of operation from 2032 (imminent retirement) to 2040 (beginning of the CCS long-term category) due to less time to amortize the capital costs of this option. Thus, natural gas co-firing as BSER is diverges from the CAA's definition of and application of BSER and should be removed from consideration.

Finally, EPA's shutdown sunset categorization is contrary the historical implementation of Section 111. Subcategories are based on unit size, fuel, or equipment type. Section 111(b)(2) allows EPA to distinguish among classes, types, and sizes within categories of new sources in development of NSPS. The subcategorization for coal-fired units based on the "operating horizon." EPA subcategorizes "like" generating units into categories based on owner/operator plans for utilization. This new concept unlawfully departs from EPA's historic implementation of Section 111 based on the equipment at hand.

VIII. The Proposed Rule erects unduly burdensome Section 111(d) State Plan requirements that remove flexibilities and impose timelines that set up States and sources for failure.

EPA proposes a heavy-handed approach that upsets the cooperative federalism tenets baked into Section 111. EPA restricts state RULOF analyses and places unreasonable timelines in place for state plans.

A. RULOF Analyses must not be eroded.

The Proposed Rule illegally restricts and fails to provide adequate time for state remaining useful life analyses. The Section 111(d) implementing regulations specifically allow for states "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[52] Although EPA has an

[51] *Essex*, 486 F.2d at 433; *NRDC*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).
[52] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1) (emphasis added).

opportunity to review the analysis as part of the state plan, this proposal should in no way limit state discretion to consider RULOF for individual sources in the state. EPA justifies narrowing state RULOF determinations by stating that it has "considered impacts on the energy sector as part of its BSER determinations." However, the framework of Section 111 does not mix RULOF into the generalized BSER process. EPA must preserve this individualized analysis that Congress specifically blessed.

States are in the best position to appreciate the contributions of and unique challenges of sources. RULOF in the context of the Proposed Rule may permit states to apply tailored and flexible requirements that will support grid reliability. For example, sources that have foreseeable retirement glidepaths but that are key resources in transmission-constrained areas could be offered a BSER that promotes EPA's carbon reduction goals but falls outside of EPA's one-size-fits-all BSER approach.

B. State plan timelines must be revised.

EPA's state plan timeline does not allow sufficient time for states to engage with affected utilities, conduct new public engagement requirements, develop RULOF analyses, and satisfy the comprehensive plan requirements necessary for EPA approval. State plans are due only 24 months from publication of final emission guidelines, which EPA projects will be April 2024.[53] State plans would be due in April 2026.

The time frame for National Ambient Air Quality Standards state implementation plans under Clean Air Act Section 110(a) is 36 months or three years. EPA likens the Section 111 state plan process to Section 110[54] but departs from the 36-month timeline.[55] Instead, EPA promulgates probably the most complex Section 111 rule of all time. This rulemaking is unlike prior Section 111(d) guidelines that had straightforward emissions limitations. States were able to simply mirror BSER in their plans, as evidenced in 40 CFR Part 62. The Proposed Rule requires states to navigate complex subcategorizations, set emissions limitations, and devise milestones for new technologies. On top of this, RULOF analyses must occur. EPA must provide states with more time.

Sources need more time to make important generation decisions for existing units. EPA is soliciting comment on the compliance date for existing units. The Proposed Rule sets a compliance date of January 1, 2030 but opens the door for an earlier compliance date defined by the date of EPA approval of the state plan.[56] Although EPA sets a 2030 compliance date, state plans will be due much sooner – April 2026 – less than three years from today. Subcategory decisions are likely to be placed

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[53] The Spring 2023 Unified Agenda projects the final rule to be released in April 2024.
[54] Proposed Rule at 33276 ("CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a CAA section 110-like procedure . . . ."); *see* 42 U.S.C. § 7411(d)(1) ("The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan . . . ." (emphasis added).
[55] 87 Fed. Reg. at 79182.
[56] *Id.* at 498.

into state plans with milestones. Sources in actuality must make coal unit sunset decisions much sooner, particularly if they are to avail RULOF flexibilities. Sources would find themselves making premature retirement decisions, while waiting and hoping that CCS, hydrogen technology, and associated infrastructure will catch up to new generation requirements in the Section 111(b) portion of the proposal. It is irresponsible to require utilities to retire generation without a feasible plan to replace it. Such a timeline hedges grid reliability on uncertainties.

Minnkota supports longer state plan development periods, removal of RULOF restrictions, and an existing compliance date that does not require retirement commitments before new generation can be constructed.

IX. Conclusion.

Thank you for your consideration of these comments. Minnkota looks forward to engaging with the Agency concerning this rulemaking. Should you have any questions regarding these comments, please contact Shannon Mikula at 701.795.4211 and smikula@minnkota.com.

National Rural Electric Cooperative Association (NRECA)

The National Rural Electric
Cooperative Association

Comments on

New Source Performance Standards (NSPS) for Greenhouse Gas (GHG)
Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired
Electric Generating Units: Proposed Rule

Submitted Electronically in response to the Small Entity
Representative Panel Outreach

to:

The Environmental Protection Agency

via

Lanelle Wiggins at Wiggins.Lanelle@epa.gov

August 24, 2023

by

Rae E. Cronmiller
Environmental Counsel
4301 Wilson Boulevard, EU 11-249
Arlington, VA. 22203-1860

(703) 907-5791 / rae.cronmiller@nreca.coop

Introduction

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) Small Entity Representative Panel Outreach on New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Proposed Rule.

NRECA commends EPA for reconsidering its initial conclusion in its May 2023 Regulatory Impact Analysis (RIA) that no small entity would be saddled with significant costs associated with this proposal's compliance. For reasons explained below EPA should reassess that conclusion incorporating realistic assumptions and other information incorporating firm technical bases to conclude that many small cooperative entities will absolutely incur very significantly costs under this proposal.

NRECA is the national service organization for America's Electric Cooperatives. The nation's member-owned, not-for-profit electric cooperatives constitute a unique sector of the electric utility industry, providing reliable, affordable, and responsible electricity is the shared commitment of NRECA's members. The association represents 900 not-for-profit rural electric utilities that provide electric service to approximately 42 million consumers in 48 states or 13% of the nation's population. The electric cooperatives provide electric service in 83% of the nation's counties that collectively covers 56 % of the U.S. landmass, as the map at the end of these comments depicts.

For over 80 years, electric cooperatives have responded to the needs of their communities and adapted to changes in policy in meeting that commitment. We believe policymakers must continue to balance realism with aspiration, recognizing that the energy transition to less carbon emitting electric generation will take time and the technologies must be inclusive of all energy sources to maintain the reliability and affordability that is the cornerstone of American energy security.

NRECA's member electric cooperatives include 63 electric generation and transmission cooperatives (G&Ts) that generate and transmit power and 832 distribution cooperatives that distribute electric power to cooperative electric consumers. The G&Ts are owned by the distribution cooperatives they serve. Some distribution cooperatives receive power directly from other generation sources within the electric utility sector. Overall, the cooperative distributed electric generation fuel mix includes 19% from renewable generation and over 32% from natural gas fired generation, which is now the dominant fuel source for the cooperative distributed electric generation.

Electric cooperatives financial options for new generation are limited. They have no equity shareholders who can bear the costs of stranded generation assets or investment in new or alternative generation resources. Cooperatives do not have a rate of return on equity as do investor-owned utilities because cooperatives operate on a not-for-profit basis. In short, all costs are passed through directly to their member-consumers that already spend more of their limited incomes on electricity as detailed below. Given that the G&T cooperatives maintain only marginal cash reserves for unforeseen events and anticipated operating expenses, financing for significant capital projects necessarily require reliance on debt investors such as the United States Department of Agriculture's Rural Utilities Service (RUS), National Rural Utilities Cooperative Finance Corporation (CFC), and CoBank. Lending by commercial banks can sometimes be an option, but regardless of the lender the costs of borrowing are necessarily passed on to cooperatives' consumer members. Ultimately, then, it is the cooperatives' consumer-members at the end of the line who bear all costs of regulations through increased electric rates.

The G&Ts participate in the wholesale markets, but many have found that owning generation is a necessity that serves as a hedge against volatile and exorbitant market process that can raise cooperative retail consumer electric rates to unacceptable level if a G&T is forced to purchase in a wholesale power under unacceptable high price market conditions. The attached Excel spreadsheet "RTO Summer 2022-2023 Peak Daily Prices" exemplifies that prices in organized markets can be exorbitant during any give summer day. Self-generation can sever to levelized costs to the consumes to keep rates within reason, thus self-generation is not a resource that can be sacrificed.

This Proposal's Impact on Small Entities is Important to NRECA

All but two of NRECA's 900 member cooperatives are "small entities" under the Regulatory Flexibility Act, 5 U.S.C. §§ 601-12, as amended by the Small Business Regulatory Enforcement Fairness Act. This fact alone highlights NRECA's interest and concern that the proposal's RIA addressing the proposal's economic impact of small entities is comprehensive and objective.

All co-ops share an obligation to serve their members by providing reliable and affordable electric service. This obligation is not without challenges. *Electric co-ops serve 92 percent of the nation's persistent poverty counties,* and the sparsely populated and primarily residential communities powered by electric co-ops are often the most expensive, hardest to serve areas of our country. Electric co-ops proudly shoulder the responsibility of bringing electricity to these communities. Data from the U.S. Energy Information Administration (EIA) show that rural electric cooperatives serve an average of 8 consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line. In other utility sectors, the averages are 32 customers and $79,000 in annual revenue per mile of line.[1] *Due to these geographically driven differences, 63% of rural electric cooperative members pay higher residential electric rates than customers of neighboring electric utilities.* Higher rates impede the economic opportunities of rural communities and can even challenge their viability. These facts make it especially important for electric cooperatives to keep their electric rates affordable and avoid any unnecessary rate increases brought about by imprudent regulatory policy. *Due to this proposal's potential financial impacts on the economically disadvantaged communities the small cooperative entities serve, it deserves a comprehensive and objective economic impacts evaluation*.

Electric Cooperatives' Specific Concerns with This Proposal

For the near future, the nation's electric grid increasingly will depend on new natural gas generation as a reliable "firm power" source of base load and intermediate load generation with the continuing transition to a less carbon intense grid. As new and impending EPA regulations threaten the financial viability of significant firm coal-fired generation power, substitutes for these "firm power" functions cannot be fulfilled by renewable energy sources such as wind, solar or four-hour batteries. These facts, combined with the increasing electrifying of other sectors of the economy, are anticipated to require a three-fold expansion of the transmission grid and up to 170% more electricity supply by 2050, according to the National Academies of Sciences.[2] More electricity demand and more renewable energy will place enhanced requirements on the electric grid and increase measures to enhance grid reliability. In this regard efforts to address

[1] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861; Platts UDI Directory of Electric Power Producers and Distributors, 2017.

[2] National Academies of Sciences, Engineering, and Medicine. 2021. *Accelerating Decarbonization of the U.S. Energy System.* Washington, DC: The National Academies Press. https://doi.org/10.17226/25932.

greenhouse gas (GHG) mitigation must not jeopardize a resilient and reliable electric grid that affordably keeps the lights on and is the cornerstone of America energy security and economy.

The North American Electric Reliability Corporation (NERC) 2022 Long-Term Reliability Assessment[3] mirrors many of our concerns over future electric reliability. NERC is the electric reliability organization whose mission is to ensure the effective and efficient reduction of risks to the reliability and security of the nation's bulk power system. The conclusions and recommendations in the NERC 2022 Long Term Reliability Assessment Executive Summary[4] include:

- Manage the pace of older traditional generator retirements until solutions are in place to continue essential reliability services that include avoiding the loss of necessary sources of system inertia.
- Consider what impacts of electrification may have on future electric demand.
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons.
- As retiring conventional generation is being replaced with substantial amounts of wind and solar, planning considerations must adapt with more attention to essential reliability services.

In addition, joint comments by four Regional Transmission Organizations (RTOs) submitted to this rulemaking docket amplify and add to these reliability and cost concerns.[5] The RTOs' comments address among various other issues "overarching reliability concerns" and "shortcomings in EPA's reliability analysis assumptions" in connection with this rulemaking. The report stresses the proposal's Best System of Emission Reduction (BSER) incorporating carbon capture and sequestration (CCS) and hydrogen co-firing "overstates the commercial

[3]https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf

[4] Id. At a pages 6-7

[5] Joint Comments of Electric Reliability Council of Texas Inc; Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc. Submitted to Docket EPA-OAR-2023-0072 and attached to these comments.

viability" and "could place the reliability of the grid in jeopardy" and summarize that "hope is not an acceptable strategy."[6]

Electric generation from natural gas combustion turbines is needed now, and more will be needed in the future to serve these vital needs of maintaining grid reliability and affordability. While this section 111 rulemaking cannot resolve growing concerns over future grid reliability, it could as the NERC and the RTOs recognize, serve as an impediment to alleviate these concerns, for example by proposing a system of emission reduction that is too costly or one that cannot be implemented broadly throughout the country or one for which necessary infrastructure to achieve the proposed performance standards is lacking and cannot be assembled within the proposal's timelines for compliance.

Comments for Ensuring an Objective and Comprehensive Small Entity Analysis

EPA concluded in its May 2023 RIA that only one cooperative small entity was potentially affected with an associated compliance cost that was below EPA's significance threshold of 1% of generation revenues.[7] NRECA believes that conclusion is clearly erroneous and unrealistic.

EPA should reconsider its earlier RIA analysis on the proposal's impacts on small cooperative entities by objectively considering the following factors:

- *More cooperative entities and generating units are affected than one, as EPA presumes.* EPA has drastically underestimated the number of affected cooperative small entity facilities. An NRECA poll of cooperative small entity generators since the August 10, 2023, SER panel concludes that at least 7 small cooperative entities plan 10 new natural gas combined cycle (NGCC) units totaling 4000 MWs and 16 new combustion turbines (CT) units totaling 2400 MWs over the next 5–7-year planning period. First, at a minimum, the NGCC units would certainly be within the proposed intermediate load category and require hydrogen fuel by 2032 and some may require the proposal's 96% hydrogen burn in 2038. Second, small entities may rationally conclude that on site

[6] Id. at p. 2

[7] Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified and Reconstructed Fossil Fuel-fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable clean energy Rule. EPA-452/R-23-006, May 2023. Section 5.3

hydrogen will not be available under any reasonable scenario due to its absolute unavailability, especially considering the limited financial means of small entity cooperatives as described earlier to independently bring hydrogen to the site. Responding to the need for reliable firm power these small entities may well decide to build multiple simple combustion turbines to avoid the hydrogen mandate. EPA needs to factor the need for these additional turbines because of this proposal into its financial analysis. Third, considering the amount of existing coal-fired generation the new and impeding EPA regulations all but promise to eliminate, these small cooperative entities new unit projections of new NGCCs and CTs intended to replace at least some of this eliminated coal-fired firm power are supported by realistic resource and system planning needs and should be used in any objective new RIA analysis.

- *The proposal's hydrogen production costs are way off the mark*. Attached to this submittal are two technical documents that will inform EPA on the technical and economic challenges associated with the production, transportation/storage, and use of hydrogen in turbines used for electric generation that EPA apparently missed in the first time around RIA[8] These two documents referred herein as the Kiewit and Campbell reports have been included in the proposal's docket along with NRECA's comprehensive comments on the proposal that were timely submitted. As Campbell technical report concludes, the required use of "clean hydrogen" requires production through electrolysis. The more realistic median price is $2.9/kg, 6 times greater that EPA's assumed production costs of $.5/kg. (Campbell at 6). EPA needs to adjust its hydrogen production costs accordingly based on this reality not on a cost number driven by apparent aspiration.
- *The proposal's assumption that existing natural gas pipelines can be used to transport hydrogen safety is flatly wrong*. Since EPA's technical document on hydrogen development assumes that existing natural gas pipelines can be used to transport hydrogen, NRECA concludes that assumption was incorporated into its May 2023 RIA analysis. This assumption is plainly wrong as explained in the both the attached technical reports. Campbell (5-6) and Kiewit (19-20). The safe hydrogen blend with natural gas in existing pipelines is 5 to 10%, which is wholly inadequate for even a 30% hydrogen

[8] Kiewit Engineering Group, Technical Comments on Hydrogen and Ammonia Firing (August 4, 2023), and D. Campbell, Analysis of Hydrogen in Combustion Turbine Electric Generating Units (August 3, 2023).

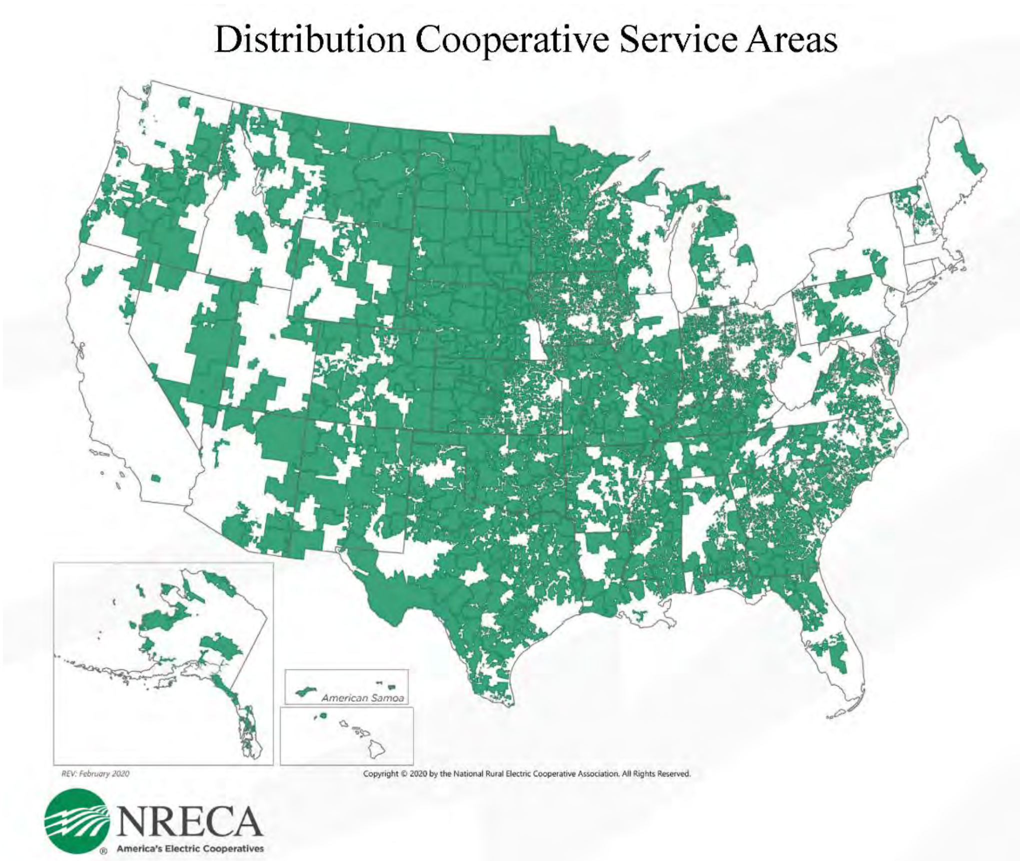
blend needed in 2032. Moreover, even a 5% hydrogen blend present safety concerns with natural gas residential use. So obviously any hydrogen transport via natural gas pipeline would need to be segregated from those pipelines supplying residential natural gas. EPA does not appear to have accounted for this needed segregation, which would be mandatory. Alternatively, EPA implies that hydrogen can be trucked to the turbine site, but that option is on its face unrealistic considering the volume and trucks required per site. (Campbell at 5, Kiewit at 17).

- *The proposal appears to ignore costs associated with supplying the required amount hydrogen needed for reliable turbine electric generation.* NRECA assumes that EPA does not assume that hydrogen is generated at the turbine site via electrolysis, that instead the hydrogen is generated and transported to the turbine. Storing enough hydrogen on site for one to five days of operation, as required for reliable power, would require significant underground or surface storage. (Kiewit at 16-17). EPA needs to factor in the costs associated on site storage if it assumes that option. Alternatively, enlarging the hydrogen pipeline transmission capacity to ensure onsite hydrogen adequacy where on site storage in not practical or feasible would require significant additional pipeline builds. (Kiewit at 20-21) EPA needs to factor in the additional costs associated with this hydrogen storage consideration either by assuming on site storage or by assuming an enlarged hydrogen pipeline buildout, costs that either way appear to be ignored by EPA in the initial RIA analysis.
- *The RIA should assume that DOE funded hydrogen hubs will not be constructed in time and with capacity to facilitate hydrogen transport to accommodate small entity cooperatives for new turbines in 2032*. As pointed out in the Kiewit Report (at 10) even if the hubs complete construction by 2031, the timing of the "Regional Clean Hydrogen Hubs Demand-side Support Notice of Intent," in which responses addressing hydrogen needs from the hub were due by July 2023, may effectively prohibit additional hydrogen needs that were not provided by this July date, since the hubs design may not be large enough to accommodate additional needs. NRECA is unaware that any that small cooperative entity responded to the required demand notice. Thus, it would be illogical for EPA to factor in any hydrogen hub gas availability for small entity cooperatives for the RIA analysis. EPA needs to adjust its new RIA analysis accordingly.
- *EPA needs to account for all costs associated with the use of clean hydrogen in geographic areas where significant water is unavailable.* The use of hydrogen for

turbines in arid areas require logistical considerations and related costs that EPA does not appear to have accounted for in the initial RIA. As detailed in the Kiewit Report (at 15-16) the electrolysis process needed to produce clean hydrogen requires significant water usage. In arid areas this poses a dilemma. Producing hydrogen even within several hundred miles from the needed burn site would be impossible in many areas of the country due to water shortages. As discussed above, trucking does not appear to be a viable option, certainly not for hundreds of miles, if at all. Presumably, the remaining option would be to construct individual pipelines directed to individual sites, an expensive proposition. EPA needs to explain its assumptions and related costs for clean hydrogen use within the country's arid areas including the time and expense needed for individual pipeline construction.

- *The RIA needs to address unrealistic timelines and inadequate lead time for bringing on new sources.* If a cooperative decides to retire any of its units, it will need to simultaneously begin the process to secure replacement capacity. To meet capacity needs and comply with RTO/ISO Planning Reserve Margin requirements, retiring a unit requires cooperatives to replace that unit's capacity with equal or greater replacement capacity. Most cooperatives do not have excess capacity within their system, at a time when load is significantly increasing. Because a cooperative's decision to retire a unit is inextricably linked to securing replacement capacity, it would need to begin these processes and incur unrecoverable costs almost immediately upon rule finalization. According to conservative estimates, retirement and replacement for individual units would require at least 7 years. The retirement and replacement process requires extensive preparation, including notification to the RTO/ISO, a request for proposal under Rural Utility Service's ("RUS") competitive bidding rules if RUS funding is sought, and an air permit application and approval. In addition, the cooperative must conduct engineering and technical analyses and go through a generation interconnection studies prior to beginning work on any replacement capacity, after which a cooperative would procure equipment and begin construction.

  Further, the cooperative would need to secure funding from a lender for any replacement capacity and comply with lender requirements, including in most cases the preparation of an Environmental Impact Statement. This process can take 6-7 years. A cooperative will be required to take certain steps immediately upon rule finalization to have any chance of securing the needed replacement capacity in conjunction with unit retirement required to meet EPA's aggressive emission reduction timelines. All these steps require outlays of a great deal of capital and carry with them significant financial risk due to the uncertain future of EPA's proposed rules. All costs not covered by grants are unrecoverable outlays and would have to be recouped by raising rates on the cooperative consumer.



NRECA Attachment 1 - RTO Summer 2022-2023 Peak Daily Prices

The purpose of this analysis is to illustrate the volatility that exists in Peak Daily prices during the Summer months in selected RTOs. This Peak Daily price represent real time prices, which lets market participants buy and sell wholesale electricity during the course of an operating day. The pricing data is from *S&P Capital IQ - ISO Real Time Prices* for the months between May and September.

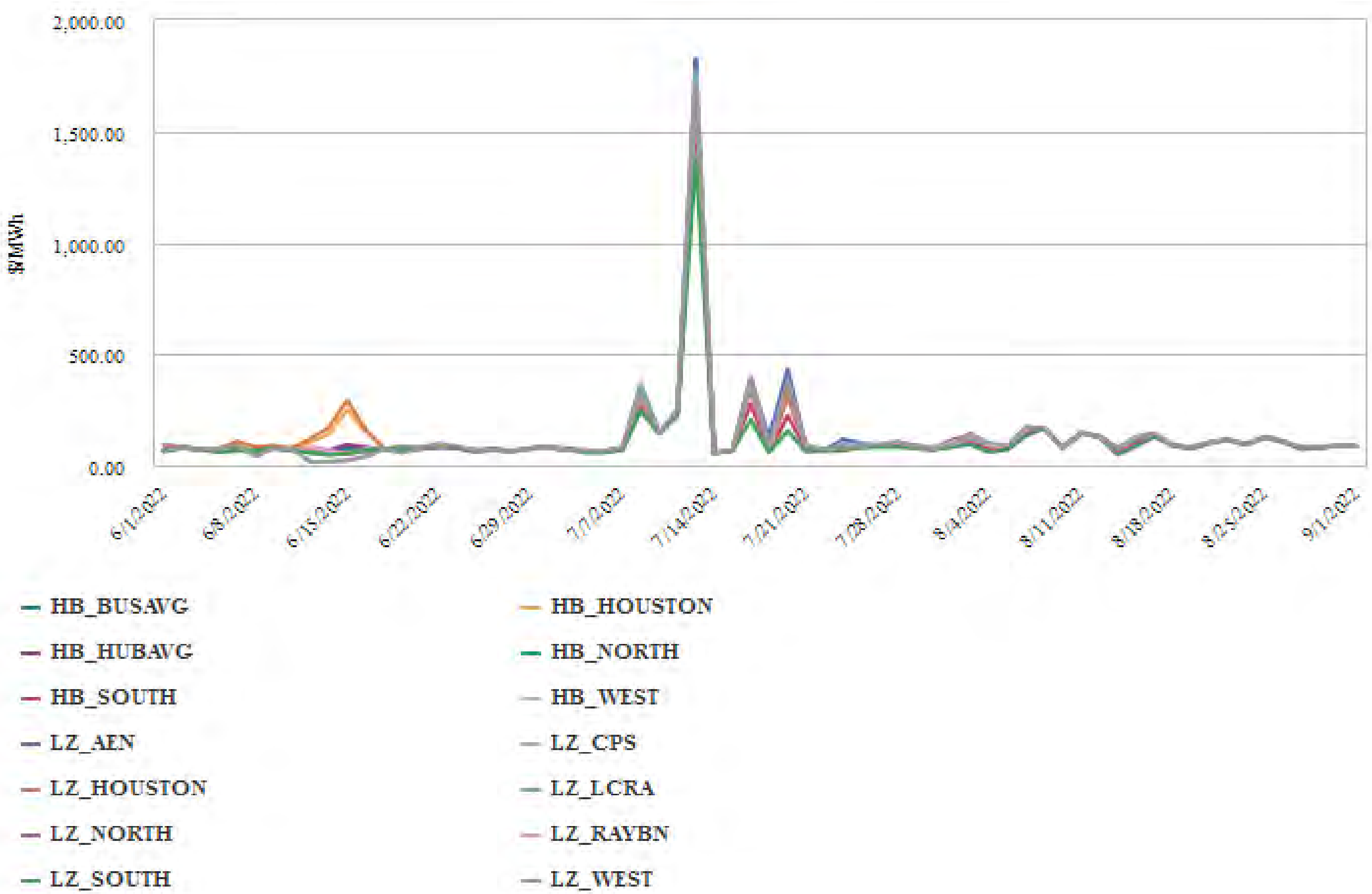
The enclosed tab (2022_2023) illustrates Summer Peak Daily Real Time Prices for ERCOT, MISO, PJM and SPP for the Summer of 2022 and 2023. As you can see there exists a great degree of volatility during these Summer months, where Peak Daily Real Time prices cand range between $250 to $1,826/MWh.

S&P Capital IQ PRO

ISO Real-Time Prices (Data)

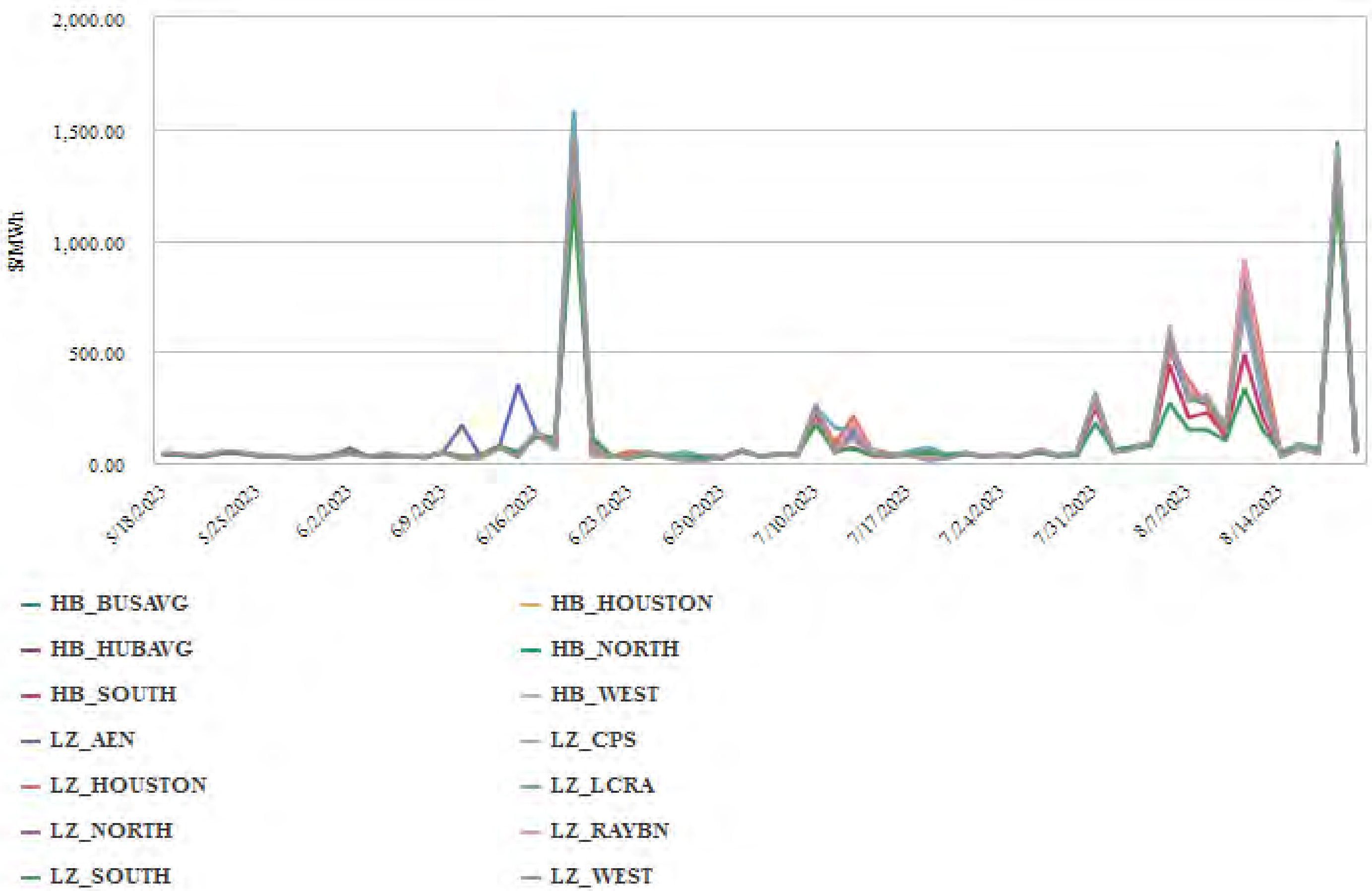
ERCOT

Summer 2022 - Peak Daily Real Time Prices



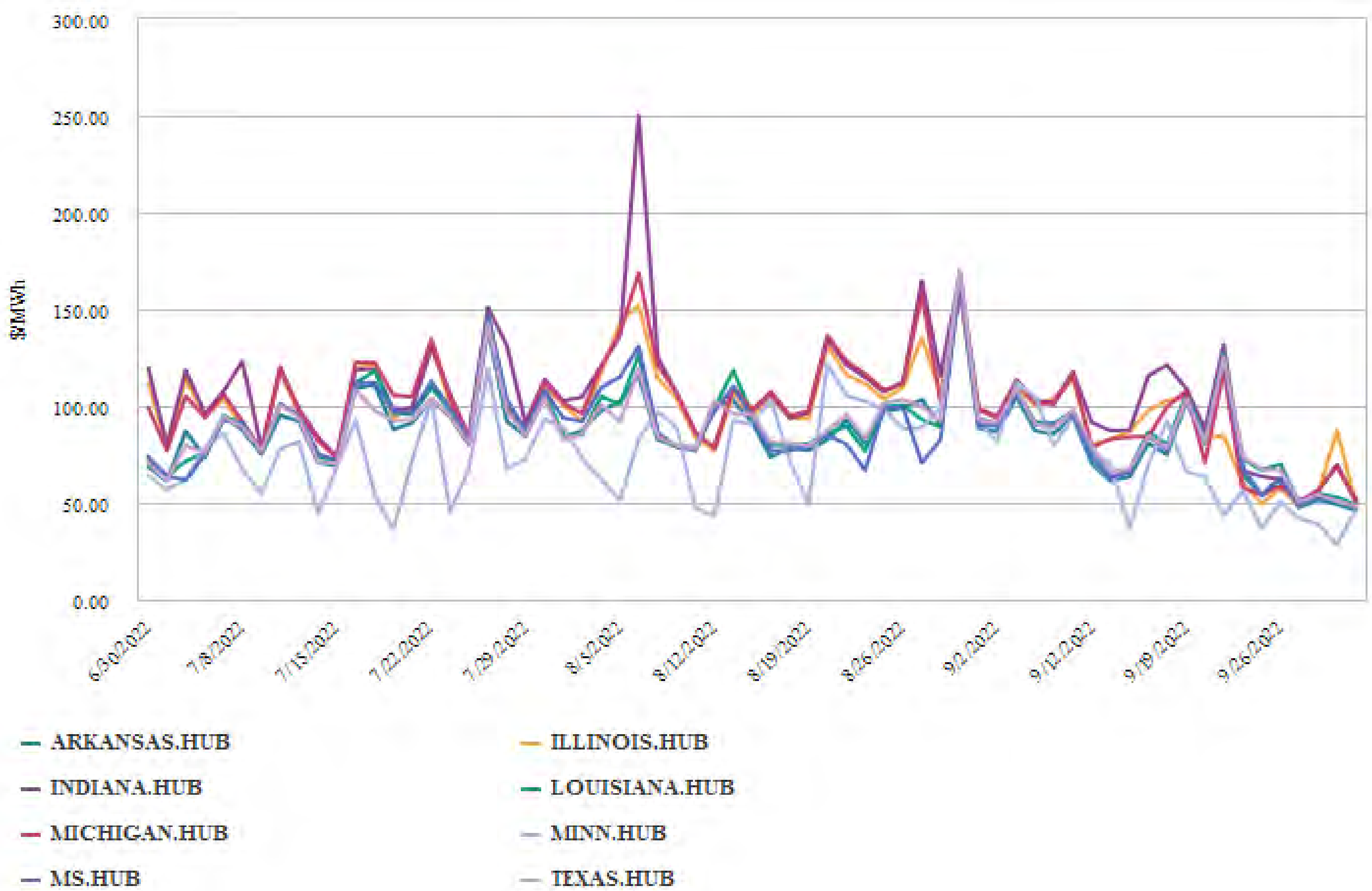
ERCOT

Summer 2023 - Peak Daily Real Time Prices



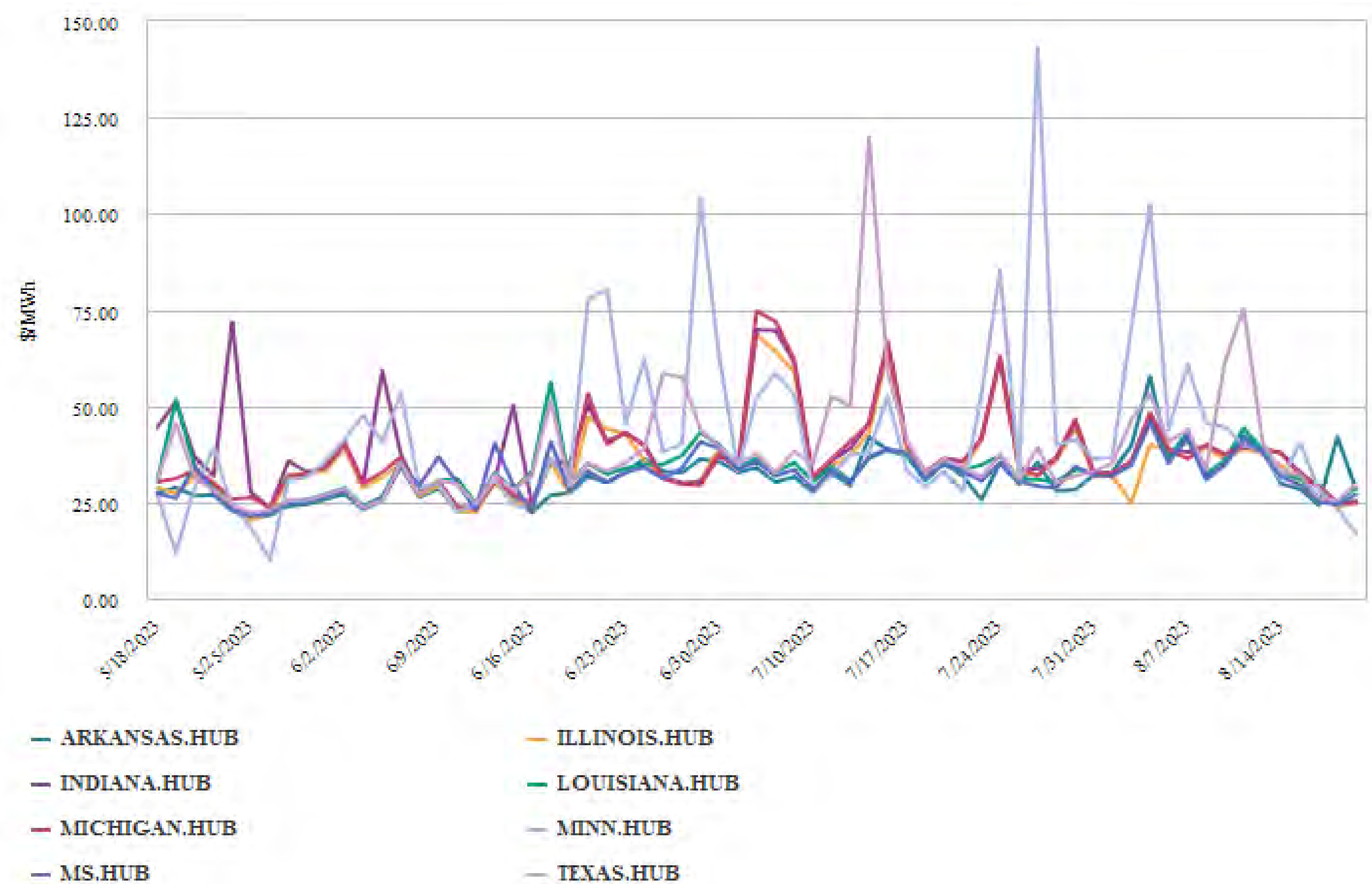
MISO

Summer 2022 - Peak Daily Real Time Prices



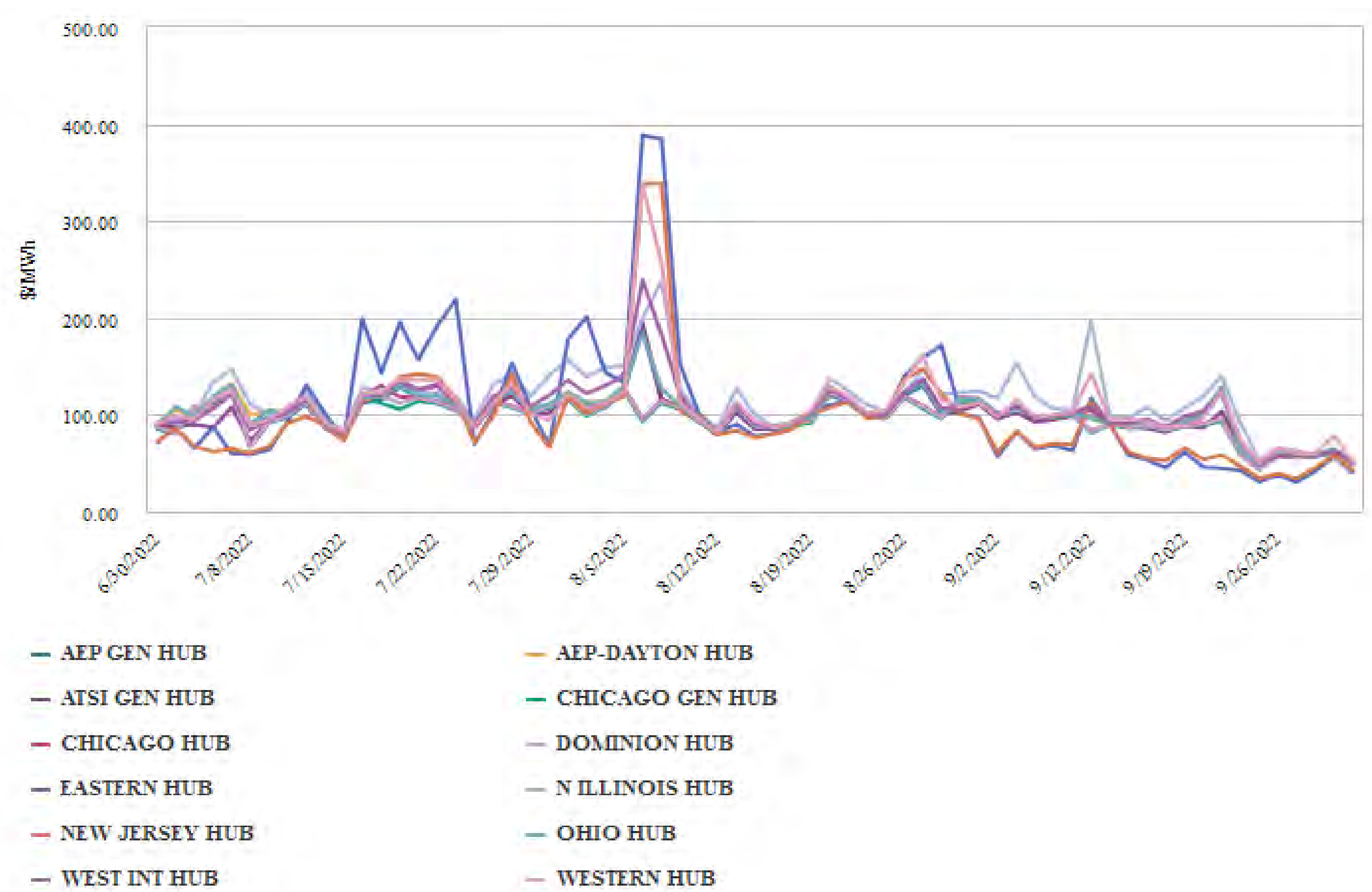
MISO

Summer 2023 - Peak Daily Real Time Prices



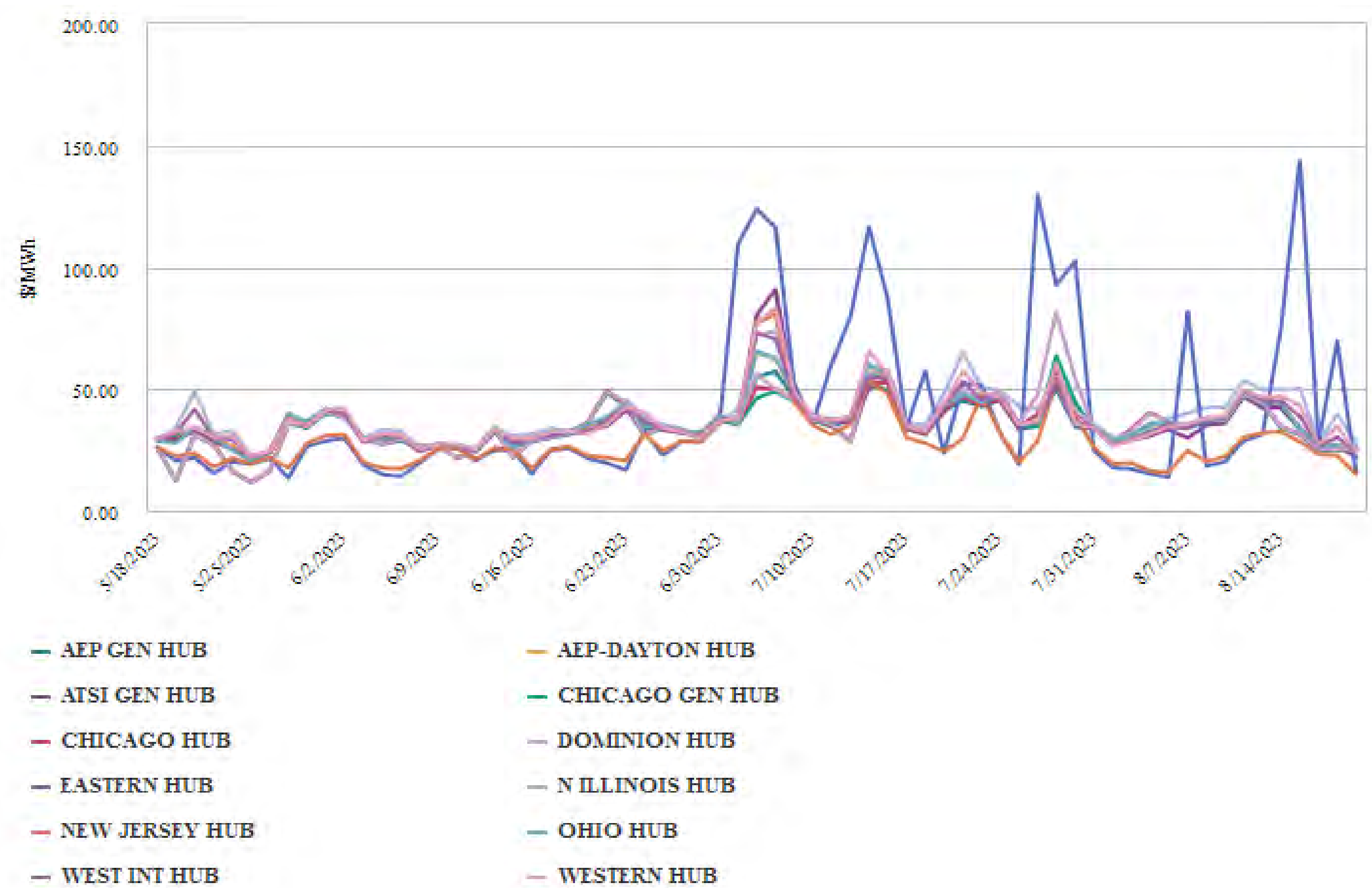
PJM

Summer 2022 - Peak Daily Real Time Prices



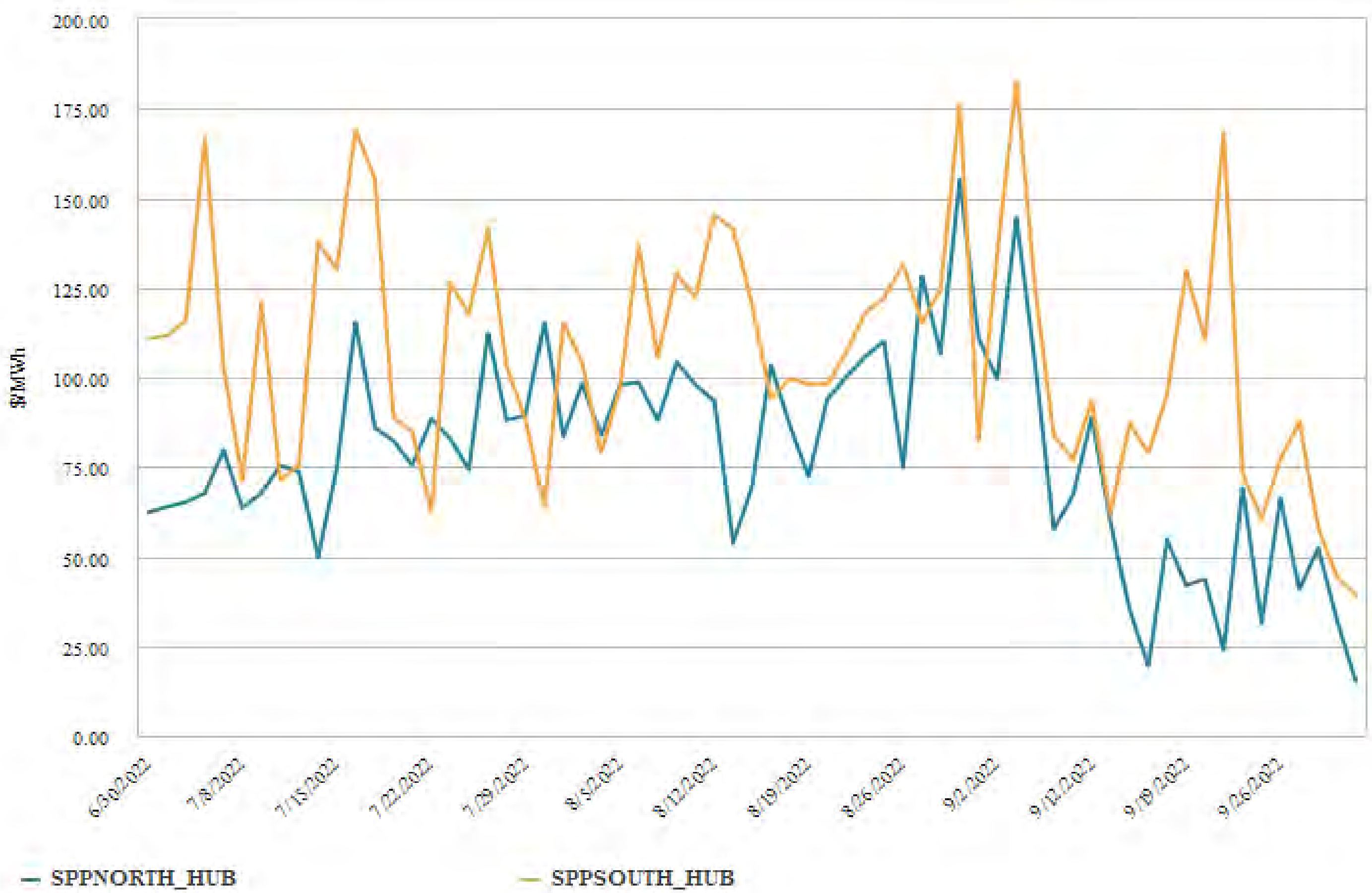
PJM

Summer 2023 - Peak Daily Real Time Prices



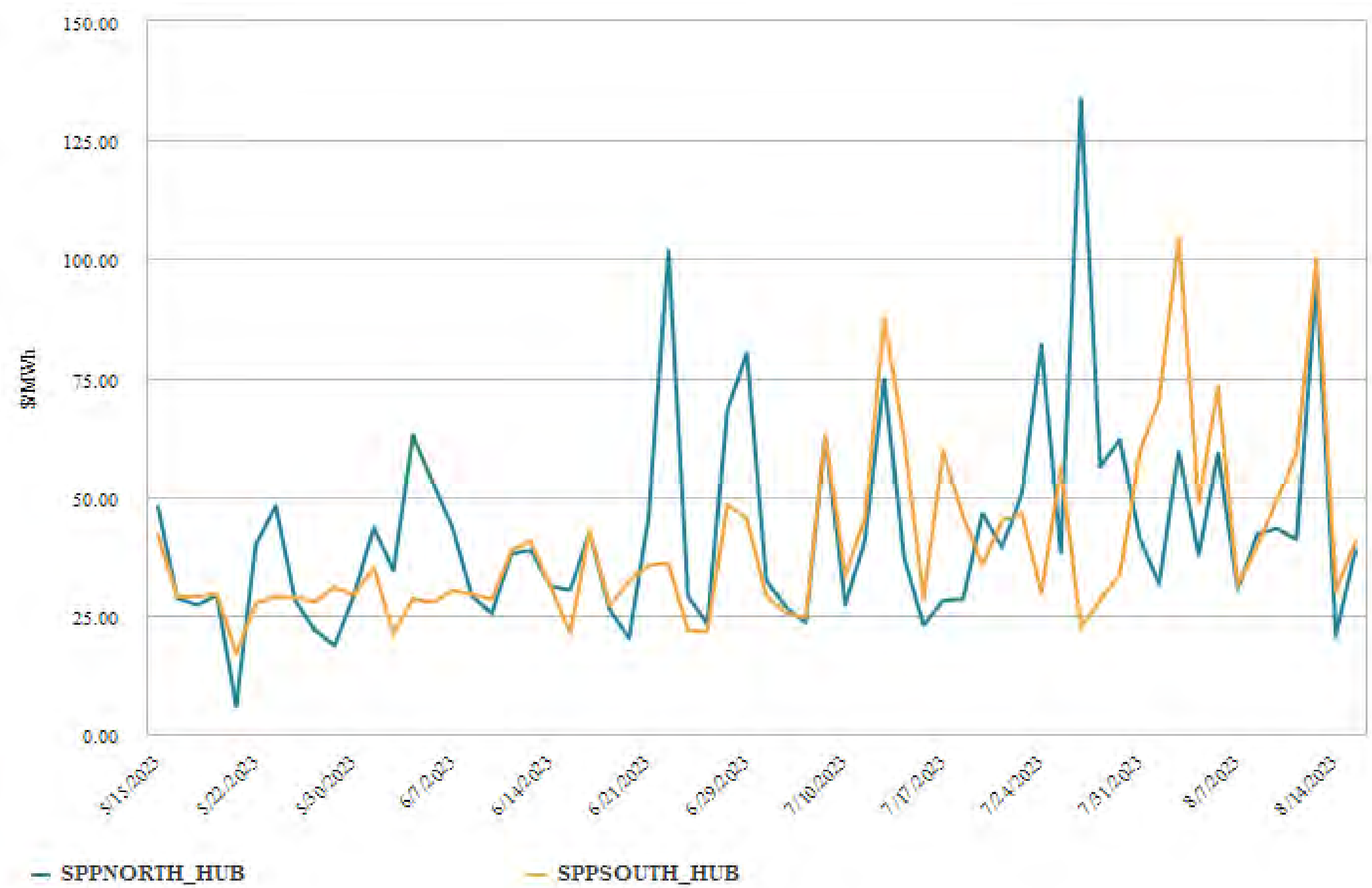
SPP

Summer 2022 - Peak Daily Real Time Prices



SPP

Summer 2023 - Peak Daily Real Time Prices



NRECA Attachment 2 - Joint Comments of Electric Reliability Council of Texas Inc; Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc. Submitted to Docket EPA-OAR-2023-0072

UNITED STATES OF AMERICA

BEFORE THE

U.S. ENVIRONMENTAL PROTECTION AGENCY

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule	EPA-HQ-OAR-2023-0072

JOINT COMMENTS OF ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.; MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.; PJM INTERCONNECTION, L.L.C.; AND SOUTHWEST POWER POOL, INC.

Introduction and Summary

Electric Reliability Council of Texas, Inc. ("ERCOT"), Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection, L.L.C. ("PJM"), and Southwest Power Pool, Inc. ("SPP") (collectively, "Joint ISOs/RTOs"), jointly submit these comments in response to the Environmental Protection Agency's ("EPA") proposed rule in the above-referenced docket ("Rule" or "Proposed Rule").[1] As described below, the Joint ISOs/RTOs are concerned that the substance of the Proposed Rule as presently configured, as well as its timing, have the potential to materially and adversely impact electric reliability. Moreover, the Proposed Rule, when combined with other EPA rules and other policy actions, could well exacerbate the disturbing trend and growing risk wherein the pace of retirements of generation with attributes needed to ensure grid reliability is rapidly exceeding the commercialization of new resources capable of providing those reliability attributes.

I. <u>Overview of Joint ISOs/RTOs' Concerns</u>

The Joint ISOs/RTOs have long been at the forefront of renewable energy integration, but have seen an increasing trend of retirements of dispatchable generation, which provides critical attributes that are needed to support the reliable operation of the grid. Although each region is working to facilitate a substantial increase in renewable generation, the challenges and risks to grid reliability associated with a diminishing amount of dispatchable generating capacity could be severely exacerbated if the Proposed Rule is adopted.

We recognize that through the creation of various sub-categories, the EPA has attempted to stagger the impact of the rule to avoid an *en masse* retirement of needed dispatchable generation.

[1] Individual RTOs and ISOs reserve the right to submit separate, supplemental comments on this rule.

However, key requirements in the Proposed Rule are premised on EPA's assumption that either (1) the development of new technologies will allow new, low-greenhouse gas (GHG) resources to substitute for the resources presently providing these necessary reliability attributes or grid services or (2) the retrofitting of fossil-based resources with either carbon capture and storage (CCS) or hydrogen co-firing to control carbon dioxide (CO_2) emissions will be economically feasible within the timeframes specified for compliance in the Proposed Rule. Although the Joint ISOs/RTOs have been and will continue to be supportive of new technologies, we believe that the Proposed Rule's Best System of Emissions Reduction (BSER) determination overstates the commercial viability of CCS and hydrogen co-firing today and ignores the cost and practicalities of developing new supporting infrastructure within the time frames projected. Without firm proof of the commercial and operational viability of these technologies, proceeding with these requirements could place the reliability of the electric grid in jeopardy. In short, hope is not an acceptable strategy.

These concerns are not limited to the future years in which the Proposed Rule would require these new technologies to be employed. The Joint ISOs/RTOs are equally concerned that the Rule (and the cumulative effect of all of the recent electric industry-related EPA actions and rulemakings) could have a chilling effect in the near-term on the investment needed to maintain dispatchable generating units until these new technologies develop. The ISOs/RTOs are already seeing retirements of generators that are concerning as they appear to be driven by a reluctance of investors to make the commitments needed to keep these capital-intensive resources operating. As the penetration of renewable resources continues to increase, the grid will need to rely even more on generation capable of providing critical reliability attributes. With continued and potentially accelerated retirements of dispatchable generation, supply of these reliability attributes will dwindle to concerning levels.

We appreciate previous efforts by the EPA to address reliability concerns raised by the Joint ISOs/RTOs through commitments to enforcement discretion (in the case of the MATS Rule) or the adjustment of compliance dates. However, these solutions do not ensure that resource owners will make sufficient investments in resource maintenance in the years preceding the effective date of the Rule, as those investments are based in part on the forecast of the viability of a given set of units. As a result, the Proposed Rule can have negative impacts on electric grid reliability even before the effective date of this rule.

Accordingly, the Joint ISOs/RTOs urge the EPA to further examine and address these reliability impacts before finalizing any Rule in this area. Joint ISOs/RTOs submit these comments to explain the challenges associated with the Proposed Rule and underscore the need for actions to address reliability concerns within any future final rule. These comments are organized as follows

A. Overarching Reliability Concerns
B. Shortcomings in EPA's Reliability Analysis Assumptions
C. Comments Regarding Revised New Source Performance Standards (NSPS) for GHG Emissions from New Fossil Fuel-Fired Stationary Combustion Turbine EGUs
D. Comments Regarding Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired Steam Generating EGUs
E. Comments Regarding Emission Guidelines for GHG Emissions from Existing Stationary Combustion Turbines

F. Need to Incorporate Timely Reviews of Technology Advancement and Unit Retirements in the Final Rule
G. Request for Specific EPA Authorization for Interstate Allowance Trading Among Affected Units
H. Request to Revise the Definition of "System Emergency"

II. Joint ISOs/RTOs' Proposed Modifications Should the Rule Go Forward

The Joint ISOs/RTOs appreciate the dialogue in which EPA has engaged with us in the past, and we wish to maintain our constructive working relationship with the EPA. As noted above, we believe the EPA must conduct further analyses and address reliability impacts before finalizing any Rule in this area. However, should the EPA nevertheless decide to adopt a rule, the Joint ISOs/RTOs propose several additional features that would help to partially mitigate, albeit not eliminate, these reliability impacts going forward. At a high level, these additional features include:

- Specification of a new sub-category for existing units, providing a time-limited means for ISOs/RTOs to designate classes of units that are needed to maintain local or region-wide reliability until alternatives (which may be new transmission or new generation or storage resources) are available to address the identified reliability need;[2]

- Building into the Rule a process to monitor and adjust the Rule's compliance schedule as applied to existing gas and coal units based on an examination as to whether the CCS and hydrogen co-firing infrastructure is developing at a sufficient pace to allow implementation in the time frame contemplated by the Proposed Rule. Such an ongoing review built into the Rule itself can help to balance of the pace of retirements of dispatchable generation needed to provide critical grid services with the new additions providing such grid services;

- Providing specific recognition in the Rule of the availability of allowance trading on a regional, if not national level to allow for greater flexibility and incentivize early and effective 'over-compliance' by those units that are capable of so doing;

- Updating the definition of 'System Emergency' to reduce uncertainty around when a unit may be called upon for reliability.

Additional details would certainly need to be addressed regarding these proposals. The specific reforms outlined herein have been developed to work within the structure of the Proposed Rule and the applicable law. Given the breadth of the impact of any risks to electric reliability, the Joint ISOs/RTOs would urge EPA to collaborate with the ISOs/RTOs, stakeholders, and states to develop the details of these measures, if the EPA proceeds with the Proposed Rule. The Joint ISOs/RTOs look forward to continued dialogue and analytical work with the EPA on the reliability impacts of the Proposed Rule and, if appropriate, the proposed modifications outlined above.

[2] As further described in these Comments, this could also be accomplished through the creation of a presumptive, automated reliability process through use of the remaining useful life and other factors (RULOF) provisions included in 40 C.F.R. § 40.60.24a(e).

Background

The Joint ISOs/RTOs are charged with maintaining the reliability of the bulk power system that provides electric service to over **154** million Americans. The geographic reach of the Joint ISOs/RTOs is broad, encompassing an area of approximately 2 million square miles, in all or parts of 30 states and the District of Columbia.

The Joint ISOs/RTOs carry out this reliability responsibility by:

- Dispatching generation and demand response resources in real time to meet the minute-by-minute demands of electricity customers;
- Operating real time and day ahead energy markets that ensure the most efficient dispatch of resources to meet demand in a given hour;
- Ensuring resource adequacy to meet projected future demands for electricity by operating wholesale markets and partnering with states;
- Planning the expansion of the transmission system to meet the reliability needs of customers; and
- Interconnecting new generation resources to the grid.

Each of the Joint ISOs/RTOs are independent of market participants and operate on a revenue-neutral basis. The Joint ISOs/RTOs are also technology-neutral, favoring neither fossil nor renewable generation, and treat all resources on a nondiscriminatory basis, as required by relevant laws.

Comments

A. *Overarching Reliability Concerns*

As a threshold matter, the Joint ISOs/RTOs are concerned that the Proposed Rule could result in material, adverse impacts to the reliability of the power grid. These reliability concerns primarily arise from the possibility that the significant technological advances in low-greenhouse gas (GHG) hydrogen production, transport and generation, as well as in carbon capture and storage (CCS) that are identified as BSER under the Proposed Rule may not occur as anticipated, or may not occur at the pace anticipated by the EPA. If the technology and associated infrastructure fail to timely materialize, then the future supply of compliant generation—given forced retirements of non-compliant generation—would be far below what is needed to serve power demand, increasing the likelihood of significant power shortages.

The EPA projects these technologies will prove economic over the compliance period as a result of subsidies built into the Inflation Reduction Act.[3] While technology development and commercialization of these technologies at a reasonable cost is not entirely out of the question, those technologies are not yet feasible on a large scale, and there are reasons to be skeptical that it will be widely available on the timeline anticipated by EPA. Low-GHG hydrogen and CCS require the development of vast new and costly infrastructure. CCS has only been implemented in two isolated

[3] Inflation Reduction Act of 2022

cases. Although the Joint ISOs/RTOs have no opposition to the development of these new technologies and, in some cases, have become platforms for their testing, the record is not sufficiently developed to determine that these technologies support a BSER finding at this time.

The Joint ISOs/RTOs are concerned that the proposed rule would greatly exacerbate an ongoing loss of critical, dispatchable generating capacity that is needed to ensure grid reliability. Over recent years, Joint ISOs/RTOs have each observed an increasing level of dispatchable generation retirements without the comparable addition of new technologies that would provide the same level of grid support.[4] Although each of the Joint ISOs/RTOs is seeing a rapid growth in renewable and energy storage resources interconnecting to the grid, given the intermittent and energy-limited nature of those resources, their capacity (or accredited) value is substantially discounted from the capacity (or accredited) value of thermal generation today. In addition, these new resources connecting to the grid are primarily inverter-based, and have distinctly different characteristics than synchronous machines.[5] Although providing valuable carbon-free electricity, these new resources do not, at present, provide the same levels of essential reliability services – or attributes – as their thermal counterparts. New technologies and industry practices are developing to enable the integration of significant inverter-based generation that provide needed essential reliability services, but the Joint ISO/RTOs are concerned about a scenario in which, similar to that stated above, needed technologies are not widely commercialized in time to balance out large amounts of retirements. The ISO/RTO-specific appendices to these Comments detail experiences, studies, and concerns by region.[4]

Finally, the Joint ISOs/RTOs are also concerned about the chilling impact of the Proposed Rule on investment required to retain and maintain existing units that are needed to provide key attributes and grid services *before* the compliance date required by the rule. Investments are based, in part, on the expected revenues associated with continuing operation of the unit. Unit owners may decide to retire units early rather than incur additional expense and risk. Alternatively, should the units remain operational, with the expectation of retirement at a future date certain, then unit owners may forgo required maintenance in the interim because of the lower return on the investment from doing so. The failure to properly maintain generating units can lead to a higher incidence of forced outages of these units, diminishing the dispatchable generation supply in the interim.

As a result, the Joint ISOs/RTOs believe that the record is insufficient for the EPA to conclude that the Proposed Rule will not adversely impact reliability. The EPA should therefore reconsider moving forward with the Proposed Rule in its present form.

However, if the EPA is inclined to move forward with the Proposed Rule, the Joint ISOs/RTOs would urge the EPA to at least include several additional features in the rule to help mitigate, although not eliminate, these reliability impacts. These features include:

- Specification of a new sub-category for existing units, providing a time-limited means for ISOs/RTOs to designate classes of units that are needed to maintain local or region-wide

[4] See ISO/RTO specific Appendices (1-4) for information applicable to each ISO/RTO.
[5] See NERC Introduction to Inverter-Based Resources on the Bulk Power System.

reliability until alternatives, which may be new transmission or new generation or storage resources, are available to address the specific identified reliability need[6];

- Building into the Rule a process to monitor and adjust the compliance schedule as applied to existing gas and coal units based on an examination as to whether the CCS and hydrogen co-firing infrastructure is developing at a sufficient pace to allow implementation in the time frame contemplated by the Proposed Rule. Such an ongoing review built into the Rule itself will ensure a better balance of the pace of retirements of dispatchable generation needed to provide critical grid services with the new additions providing such grid services;

- Providing specific recognition in the Rule of the availability of allowance trading on a regional, if not national, level to allow for greater flexibility and incentivize early and effective "over-compliance" by those units that are capable of doing so;

- Updating the definition of "System Emergency" to reduce uncertainty around when a unit may be called upon for reliability.

These comments will describe the reliability concerns highlighted above and then address the specific rule features proposed by the Joint ISOs/RTOs.

B. ***<u>Shortcomings in EPA's Reliability Analysis Assumptions</u>***

EPA's Resource Adequacy Analysis Technical Support Document[7] does not address the range of reliability issues that the proposed Rule could trigger, but, rather by its own terms, is solely focused on resource adequacy. While EPA distances itself from potential impacts to the grid, EPA acknowledges that resource adequacy on its own is "not sufficient" for determining grid reliability:

> *"While such potential impacts would not be a direct result of these rules but rather of the compliance choices source owners and operators may pursue, we have analyzed whether the projected effects of the rules would in this regard pose a risk to resource adequacy, a key planning metric that is necessary (but not sufficient) for grid reliability*."[8]

The Joint ISOs/RTOs' reliability duties extend beyond resource adequacy and include the provision of essential reliability services that are critical to the grid.[9] Power-industry-defined reliability attributes include inertia, primary frequency response, reactive power support, system stability, system strength, frequency regulation, ramping, flexibility, dispatchability, black start capability, fuel and energy assurance, and extreme weather performance. The Joint ISOs/RTOs urge EPA to work with the Joint ISOs/RTOs in assessing the proposal's impact on reliability, incorporating additional metrics around essential reliability services and attributes.

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[6] This could also be accomplished through the creation of a presumptive, automated reliability process via remaining useful life and other factors (RULOF) provisions included in Code of Federal Regulations Title 40. Protection of Environment § 40.60.24a(e).

[7] Resource Adequacy Analysis TSD, page 2.

[8] Resource Adequacy Analysis TSD, page 3

[9] Energy Transition in PJM: Frameworks for Analysis.

EPA's underlying assumptions for the Resource Adequacy Analysis are dependent on modeling the 2022 Inflation Reduction Act (IRA) in the base case. In the Joint ISOs/RTOs' view, the base-case modeling masks the impact of the proposed Rule by assuming that the retirements have occurred independent of the Proposed Rule. Because the base case shows significant coal and nuclear retirements, renewable and storage additions, and a significant decline in energy generated from natural gas while natural gas capacity significantly increases, the resulting comparison to the modeled proposal shows little impact to the system. This ignores the cumulative impact of the various EPA rules and their intertwined nature, leaving an incomplete picture of the impact of the GHG rule on unit retirement decisions and resource adequacy. This analysis also does not consider the impacts to minimum resource adequacy requirements caused by a changing resource mix. In other words, replacement of dispatchable generation by generation that is, by its nature, not as dispatchable will, among other items, drive requirements for larger amounts of generation (nameplate capacity) in order to maintain an equivalent amount of reliability.

To explore the ability to rely on modeled projections of the impact of the IRA on the grid as a basis for adequately projecting grid reliability, the Joint ISOs/RTOs added EPA modeling projections[10] to a recent third party comparison of numerous models that all attempted to model grid impacts of the IRA by Bistline, et al. (2023) "Emissions and Energy Impacts of the Inflation Reduction Act"[11] and found a continuation of the "substantial variation" noted by the authors, in projected capacity and generation (as illustrated in Figure 1 below). The authors point out the difficulty in modeling the IRA:

> "*Models attempt to capture many economic factors that could influence technology adoption, but several implementation challenges are difficult to model, including the scale-up of supply chains and materials, siting and permitting, infrastructure expansion, network effects, non-cost barriers to consumer uptake of incentives, and the economic incidence of subsidies*."[12]

The authors add that:

> *"Additional analysis is important for understanding potential impacts of partial coverage of IRA provisions and IRA implementation uncertainties, as well as uncertainties about external factors,*

[10] Analysis of the Proposed Greenhouse Gas Standards and Guidelines: Power Sector Modeling

[11] Data for Bistline, et al. (2023) "Emissions and Energy Impacts of the Inflation Reduction Act",

[12] "Emissions and Energy Impacts of the Inflation Reduction Act," *Science*, June 30, 2023, Vol 380, Issue 6652, Page 1327.

including inflationary trends, domestic macroeconomic environment, and global drivers."

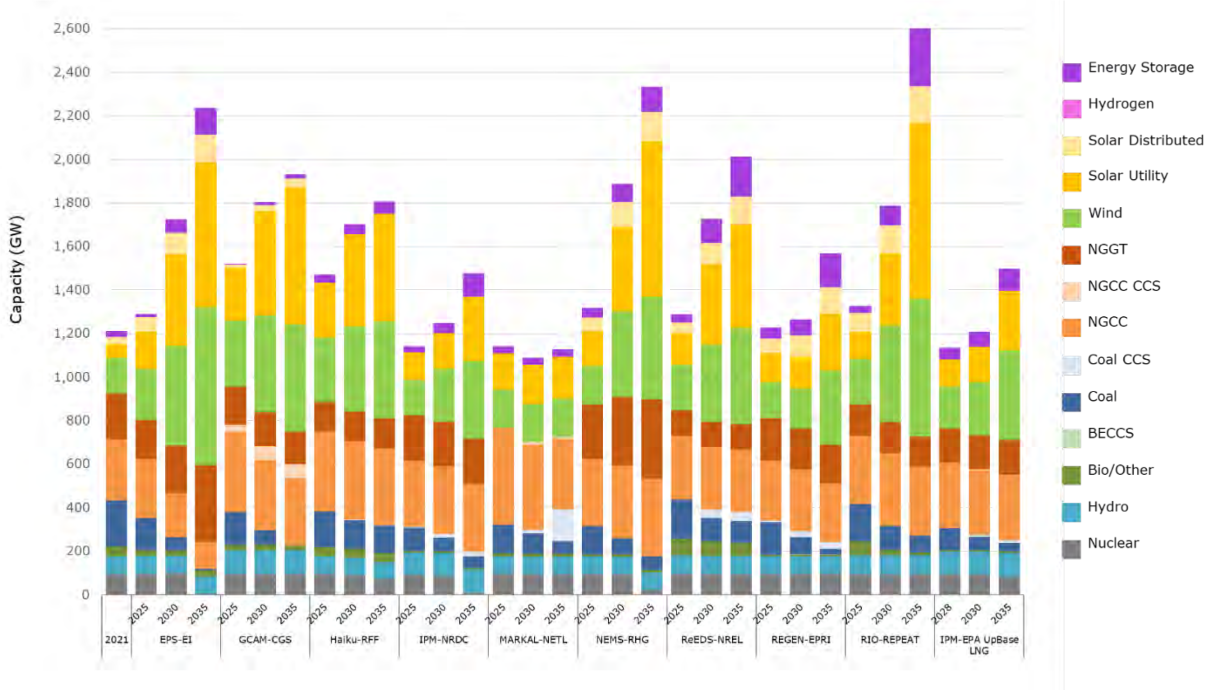

Figure 1: Projected Capacity when Modeling the Inflation Reduction Act.

(Figure from the Bistline analysis supplemented by the Joint ISOs/RTOs to include the projected capacity from the *IPM-EPA Updated Baseline with LNG Update* released on July 7.[13])

As mentioned above, EPA should undertake additional analysis that reflects supply chain constraints, real world siting and permitting expense and timelines, requisite infrastructure expansion and the maintenance of essential grid reliability attributes in order to provide a full assessment of the Rule's potential reliability impacts. The Joint ISOs/RTOs, each of whom administer interconnection queues for new resources, have information that would be informative to that analysis.

C. ***Comments Regarding Revised New Source Performance Standards (NSPS) for GHG Emissions from New Fossil Fuel-Fired Stationary Combustion Turbine EGUs.***

The Joint ISOs/RTOs are concerned that the BSER findings for new fossil fuel-fired stationary combustion turbines lead to assumptions about new generation capacity construction that simply are infeasible and uneconomic at the levels proposed. EPA's and others' modeling shows little to no generation applying the BSER control technologies (CCS and co-firing low GHG Hydrogen) in the future,[14] pointing to, among other factors, the current and less-than-beneficial economics of those technologies in the future (see Figure 1 above). As such, we recommend EPA conduct the BSER determination again, focusing, for example, on levels of co-firing that could be ***economically and practically achievable*** in the timeframe cited. For example, if BSER were determined to be co-firing 30% hydrogen, this would

[13] Data for Bistline, et al. (2023) "Emissions and Energy Impacts of the Inflation Reduction Act."

[14] See Appendix 1 for modeled capacity projections of coal with CCS, natural gas with CCS and hydrogen.

increase the potential of being achievable in some locations under today's combustion technology, hydrogen production and national pipeline infrastructure. On the flip side, co-firing with hydrogen at 96% or installing CCS on a mass scale would undoubtedly require the development of a vast new infrastructure that could take many years to develop. As a result, in this example, a BSER based on more realistic levels for hydrogen co-firing might serve to promote the hydrogen industry and associated infrastructure in a more feasible fashion, while potentially mitigating the large upfront cost and system retrofits needed to co-fire at the much higher levels found in the Proposed Rule, which could help reduce the obstacles to new generation construction. Such a more graduated approach would also recognize that EPA retains the ability to review the NSPS at least every eight years and adjust the BSER accordingly as technology, economics, and the bulk power system evolves. By the same token, adoption of the Joint ISOs/RTOs' proposal on interstate emissions trading would allow unit owners to potentially comply with the Rule while recognizing that the availability of infrastructure to transport and produce hydrogen, and the infrastructure necessary to transport and store carbon dioxide from CCS, varies across the nation. This proposal is discussed in further detail in Section VII below.

D. ***Comments Regarding Emission Guidelines for GHG Emissions from Existing Fossil Fuel-Fired Steam Generating EGUs***.

Subject to the reliability concerns identified above, the Joint ISOs/RTOs offer the following recommendations for the EPA's consideration.

1. Combining Certain of the Proposed Rule's Subcategories

The Joint ISOs/RTOs recommend the subcategories for existing fossil fuel-fired steam generating EGUs be modified to improve flexibility and help mitigate reliability concerns. We recommend EPA modify the proposed subcategories for existing coal units. The current proposal is:

(A) *Long-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have not adopted enforceable commitments to cease operations by January 1, 2040.

(B) *Medium-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2040, and that are not near-term units.

(C) *Near-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2035, and elected to commit to adopt an annual capacity factor limit of 20 percent.

(D) *Imminent-term existing coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date before January 1, 2032.

In order to promote the economic, in-market, near-term retention of resources necessary to the reliability of the grid, the Joint ISOs/RTOs propose that the above subcategories (C) and (D) be combined into one subcategory entitled *Near-term existing coal-fired steam generating units*, which consist of coal-fired steam generating units that have elected to commit to permanently cease operations by a date before January 1, 2035. These units would not have any limitation on their capacity factor and would apply what EPA has branded 'routine methods of operation' as BSER.

By the same token, the separate subcategory of units that commit to adopt an annual capacity factor of 20% ignores the fact that such a capacity factor limitation almost certainly renders these units uneconomic in the marketplace. In short, category (C) is not an economically viable category as few unit owners, particularly in states that have adopted retail choice and operate in competitive wholesale market areas, will be able to recover their going forward costs under such a limitation. This would contribute to the retirement risk concern that the Joint ISOs/RTOs have illustrated throughout these comments.

2. Creation of a New Reliability-Based Sub-Category

The Joint ISOs/RTOs propose the adoption of an additional sub-category that would accommodate units deemed needed for reliability, whether natural gas or coal. This subcategory would be populated with specific units or locations as identified by the ISO/RTO where unit retirement would cause significant reliability challenges until other longer-term solutions, such as transmission, demand response, or new generation resources, would obviate the need for those units. The ISO/RTO would identify these units or locations to EPA and a unit's placement in this sub-category would allow the non-compliant units to continue to operate beyond the date of compliance with the rule until the alternative solution can be placed into service.

As a threshold matter, each ISO/RTO would provide a public explanation of the methodology it would use to determine which units, or classes of units, qualify for inclusion in this subcategory and the process for identification of such units. The ISO/RTO would then conduct a unit or location-specific reliability analysis for each of these units. The analysis would establish the defined period past the initial retirement date that the unit is needed to maintain grid reliability while measures are implemented to address reliability issues caused by the affected unit's retirement. Within the bounds of respecting the confidential nature of certain commercially sensitive information, the ISO/RTO would publish its analysis for review and feedback from industry stakeholders. Completion of that analysis would then trigger an identification of those units or classes of units in a given location to the EPA. EPA would give deference to the ISO/RTO determination. Units ultimately identified as needed for reliability would not be subject to compliance until the date after which the unit is needed for reliability.

A similar process is already in place for the designation of units as eligible for Reliability Must Run (RMR) agreements. The Joint ISOs/RTOs' proposal is to incorporate into the Final Rule the means by which this existing RMR process would be linked to the new process in the Proposed Rule so that the two can complement rather than conflict with one another.

To be clear, the reliability sub-category is not a panacea. It still would leave generation owners with considerable uncertainty as they assess the long-term future of market participation. However, if exercised sufficiently in advance, with clear and transparent checks to prevent its over-use, the sub-category designation could be a useful tool to preserving those unit(s), either locationally or by class, so as to avoid their premature retirement before alternative commercial technologies have developed and can be deployed economically and practically to address reliability.

Another circumstance which would justify a unit being placed into this subcategory exists where a unit commits to implementing a control technology, but for reasons beyond its control, is unable to do so. While the EPA may have the authority to enter into an agreement to extend the compliance date, the Joint ISOs/RTOs recommend a process be incorporated into the rule itself that addresses the risk to the unit for continued operation, and the risk to reliability. The goal would be to avoid a situation in which the unit owner would need to comply or else a Department of Energy Section 202(c) emergency order would be required to continue the unit's operation, and to instead create a clear process where the reliability requirements are incorporated into the Rule.

The Joint ISOs/RTOs believe the creation of such a subcategory in the Rule is entirely consistent with the EPA's existing authority under Section 111 of the Clean Air Act. That Section provides significant discretion to EPA to establish subcategories based on source type, class, or size.[15]

3. Use of Remaining Useful Life and Other Factors (RULOF) Authority

A complementary approach to the above creation of a reliability sub-category would be for EPA to establish a presumptive, automated reliability process under which the ISO/RTO would certify that a unit is needed for reliability for a certain period, and then each affected state could then incorporate that certification in its plan, as contemplated by CAA 111(d):

> *"Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."*

The ISO/RTO determination in this case would be anchored in an analysis of the remaining useful life of a unit needed for grid reliability and forces which may drive its premature retirement. Use of this flexibility is not new. EPA currently considers a formal reliability assessment from ISOs/RTOs in implementing conditions of the Coal Combustion Residuals rule.[16] This process will allow the required unit to continue to operate for the required period of time, applying routine methods of operation, to address grid reliability.

E. *Comments Regarding Emission Guidelines for GHG Emissions from Existing Stationary Combustion Turbines*

Certain individual ISOs/RTOs have conducted studies on integrating increasingly higher penetrations of renewable resources into the grid. These studies have found that as the resource mix continues to evolve, it is crucial for reliability purposes to maintain certain levels of resources with attributes such as quick start-up and ramping capabilities, synchronous connection to the grid, and

[15] Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act,

[16] Final Decision: Denial of Alternative Closure Deadline for General James M. Gavin Plant, Cheshire, Ohio, page 85.

ability to operate for both short and long periods of time.[17] Currently, natural gas-fired combustion turbines are a major source of these needed reliability attributes. Someday, other types of resources such as long-duration battery storage may become commercially and economically viable enough to provide these critically needed attributes at grid scale for long durations. But unless or until that happens, it will be critical to ensure a sufficient amount of dispatchable generation remains available to offset the intermittent nature of renewables on grid reliability. Additionally, there may also be a need to build dispatchable resources such as new natural gas combustion turbines in the coming years to ensure that grid reliability is not jeopardized as emerging technologies with needed reliability attributes continue to mature towards grid-scale viability. As such, the Joint ISOs/RTOs wish to ensure that the Final Rule not serve as an impediment to the operation of these resources to the extent they provide critical grid services. With the increasing amounts of renewables and storage, we expect the dispatchable fossil fleet to run fewer hours, but until wide commercialization of alternatives such as long duration storage and grid-forming inverters come into alignment with the pace of retirements, the Rule should not, through strictures on capacity factors, drive the premature retirement of units that provide such critical grid services.

EPA projects that 37 GW of gas capacity will be in the greater than 300 MW and greater than 50 percent annual capacity factor subcategory for existing stationary combustion turbines on a nationwide basis in 2035.[18] Recent analysis by BTU Analytics estimates 73 GW potentially impacted by the proposal.[19] Should this significant portion of capacity nation-wide be required to either co-fire hydrogen, install carbon capture and sequestration, or reduce capacity factors to 50% or below, this would have significant implications to a grid that is otherwise increasingly dependent on this resource in the near term. For regions with a relatively small quantity of no- or low-carbon emitting resources, these requirements may also have the unintended impact of increasing emissions if required energy is met by units with higher emission rates.

F. ***Need to Incorporate Timely Reviews of Technology Advancement and Unit Retirements in the Final Rule***

As noted above, the compliance deadlines set forth in the Rule are premised on the timely development of new technology as a result of the IRA. The compliance deadlines also assume that the pace of new resources can keep up with if not surpass the rate of retirement of generation providing the key attributes needed to keep the grid in balance.

If these optimistic assumptions come to pass, the Final Rule may not have a significant adverse impact on reliability; however, if they do not, the reliability challenges remain and become more critical with each passing year. For these reasons, the Joint ISOs/RTOs urge that the Final Rule specify a process for evaluating on a regularly scheduled basis, the assumptions that informed the compliance schedule and, if necessary, delay the implementation date of the rule based on the pace of technology development as well as the pace of retirements compared with the rate of new generation

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[17] "The integration of renewable resources increases the need for balancing resources to meet forecasted ramping requirements." Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, Page 2.
[18] Proposed Rule, 33,361
[19] U.S. EPA Climate Rule Could Affect Twice as Much Gas- Fired Capacity as Agency Projects.

development. The Joint ISOs/RTOs recognize that EPA is already required to conduct a review of New Source Performance Standards at least every eight years.[20] However, because of the breadth of the Proposed Rule and the intertwined nature of these assumptions with the compliance deadlines, this review should occur more frequently than once every eight years. Moreover, the analysis of generator retirements and additions should be focused on longer-term reliability impacts, and should therefore supplement, not replace, the use of the reliability sub-category for specific units or locations as outlined above.

Notwithstanding certain stakeholder concerns regarding the finality of the original BSER determination, this review would be focused on the compliance calendar. Such a periodic review with the potential for course-correction is entirely consistent with the principles underlying the EPA's existing eight-year review process and can easily be accomplished within the four corners of the Clean Air Act. The Joint ISOs/RTOs urge adoption of this feature and its specific inclusion in the Final Rule.

G. ***Request for Specific EPA Authorization for Interstate Allowance Trading Among Affected Units***

In the Final Rule, the EPA should expressly provide for allowance trading as a means of compliance. As the Preamble to the GHG Rule recognizes, allowance trading has proven successful in similar environmental programs dating back to the SO_2 rule in the 1990s, providing flexibility and bringing down the overall cost of compliance.[21] Moreover, since the GHG rule is premised on the development and deployment of new technologies, a large-scale allowance trading program would provide incentives for the development and deployment of these technologies as allowance trading provides a means for those unit owners who can 'over-comply' with the rule to monetize the value of that over-compliance while providing flexible options for other unit owners who face more costly compliance.

The Proposed Rule recognizes the benefits of allowance trading, but takes no position and provides limited direction on this subject, especially as to the potential for interstate trading.[22] On the other hand, the Preamble seeks comment as to whether the proposed subcategories obviate the need and benefit of allowance trading as part of a compliance strategy.[23]

The Joint ISOs/RTOs do not agree with EPA's tentative conclusion that the specific subcategories for existing coal-fired steam generating units and existing gas combustion turbines "provide for much of the same operational flexibility as would be provided through trading." We remain equally concerned with EPA's tentative conclusion that allowance trading as a compliance strategy:

> "*would not be appropriate to allow affected EGUs in certain subcategories—imminent-term and near-term coal-fired steam generating units and natural gas and oil-fired steam generating units—to comply with their standards of performance through trading*."[24]

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[20] 42 USC § 7411(b)(1)(B)
[21] Proposed Rule, 33,393
[22] Proposed Rule, 33,393-33,396
[23] Proposed Rule, 33,393
[24] Proposed Rule, 33,393

As noted in these Comments, the Joint ISOs/RTOs believe that the Rule may force the premature retirement of those imminent and near-term dispatchable units prior to the commercialization of replacement generation with similar attributes or capabilities to provide grid services. Yet, by touting the staggered compliance dates contained in the sub-categories for these units as potentially obviating the need for allowance trading, the Proposed Rule assumes that units will necessarily operate right up to their permitted date for their particular sub-category before retiring. However, in today's environment this assumption is no longer valid. The Joint ISOs/RTOs note there are a host of factors that can drive earlier retirement, including market economics, the cost of maintaining the unit, the difficulty in retaining qualified staff for a unit facing a known retirement date, as well the fact that investors will be inclined to take their resources elsewhere rather than continuing to invest capital in a unit with a limited life. In many cases these may be the very units that the ISO/RTO will need to maintain system reliability and critical grid services in this interim period.[25] For these reasons, the EPA's conclusion that the subcategory staggered compliance dates obviate the need for allowance trading is not supported.

Moreover, as the goal should be to control overall sector emissions rather than dictate the controls at each particular unit, the Joint ISOs/RTOs do not find merit in the Preamble's statement that:

> *"An emission trading program that included affected EGUs that have BSERs and resulting standards of performance based on limited expected emission reduction potential---or, in the case of affected EGUs for which states have invoked RULOF, less stringent standards of performance—may introduce the risk of undermining the intended stringency of the BSER for other facilities*."[26]

By the same token, the fact that units may "fall in or out of a trading program from year to year" as a result of the 50% capacity factor that triggers standards of performance, does not "preclude their inclusion in any such program as a practical matter."[27] Rather, allowance trading and the ability to bank allowances can allow units that are on the margin, but are needed by the ISO/RTO, to operate without fear that running above a 50% capacity factor could trigger costly standards of performance. The Joint ISOs/RTOs need the flexibility to call on such units when needed for reliability. Allowance trading will provide added flexibility while a "hard trigger" that pushes a unit into standards of performance in a given year sets up an unnecessary conflict between the GHG rule and the Joint ISOs/RTOs' ability to ensure that the units ISOs and RTOs call upon to ensure reliability will be able to respond.

Although nothing in the Proposed Rule prevents states from proposing allowance trading in their SIPs, an effective allowance trading market requires a common product (*i.e.*, an allowance) that is both liquid and tradable across state lines. As a result, although the Joint ISOs/RTOs endorse the EPA's preliminary conclusion to allow states to propose such programs, the GHG rule does not provide sufficient guidance on how effective interstate trading could be utilized as a compliance strategy.[28] The Joint ISOs/RTOs believe that the considerations that go into choosing a rate-based or mass-based trading system are equally applicable if not even more relevant for interstate trading programs. But

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[25] To date, RTOs and ISOs have utilized Reliability Must Run Agreements as one tool to maintain those plants during this period. However, that out-of-market solution should be the exception rather than the Rule.
[26] Proposed Rule, 33,394
[27] Proposed Rule, 33,394
[28] Proposed Rule, 33,396

given their interstate nature, the Final Rule needs to provide guidance as to how a proposed interstate trading market can meet EPA's requirements so as to serve as an effective compliance strategy.

On the other hand, the Joint ISOs/RTOs recognize that some states may not prefer to allow units under their jurisdiction to participate in an allowance trading program. These states may want to ensure strict emissions compliance so as to meet individual state goals, which, in some cases, could be stricter than the GHG rule. Accordingly, the Joint ISOs/RTOs propose that the EPA establish clear guidance on the use of allowance trading as an acceptable compliance strategy while making clear that the decision of a particular state to utilize allowance trading as a compliance strategy through their SIP is entirely *voluntary* within that state. In this way, state environmental policies that go beyond the GHG rule could be honored while allowance trading programs could still develop on a national level for those states seeking to opt into such a program.

At the very least, allowance trading would be appropriate among existing units, some of which could over-comply through technology and monetize that over-compliance through trading of allowances to units with higher compliance costs. However, to maximize the benefits of trading and further incentivize new technologies, that trading should not be limited to existing units but should instead allow trading between existing and new units as well. The Joint ISOs/RTOs see nothing in Sections 111(b) and 111(d) that constrains EPA from allowing trading between existing and new units as a compliance strategy.

H. ***Request to Revise the Definition of "System Emergency"***

The Joint ISOs/RTOs generally concur with the definition of "system emergency" detailed in the Proposed Rule with one exception: The Joint ISOs/RTOs recommend that definition of "system emergency" be revised by striking the term "abnormal" as shown below:

> *"Any ~~abnormal~~ system condition that the RTO, Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load."*

The system operator is required to call system emergencies only during defined events as specified in its Tariffs or rules and in NERC's Reliability Standard EOP-011-01.[29] The Joint ISOs/RTOs submit that the use of the word "abnormal" is unnecessary because the definition already requires that the grid operator must determine the generator is necessary to operate to ensure grid reliability. To avoid creating confusion about whether a given grid condition may be considered "abnormal," and because the protocol for declaring system emergencies is transparent and well-defined, the word "abnormal" should be stricken.

CONCLUSION

[29] NERC Reliability Standard EOP-011-01

The Joint ISOs/RTOs note that this short Comment Period and the lack of dialogue on these specific issues leading up to the Proposed Rule have made it difficult for the Joint ISOs/RTOs to undertake the full analysis of reliability impacts that a Rule of this magnitude should include. It is for this reason that the Joint ISOs/RTOs urge that the EPA refrain from adopting the Final Rule for a sufficient but finite time to allow for a more thorough exploration of the reliability impacts of the proposed Rule and its impact on investment decisions, and to discuss these conclusions with the ISOs/RTOs.

Should the EPA nevertheless wish to proceed on its accelerated timeline, the Joint ISOs/RTOs urge consideration of including in the Final Rule the tools outlined herein to allow for mitigation of some of these impacts.

In either instance, the Joint ISOs/RTOs look forward to continuing their constructive dialogue with the EPA as it proceeds to the next step in this process. We appreciate our past work with EPA and stand ready to work constructively to address the reliability issues surrounding the Proposed Rule as well.

Respectfully submitted,

/s/ Timothy Caister
Timothy Caister
Deputy General Counsel-Tariff & Policy Transformation
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032
Telephone: (317) 249-5400
tcaister@misoenergy.org

/s/ Craig Glazer
Craig Glazer
Vice President-Federal Government Policy
M. Gary Helm
Sr. Lead Energy & Environmental Strategist
Natalie Tacka Furtaw
Sr. Engineer II
Thomas DeVita
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
Ph: (610) 666-8248
Fax: (610) 666-8211
craig.glazer@pjm.com
gary.helm@pjm.com
natalie.furtaw@pjm.com
thomas.devita@pjm.com

/s/ Chad V. Seely
Chad V. Seely
Senior Vice President & General Counsel
Nathan Bigbee
Deputy General Counsel
Katherine Gross
Senior Corporate Counsel
Electric Reliability Council of Texas, Inc.
8000 Metropolis Drive, Bldg. E, Suite 100
Austin, Texas 78744
chad.seely@ercot.com

/s/ Paul Suskie
Paul Suskie
Executive Vice President & General Counsel
Lanny Nickell
Chief Operating Officer
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, Arkansas 72223-4936
(501) 614-3232
psuskie@spp.org
lnickell@spp.org

Dated: August 8, 2023

cc: Joseph Goffman, Principal Deputy Assistant Administrator

Christian Fellner, Sector Policies and Programs Division, OAQPS

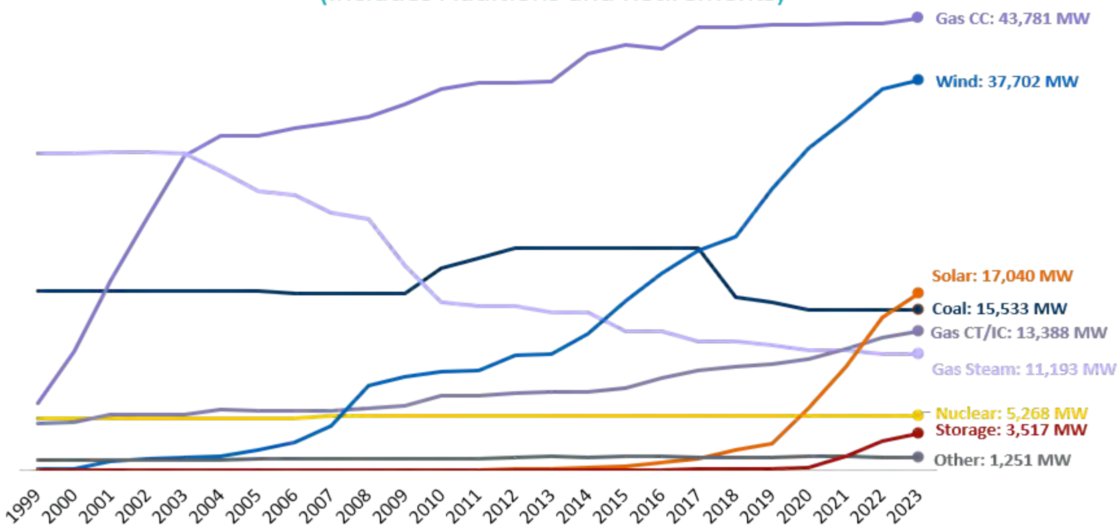
Lisa Thompson, Sector Policies and Programs Division, OAQPS

APPENDIX 1

ERCOT

ERCOT Installed Net Generation Capacity Mix Trends, as of 8/1/2023

(Includes Additions and Retirements)



Notes: Capacity totals are based on the Installed Capacity Ratings for generating units. "Other" comprises of Biomass, Hydro, and Diesel.
- Planned generation projects are added to installed capacity after approval for synchronization to ERCOT Grid.
- Totals include Private-Use Network generators that export to the ERCOT grid, Distribution Generation Resources (DGRs), Settlement-Only Distribution Generators (SODGs), Unavailable Switchable Capacity, Extended Outage Units, and Mothballed Units.

APPENDIX 2

MISO

MISO's Response to the Reliability Imperative

The Reliability Imperative is the term MISO uses to describe the shared responsibility that MISO, its members, and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's response to the Reliability Imperative consists of a host of interconnected initiatives that address the region's challenges in a comprehensive and prioritized fashion. These initiatives are described in a "living" report located on MISO's public website here: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-reliability-imperative/

The following is an excerpt from the Reliability Imperative report:

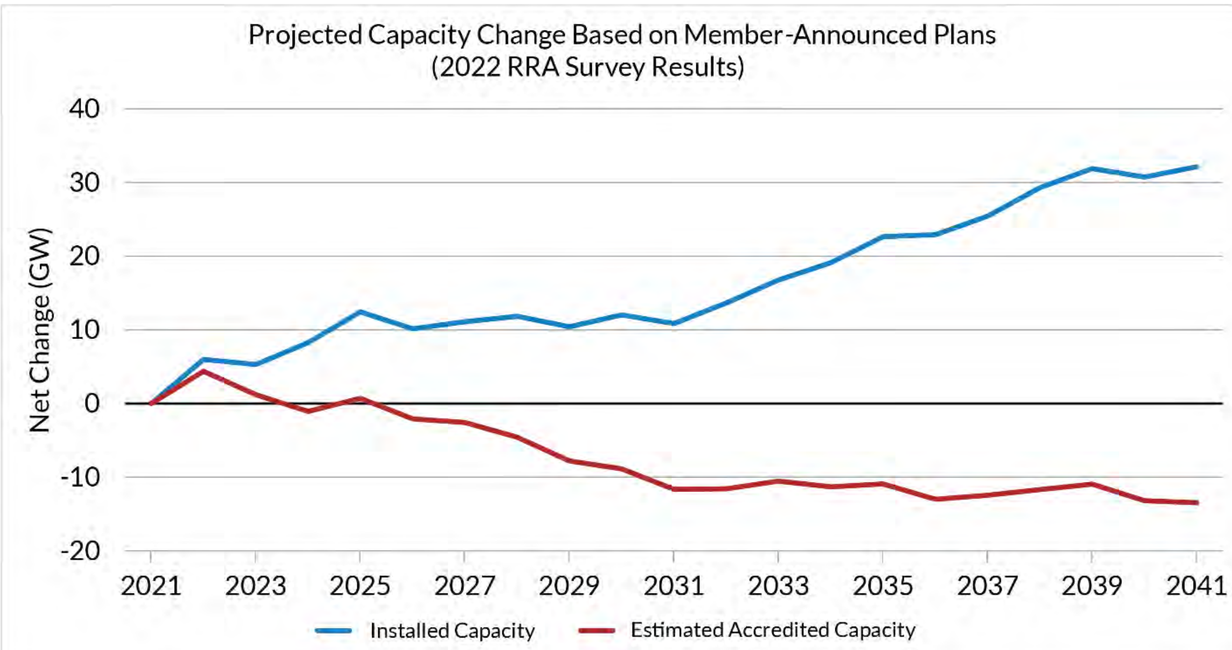
Many MISO members and states have set ambitious goals to partially or fully decarbonize their fleets of generating resources by future target dates. To be sure, utilities, states, and MISO must consider what the system will look like and how it will operate at the eventual "end state" of the decarbonization efforts that are playing out across the region. However, we must first ensure that the system remains reliable and affordable *during the transition* to that end state—and the rapid transition of the region's fleet of generating resources is giving rise to a host of urgent and complex reliability challenges. These challenges include:

- The region's level of "accredited" generation capacity is declining because the new resources that are being built—primarily wind and solar—have lower accreditation values than the conventional thermal resources that are retiring. The resulting lower reserve margins mean the region has fewer reserve resources to call on in emergencies or other tight grid conditions.
- Aging conventional resources that remain in service can be more prone to outages, potentially rendering them unavailable when they are needed most.
- Wind and solar resources are not always available during times of need due to their intermittent, weather-dependent nature.
- Due to the region's projected increasing reliance on solar generation, the system's need for controllable resources that can rapidly ramp up their output when solar becomes unavailable could triple by 2031 and quadruple by 2041 compared to current levels.
- Some fast-ramping resources may be critically needed going forward to back up intermittent renewables, but because they may not run very often, there may be little economic incentive for utilities and states to build new resources of this type, or to keep existing resources with these attributes in service.
- The region is becoming increasingly reliant on Load Modifying Resources that MISO can currently only access by engaging its emergency operating procedures.
- Distribution-level and behind-the-meter resources are becoming more prevalent, yet MISO does not yet have visibility into how these resources may affect the larger grid system.

MISO's Regional Resource Assessment (RRA): The RRA is a recurring study based on the plans and goals that MISO members have publicly announced for their generation resources. The RRA aggregates these plans and goals and uses them to develop an indicative view of how the region's resource mix might evolve going forward. The RRA is located on MISO's public website here: https://www.misoenergy.org/planning/policy-studies/RRA/#t=10&p=0&s=FileName&sd=desc

The key insights from the 2022 RRA are as follows:

KEY INSIGHT 1: The 2022 snapshot of MISO member plans indicates an increase in the overall amount of installed capacity, but a decline in accredited capacity compared to current levels.



KEY INSIGHT 2: The RRA modeling indicates a continued near-term capacity risk, highlighting the urgent need for coordinated resource planning and additional investment.

KEY INSIGHT 3: Wind and solar generation are projected to serve 60% of MISO's annual load by 2041, which would reduce emissions by nearly 80% relative to 2005 levels but also sharply increase the complexity of reliably operating and planning the system.

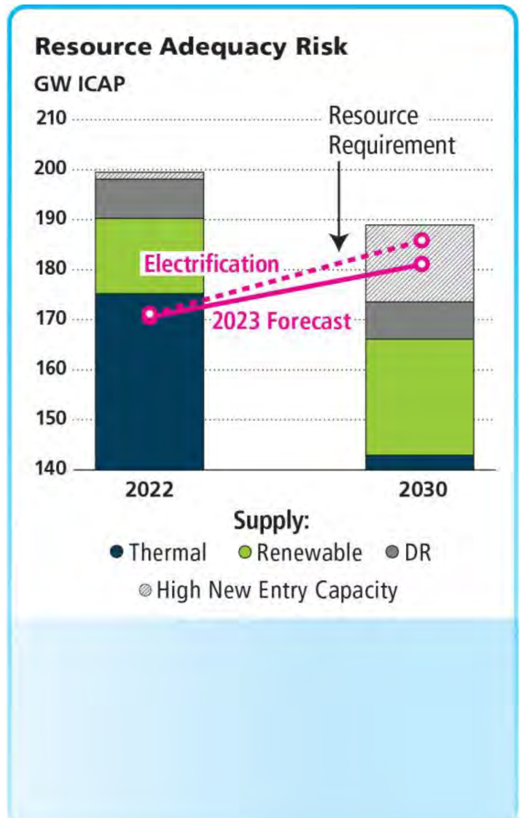
KEY INSIGHT 4: As the solar generation fleet grows, the system will have a much greater need for controllable ramp-up capability. Maximum short-duration up-ramps increase by three times by 2031 and four times by 2041 compared to current levels.

KEY INSIGHT 5: The capacity contribution of solar generation is forecast to decline rapidly as more solar capacity is added to the system, impacting the region's overall capacity outlook. The contribution of wind generation remains relatively stable as more wind capacity is added.

APPENDIX 3

PJM

PJM is undertaking efforts aimed at maintaining reliability during the energy transition. [Ensuring a Reliable Energy Transition] details PJM's efforts to identify challenges and solutions to maintaining reliability as the bulk power grid evolves into a system deriving most of its energy from low-carbon resources. Near- and medium-term challenges have been identified in a series of reports PJM has released, entitled *Energy Transition in PJM*. The most recent edition, Resource Retirements, Replacements and Risks, indicates that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The report describes 40 GW of dispatchable generation at-risk for retirement by 2030, approximately 21% of PJM's installed capacity.



These potential retirements coupled with low new resource entry risks reducing capacity reserve margins below required levels near the latter part of this decade, largely due to policy driven retirements, and prior to accounting for the impacts of the Proposed Rule (see Table 1 below). The Proposed Rule puts an additional 15 GW of coal at-risk in PJM, pushing at-risk generation to 29% of installed capacity. An additional 22% of PJM's installed capacity, the most-efficient, dispatchable gas-fired generation will be forced to undertake expensive control options or significantly reduce operations under the Proposed Rule. Recent analysis by S&P Global[30] on the Proposed Rule finds that the cost to retrofit CCS on coal units will drive most to retire, creating a firm capacity gap and heightening the need for replacement capacity with the appropriate characteristics and capabilities.

[30] "EPA's proposed power plant rule to accelerate coal retirements —but what about gas?", P. Luckow & M. Lester, Aug 2, 2023, S&P Global Commodity Insights (subscription)

Table 1. Reserve Margin Projections Under Study Scenarios

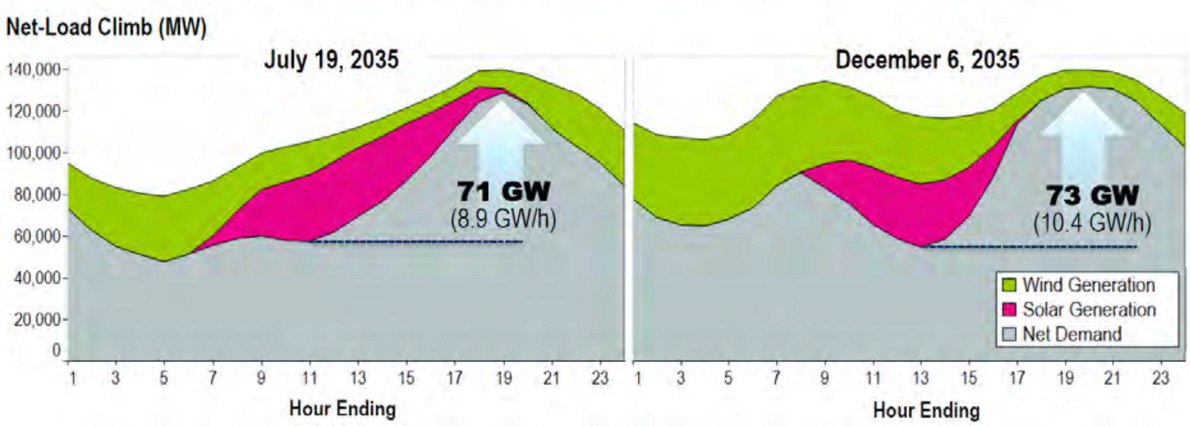
Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

PJM's first report in the Energy Transition in PJM series: Frameworks for Analysis [31] found, among other things, that:

> *Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability. PJM and stakeholders must ensure that the market structure provides the right incentives to maintain an adequate supply of these services.*

PJM's second report in the Energy Transition in PJM series: Emerging Characteristics of a Decarbonizing Grid documented the need for additional ramping capability as intermittent resources increase (See Figure below).[32] This important operational flexibility is provided by mainly by thermal resources, but will be complemented by storage resources as they grow in duration and total capacity. This also reinforces the need to maintain thermal resources until substitutes are available at scale.

Figure 17. Total Climb From Beginning to End of the Ramping Period for Selected Summer and Winter Days



PJM also continues to monitor and anticipate the need for essential reliability services, and encourage the development of new technologies with the capabilities to provide those services. This builds on previous studies[33], including those cited above.

31 Energy Transition in PJM: Frameworks for Analysis
32 Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid
33 Reliability in PJM: Today and Tomorrow

From a regional transmission planning perspective, PJM's Grid of the Future report details continuing efforts to enhance planning processes to address key trends driving future grid expansion.[34]

PJM and its stakeholders are working to retain the needed resources; however, maintaining reliability is a shared responsibility, which points to the importance of incorporating all aspects of reliability when regulating thermal resources. Grid reliability needs to consider policies that are increasing, or are expected to increase, electrification and dependency on the electric grid. Policies that accelerate building[35], vehicle[36] and industrial[37] electrification are increasing load growth at the same time current EPA regulations and proposals are targeting resources needed to maintain reliability.

NERC's latest Long Term Reliability Assessment[38] also addressed concerns regarding regulatory and policy related retirements, containing the following recommendations:

> State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks.
>
> Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.

PJM also reviewed the modeling EPA conducted for the Proposed Rule, which reinforced our concerns regarding EPA basing their assessment of reliability impacts on projections of modeled outcomes of the Inflation Reduction Act, in particular meeting the significant new builds of renewables and energy storage and the resultant energy projections (see Figures below). This modeling of the IRA build out reflects an assumption common in modeling that "investors and lenders take advantage of subsidies in an optimized world in which economic incentives are the sole drivers of change."[39] IPM documentation states: "IPM's objective function is to minimize the total, discounted net present value of the costs of meeting demand, power operation constraints, and environmental regulations over the entire planning horizon."[40] Additionally, that "the tax credits for new renewable technology investments provided under the Inflation Reduction Act of 2022 are implemented in EPA Platform v6 as a reduction to capital costs."[41] EPA acknowledges that "additional effects of the IRA beyond those modeled in this RIA could result in a change in projected system compliance costs and emissions outcomes."[42]

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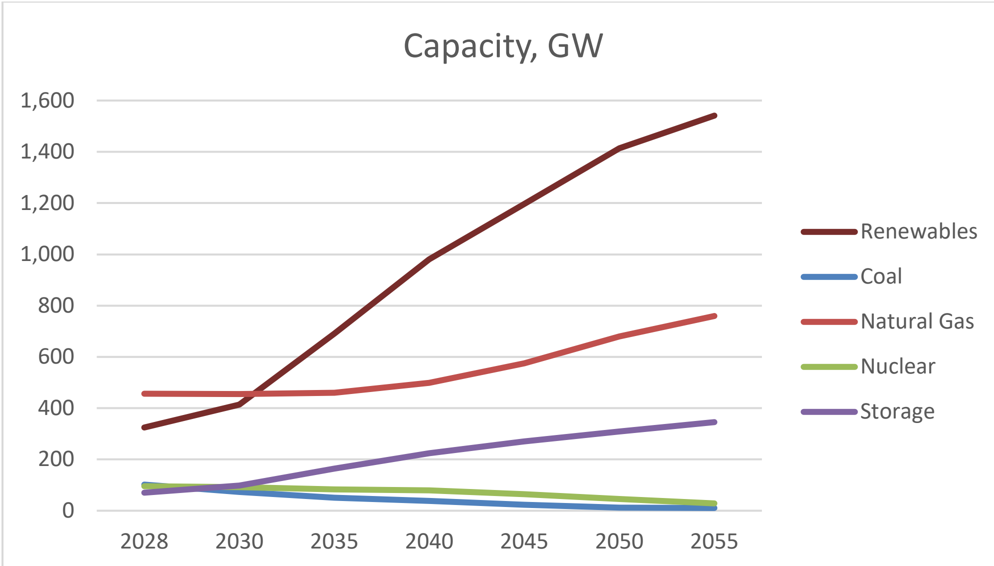
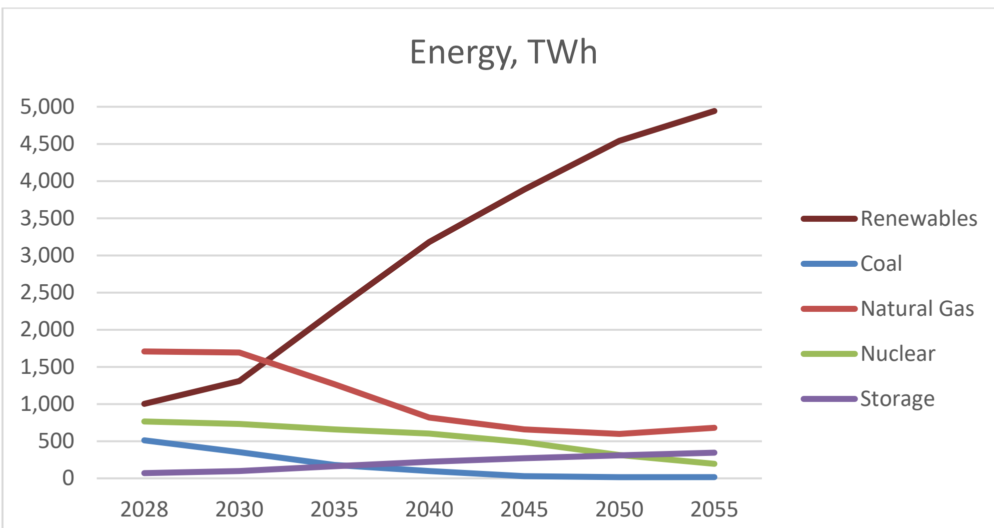
34 Grid of the Future: PJM's Regional Planning Perspective
35 Federal Building Performance Standard
36 Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles
37 DOE Industrial Decarbonization Roadmap.
38 NERC, 2022 Long Term Reliability Assessment, December 2022,
39 Growing Pains: The Renewable Transition in Adolescence, M. Cembalest, March 28, 2023, p.11.
40 EPA Platform v6 – Post IRA 2022 Reference Case, Chapter 2: Modeling Framework.
41 EPA Platform v6 – Post IRA 2022 Reference Case, Chapter 4: Generating Resources.
42 EPA Regulatory Impact Analysis.



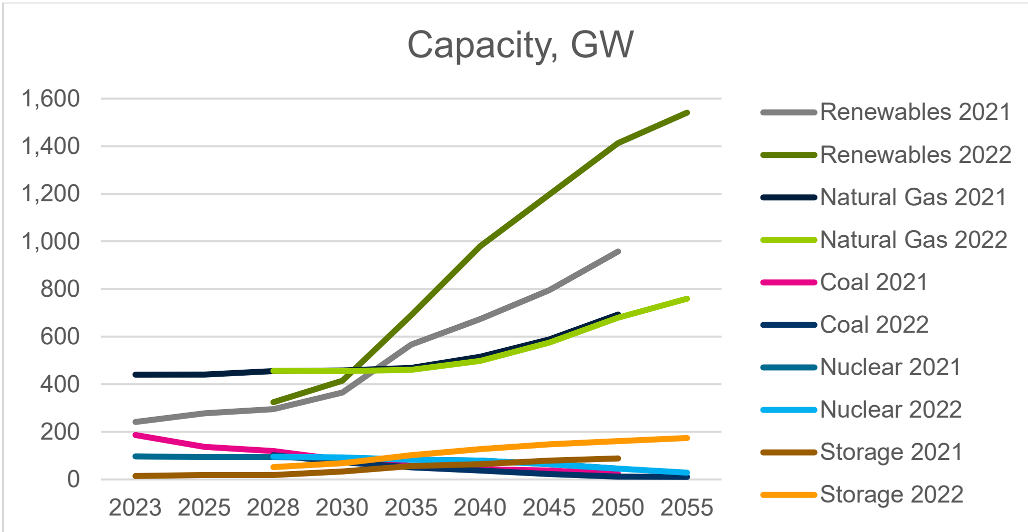
Total Capacity (Cumulative GW) from *IPM-EPA Updated Baseline with LNG Update*.[43]



Total Energy (Cumulative TWh) from *IPM-EPA Updated Baseline with LNG Update*.[44]

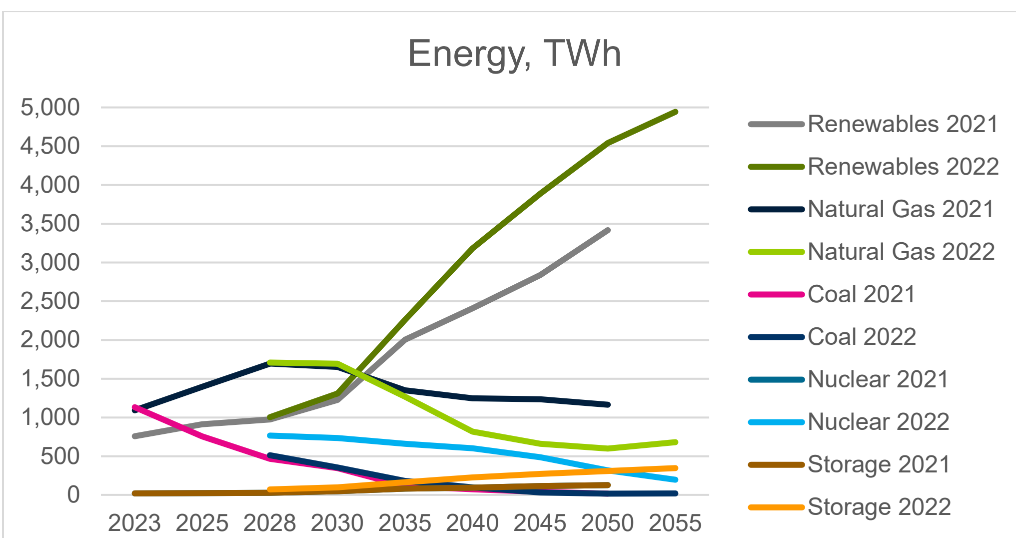
The Figure below shows a comparison of projected generation capacity results from EPA modeling the IRA using EPA's Power Sector Modeling Platform v6 based on IPM Summer 2021 Reference Case versus the 2022 Post-IRA Reference Case. This is helpful in showing how the modeling effort

[43] EPA Updated Baseline with LNG Update, July 7, 2023.
[44] Same citation as above



Comparison of Good Neighbor Rule + IRA[45] to GHG NSPS Updated Baseline with LNG Update

progressed, as well as providing a starting point in 2023 rather than 2028, enabling the visualization of the projected impacts from a point closer to today. The comparison shows a significant change (increase) in renewable capacity, as well as a noticeable change (increase) in storage capacity between the models, while not showing similar changes in coal, natural gas or nuclear capacity between models. Similarly, comparing the projected energy output results of the two models (in Figure below) shows a significant change (increase) in renewable energy, a noticeable change (increase) in storage energy, and a significant change (decrease) in natural gas energy, while not showing any change in coal or nuclear. This again points to the inherent difficulties in modeling the IRA and subsequently basing reliability assessments of the Proposed Rule on those projected results.



Comparison of Good Neighbor Rule + IRA[46] to GHG NSPS Updated Baseline with LNG Update

[45] Sensitivity Final Rule + IRA.

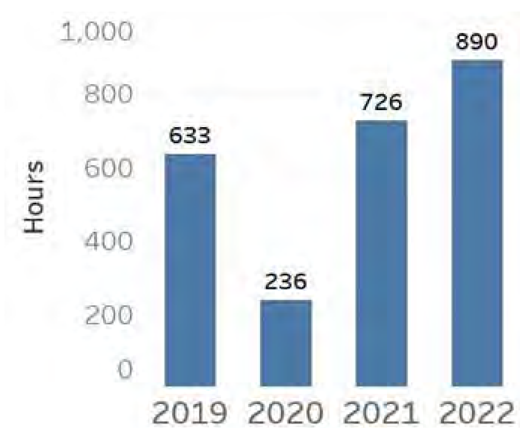
[46] Sensitivity Final Rule + IRA.

APPENDIX 4

SPP

SPP has adapted its market design, operations processes, and transmission planning practices to keep pace with the changing resource fleet thus far. However, since 2014, SPP has experienced the retirement of over 7,600 MW of thermal resources. SPP saw over 2,796 MWs of thermal generation retire from 2019 to 2022, and SPP has already seen an additional 809 MW retire thus far in 2023. As the thermal fleet shrinks without comparable replacement in fuel-assured, ramp-able capacity, the remaining fleet carries the additional burden the recently retired resources provided. This additional stress has led to more planned and forced outage rates, particularly with an aging fleet of such resources. Some resources are being forced to take maintenance outages during summer and winter conditions.

These retirements have also contributed to declining reserve margins. SPP has recently seen an increase in levels of system alerts as the remaining thermal fleet is increasingly stressed by managing typical load fluctuations. As illustrated below, from 2019 to 2022, SPP experienced over 2,475 hours of system alerts, including 33 hours of Energy Emergency Alerts. In 2022, SPP experienced 257 more alert hours than it did in 2019, which amounts to almost eleven days.



The graph below illustrates that SPP has determined that with a mere 3% increase of historical gross load, the region's conventional resources serving net load (gross load minus wind and solar output)[47] have no margin for additional retirements.

[47] Impacts from Winter Storm Uri were not included in this analysis.

Please note loads are projected to be higher than 3% on average due to general load growth, electrification, electric vehicle charging, hydrolyzers, crypto-mining, data centers, and micro-grids (when they are grid-served). In an effort to facilitate an orderly transition that ensures the reliability levels the region has enjoyed for decades, it is imperative resources do not accelerate retirement until there are adequate replacements.

SPP establishes a Planning Reserve Margin ("PRM") requirement designed to ensure that SPP will have sufficient capacity to serve peak demand obligations. The current PRM requirement of 15% was determined in accordance with SPP's tariff, which directs SPP to conduct an LOLE study and set a PRM value to maintain a loss of load value equal to or less than one day in ten years. That PRM requirement is subject to change and may need to be increased in future years as the transition to a less-dispatchable resource mix continues.

SPP planning staff has analyzed projected capacity levels as reported by its LREs and has issued a five-year outlook for the SPP Balancing Authority Area.[48] The current reported PRM for the 2023 summer season is 20.1%, which is above the current PRM requirement of 15%. However, the combined impacts of decreasing resource capacity and increasing demand by current projections would lead to a significant decrease in the PRM over the next five years. As reflected in the graph below, the projected margin will barely exceed the current PRM requirement by 2026. If the projection were to hold true, it will fall below the requirement in 2027, and it will continue to drop to 9.7% by 2028. Of course, the current 15% PRM requirement and any future established PRM requirements must be maintained by the Load Responsible Entities in SPP. However, such requirements and penalties for not maintaining the required PRM cannot override a mandate from this Proposed Rule. Once the reserve margin has fallen below

[48] *See* the 2023 SPP June Resource Adequacy Report at: https://www.spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf

the 15% PRM requirement, SPP would no longer be able to meet the industry standard for loss of load of one day in ten years.

NRECA Attachment 3 - Kiewit Engineering Group, Technical Comments on Hydrogen and Ammonia Firing (August 4, 2023)

TECHNICAL COMMENTS ON HYDROGEN AND AMMONIA FIRING

REGARDING:

EPA'S PROPOSAL ENTITLED "NEW SOURCE PERFORMANCE STANDARDS FOR GHG EMISSIONS FROM NEW AND RECONSTRUCTED EGUS; EMISSION GUIDELINES FOR GHG EMISSIONS FROM EXISTING EGUS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE" (DOCKET EPA-HQ-OAR-2023-0072)

PREPARED FOR:

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

PREPARED BY:

KIEWIT ENGINEERING GROUP, INC.

AUGUST 4, 2023

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1. ANALYSIS OF EPA'S TECHNICAL SUPPORT DOCUMENT

This section of the report will discuss two of the Environmental Protection Agency's (EPA) Technical Support Documents:

- Resource Adequacy Analysis
- Hydrogen in Combustion Turbine Electric Generating Units

1.1 RESOURCE ADEQUACY ANALYSIS

The Technical Support Documents for EPA's proposed "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" ("proposed EPA CO2 Rule") are based on the Integrated Planning Model (IPM) model. They developed two cases: a post-Inflation Reduction Act (IRA) 2022 Reference case and a Proposal case, which models the impact of EPA's rule. The proposal case is summarized in table below.

EPA: CO2 Rule, Proposal Case, Resource Adequacy	2028	2030	2035	2040	2045	2050	2055
1. Reserve Margin Capacity Summer [MW]	926,851	950,216	1,016,190	1,093,695	1,182,107	1,280,223	1,359,074
Plus Firm Contract Purchases Summer [MW]	0	0	0	0	0	0	0
Plus Transmission In Summer [MW]	100,391	98,069	99,476	99,293	124,498	146,303	151,862
Less Firm Contract Sales Summer [MW]	0	0	0	0	0	0	0
Less Transmission Out Summer [MW]	96,561	93,756	93,611	92,304	118,358	141,362	147,196
Total Reserve Margin Capacity Summer [MW]	**930,682**	**954,529**	**1,022,056**	**1,100,684**	**1,188,246**	**1,285,164**	**1,363,740**
Accredited Capability (MW)	1,733,344	1,777,388	1,901,950	2,047,662	2,212,026	2,394,207	2,541,250
2. Peak Load Summer [MW]	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,984**	**1,182,176**
Less DSM [MW]	0	0	0	0	0	0	0
Net Demand Summer [MW]	**806,492**	**827,172**	**885,760**	**953,967**	**1,029,920**	**1,113,984**	**1,182,176**
Peak Load Growth (%/year)		1.27%	1.38%	1.49%	1.54%	1.58%	1.20%
3. Reserve Margin Summer [%]	**15**	**15**	**15**	**15**	**15**	**15**	**15**

To expand on this information, we provide a comparison of the Proposal case (vs. Reference Case) through 2035 is shown in tables below.

The first table shows the Reference Case.

EPA: New CO2 Rule (5/11/2023), Reference Case, Capacity Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	9,338	1,351	0	0	0	10,689	1,527
New_Gas_CCS	0	6,662	3,713	0	0	0	10,375	1,482
Retrofit Coal_CCS	0	16,000	5,064	0	0	0	21,064	3,009
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**31,999**	**10,129**	**0**	**0**	**0**	**42,128**	**6,018**
Retire_Coal	56,296	24,855	23,068	8,803	13,672	12,145	138,838	5,142
Retire_Gas	1,695	733	3,797	639	14,648	14,542	36,055	1,335
Total_Retire_CG	**57,991**	**25,588**	**26,865**	**9,442**	**28,320**	**26,687**	**174,893**	**6,478**
New_Gas_CC	33,685	0	3,167	286	116	2,939	40,193	1,489
New_Gas_CT	13,812	0	10,222	43,528	94,760	106,386	268,707	9,952
Total_New_Gas	**47,497**	**0**	**13,389**	**43,814**	**94,876**	**109,325**	**308,901**	**11,441**
Gas ($/MMBtu)	$3.02	$2.53	$2.10	$2.19	$2.13	$1.91	$2.31	
Source: EPA, Post-IRA 2022 Reference Case, Integrated Planning Model (5/11/2023)								

The second table shows the proposal case.

EPA: New CO2 Rule (5/11/2023), Proposal Case, Capacity Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	12,104	6	0	0	0	12,111	1,730
New_Gas_CCS	0	4,188	3,855	0	0	0	8,043	1,149
Retrofit Coal_CCS	0	16,293	3,861	0	0	0	20,154	2,879
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**32,586**	**7,722**	**0**	**0**	**0**	**40,308**	**2,118**
Retire_Coal	57,758	23,626	44,988	3,655	9,028	158	139,213	5,156
Retire_Gas	1,695	1,162	3,595	574	14,693	14,461	36,181	1,340
Total_Retire_CG	**59,454**	**24,788**	**48,584**	**4,229**	**23,721**	**14,619**	**175,394**	**6,496**
New_Gas_CC	37,193	0	686	341	727	2,439	41,386	1,533
New_Gas_CT	13,990	123	33,048	38,638	89,406	96,079	271,283	10,048
Total_New_Gas	**51,183**	**123**	**33,734**	**38,979**	**90,133**	**98,518**	**312,669**	**11,580**
Gas ($/MMbtu)	$3.02	$2.76	$2.05	$2.14	$2.12	$1.88	$2.33	
Hydrogen ($/MMbtu)	$0.00	$7.40	$3.70	$3.70	$3.70	$3.70	$3.70	
New H2-CCGT (MW)	0	233	10,382	1,997	632	7,887	**21,131**	1,057
New H2-CCGT (Tbtu)	0	3	294	347	58	80		
EPA Peak Demand	806,492	827,172	885,760	953,967	1,029,920	1,113,987	307,495	1.5%
Source: EPA, CO2 Rule, Proposal Case, Integrated Planning Model (5/11/2023)								

Of these projected NGCC builds, 6.4 GW are to co-fire hydrogen under the Proposal case. Using the methodology outlined above, EPA estimated that in 2040, approximate 2 GW of capacity increased hydrogen co-fire blends to 96% by volume while the remaining capacity reduced dispatch to below 50% under the Proposal case.

EPA did not analyze the impacts of gas-CCS as a compliance measure within this subcategory, which is not helpful to the industry in trying to evaluate the impact to manufacturing and construction resources. It is not possible to determine how much hydrogen production will be needed without determining how many plants are expected to implement CCS instead of using hydrogen to achieve compliance.

EPA estimated that in 2040 approximately 2 GW of capacity increased hydrogen co-fire blends to 96% by volume and the remaining capacity reduced dispatch to below 50% capacity factor. About 80% of the reduction in generation were apportioned to existing NGCC units operating below 50% capacity factor and the remaining 20% apportioned to incremental non-emitting resources. The decreases in generation from affected new NGCC units are offset by increases in replacement generation.

The net result is that utilities would need to expend significant capital to comply with this rule. Since the volumes of hydrogen are likely to be limited, the ability to satisfy 96% hydrogen firing for a 300 MW plant with greater than 50% capacity factor will be challenging. Therefore, the remaining choices for compliance will be to reduce capacity factor to less than 50% or implement CCS. In the case of reducing capacity factor to less than 50%, additional generating capacity will have to be brought online to meet electricity demand or existing, less efficient generation will have to increase its output. The result is that no decrease, or even an overall increase, in emissions will occur, and a duplication or overbuilding of plants required to meet overall capacity demands will occur instead. Bottom line, the regulations will likely result in a lot of units, including a lot of new units running below 50% capacity. Thus, this modeling shows the potential flaws of EPA's rule which are likely to significantly increase costs and decrease efficiency of capital without achieving any emissions reductions.

1.1.1 FORECAST COMPARISON OF EPA TO EIA

U.S. Energy Information Administration (EIA) in March 2023 released their Reference Case for the EIA 2023 Annual Energy Outlook, which includes the Inflation Reduction Act (IRA) tax credits, with new generation capacity additions for fossil generation summarized below. Since it came out in March, it does not include the EPA's GHG rule. However, it is relevant to compare to the EPA's numbers because the EIA's forecast is used by the entire power industry as a benchmark for future forecasting. The EIA uses its NEMS model for forecasting, while the EPA uses its own IPM model. The NEMS model has several advantages over the IPM model, which is why it is the standard bearer for the industry. One of the significant differences between the two models is that the NEMS model accounts for demand side management. Utilities use demand side management to cost effectively limit the amount of generation they need to build and burden the rate payers with. It is a valuable tool for managing the grid and the fact that it is not in the IPM model is a significant limitation of EPA's model.

Below is the EIA forecast.

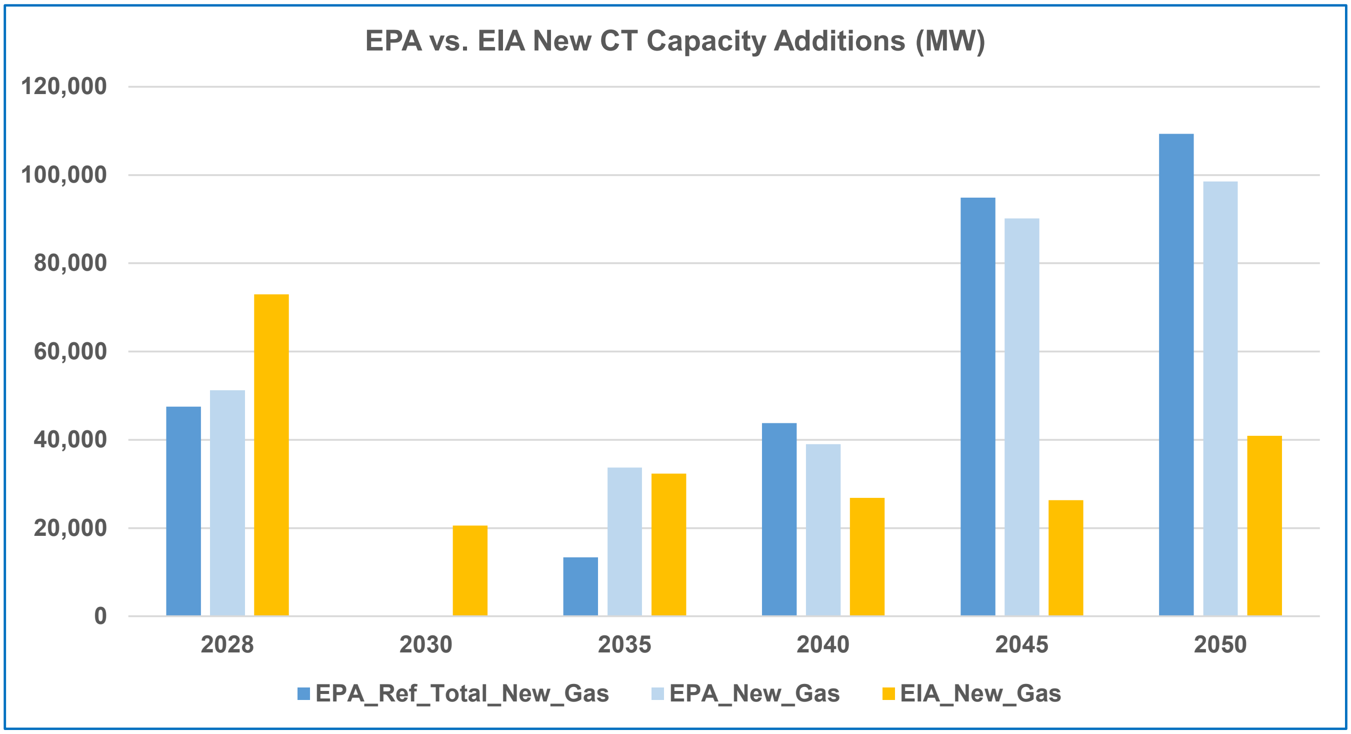
EIA: Reference Case (3/17/2023), Fossil Generation Additions (MW)								
	2028	2030	2035	2040	2045	2050	Total MW	MW/Yr
New_Coal_CCS	0	0	0	0	0	0	0	0
New_Gas_CCS	0	0	0	0	0	0	0	0
Retrofit Coal_CCS	0	0	0	0	0	0	0	0
Retrofit Gas_CCS	0	0	0	0	0	0	0	0
Total_CCS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Retire_Coal	0	24,519	10,949	14,119	2,184	4,344	56,116	2,806
Retire_Gas	0	1,590	8,349	466	2,061	2,243	14,709	735
Total_Retire_CG	**0**	**26,109**	**19,298**	**14,585**	**4,245**	**6,587**	**70,824**	**3,541**
New_Gas_CC	18,790	3,296	4,651	1,807	217	10,670	39,432	1,460
New_Gas_CT	54,178	17,246	27,672	25,053	26,074	30,236	180,458	6,684
Total_New_Gas	**72,968**	**20,542**	**32,323**	**26,860**	**26,291**	**40,906**	**219,890**	**8,144**
Source: EIA, 2023 Annual Energy Outlook, NEMS Model (3/17/2023)								

Over 2023-2028, EIA is projecting that 18,790 MW new gas-CC and 54,178 MW new gas-CT, totaling 72,968 MW will be built. Beyond 2028, EIA is projecting gas-CCGT additions ranging 20-40 GW in 5-year intervals, or annual gas additions over 2023-2050 averaging 8.1 GW per year.

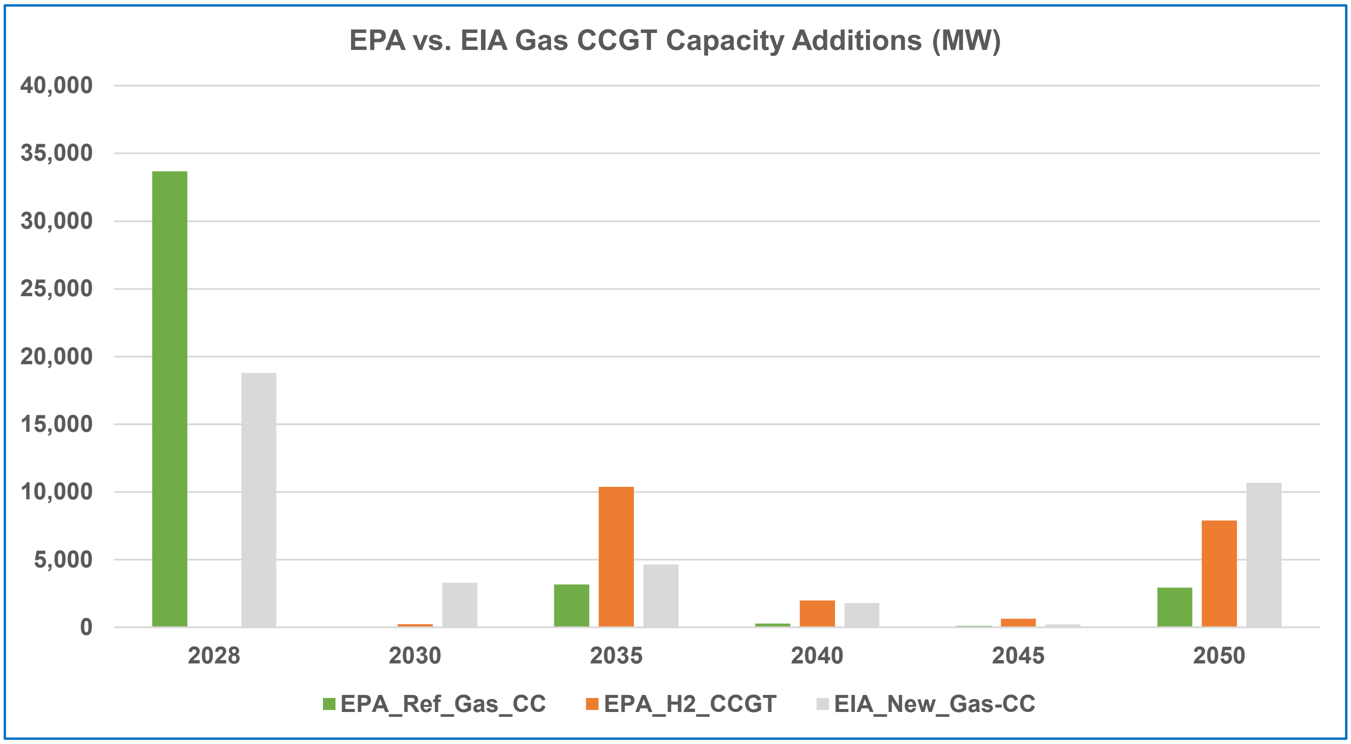
A forecast comparison of EPA (CO_2 Rule, Reference Case and Proposal Case) to EIA (AEO 2023 Ref Case) for new gas-CCGT and H2-CCGT generation additions (MW), in 5-year intervals, is summarized in the table and chart below.

Forecast Comarison: EPA CO2 Rule (5/11/23) vs. EIA 2023 AEO (3/17/23), Gas-CCGT Generation Additions (MW)								
	2028	2030	2035	2040	2045	2050	2023-2050	MW/Yr
EPA Reference Case								
EPA_Ref_Total_New_Gas	47,497	0	13,389	43,814	94,876	109,325	308,901	11,441
EPA_Ref_Gas_CC	33,685	0	3,167	286	116	2,939	40,193	1,489
EPA Ref_%New_Gas-CC	71%	0%	24%	1%	0%	3%	13%	13%
EPA Proposal Case								
EPA_New_Gas	51,183	123	33,734	38,979	90,133	98,518	312,669	11,580
EPA_H2_CCGT	0	233	10,382	1,997	632	7,887	21,131	1,057
EPA_%H2-CCGT	0%		31%	5%	1%	8%	7%	9%
EIA Reference Case								
EIA_New_Gas	72,968	20,542	32,323	26,860	26,291	40,906	219,890	8,144
EIA_New_Gas-CC	18,790	3,296	4,651	1,807	217	10,670	39,432	1,460
EIA_%New_Gas-CC	26%	16%	14%	7%	1%	26%	18%	18%

The table above is presented in graphic form in the two graphs below. The first graph is the total gas generation, and the second graph is the likely hydrogen fired gas generation.



EPA vs. EIA New CT Capacity Additions (MW)
120,000
100,000
80,000
60,000
40,000
20,000
0
2028
2030
2035
2040
2045
2050
EPA_Ref_Total_New_Gas
EPA_New_Gas
EIA_New_Gas



EPA vs. EIA Gas CCGT Capacity Additions (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
2028
2030
2035
2040
2045
2050
EPA_Ref_Gas_CC
EPA_H2_CCGT
EIA_New_Gas-CC

1.1.2 CONCLUSIONS REGARDING EPA FORECASTS

There are several key conclusions that can be made from the above data:

- It may be difficult to make direct a comparison of the EIA data with the EPA proposal case since the EPA proposed data case considers the EPA proposed rule. It is for these reasons that Kiewit evaluated the EPA reference case as well.
- When comparing the EPA reference case to the EIA cases, it is concerning that the EPA case has so much more total combustion turbines forecasted than the EIA. It has almost 50 percent more combustion turbines forecasted as being built between now and 2050. This is likely a result of requiring plants to operate at less than a 50% capacity factor to maintain compliance, which again causes more plants to be built, more capital to be expended, but without any net reduction in emissions.
- Compared to the EIA, the EPA's estimates for combustion turbine generation requirements appear to be underestimated, despite overestimating total combustion turbine needs. The EIA is indicating that typically between 15 and 25 percent of new gas generation is combined cycle, whereas the EPA percent is between 0 and 10 percent. The result is a significant difference in potential hydrogen needs.

Total Potential Hydrogen Needs

Forecast	Total New MWs 2028 to 2050
EPA_H2_CCGT	21,131
EIA_New_CCCT	39,432

- The EIA's model represents the industry benchmark forecasting and planning. One of its benefits is that it does a better job of accounting for demand side management than does the EPA model. Therefore, its total energy needs are more accurate starting point for this analysis than the EPA's.

1.1.3 REVIEW OF ADDITIONAL EPA MODELING

On July 7, 2023, EPA released additional modeling in support of the proposed rule. The additional modeling reflects EPA's analysis of the integrated proposal (i.e., modeling the requirements on existing combustion turbines) and the third phase after 2040 of the NSPS together with the requirements that were already modeled as part of the Regulatory Impact Analysis for this rulemaking. Additionally, the analysis also separately projects illustrative impacts of higher LNG export demand consistent with the recently released EIA annual energy outlook AEO 2023. The EPA changed assumptions for natural gas prices and LNG prices in the IPM model scenarios for the Updated Baseline scenario and the Illustrative Integrated Proposal scenario, and *"exogenously"* evaluated the potential for hydrogen co-firing in existing combustion turbines, which were not evaluated in EPA's original Proposal case. This means that they evaluated hydrogen co-firing on existing turbines *outside* of the main model. It is difficult to know what this fully means, but it does appear that the existing combustion turbines were not fully integrated into the main model.

We draw attention to the following statements from EPA's memo of July 7, 2023, with concern as stated:

- The EPA indicates that 17 GW of NGCCs and 6 GW of NGCT additions will co-fire hydrogen in 2035.
- In 2040, the EPA forecasts that 1 GW of NGCC and 6 GW of NGCT additions are projected to continue to co-fire hydrogen.
- Of the existing NGCC units greater than 300 MW, 25 GW are projected to co-fire hydrogen in 2035 and 5 GW are projected to co-fire hydrogen in 2040.

- Table 22 (Integrated Proposal with LNG Update) shows additional hydrogen co-firing of 48 GW in 2035, and 12 GW in 2040.
- There is a discrepancy in EPA's estimate of additional hydrogen co-firing (2035, 25 GW vs 48 GW) in Table 22.
- EPA did not state the percentage of hydrogen co-firing in existing gas-CC over 300 MW size assumed.
- While proposed CO2 Rule requires minimum 30% co-firing of hydrogen in 2032, most existing gas-CC over 300 MW size do not have the capability to co-fire 30% hydrogen, and EPA did not evaluate how they would be retrofitted to maintain capacity.
- The economics of retrofits to existing gas-CCs over the 300 MW size to be capable of co-firing 30% hydrogen does not appear to be evaluated in EPA's analysis.

Kiewit has the following concerns with the July 7, 2023, modeling:

- The EPA did not provide a complete set of information on the July modeling, as they did with the original modeling. As a result, it is impossible assess the validity of this additional modeling.
- The modeling was provided extremely late in the comment period and, therefore, there was not time to analyze this information appropriately. Yet, EPA is presenting it as justification along with the rest of information as equal justification.
- By the EPA's own admission, the modeling of the existing combustion turbines is not fully integrated into the rest of the model. So, as a result, it is unknown whether they are being modeled correctly or whether they are accurately interacting with the rest of the grid.
- As will be discussed further in this report, it does not appear that the EPA has accounted for the fact that units retrofitted for hydrogen firing will not be able to maintain their original capacity without significant retrofit. This is a significant economic hit to these turbines that has not been modeled.

In summary, the lateness of the EPA's additional modeling, the way it was performed (i.e., outside of the IPM model), and the fact it does not account for lost capacity, make the July 7, 2023 modeling results extremely questionable and unreliable. In Kiewit's opinion, they cannot be depended on for policy decisions.

1.1.4 EPA COMMENTS ON HYDROGEN

EPA incorrectly assumes hydrogen firing will not impact the capacity of affected units.

EPA's Resource Adequacy Analysis document incorrectly asserts that:

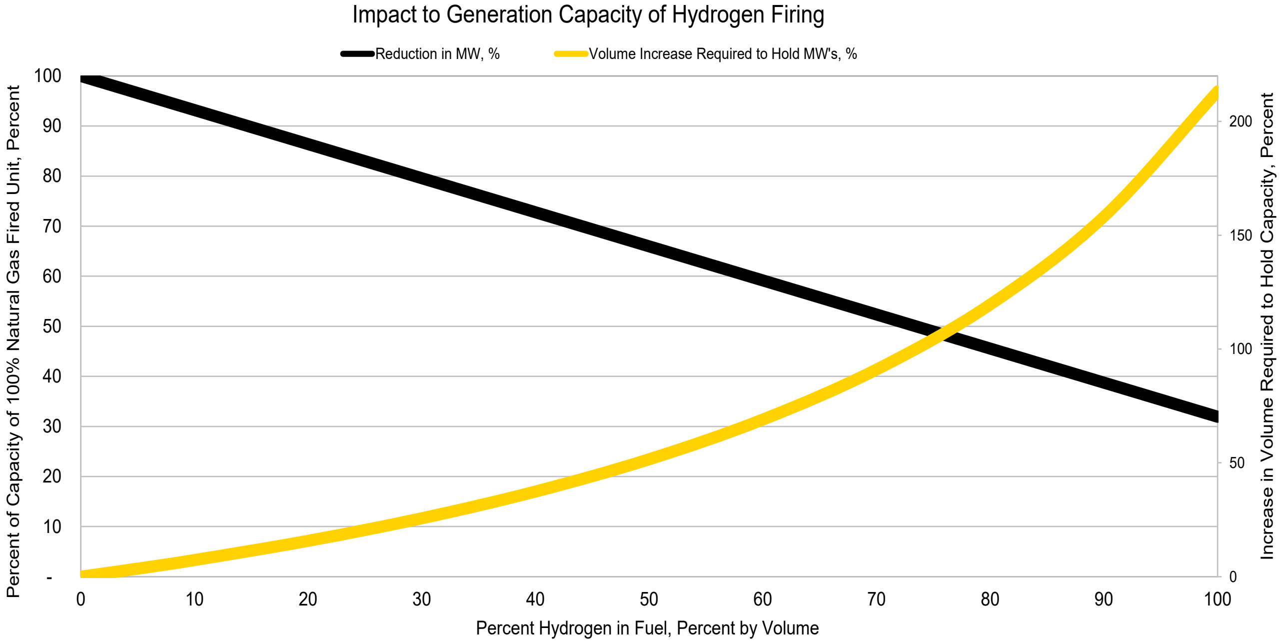
> *"For both the affected units that reduce capacity factor to 50% and those that increase hydrogen co-firing to 96% by volume, unit capacity accreditation and the amount that they contribute to resource adequacy is unchanged, as there is no capacity derate for hydrogen co firing."*

[CITE at p. 8.]

It is important to understand that capacity refers to a unit's maximum electric output, while capacity factor refers to the fraction of a unit's total available capacity utilized over a period of time. Hydrogen co-firing at 96% is likely to negatively affect a unit's capacity. That is because hydrogen has an energy density that is roughly 1/10th of natural gas. Therefore, even though the heating value of hydrogen is higher than natural gas, the increased heating value does not make up for the lower energy density. The EPA acknowledges this difference in its Technical Support Document titled "Hydrogen in Combustion Turbine Electric Generating Units" on Page 3:

> *"One of the differences between hydrogen and natural gas is the energy density by volume of the gases. To achieve significant GHG reductions from burning hydrogen in a combustion turbine, the volume of hydrogen must be high relative to the volume of natural gas."*

This difference in energy density means that for a combustion turbine to achieve the same capacity burning hydrogen as it would with natural gas, it would need to fire significantly more hydrogen. The graph below shows this impact.



The black line on the graph shows how the capacity of a unit changes as hydrogen firing is increased. For example, if hydrogen provides 70 percent of the fuel (by volume), the capacity of the unit will drop to 50% of the MW's it could produce when it was firing natural gas. When the unit is firing 96% hydrogen, it can only produce approximately 35% of the MW's that could produce when firing natural gas. So, to maintain the same MW production in a combustion turbine that is firing 96% hydrogen, a utility would have to fire almost 200% more fuel. The yellow line on the graph shows this. As such, a combustion turbine burning 96% hydrogen would have a significantly lower capacity.

To the extent that EPA is referring to capacity factor, its assertion is equally unsupported. A unit burning 96% hydrogen would have 65% less capacity than the same unit burning natural gas. For example, for a 100 MW unit firing natural gas, the same unit firing 96% hydrogen would have a capacity of 35 MW. Even if one were to assume that the unit's availability and utilization were the same (an assumption that is speculative because there is no history or data with which to assess the reliability of units burning 96% hydrogen since they do not exist), its capacity factor would be lower. That is because capacity factor is expressed as capacity in MW / utilization. And since the capacity will have decreased, so will the capacity factor.

For EPA's assertion to be true, the combustion turbine would have to burn approximately 200% more fuel to provide the same amount of power. It is unlikely that every unit can be designed or retrofitted to do so. Among other reasons, combustors would have to be converted for a much larger flow rate, which may or may not be possible. It would also require that the fuel supply system and the control system would need to be modified to handle 200% more flow, again it is unlikely to be possible on all the units where this would be needed. In addition, to our knowledge, it has not yet been attempted. The HRSG and emissions control equipment would also need to be able to handle the additional exhaust. Even if a few units could make such changes, it is unlikely that these changes will be able to be made on a consistent basis, system wide, to maintain capacity.

In short, EPA's assumption that 96% hydrogen firing will allow existing units to maintain their capacity is incorrect. Instead, the proposed rules would likely require significant additional generation to be built to make up for the loss of generating capacity because of switching to hydrogen. The EPA did not model this.

1.2 HYDROGEN IN COMBUSTION TURBINE EGUS

To support its assertion that hydrogen co-firing is ready for implementation on a large scale, EPA provides a list of new hydrogen firing projects on pages 8 and 9 of its Hydrogen in Combustion Turbine Electric Generating Units technical support document. The list fails to support EPA's conclusions.

Below is the list of projects in EPA's report, along with the total MWs and some additional comments on these projects. It should be noted that several of these projects are Kiewit projects.

Facility	Total MW[1]	Initial Hydrogen Firing	MW of Hydrogen[2]	Comments
Long Ridge Energy Center*	485	5%	24	Not green hydrogen, can only operate on hydrogen 45 minutes at a time
Intermountain Power Agency*	840	30%	250	Not yet operational
LADWP	297	30%	89	Not operational on hydrogen until 2029
Lincoln Land Energy Center	1,100	30%	~230	Not operational
Newman Power Station	178	30%	50	Not currently operational on hydrogen
Orange County Advanced Power Station*	1,215	30%	250	Design not started yet; EPA's description does not specifically indicate green hydrogen
Magnolia Power Plant*	725	50%	200	Not operational until 2025, capable of 50% H2 firing if hydrogen is available, EPA's description does not specifically indicate green hydrogen
Total	4,840		1,093	

Notes:
1. **Total MW = Total MW's that will be produced by the facility**.
2. MW of Hydrogen = Total MW's that will be produced from firing hydrogen initially (not including power from steam turbines). In all cases, 100% hydrogen firing is aspirational.
3. The (*) indicates Kiewit projects.

The only one of these units that is in operation and using hydrogen firing is the Long Ridge Energy Center. Long Ridge Energy Center's onsite storage only allows for firing up to 5% hydrogen. In addition, the facility can only fire hydrogen for 45 minutes before it runs out of storage. The other units on this list are all in the planning, design, or construction stage. None of the other units are in operation. In addition, none of these units are expected to fire anywhere close to 96% hydrogen initially. Instead, they expect to burn between 30-50% hydrogen, with an aspirational goal of having the capability of firing more.

Second, it should be noted that the timeline for most of these projects to be firing 100% hydrogen is 2045. This is significant since these units are the *early adopters*, with high aspirations for firing hydrogen. The 2045 date of these units, which the EPA presents as examples of what is possible with hydrogen firing, does not support EPA's 2038 deadline for 96% hydrogen firing.

In addition to the technical concerns discussed above, the list in the table represents an exceedingly small proportion, less than 0.1 percent, of the US combustion turbine fleet. While it may indicate that the industry is moving towards the technical ability to fire hydrogen, the EPA has not made (and cannot make) the case that the industry can meet the demands for hydrogen firing that this rule would require. Hydrogen transportation, availability, along with capability of combustion turbines all play a part in why the industry is not ready for this challenge, as will be discussed later in the report. But the timeline presented by EPA in the regulations is too aggressive.

2. HYDROGEN COMBUSTION

This section will discuss the industry status of hydrogen combustion in combustion turbines.

2.1 CAPABILITY OF COMBUSTION TURBINE OEMS

2.1.1 HYDROGEN FIRING

The capability of the turbine OEMs for hydrogen firing, as reported by the EPA, are shown in EPA's table on Page 7 of EPA's Hydrogen in Combustion Turbine Electric Generating Units technical resource document:

Manufacturer	Turbine Model/Type	Current Hydrogen Capability[1]	Future Hydrogen Capability[2]
GE Gas Power			
	Aeroderivative	85%	100%
	B/E-Class	100%	
	F-Class	100%	
	HA-Class	50%	100%
Siemens Energy			
	SGT5/6-9000HL	50%	
	SGT5/6-8000H	30%	
	SGT-700	75%	
	SGT-750	40%	
Mitsubishi Heavy Industries			
	M501GAC	30%	100%
	M501JAC	30%	100%
	M701JAC	30%	100%

[1] The actual % by volume hydrogen levels may vary based on combustion turbine model, combustion model, combustion system, and overall fuel consumption. Turbines currently co-firing greater than 30% hydrogen by volume typically utilize wet, low-emission (WLE) or diffusion flame combustors.
[2] Manufacturers are developing DLN combustor modifications for several turbine models that will allow for increased hydrogen firing while limiting emissions of NO_X. These include pre-planned small modification or retrofits kits for certain models to increase their levels of hydrogen combustion.

Figure 2: Hydrogen Capabilities in Certain Models of Combustion Turbines

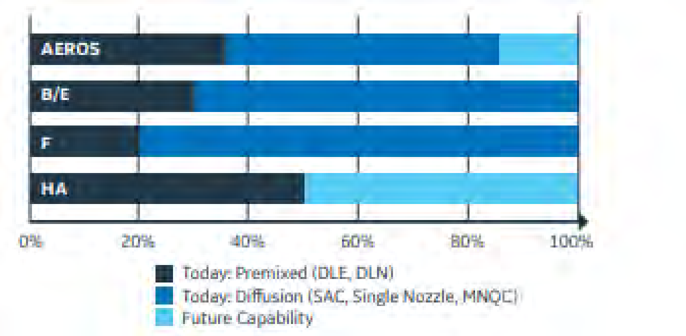
The current capability of burning hydrogen varies based on the OEM and the classification of combustion turbine. The table below is a summary of the capabilities and future target capabilities from the three (3) largest combustion turbine manufacturers from their respective websites.

Combustion Turbine Class	Current Capability	Future Capability (Target)	Expected Year for Target Hydrogen Firing
Aeroderivative	30-100% depending on OEM	100%	2025-2030
B/E Class	30-100% depending on OEM	100%	2030
F Class	20-100% depending on OEM and combustor	100%	2030

Combustion Turbine Class	Current Capability	Future Capability (Target)	Expected Year for Target Hydrogen Firing
G Class	30%	100%	2030
H Class	30-50%	100%	
J Class	30%	100%	2030

The numbers shown in EPA's table are misleading, especially for the larger frame units (F, G, H and J Class). For the GE Frame F, EPA indicates that GE can fire 100 percent hydrogen. However, GE indicates that the unit must use GE's Single Nozzle combustor (aero derivatives) or the multi-nozzle quiet combustor (frame CT's), as seen from the figure below. These combustors produce higher NOx than the dry low NOx (DLN) combustors. As of today, GE's DLN combustor can only burn between 20% and 30% hydrogen. If utilities switch away from DLN combustors to allow for more hydrogen combustion, it will increase NOx emissions from 9 ppm to 25 ppm.

Current status of GE turbines hydrogen capabilities (%vol)



Each of the three largest combustion turbine manufacturers aspire to construct 100% hydrogen fired units by 2030. However, as acknowledged by the Department of Energy National Energy Technology Laboratory's (DOE/NETL) white paper titled "A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOx Control" (https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf); there are some major obstacles to overcome before those aspirations could be realized. Gas turbine combustors are designed to work at specific operating pressures and with a fixed volume with little room for variation. To accommodate the hydrogen fuel, the turbines will either need to be larger, use higher max pressures to reduce the hydrogen volume or both. To achieve a similar performance and emissions from a hydrogen fired turbine will cost more to produce than its natural gas fired counterpart because of the higher volumes and/or pressure requirements.

Hydrogen has a higher flame temperature, faster flame speed, and creates a higher concentration of H• radicals than natural gas, which presents some additional areas of concern for the turbine manufacturers. The higher flame temperature causes increased metal temperatures, while the higher flame speed, and particularly higher concentration of H• radicals, creates the potential for higher thermal NOx emissions and changes to thermal acoustics. These factors cause vibrations that could potentially destroy the turbine combustors. The increased metal temperatures will require localized cooling or other technique to protect parts of the turbine from thermal stresses.

One of the largest concerns with making the transition to 100% hydrogen-fired combustion turbines is the increased flame speed. Hydrogen's flame speed is an order of magnitude faster than natural gas. The higher flame speed can also increase the local flame temperature (added to the higher natural flame temperature) which accentuates the issues described above. The increased flame speed also causes concerns with flame stability within the combustion turbine. If the flame speed is higher than the fluid velocity, there will be "flashback" into the fuel mixing zone, which causes damage to the injectors and other components. If the fluid velocity is increased to avoid flashback, there is the possibility of blowout, where the flame is extinguished. This creates a challenge for the combustion turbine manufacturers, to design the combustion system to maintain the flame stability, while also designing the turbines to handle the higher temperatures and/or pressures of the hydrogen fuel.

Regarding retrofits, as stated before in Section 1.2, there is no guarantee that the capacity of CT's will be maintained when switching to hydrogen from natural gas. With the higher flame speed and temperatures of hydrogen, retrofitting the existing combustion turbines will not be as simple as switching out the combustors. If the fuel velocity is increased to eliminate flashback, this will cause increased pressure drop across the combustor, which will have an impact on the reliability, maintenance schedule and life expectancy of the turbines.

Also of note is that the combustion turbines that can currently burn the higher percent of hydrogen are the aeroderivative and smaller combustion turbines. These smaller units are typically used as peaking units and are not typically base loaded turbines; therefore, they are not likely to be impacted by the EPA requirements. Most base load facility utilize the larger frame (F, G, H and J Class) in either simple or combined cycle configurations. The larger frame units are more efficient which makes them a better solution for base load operation.

Finally, as stated in Section 1.1.4, existing heavy duty frame gas turbines will require a new combustion and fuel system to burn the higher rates hydrogen because higher volumes of hydrogen will be required to maintain capacity. In addition, retrofit costs have not been fully assessed for converting to hydrogen, nor has the downtime required to make the conversion.

2.1.2 AMMONIA FIRING

For ammonia firing, the following information has been provided by the OEM's.

Combustion OEM	Class Size	Current Capability	Future Capability
Mitsubishi	Smaller Frame Sizes Larger Frame Size	None None	100% Planned by 2026 None
GE	6F, 7F	None	100% by 2030

EPA's proposal is unclear as to whether the agency intends to allow ammonia firing as a form of hydrogen firing. However, ammonia firing information is being presented here because there would be some advantages to being able to fire ammonia instead of hydrogen. Those advantages have to do with transportation and storage infrastructure. Ammonia is already a common commodity in the US because it is used for fertilizer. The regulations for storage and transport are well established and it is much more commonly transported than hydrogen. However, as can be seen by the table above, there is limited effort being made by the OEMs to develop ammonia firing capability. Therefore, ammonia is unlikely to significantly change the US's ability to implement widespread hydrogen firing.

2.2 OPERATING IMPACTS OF FIRING HYDROGEN

Within each combustion turbine class, there are different turbines each with different current capabilities for burning hydrogen. Using the current hydrogen capability of each turbine we calculated how much hydrogen (kg) each turbine can burn currently and divided that by the output of the combustion turbine to get the amount of hydrogen required per megawatt of power. Below is a table which shows the hydrogen required to generate 1 MW of power output for each of the turbine classes averaged across all the combustion turbine OEMs. The table also shows how much hydrogen would be required in each of the turbine classes to burn 100% hydrogen, again averaged across each of the OEMs. Using electrolysis to create hydrogen requires both demineralized water and auxiliary power. Electrolysis is the process of splitting water into hydrogen and oxygen using electricity. The demineralized water and auxiliary power required shown below is based on using Proton Exchange Membrane (PEM) electrolysis for generating hydrogen and is representative of various electrolyzer OEMs.

Turbine Class	Output Range	Hydrogen Req'd Current Capability	Hydrogen Req'd Future Capability	Demin Water Req'd Current Capability	Demin Water Req'd Future Capability	Aux Power Req'd Current Capability	Aux Power Req'd Future Capability
Units	(MW)	(kg/MW)	(kg/MW)	(gal/MW)	(gal/MW)	(MW/MW)	(MW/MW)
Aeroderivative	5-65	14	25	0.66	1.18	0.764	1.364
B/E Class	75-120	15	25	0.71	1.18	0.819	1.364
F Class	170-250	7	23	0.33	1.09	0.382	1.255
G Class	225-285	7	22	0.33	1.04	0.382	1.201
H Class	275-390	9	21	0.43	0.99	0.491	1.146
J Class	330-430	6	20	0.28	0.95	0.327	1.091

As shown from the table above, the amount of hydrogen required per MW is larger for the smaller combustion turbines. These turbines are less efficient and require more fuel per MW than the larger turbines. The table also shows that for all combustion turbine classes, **the auxiliary power required to create hydrogen using PEM electrolysis is greater than the power generated by burning 100 percent hydrogen in a combustion turbine.** Such basic energy balance shows that firing hydrogen in combustion turbines is a net energy loser rather than a net energy producer. It is neither possible nor practical to require more auxiliary power than the power generated by the combustion turbine, this would create a significant reduction in energy capacity in the grid, thus resulting in a significant increase in overall construction, which defeats the overall goal of reducing greenhouse gases.

2.3 ONSITE STORAGE REQUIREMENTS

The hydrogen required for each turbine classification in the table above were used to calculate the hydrogen storage required and is shown below for both 1- and 5-days storage. The storage criteria is consistent with the current storage philosophy used at power generating facilities. The table below shows how much hydrogen would need to be stored to meet the current hydrogen capability as well as the future target capability of 100% hydrogen. The values shown below are based on a single MW output for each of the turbine classification ranges. The storage pressure of hydrogen is assumed to be 2,500 psi. When calculating how much hydrogen needs to be stored the assumption is that no onsite compressors will be used to send hydrogen from the storage to the combustion turbines which means there will always be a certain amount of hydrogen in the storage. Using the turbine gas supply pressure requirement and accounting for pressure losses between the onsite storage and the combustion turbines shows that you need to store ~32% more hydrogen than the turbine requires. The values below show how much hydrogen needs to be stored to generate the power output shown.

Turbine Class	Output (MW)	Current Hydrogen Capability Stored (1 Day) (kg)	Future Hydrogen Capability Stored (1 Day) (kg)	Current Hydrogen Capability Stored (5 Day) (kg)	Future Hydrogen Capability Stored (5 Day) (kg)
Aeroderivative	65	28,829	51,480	144,144	257,400
B/E Class	120	57,024	95,040	285,120	475,200
F Class	250	55,440	182,160	277,200	910,800
G Class	285	63,202	198,634	316,008	993,168
H Class	390	111,197	259,459	555,984	1,297,296
J Class	430	81,734	272,448	408,672	1,362,240

Based on the storage requirements in the above table, onsite, above ground storage would be as shown in the table below. There are options for underground storage of hydrogen, but those are currently limited to salt caverns which are not widely available throughout the US. Accordingly, aboveground storage was assumed for this evaluation because that would be available at more power generation facilities than underground salt caverns.

Turbine Class	Output (MW)	Number of Tanks (1 Day) Current/Future	Number of Tank (5 Days) Current/Future	Truck Deliveries to Fill the Tank (1 Day of Storage) Current/Future	Truck Deliveries to Fill the Tank (5 Day of Storage) Current/Future
Aeroderivative	65	16 / 28	77 / 138	46 / 83	233 / 416
B/E Class	120	31 / 52	153 / 255	92 / 153	460 / 767
F Class	250	30 / 98	149 / 489	89 / 294	448 / 1,470
G Class	285	34 / 107	170 / 533	102 / 320	510 / 1,602
H Class	390	60 / 140	298 / 696	179 / 418	897 / 2,093
J Class	430	44 / 147	219 / 731	132 / 439	660 / 2,198

Note:
Truck delivery assumes all truck deliver in a 12-hour period. Each truck delivery contains 310 kg. Each tank holds 1,863 kg.

Most facilities store backup fuel supplies (1 to 5 days) on site to guard against infrastructure and transportation disruptions. Accordingly, it is reasonable to assume that they would similarly do so with hydrogen, especially because of the high degree of uncertainty and unknowns surrounding the current and future hydrogen infrastructure. Even with only 1 day of hydrogen storage onsite, a generating facility would be significantly hampered in its ability to continue generating power during supply disruptions.

Each tank would require approximately 1,500 ft^2 of land. For 1 day of storage for an H-Class turbine requiring 140 aboveground tanks that would require approximately four acres of storage tanks. If 5 days of storage was used for the H-Class turbine that would be approximately 17 acres for the storage tanks. The required storage area will be a concern for many existing facilities. There will also be safety and fire protection implications for storing this amount of hydrogen aboveground, including zoning restrictions.

The tables above show that truck delivery and storage of even a small amount of hydrogen onsite is not practical. For an F-Class turbine, the facility would need to receive 294 trucks in a 12-hour period to maintain the 1-day storage. To do that, each truck would need to unload in less than 2.5 minutes; For H-Class turbines that would have to be done in 2 minutes. It is not possible to have trucks pull into site and unload in less than 3 minutes.

A more realistic duration for truck deliveries would be 30-60 minutes for each truck. With the trucks being unloaded 12 hours per day, it would take between 12 and 24 days to unload the number of trucks for a single F-Class turbine to provide 1 day of hydrogen storage. It would take between 17 and 35 days of truck deliveries for a single H-Class turbine and 1 day of storage. Many existing power generation facilities have multiple combustion turbines on their site, which would cause even longer durations and larger tanks requirements on the site.

Even if a facility could be designed to include the number of tanks required in the tables above, additional infrastructure would be required to upgrade the roads to the plant to be able to handle hydrogen tanker trucks arriving to and leaving from the plant every 2 minutes. These roads would have to be designed all over the country for the same situation, as hydrogen would be delivered to many facilities throughout the U.S. In addition, the delivery travel from the hydrogen production facilities to these power plants would place a lot of wear and tear on road.

2.4 IMPACT ON NO_X EMISSIONS

One of the potential environmental impacts of firing hydrogen is the potential increase in NOx emissions. As stated on Page 4 and 5 of the EPA's Technical Support Document titled "Hydrogen in Combustion Turbine Electric Generating Units":

> *"The technical challenges of co-firing hydrogen in a combustion turbine EGU result from the physical characteristics of the gas. Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane; at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas.12 A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NOx emissions. It is necessary in combustion for the working fluid flow rate to move faster than the rate of combustion. When the combustion speed is faster than the working fluid, a phenomenon known as "flashback" occurs, which can damage injectors or other components and lead to upstream complications.*
>
> *Other differences include a hotter hydrogen flame (4,089 °F) compared to a natural gas flame (3,565 °F) and a wider flammability range for hydrogen than natural gas.16 It is also important that hydrogen and natural gas are adequately mixed to avoid temperature hotspots, which can also lead to formation of greater volumes of NOx.*
>
> *Combustor modifications or retrofits have the potential to limit NOx emissions. For example, a larger selective catalytic reduction (SCR) unit inside the heat recovery steam generator (HRSG) is an option for combined cycle turbines. For combined cycle plants planning to co-fire higher volumes of hydrogen over time, it is important to estimate the increased NOx emissions when sizing the SCR unit."*

The EPA has therefore acknowledged that NOx will go up in many cases for combustion turbines firing hydrogen. While the combustion turbine OEMs have not yet expressed significant concerns with increased NOx emissions at the 30% hydrogen firing case, there is no testing data available to show that NOx emissions will not be a problem. Especially in the case of retrofitting existing combustion turbines, where the OEMs will have less flexibility to make changes, the potential for increasing NOx emissions is higher, even at 30% hydrogen firing.

In addition, while the OEMs are working to produce dry low NOx (DLN) hydrogen combustors that can maintain lower NOx emissions in the future, it is uncertain whether they will be successful at maintaining the levels that are currently achievable. As with the 30% hydrogen firing case, the OEMs' ability to keep NOx low is most limited for the combustion turbines that are retrofitted to fire hydrogen.

Finally, as discussed in detail above in Section 1.1.5, when a unit fires 96% hydrogen, it will need to fire almost 200% more fuel to maintain the same capacity. A combustion turbine firing more fuel will also produce more NOx emissions because of the increase in the fuel being fired. So, hydrogen firing is potentially a double hit on NOx emissions: 1) because it results in a higher concentration of NOx emissions and 2) because the mass of emissions is higher due to more fuel being used.

3. HYDROGEN STORAGE AND TRANSPORT

3.1 HYDROGEN HUBS

It is believed that approximately 20 hydrogen hubs in the US submitted final applications by April 7, 2023 deadline to the US Department of Energy (DOE) for "regional clean hydrogen hubs" funding up to $1.25 billion (out of total of $7 billion) available for an expected 6-10 clean hydrogen hubs that will be awarded by 2030. Concept papers for the Hubs were due on November 7, 2022, and full applications were due on April 7, 2023

The ultimate winners of the DOE hydrogen hub funding selection process may not be known for some time. According to the DOE's funding opportunity announcement, the application period that concluded on April 7 leads into the first phase of the selection process, in which the DOE will dole out up to $20 million to hubs with a 50% minimum cost matching requirement following the merit review process. That phase will span 12 to 18 months during 2023-2024.

Then, awardees move into a "negotiated go/no-go" process in 2024 before moving into phase two, where they can receive up to 15% of each hub's total requested amount. This phase can take up to 2-3 three years by 2026-2027.

Once in phase three by 2027, the DOE will begin releasing the remaining 85% of federal funding on an undefined schedule while closely monitoring each hub's implementation process -- a stage that could take 2-4 years by 2029-2031. In the final fourth stage, hubs will transition to their operational stage after 2031.

It should be noted that the other side of this equation is the "Regional Clean Hydrogen Hubs Demand-side Support Notice of Intent." Responses were due by July 24, 2023. This is where parties interested in receiving hydrogen from the hubs are requested to provide notice to the DOE. This timeline is vastly out of step with the timeline for the GHG rule that the EPA has established. As defined in Section 2.3, combustion turbine units that are firing 30% or 96% hydrogen are not going to be able to have a lot of onsite storage of hydrogen because hydrogen has such a low density that makes onsite storage impractical. As a result, utilities will need to depend on hydrogen transport through pipelines for hydrogen supply. Therefore, the infrastructure created by these future hydrogen hubs will represent most of the US supply storage for hydrogen for the foreseeable future. Unfortunately, because of the 2035 and 2038 timelines in the EPA's rule, utilities will have already missed their deadline to notify the DOE of their interest in reserving supply in the hydrogen hubs. As a result, there is no guarantee that the hubs will be sized to meet the hydrogen needs of combustion turbines built or retrofitted to meet the EPA rule. Currently, there is no hydrogen fuel storage constructed to supply the needs for the combustion turbine fleet and no pipelines available for transportation.

3.2 HYDROGEN PIPELINES

As stated previously, to supply hydrogen to combustion turbine units firing hydrogen, most of the hydrogen will need to come from hydrogen hubs because onsite storage is impractical. However, there are many concerns with conveying hydrogen in pipelines. As EPA has acknowledged:

> *"Hydrogen blends of up to 5 percent in the natural gas stream are generally safe. However, blending more hydrogen in gas pipelines overall results in a greater chance of pipeline leaks and the embrittlement of steel pipelines.*
>
> *Hydrogen blends of more than 20 percent present a higher likelihood of permeating plastic pipes, which can increase the risk of gas ignition outside the pipeline.*
>
> *Analysts assert that 20 percent hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required. Other recent analyses of existing pipeline materials indicate that 12 percent may be the maximum blend. In addition, the existing end-use equipment in power plants and industrial facilities may not tolerate higher hydrogen concentrations without modification. If implemented with relatively low concentrations, less than 5 to 15 percent hydrogen by volume, this*

strategy of storing and delivering low-GHG hydrogen to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in most end-use devices, overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis."

Indeed, these concerns are well documented in other sources, such as:

- "Once hydrogen enters pipelines, it can weaken metal pipes which can lead to cracking. Hydrogen is also far more explosive than natural gas which could create safety issues." – *"Focus: Has green hydrogen sprung a leak?,"* By Sarah Mcfarlane and Ron Bousso, December 22, 2022
- "It is well known that the presence of hydrogen increases fatigue crack growth rates in commonly used pipeline steels, and studies have shown that metals with higher tensile strength tend to experience greater reductions in fracture resistance than metals with lower tensile strength when in contact with hydrogen. Recent research has shown that fatigue crack growth and fracture resistance can degrade even with low partial pressures of hydrogen, with subsequent degradation being more modest as the partial pressure is increased. In high-stress situations, fatigue crack growth is fairly independent of hydrogen concentration." – *"Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology,"* National Renewable Energy Laboratory, University of Colorado Boulder, Sandia National Laboratories, Pacific Northwest National Laboratory, October 2022

The potential for pipeline leaks is of significant concern because these pipelines will need to be routed in areas where the public lives and works, resulting in potential hazards associated with gas ignition in populated areas.

The potential for embrittlement of pipeline material is a well-known phenomenon with hydrogen. This increases the potential for leaks. In addition, embrittlement increases the maintenance potential and inspection requirements on the pipeline. Given the quantity of pipelines that will be required to supply hydrogen to hydrogen-fired combustion turbines throughout the country, the inspection and maintenance requirements will become challenging, especially in populated areas.

Finally, these quotes establish that transporting 96% to 100% hydrogen is especially challenging. Yet, to meet the proposed requirements, the hydrogen transport piping will need to be able to transport this high concentration of hydrogen to supply 96% fired combustion turbines. The EPA's discussion of pipelines does not address the significant challenges of this transport piping at all.

In addition to the above discussions about the technical challenges with hydrogen transport piping, the EPA acknowledges the cost challenges associated with hydrogen transport piping:

"The capital costs of new pipeline construction constitute a barrier to expanding hydrogen pipeline delivery infrastructure."

As such, the hydrogen supply will be hindered by the cost of transporting the hydrogen. It is simply not practical to resolve such costly technical, engineering, let alone complete construction of an entirely new nationwide pipeline system in the timeframe and cost estimates assumed by EPA. In addition, unlike hydrogen used for transport vehicles or for shipment overseas, combustion turbines firing hydrogen need to be located in a distributed manner to meet power delivery requirements. As a result, expansive hydrogen pipeline infrastructure will be essential to the feasibility of hydrogen firing for power productions.

3.3 QUANTITY REQUIREMENTS

On Page 25 of the Technology Support Document ""Hydrogen in Combustion Turbine Electric Generating Units", the EPA indicates that "approximately 1,600 miles of dedicated hydrogen pipelines are deployed in regions of the U.S." According to the Congressional Research Service Report, "Pipeline Transportation of Hydrogen: Regulation, Research, and Policy," published March 2, 2021, 90% of that pipeline is located along the Gulf Coal in Texas, Louisiana, and Alabama. "By comparison, there are over 300,000 miles of U.S. natural gas transmission pipeline (not counting distribution mains) located in the 48 contiguous states and Alaska." From a comparison perspective, this means there are almost 200 times more miles of natural gas pipelines in the country than hydrogen pipeline. This comparison is important because it demonstrates the infrastructure needed for natural gas to be a critical part of the US's energy supply and gives an indication of the magnitude of need for hydrogen supply pipelines. To meet EPA's goals a pipeline network close to the size of the existing (and expanding) natural gas pipeline network would need to be constructed on a timeline never before seen.

This is not speculation. According to EIA, through 2021 there were over 800 combustion turbines, in 47 states, in the US being used for power production. This demonstrates that the use of combustion turbines for power is widely distributed throughout the US. In addition, as stated previously, hydrogen supply cannot be provided by onsite storage since that is unpractical. Therefore, hydrogen supply to support hydrogen firing will need to be provided through hydrogen pipelines.

The hydrogen pipeline must reach more areas than just the current 1,600 miles along the Gulf coast and must have a reach that is much more like the 300,000 miles of natural gas pipelines that the country currently has to support combustion turbines spread through the country. In fact, while Kiewit has not calculated the exact need, the need is several orders of magnitude greater than the current pipelines available. Much of this pipeline will need to be routed in highly populated areas. Given the safety concerns discussed in Section 3.2, the issue of supply pipelines is a significant barrier to the practicality of the hydrogen requirements of the proposed rule.

4. HYDROGEN PRODUCTION

4.1 ELECTROLYZER OEMS

Electrolyzer manufacturers offering their products in the US consist of industrial conglomerates with an electrolyzer division such as Siemens, mature "pure play" manufacturers such as Plug Power and new start-ups with a successful lab experiment. Offerings vary from stack-only to complete plug and play packages.

We have identified twelve (12) manufacturers currently active in the US market. While this list is not exhaustive, it includes the majority of the players in the U.S. market. The different electrolyzer technologies are described below:

AEM – Anion Exchange Membrane

AWE – Alkaline Water Electrolysis

E-TAC – Electrochemical, Thermally Activated Chemical

PEM – Proton Exchange Membrane

SOEC – Solid Oxide Electrolyzer

In the table below, "capacity" indicates the amount of power required by the electrolyzer to produce hydrogen. This is the typical convention used when defining the size of electrolyzer capacity. The manufacturers in the table below have a combined 2023 capacity of approximately 12 GW of hydrogen production. Since every GW of electrolyzer capacity can produce an estimate 400 tons per day of hydrogen, this represents 4,800 tons per day of hydrogen production for 2023. **If all the electrolyzers forecasted for 2023 were built to produce hydrogen for combustion turbines, the forecasted hydrogen production for 2023 would provide enough hydrogen to fuel approximately 87 F-Class or 43 H-Class combustion turbines burning 100% hydrogen for just 1 day.**

COMPANY	TECHNOLOGY	YEAR OF EXPERIENCE(1)	BNEF 2023 FORECAST MFG CAPACITY (MW)	MARKET CAP(2) (MILLIONS)	2022 REVENUE (MILLIONS)	2022 NET INCOME (MILLIONS)
Bloom	SOEC	22	2000	$4,150	$1,199	($301)
Accelera (Cummins)	PEM, AWE	70+(3)	1600	$34,190	$28,074	$2,151
Enapter(4)	AEM	6	280	$344	$13,924	($10,291)
H2Pro	E-TAC	4	No Forecast	Private(5)	Unknown	Unknown
H-TEC(6)	PEM	26	0	$16,597	$138,009	$6,000
Hydrogen Optimized(7)	AWE	6(8)	No Forecast	Private	Unknown	Unknown
NEL	PEM, AWE	96	500	$2,330	$96	($122)
Ohmium	PEM	4	2000	Private(9)	Unknown	Unknown

COMPANY	TECHNOLOGY	YEAR OF EXPERIENCE[1]	BNEF 2023 FORECAST MFG CAPACITY (MW)	MARKET CAP[2] (MILLIONS)	2022 REVENUE (MILLIONS)	2022 NET INCOME (MILLIONS)
Plug	PEM	26	3000	$7,330	$701	($274)
Siemens	PEM	TBD	1300	$125,030	$78,028	$4,036
Sunfire[10]	AWE, SOEC	13	500	Private	Unknown	Unknown
ThyssenKrupp	AWE	100[11]	1500	$4,600	$43,336	`

1. Measured from date of incorporation.
2. As of 10 March 2023, PER S&P Global Intelligence
3. Includes Stuart Energy experience.
4. 2021 results
5. Has publicly announced 4 rounds of funding, most recent in January 2022, totaling ~$97m.
6. Owned by MAN Energy Solutions SE, a wholly owned subsidiary of Porsche Automobil Holding SE. Revenue and income 2022 forecasts for ultimate parent, Porsche.
7. Hydrogen Optimized technology is basically AWE, however they have a unique electrode arrangement that has not been deployed on a large scale.
8. The founders of Hydrogen Optimized, the Stuart family, has electrolysis experience of more than 100 years.
9. Series B funding round completed April 2022. Raised $45m, estimated valuation of $135m.
10. Has publicly announced 6 rounds of funding, most recent in July 2022, totaling ~$262m, with last available valuation of $1.7B. Revenue and net income from 2020.
11. Includes experience of De Nora

It should be noted that the above listed forecasted capacities are the nameplate capacities of the electrolyzer. If renewable energy is utilized as the power source for the electrolyzer, the actual output will be lower. The capacity factor, or amount of time energy is produced, for renewables is approximately 30%. So, the actual production of hydrogen could be 30% of the above listed values. Using the forecast data presented in Section 1.1.4, the hydrogen required is as follows:

Total Potential Hydrogen Needs for New Units

Forecast	Total New MWs 2028 to 2050	Hydrogen Needs, tons per day
EPA_H2_CCGT	21,131	14,000
EIA_New_CCCT	39,432	26,233

This does not include any other uses for electrolyzers, including international uses and other US uses. It also does not include any existing combustion turbine facilities that will require hydrogen retrofits. This indicates that a significant increase in electrolysis project manufacturing and execution would be required to meet the hydrogen needs required by the EPA. Bottom line, the electrolyzer industry is simply not suitable to meet the demand that would be put on the industry if EPA's rule is passed.

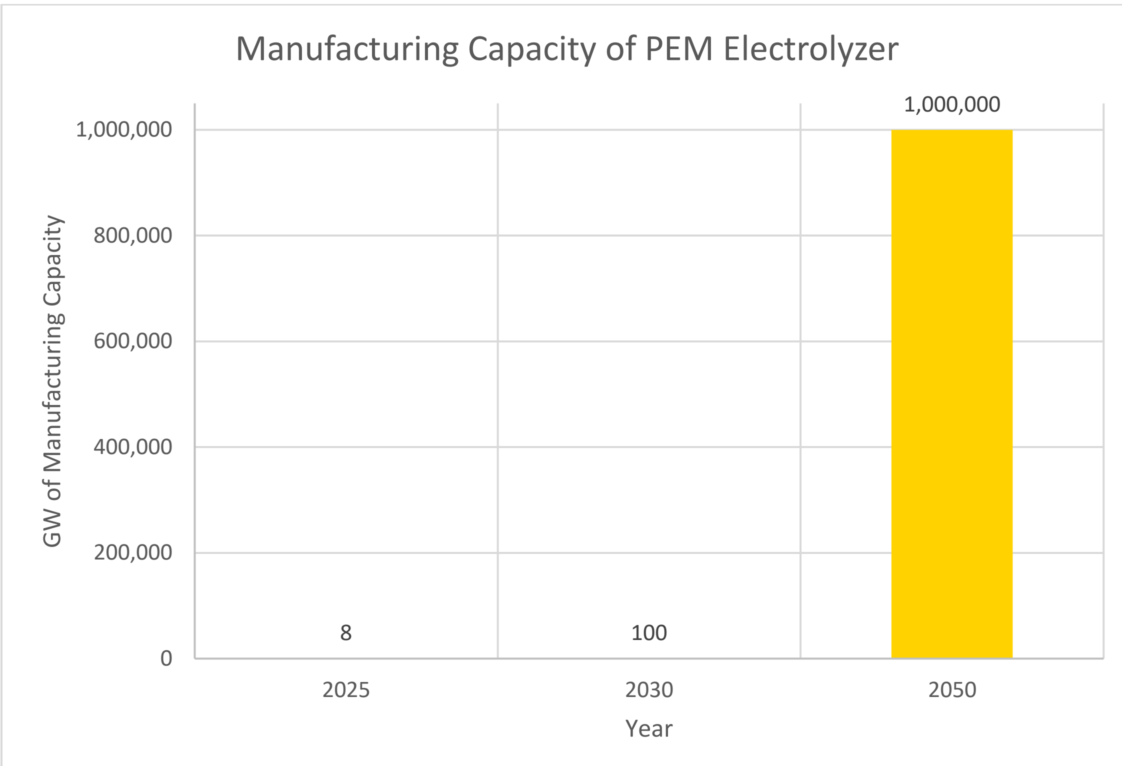
4.2 ELECTROLYZER PRECIOUS METALS

In addition to the electrolyzer production not being able to support the demand from EPA's rule, the precious metals, especially iridium and platinum, needed to produce electrolyzers are a critical barrier to production.

PEM electrolysis is the most popular technology, and it uses iridium and platinum. According to an article published by the International Renewable Energy Agency (IRENA) https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_Hydrogen_breakthrough_2021.pdf?la=en&hash

=40FA5B8AD7AB1666EECBDE30EF458C45EE5A0AA6, scarce materials can represent a barrier to electrolyzer cost and scale-up.

The current production of iridium and platinum for PEM electrolyzer will only support an estimated 7.5 GW of annual manufacturing capacity. However, IRENA estimates that demand will require an annual manufacturing requirement of 100 GW by 2030. IRENA also projects that 1 TW of installed capacity would be required in 2050. The graph below demonstrates these numbers if visual form and shows the impractical requirements for iridium and platinum if IRENA's forecasts are correct. However, even if IRENA's forecasts are close, it demonstrates a significant problem in the commodities market with meeting the needs of the electrolyzer market for green hydrogen.



The bottom line for electrolyzers is that the demand for them in the next two decades is exponential. However, the precious metals availability means meeting these goals are highly unlikely. Given these facts, EPA's assumption that hydrogen can be produced by electrolysis, in the quantities that will be required to by the rule, is flawed.

NRECA Attachment 4 - D. Campbell, Analysis of Hydrogen in Combustion Turbine Electric Generating Units (August 3, 2023)

Analysis of Hydrogen in Combustion Turbine Electric Generating Units

Regarding: EPA's Proposal entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule"
(Docket EPA-HQ-OAR-2023-0072)

Prepared for the National Rural Electric Cooperative Association By:
Mr. Doug Campbell, FTB Energy Solutions, Inc.

August 3, 2023

Introduction

This paper provides technical commentary on the Environmental Protection Agency's (EPA's) proposed rule "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule." The proposed rule would require some fossil fuel-fired stationary combustion turbine electric generating units (EGUs) to use emission control measures that are based on highly efficient generating practices, hydrogen co-firing, and carbon capture and storage (CCS). [1]

Executive Summary

This document focuses on various aspects of hydrogen co-firing, including known demonstrations to date, status of hydrogen production and transportation, and numerous identified technology challenges. The EPA's stated objective is "each of the [New Source Performance Standards (NSPS)] and emission guidelines proposed here would ensure that EGUs reduce their [greenhouse gas (GHG)] emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable [Clean Air Act (CAA)] requirements and caselaw."

This paper only looks at the evaluation of the status of the technology as presented in "Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document." [2] This paper does not evaluate the proposal's consideration of CCS for gas-fired units.

The following key findings were determined:

1) Approximately 176 MW of clean energy is required to produce enough green hydrogen to generate 46.6 MW of electricity, firing in a gas turbine at 100% hydrogen. This is extremely inefficient and would result in the addition of a significant amount of electrical generation required to create the hydrogen fuel.
2) The only available transport currently being used to get hydrogen to test sites is tube trailer trucks. To run one LM6000 at full load (approximately 45 MW) for 24 hours would require more than 200 trailer truckloads to be delivered and unloaded in that period. The amount of GHG emissions from the transportation of the fuel would be significant and would undercut any perceived benefit derived. (The LM6000 is one of the more common gas turbines in the generation fleet and has a full load rating at sea level standard conditions of 46.6 MW.)
3) Although hydrogen can be transported in specially built pipelines, there is not currently a sufficient piping network available, nor will there be in the foreseeable future.
4) A hydrogen production price of $0.5/kg or $1/kg, as referenced by EPA, is based solely on the Department of Energy's goals. [3] This is significantly lower than the current estimated cost of $5/kg of hydrogen produced by electrolysis and significantly lower than even the International Energy Agency's most optimistic projections of future hydrogen costs.

Background

For the purposes of the EPA's proposal, "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," [1] affected gas units are categorized in Table 2 (Proposed Sales Thresholds for Subcategories of Combustion Turbine EGUs) of page 33322 of the proposed rules as either new gas combustion units or existing gas combustion units. New gas combustion units (i.e., those that commenced construction on or after May 23, 2023) would need to meet certain emissions limitations, clean hydrogen co-firing requirements, and/or CCS requirements. The compliance requirements for new gas units depends upon their capacity factor categorization as either baseload units (generally above 40% for simple cycle units or above 55% for natural gas combined cycle (NGCC)), intermediate load units (between 20% and 40% for simple cycle or 55% for NGCC), or low load units (less than or equal to 20%). For existing gas combustion units, large units with a nameplate capacity of greater than 300 MW and a capacity factor of greater than 50% would be required to meet either clean hydrogen co-firing requirements or CCS requirements.

The EPA has modelled its assumptions using the Integrated Planning Model (IPM) v6.21 model, [4] using assumptions of cost data, such as the National Energy Technology Laboratory (NETL), the International Energy Administration (IEA) Energy Outlook, and other industry reports. The classifications for this model are as defined in Table 2 on page 4 of the "Integrated Proposal Modeling and Updated Baseline Analysis." [5] It appears that the EPA has grouped multiple years in each run, with a total of four runs. Although selective output is presented in the reports, there does not appear to be sensitivity runs on the variables that would be considered most important, other than gas supply curves. Other variables might be just as important for modeling, such as demand, dry or wet hydropower years, or oil prices. This generally would be determined by a presentation of the statistical relevance of each factor. The EPA does say run time was a consideration in making these choices, but provides no insight as to the boundaries. Furthermore, there appears to be no consistency in batching the years run. All this is important because big swings in major variables can change dispatch significantly. By running sensitivities, risk exposure can be defined.

Analysis and Considerations

The information reviewed in this section is found in the EPA's document "Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document," Docket ID No. EPA- HQ- OAR-2023-0072. [2] The EPA uses NETL cost data that is developed through a well-defined procedure described in NETL document "Quality Guidelines for Energy Systems Studies," [6] using Class 4 or Class 5 estimates. It is noted that these guidelines are consistent and widely accepted in cost comparisons of one technology to another, but they do not provide a comprehensive assessment of total project costs. As the owner is exposed to full project cost, for such a comprehensive assessment, a full project cost approach should be used, as referenced in the U.S. Energy Information Administration's (EIA) "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies" report. [7] That approach better demonstrates the cost for specific projects. Further details on the analysis supporting this recommendation can be found in the accompanying comment paper, “Analysis of the National Energy Technology Laboratory Cost Estimation Guidelines and Comparison with Alternate Estimate from the Energy Information Administration, Sargent & Lundy,” (Doug Campbell, August 3, 2023).

Hydrogen Production

The EPA document states that “most of the dedicated hydrogen currently produced in the U.S. (more than 95 percent) originates from natural gas using a process known as steam methane reforming.” The paper then goes on to discuss various other processes for hydrogen production that are at different stages in development. The target date for new and existing natural gas units of 30% co-firing with low-GHG hydrogen is 2032.

By the definition of low-GHG hydrogen, this energy would have to come from renewable energy resources, such as wind or solar. In reviewing estimated timelines for permitting, licensing, and construction of new zero-emitting nuclear generating facilities, such as small modular reactors, it is unlikely that this would be a viable option for hydrogen production in the timeframe required. When considering small modular reactors, it is noted that the process of mining and refining uranium ore requires large amounts of energy that generally come from CO_2 emitting resources.

The only technology that appears to be viable at scale in the time frame that would meet EPA’s low-GHG requirements is hydrogen produced by electrolysis. Electrolysis is a process that uses the power of electricity to split elements into compounds. In this process, electric current is passed between a cathode and an anode in water to release hydrogen and oxygen. Electrolysis is forecast to require between 48-53 kWh of electricity to produce one kilogram of hydrogen. [8] The energy required to produce enough hydrogen to fire one single LM6000 simple cycle gas turbine (46.6 MW gross) is calculated to be 176.5 MW or 3.8 times the output power. This calculation assumes a rating of 46.6 MW gross for the LM6000. Gross power is the total power generated by the unit including the power required to supply auxiliary equipment. Net power to the system is gross power minus auxiliary power.

Important to the EPA analysis is the cost of hydrogen. The second phase of the proposed regulation starts in 2032, and the EPA states in the notes of page 4 of the reference document [5] “delivered hydrogen price is assumed to be $0.5/kg in years in which the second phase or third phase of the NSPS is active, and $1/kg in all other years.” Cost studies that I have reviewed show that the most optimistic price being used today is about $5/kg using electrolysis. The IEA Global Hydrogen Review 2022 [9] page 6 shows the cost range of clean hydrogen, even under an optimistic scenario, would still fall between $1.3/kg and $4.5/kg by 2030. This optimistic scenario assumes electrolyser projects currently under development are completed, manufacturing capacities are rapidly scaled up, and the costs of renewable energy continues to drop.

The lower end of that range would only be possible for regions with sufficient access to renewable energy to be competitive. A median price of $2.9/kg, based on that IEA projection, could reflect a 40% reduction in the cost of low-GHG hydrogen, but would still be six times greater than the EPA’s modelled price. This is a major concern.

The EPA also notes on page 20 of the reference document that "for each kg of hydrogen produced through electrolysis, 9 kg of by-product oxygen are also produced and 9 kg of purified water are consumed." [2]. To create enough fuel to run a single LM6000 for 24 hours at 46.6 MW gross on 100% hydrogen, one would use 173,142 U.S. gallons of water per day just to make hydrogen. Any additional water requirements to run the unit would be added to this. In many regions of North America, water resources are at a premium now and would not be able to support these levels of low-GHG hydrogen production, so this provides another challenge to the hydrogen supply.

Use of Hydrogen in Combustion Turbines

It is recognized that combustion turbines have been burning by-product fuels containing hydrogen for decades. It is noted in the EPA documents that these applications are generally in the oil and gas sectors, as well as some developments with syngas firing for Integrated Gas Combined Cycle (IGCC) units. The discussion that is presented in the Technical Support Document references a long list of original equipment manufacturers' (OEMs') marketing material related to hydrogen co-firing from major manufactures such as GE, Siemens, and Mitsubishi. After reviewing several of these documents, my determination is that they are presented as either design goals for potential modification for existing units or development goals for futures offerings. Therefore, sales information that market blends beyond 20% have not been demonstrated in field tests with publicly available data. Until these units are proven commercial, they are not available to meet the EPA standards. The EPA is instead assuming that all the proposed test work will result in commercially-proven offerings.

The document also provides a list of proposed projects with specified hydrogen blends of 30% by volume and have projected completion dates between 2025 and 2029. Other projects are also described as "hydrogen ready," but there is no detailed information on what that means. As far as can be determined from literature searches, these projects are still in either the pre-Front-End Engineering Design (FEED) or FEED process of design and characterization and have not yet been determined to be economical or feasible. In some cases, permits have been obtained, but no firm operational dates are available. Based on publicly available information, these are only on paper or could be test runs in OEM research facilities. An example project that the EPA uses is the Los Angeles Department of Water and Power (LADWP) Scattergood Generating Station project. [1] An article in Hydrogen Insight [10] states that the actual status of this project is that the LADWP is to conduct a new or updated assessment and report the results to council in six months. Projects such as this, or technology tests, do not present an available option for meeting the EPA guidelines in the timelines specified.

An effort to determine the status of hydrogen firing was undertaken through searching publicly available information. Only two tests that were performed in North America were verified. The test with the most publicly available information was the New York Power Authority (NYPA) test on a GE LM6000 turbine in 2022. In their report, NYPA claimed to have burned from 5% to 44% blend by volume at its Brentwood facility. A search showed no publicly available data can be found to verify the duration of the test runs and the related performance. The Electric Power

Research Institute (EPRI) has a summary review of the test on its portal. [11] Information found suggests that the hydrogen was supplied via tube trailers, and due to the limited storage capacity of the trailers on the site, run times were relatively short. The mixing skid and associated piping had to be custom designed for this demonstration. (A mixing skid blends the hydrogen with the natural gas for the prescribed volumetric ratio.)

The second test was carried out at Georgia Power's Plant McDonough on a Mitsubishi M501 G gas turbine at 20% blend by volume. [12] Again, a specially designed fuel mixing skid was employed, and the test was limited by the amount of hydrogen that was available. A search showed no additional publicly available data on this test. In the literature, there is mention of test firing of lower blends in the 5% by volume range, but data are not available. The conclusion is that these very limited and short-duration hydrogen co-firing demonstrations do not provide justification to qualify as being adequately demonstrated today, and much work would be required to meet a 2032 goal on a commercial basis.

Transportation and Storage

As noted above, the gas unit that has the most publicly available information on hydrogen co-firing was the NYPA test fire of the LM6000 at Brentwood. With this information and known performance data of an LM6000, specifically heat rate, a calculation was done to determine what would be required to transport and store enough hydrogen for operation of a single simple cycle combustion turbine. In doing this calculation, a heat rate of 8,600 Btu/kWh LHV was used. This would be a rated performance for a new LM6000. A typical running unit could see a degradation of performance overtime of up to 10%. If that was the case, more hydrogen would be burned for the same output. It was assumed to be fired at the design rated full load of 46.6 MW at standard conditions. The EPA implies in its work that trucking is a cost-effective option up to 200 miles. One hydrogen tube trailer can contain 380 kg of hydrogen compressed to 2,600 pounds per square inch gauge (psig). [13] Using calculations from the LM6000 mentioned above, nine tube trailers would be required for each hour of full load operation, or more than 200 trucks a day for a single 46.6 MW machine. The logistics of moving this many trucks would be unmanageable. The other option is to store on site the equivalent amount of hydrogen. Although not sized here, this would be a significant sized high-pressured tank.

While the EPA's support document states that there are about 1,600 miles of dedicated hydrogen pipeline services that exist, it is very user-specific, transporting hydrogen between oil, gas, and chemical process facilities. [14] This is compared to the about 3 million miles of natural gas pipeline installed. In the discussion section on transportation and storage, the EPA states that analysts "assert that 20 percent hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required." In doing literature research on the subject, very little definitive data were found. Some researchers say this number could be 5%-15%. [15] The IEA Global Hydrogen Review 2022 makes it clear that that upper bound of 20% hydrogen blend in pipelines without significant infrastructure changes is limited to certain distribution networks and would still require some upgrading. For natural gas transmission networks, the IEA notes that research indicates levels of only 5-10% of hydrogen blending is feasible without significant upgrades.

Another option could be a dedicated hydrogen pipeline. It could be designed to move approximately 88% of the equivalent energy of a natural gas pipeline in the same diameter pipe. [15] To do this, additional compression would be required. The construction of a new pipeline would also face all the challenges, costs, and timelines related to permitting, design, and construction. It is noted that due to the molecular weight of hydrogen, compressors need to operate at three times the speed of natural gas compressors. This requires specialized equipment and more energy to compress the gas.

If existing gas lines are to be used for hydrogen blends, then consideration needs to be given to all users. This often includes gas distribution companies that provide gas to residential and commercial services. Various studies are being carried out in Europe on how much hydrogen could be safely blended for this use, and 1% to 5% is the most recognized range of blends identified. Since the EPA's target date for 30% blending is 2032, we can rule out this option.

Conclusions

After reviewing the EPA technical document on hydrogen development, I can make several conclusions. One of the most important is the document's assertion that there is available pipeline capacity in the United States to meet the EPA requirements. This is not accurate. Although there is much talk about blending hydrogen into the natural gas transmission and distribution system, an amount of between 1% and 5% is likely all that is practical without major changes to end use equipment. This does not meet an EPA 30% blend target in 2032. The EPA proposes trucking on tube trailers for transport. As the LM6000 example shows, the logistics of moving this many trucks are not feasible. That would only leave on-site storage as an option, which the EPA does not adequately assess or account for in its support document.

The EPA's technical document reviewed the technical readiness level of the various turbine options. Although there is a lot of marketing or forecast development of machines that will run at 30% blends, they are neither demonstrated nor commercially available with guaranteed performance today to be a viable option to meet the EPA requirements.

As mentioned in the production section discussion, the EPA's targeted price for low-GHG hydrogen of $0.5/kg used in the modelling is not a reasonable assumption for the early years of compliance requirements.

To summarize:

1) Approximately 176 MW of renewable electricity is required to produce enough green hydrogen to generate 46.6 MW of electricity, firing in a gas turbine at 100% hydrogen.
2) The only available transport currently being used to get hydrogen to test sites is tube trailer trucks. To run one LM6000 at full load (46.6 MW) for 24 hours would require more than 200 tube trailer truckloads to be delivered and unloaded daily.
3) Although hydrogen can be transported in specially built pipelines, there will not be a sufficient network available in the foreseeable future.

4) A hydrogen production price of $0.5/kilogram (kg) or $1/kg, as referenced by the EPA, is based solely on the Department of Energy's goals. [3] This is significantly lower than the current estimated cost of $5/kg of hydrogen produced by electrolysis and significantly lower than even the International Energy Agency's most optimistic projections of future hydrogen costs.

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About the Author

Mr. Doug Campbell, FTB Energy Solutions, Inc.

Mr. Doug Campbell is a professional engineer with demonstrated managerial ability including planning, financial control, contract management, staff supervision and reporting. Over a 48-year career, Mr. Campbell has developed a wide range of technical skills associated with the design construction and start-up of new generation and the operation and maintenance of existing generation facilities. He has held positions as Manager of Hydro, Manager of a Multi-unit Steam Plant and Combustion Turbine operation, as well as Director of Generation Services in a vertically-integrated utility. As a Senior Technical Advisor, Mr. Campbell contributed to various engineering problems, such as recent studies on inspection and evaluation of fitness for service for high pressure equipment and various pressure retaining component parts. His involvement as an independent contractor has been in providing expert advice on new and developing technologies to support the transformation of the electrical grid. Current work includes providing insights in these developments, especially as related to a low carbon world. Mr. Campbell completed a Master of Science in Energy from Heriot-Watt University in 2018 and a Master of Applied Economics from Saint Mary's University in 2022, which has allowed him to obtain additional skills to evaluate technology and to comment on the strategic outcomes of their application.

Reference calculation and terminology to be aware of in Hydrogen Natural Gas Comparisons

Doug Campbell

July 11, 2023

Conversion Factors

Definition of and calculation of decatherms for natural gas consumption and billing

Explanation as found in Wikipedia, often useful never cited.

The **therm** (symbol, **thm**) is a non-SI unit of heat energy equal to 100,000 British thermal units (BTU),[1] and approximately 105 megajoules, 29 kilowatt-hours, 25200 kilocalories and 25.2 thermies. One therm is the energy content of approximately 100 cubic feet (2.83 cubic metres) of natural gas at standard temperature and pressure. However, the BTU is not standardised worldwide, with slightly different values in the EU, UK, and USA, meaning that the energy content of the therm also varies by territory.

Natural gas meters measure volume and not energy content, and given that the energy density varies with the mix of hydrocarbons in the natural gas, a 'therm factor' is used by natural gas companies to convert the volume of gas used to its heat equivalent, usually being expressed in units of 'therms per CCF' (CCF is an abbreviation for 100 cubic feet). Higher than average concentration of ethane, propane or butane will increase the therm factor and the inclusion of non-flammable impurities, such as carbon dioxide or nitrogen will reduce it. The Wobbe Index of a fuel gas is also sometimes used to quantify the amount of heat per unit volume burnt.

Definitions

- Therm (EC) ≡ 100000 BTU_{ISO}[2]

  = 105506000 joules
  ≈ 29.3072 kWh
  The therm (EC) is often used by engineers in the US.

- Therm (US) ≡ 100000 $BTU_{59\,°F}$[3]

  = 105480400 joules
  ≈ 29.3001111111111 kWh.

- Therm (UK) ≡ 105505585.257348 joules[4]

  ≡ 29.3071070159300 kWh

Decatherm

A **decatherm** or **dekatherm**[5] (dth or Dth) is 10 therms, which is 1,000,000 British thermal units or 1.055 GJ.[6][7] It is a combination of the prefix for 10 (deca, often with the US spelling "deka") and the energy unit therm. There is some ambiguity, as "decatherm" uses the prefix "d" to mean 10, where in metric the prefix "d" means "deci" or one-tenth, and the prefix "da" means "deca", or 10, though decatherm may use a capital "D". The energy content of 1,000 cubic feet (28 m^3) natural gas measured at standard conditions is approximately equal to one dekatherm.

This unit of energy is used primarily to measure natural gas. Natural gas is a mixture of gases containing approximately 80% methane (CH_4) and its heating value varies from about or 10.1 to 11.4 kilowatt-hours per cubic metre (975 to 1,100 Btu/cu ft), depending on the mix of different gases in the gas stream. The volume of natural gas with heating value of one dekatherm is about 910 to 1,026 cubic feet (25.8 to 29.1 m^3). Noncombustible carbon dioxide (CO_2) lowers the heating value of natural gas. Heavier hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}) increase its heating value. Since customers who buy natural gas are actually buying heat, gas distribution companies who bill by volume routinely adjust their rates to compensate for this.[8]

The company Texas Eastern Transmission Corporation, a natural gas pipeline company, started to use the unit dekatherm in about 1972. To simplify billing, Texas Eastern staff members coined the term dekatherm and proposed using calorimeters to measure and bill gas delivered to customers in dekatherms.[9] This would eliminate the constant calculation of rate adjustments to dollar per 1000 cubic feet rates in order to assure that all customers received the same amount of heat per dollar. A settlement agreement reflecting the new billing procedure and settlement rates was filed in 1973. The Federal Power Commission issued an order approving the settlement agreement and the new tariff using dekatherms later that year,[10] Other gas distribution companies also began to use this process.[11]

In spite of the need for adjustments, many companies continue to use cubic feet rather than dekatherms to measure and bill natural gas.[12][13]

Referenced from " Kyle's Converter"

https://www.kylesconverter.com/energy,-work,-and-heat/cubic-feet-of-natural-gas-to-dekatherms-(us)

Unit Descriptions	
1 Cubic Foot of Natural Gas: 1000 BTU_{IT}	1 Dekatherm (US): Roughly energy equivalent of a thousand cubic feet of natural gas (MCF). Equivalent to 1 000 000 BTU; dekatherm (US) based on the $BTU_{59° f}$ popular in USA. 1 Dekatherm (Dth US) = 1 054 804 000 joules (J).

Link to Your Exact Conversion
https://www.kylesconverter.com/energy,-work,-and-heat/cubic-feet-of-natural-gas-to-dekatherms-(us)#400000

Conversions Table	
1 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.001	70 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.07
2 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.002	80 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.08
3 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.003	90 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.09
4 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.004	100 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.1
5 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.005	200 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.2
6 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.006	300 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.3001
7 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.007	400 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.4001
8 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.008	500 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.5001
9 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.009	600 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.6001
10 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.01	800 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.8002
20 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.02	900 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.9002
30 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.03	1,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 1.0002
40 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.04	10,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 10.0024
50 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.05	100,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 100.0239
60 Cubic Feet Of Natural Gas to Dekatherms (us) = 0.06	1,000,000 Cubic Feet Of Natural Gas to Dekatherms (us) = 1000.2388

Calculation:

# of million cubic feet * Btu energy = dekatherms

Important things to be aware of:

Carbon dioxide emission coefficients in fuel is stated in:

lbs CO2 per million btu of fuel (Ex. Natural gas 116.65 of fuel burned)

EPA emission limits are stated in CO_2 /MWh -gross:

Example is 1,150 lb CO_2/MWh -Gross

Gas turbine efficiency calculations utilize Low Heating Values.

This is important to be aware of as conventional boilers following ASME heat rate calculations determine heat rate by HHV high heating value. Generally, units are dispatched on the HHV calculation.

Rule of thumb is to HHV = 1.11 * LHV.

Hydrogen Natural gas Comparisons:

Always be aware if you are talking by volume or by mass. Generally speaking, when suppliers are talking blending, they will be speaking in terms of % by volume.

6 Important properties of Natural Gas and Hydrogen

The following is extracted from Power Engineers:

https://www.powereng.com/library/6-things-to-remember-about-hydrogen-vs-natural-gas

Chemical Formula:	Hydrogen: H_2 Natural gas (methane): CH_4
Molecular Weight:	Hydrogen: 2 Natural gas (methane): 16
Flammability Limit	Hydrogen :4%/75% Natural Gas: 7%/20%
Flame Speed	Hydrogen :200-300cm/sec Natural Gas: 30-40cm/sec
Adiabatic Flame Temperature	Hydrogen :4000F Natural Gas: 3565 F
Heating value LHV (BTU/Lb)	Hydrogen: 51623Btu/lb. Natural Gas :(methane) 21518 Btu/lb
Volumetric LHV (Btu/ft^3)	Hydrogen: 266 Btu/ft^3 Natural Gas (methane): 881Btu/ft^3

Note: Absolute numbers vary depending on refence used. This reflects different gas quality from various processors.

Calculation for LM 6000 Gas Turbine with associated Reference Material

Doug Campbell

July 11, 2023

Calculation of LM 6000 fuel requirements:

Heat rate LHV = 8600 Btu/kwh

Heating Value Natural Gas LHV = 21,500 Btu/Lb (CH_4)

Fuel Burned:

8,600/21500 = .4Lb/kwh   Btu/kwh /btu/Lb = Lb /kwh

.4Lb/kwh * 1000 kwh /MWh = 400 Lb/MWh

1 MWh = 3.412 mmBtu

400Lb/MWh * 1Mwh/3.412 = 117 Lb/mmBtu

21,500 Btu/ln * 400 Lb/MWh = 8.6 * 10^6 Btu/MWh

Co_2 emissions = 116.65 LbCO_2/MBtu

CO_2 = 116.65 * 8.6 = 1003.19 Lb/MWh

LM 6000 full load meets CO_2 limit.

Full Load Calculation:

Fuel burned = 400 Lb/MWh

Full load = 46.6MW

Fuel burned: 400 * 46.6 = 18,600 Lb /hr

Btu input:

18,600 Lb/Hr * 21,500 Btu/lb.= 400.76 MMBtu/Hr.

Calculate number of tube trailers required 380 Kg trailers.

Hydrogen = 51,591Btu/Lb

One hour use = 400.76 MM Btu/51591 Btu/Lb = 7,780 Lb/hr = 3530.9 Kg/hr

Therefore 9 .29 tube trailers per hour required at full load.

Volume calculation:

NG = 964 Btu/ft^3

H_2 = 290 Btu/ft^3

Hydrogen = 400.76 mmBtu/hr * 1ft^3/290 Btu = 1.38 * 10^6 ft^3/hr

Natural Gas = 400.76mmbtu * 1ft^3 / 964 Btu = .41 * 10^6 ft^3/hr

When sizing pipe it is important to maintain the maximum allowable velocity in the pipe. We can see that velocities will increase greatly with hydrogen vs. natural gas. Therefore, in order to meet full load either pipelines need to be made larger or the pressure to maintain energy density needs to increased. A detailed engineering study by a piping engineer would be required to optimize the solution.

2.1 Low Density and Energy Content

Hydrogen has the lowest mass density of any substance in the universe, with an atomic weight of only 2.0. It is about eight times lighter than methane (CH_4) [1]. Because of this, there is a common misconception that hydrogen is a superior fuel to natural gas because of its larger heating value (141.86 MJ/kg for H_2 versus 55.53 MJ/kg for pure methane). However, this is due to the fact that hydrogen is *very light* compared to natural gas, not because it actually contains that much energy on a volume basis compared to natural gas. On a molecular basis, there is more energy contained within four C-H bonds compared to one single H-H bond. Also, gas turbine combustors are of fixed volume and designed to work at specific operating pressures with little room for deviation. Therefore, the amount of hydrogen that can be used in a particular gas turbine is limited by volume. Indeed, looking at the energy content on a per-unit-volume or mole basis reveals that natural gas has more than three times the energy density of hydrogen by volume (10,050 kJ/m^3 H_2 versus 32,560 kJ/m^3 CH_4) [1]. Thus, to accommodate hydrogen fuel, hydrogen gas turbines will either need to be larger, incorporate higher max pressures to reduce gas volumes, or both to compete with natural gas turbines. This means that, to achieve similar performance/emissions ratings to their natural gas counterparts, hydrogen turbines may be more costly to produce.

How do you calculate specific fuel consumption of gas turbine?

A simple-cycle gas turbine used for power generation has a thermal efficiency of about 34 percent. Since 1 kwh is theoretically equivalent to 3,415 Btu,the simple-cycle gas turbine has a fuel connsumption of:3,415 / 0.34 = about 10,000 Btu/kwh.

Given the heating value (i.e, heat of combustion) of a fuel, we can easily calculate thesimple-cycle gas turbine fuel usage.

For example, natural gas has a net heating value of about 21,500 Btu/pound.Thus, the natural gas consumption in a simple-cycle gas turbine would be:10,000 / 21,500 = 0.47 pounds/kwh = 0.21 kg/kwh.

As another example, a typical diesel oil has a net heating value of 130,000 Btu/gallon.Thus, the diesel oil consumption in a simple-cycle gas turbine would be:10,000 / 130,000 = 0.077 gallon/kwh.

(The gallon used just above is the U.S. gallon rather than the Imperial gallon)A combined-cycle gas turbine will have a higher thermal efficiency and, hence, lower fuel consumptions.

	LM6000 PC	LM6000 PG	LM6000 PF	LM6000 PF+
Net output (MW)	46.6/51.1*	56/57.2*	44.7/50*	53.9/57.1*
Net heat rate (Btu/kWh, LHV)	8533	8728	8248	8357
Net heat rate (kJ/kWh, LHV)	9002	9208	8702	8817
Net efficiency (%, LHV)	40%	39.1%	41.4%	40.8%
Ramp rate (MW/minute)	30	30	30	30
Startup time (cold iron) (min.)	5	5	5	5
GT Min. Turn Down Load (%)	25%	25%	50%	50%

LM6000 gas turbines can start up in 5 minutes

*MW output without SPRINT/with SPRINT

NOTE: All ratings are based on ISO conditions and natural gas fuel. Actual performance will vary with project-specific conditions and fuel.

Fuels - Higher and Lower Calorific Values

Higher and lower calorific values (heating values) for fuels like coke, oil, wood, hydrogen and others.

Energy content or calorific value is the same as **the heat of combustion**, and can be calculated from thermodynamical values, or measured in a suitable apparatus:

A known amount of the fuel is burned at constant pressure and under standard conditions (0°C and 1 bar) and the heat released is captured in a known mass of water in a calorimeter. If the initial and final temperatures of the water is measured, the energy released can be calculated using the equation

$$H = \Delta T \, mC_p$$

where H = heat energy absorbed (in J), ΔT = change in temperature (in °C), m = mass of water (in g), and C_p = specific heat capacity (4.18 J/g°C for water). The resulting energy value divided by grams of fuel burned gives the energy content (in J/g).

The combustion process generates water vapor and certain techniques may be used to recover the quantity of heat contained in this water vapor by condensing it.

- **Higher Calorific Value** (= Gross Calorific Value - GCV = Higher Heating Value - HHV) - the water of combustion is entirely condensed and the heat contained in the water vapor is recovered
- **Lower Calorific Value** (= Net Calorific Value - NCV = Lower Heating Value - LHV) - the products of combustion contains the water vapor and the heat in the water vapor is not recovered

The table below gives the gross and net heating value of fossil fuels as well as some alternative biobased fuels.

See also Heat of combustion, Fossil and Alternative Fuels - Energy Content and Combustion of Fuels - Carbon Dioxide Emission

Fuel	Density @0°C/32°F, 1 bar		Higher Heating Value (HHV) (Gross Calorific Value - GCV)					Lower Heating Value (LHV) (Net Calorific Value - NCV)				
Gaseous fuels	[kg/m³]	[g/ft³]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/m³]	[Btu/ft³]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/m³]	[Btu/ft³]
Acetylene	1.097	31.1	13.9	49.9	21453	54.7	1468					
Ammonia				22.5	9690							
Hydrogen	0.090	2.55	39.4	141.7	60920	12.7	341	33.3	120.0	51591	10.8	290
Methane	0.716	20.3	15.4	55.5	23874	39.8	1069	13.9	50.0	21496	35.8	964
Natural gas (US market)*	0.777	22.0	14.5	52.2	22446	40.6	1090	13.1	47.1	20262	36.6	983
Town gas						18.0	483					
	@15°C/60°F											
Liquid fuels	[kg/l]	[kg/gal]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/l]	[Btu/gal]	[kWh/kg]	[MJ/kg]	[Btu/lb]	[MJ/l]	[Btu/gal]
Acetone	0.787	2.979	8.83	31.8	13671	25.0	89792	8.22	29.6	12726	23.3	83580
Butane	0.601	3.065	13.64	49.1	21109	29.5	105875	12.58	45.3	19475	27.2	97681
Butanol	0.810		10.36	37.3	16036	30.2	108359	9.56	34.4	14789	27.9	99934
Diesel fuel*	0.846	3.202	12.67	45.6	19604	38.6	138412	11.83	42.6	18315	36.0	129306
Dimethyl ether (DME)	0.665	2.518	8.81	31.7	13629	21.1	75655	8.03	28.9	12425	19.2	68973
Ethane	0.572	2.165	14.42	51.9	22313	29.7	106513	13.28	47.8	20550	27.3	98098
Ethanol (100%)	0.789	2.987	8.25	29.7	12769	23.4	84076	7.42	26.7	11479	21.1	75583
Diethyl ether (ether)	0.716	2.710	11.94	43.0	18487	30.8	110464					
Gasoline (petrol)*	0.737	2.790	12.89	46.4	19948	34.2	122694	12.06	43.4	18659	32.0	114761

Gas oil (heating oil)*	0.84	3.180	11.95	43.0	18495	36.1	129654	11.89	42.8	18401	36.0	128991
Glycerin	1.263	4.781	5.28	19.0	8169	24.0	86098					
Heavy fuel oil*	0.98	3.710	11.61	41.8	17971	41.0	146974	10.83	39.0	16767	38.2	137129
Kerosene*	0.821	3.108	12.83	46.2	19862	37.9	126663	11.94	43.0	18487	35.3	126663
Light fuel oil*	0.96	3.634	12.22	44.0	18917	42.2	151552	11.28	40.6	17455	39.0	139841
LNG*	0.428	1.621	15.33	55.2	23732	23.6	84810	13.50	48.6	20894	20.8	74670
LPG*	0.537	2.033	13.69	49.3	21195	26.5	94986	12.64	45.5	19561	24.4	87664
Marine gas oil*	0.855	3.237	12.75	45.9	19733	39.2	140804	11.89	42.8	18401	36.6	131295
Methanol	0.791	2.994	6.39	23.0	9888	18.2	65274	5.54	19.9	8568	15.8	56562
Methyl ester (biodiesel)	0.888	3.361	11.17	40.2	17283	35.7	128062	10.42	37.5	16122	33.3	119460
MTBE	0.743	2.811	10.56	38.0	16337	28.2	101244	9.75	35.1	15090	26.1	93517
Oils vegetable (biodiesel)*	0.92	3.483	11.25	40.5	17412	37.3	133684	10.50	37.8	16251	34.8	124772
Paraffin (wax)*	0.90	3.407	12.78	46.0	19776	41.4	148538	11.53	41.5	17842	37.4	134007
Pentane	0.63	2.385	13.50	48.6	20894	30.6	109854	12.60	45.4	19497	28.6	102507
Petroleum naphtha*	0.725	2.745	13.36	48.1	20679	34.9	125145	12.47	44.9	19303	32.6	116819
Propane	0.498	1.885	13.99	50.4	21647	25.1	89963	12.88	46.4	19927	23.1	82816
Residual oil*	0.991	3.752				41.8	150072	10.97	39.5	16982	39.2	140470
Tar*			10.00	36.0	15477							
Turpentine	0.865	3.274	12.22	44.0	18917	38.1	136555					
Solid fuels*			**[kWh/kg]**	**[MJ/kg]**	**[Btu/lb]**			**[kWh/kg]**	**[MJ/kg]**	**[Btu/lb]**		
Anthracite coal			9.06	32.6	14015							
Bituminous coal			8.39	30.2	12984			8.06	29.0	12468		
Carbon			9.11	32.8	14101							
Charcoal			8.22	29.6	12726			7.89	28.4	12210		
Coke			7.22	26.0	11178							
Lignite (brown coal)			3.89	14.0	6019							
Peat			4.72	17.0	7309							
Petroleum coke			8.69	31.3	13457			8.19	29.5	12683		
Semi anthracite			8.19	29.5	12683							
Sub-Bituminous coal			6.78	24.4	10490							
Sulfur (s)			2.56	9.2	3955			2.55	9.2	3939		
Wood (dry)	0.701		4.50	16.2	6965			4.28	15.4	6621		

* Fuels which consist of a mixture of several different compounds may vary in quality between seasons and markets. The given values are for fuels with the given density. The variation in quality may give heating values within a range 5 -10% higher and lower than the given value. Also the solid fuels will have a similar quality variation for the different classes of fuel.

- 1 Btu(IT)/lb = 2.3278 MJ/t = 2327.8 J/kg = 0.55598 kcal/kg = 0.000646 kWh/kg
- 1 kcal/kg = 1 cal/g = 4.1868 MJ/t = 4186.8 J/kg = 1.8 Btu(IT)/lb = 0.001162 kWh/kg
- 1 MJ/kg = 1000 J/g = 1 GJ/t = 238.85 kcal/kg = 429.9 Btu(IT)/lb = 0.2778 kWh/kg
- 1 kWh/kg = 1547.7 Btu(IT)/lb = 3.597 GJ/t = 3597.1 kJ/kg = 860.421 kcal/kg

- 1 Btu(IT)/ft^3 = 0.1337 Btu(IT)/gal(US liq) = 0.03531 Btu(IT)/l = 8.89915 kcal/m^3 = 3.7259x10^4 J/m^3
- 1 Btu(IT)/gal(US liq) = 0.2642 Btu(IT)/l = 7.4805 Btu(IT)/ft^3 = 66.6148 kcal/m^3 = 2.7872x10^5 J/m^3
- 1 MJ/m^3 = 26.839 Btu(IT)/ft^3 = 3.5879 Btu(IT)/gal(US liq) = 0.94782 Btu(IT)/l = 239.01 kcal/m^3
- 1 kcal/m^3 = 0.11237 Btu(IT)/ft^3 = 0.01501 Btu(IT)/gal(US liq) = 0.003966 Btu(IT)/l = 4186.8 J/m^3

ENVIRONMENT

Carbon Dioxide Emissions Coefficients

Release Date: October 5, 2022 | XLS | METHODOLOGY

Carbon Dioxide Emissions Coefficients by Fuel

Carbon Dioxide (CO_2) Factors:	Pounds CO_2 Per Unit of Volume or Mass	Kilograms CO_2 Per Unit of Volume or Mass	Pounds CO_2 Per Million Btu	Kilograms CO_2 Per Million Btu
For homes and businesses				
Propane	12.68 gallon	5.75 gallon	138.63	62.88
Diesel and Home Heating Fuel (Distillate Fuel Oil)	22.45 gallon	10.19 gallon	163.45	74.14
Kerosene	21.78 gallon	9.88 gallon	161.35	73.19
Coal (All types)	3,876.61 short ton	1,758.40 short ton	211.87	96.10
Natural Gas	120.96 thousand cubic feet	54.87 thousand cubic feet	116.65	52.91
Finished Motor Gasoline[a]	17.86 gallon	8.10 gallon	148.47	67.34
Motor Gasoline	19.37 gallon	8.78 gallon	155.77	70.66
Residual Heating Fuel (Businesses only)	24.78 gallon	11.24 gallon	165.55	75.09
Other transportation fuels				
Jet Fuel	21.50 gallon	9.75 gallon	159.25	72.23
Aviation Gas	18.33 gallon	8.32 gallon	152.54	69.19
Industrial fuels and others not listed above				
Petroleum coke	32.86 gallon	14.90 gallon	225.13	102.12
Nonfuel uses				
Asphalt and Road Oil	26.25 gallon	11.91 gallon	166.12	75.35
Lubricants	23.58 gallon	10.70 gallon	163.29	74.07
Naphthas for Petrochemical Feedstock Use	18.74 gallon	8.50 gallon	149.95	68.02
Other Oils for Petrochemical Feedstock Use	22.61 gallon	10.26 gallon	163.05	73.96
Special Naphthas (solvents)	19.94 gallon	9.04 gallon	159.57	72.38
Waxes	21.10 gallon	9.57 gallon	160.06	72.60
Coals by type				
Anthracite	5,715.11 short ton	2,592.33 short ton	228.60	103.69
Bituminous	4,933.59 short ton	2,237.84 short ton	205.57	93.24
Subbituminous	3,747.36 short ton	1,699.78 short ton	214.13	97.13
Lignite	2,813.18 short ton	1,276.04 short ton	216.40	98.16
Coke	7,196.24 short ton	3,264.17 short ton	250.59	113.67
Other fuels				
Geothermal (steam)	NA	NA	26.03	11.81
Geothermal (binary cycle)	NA	NA	0.00	0.00
Municipal solid waste[b,c]	1,552.88 short ton	704.38 short ton	109.98	49.89
Tire-derived fuel[b]	5,306.87 short ton	2,407.16 short ton	189.53	85.97

Geothermal (steam)	NA	NA	26.03	11.81
Geothermal (binary cycle)	NA	NA	0.00	0.00
Municipal solid waste[b,c]	1,552.88 short ton	704.38 short ton	109.98	49.89
Tire-derived fuel[b]	5,306.87 short ton	2,407.16 short ton	189.53	85.97
Waste oil[b]	22.51 gallon	10.21 gallon	163.14	74.00

Data source: arbon factors provided by the U.S. Environmental Protection Agency, Inventory of *U.S. Greenhouse Gas Emissions and Sinks*: 1990-2020, Tables A-22, A-27, A-34, and A-230

[a]Includes fuel ethanol blended into motor gasoline. The fuel ethanol component of finished motor gasoline is treated as nonemissive. See methodology documentation for further details on calculations.

[b]Carbon factors for municipal solid waste, tire-derived fuel, and waste oil are provided by the U.S. Environmental Protection Agency, *Greenhouse Gas Emissions Factor Hub*

[c]The carbon factor for municipal solid waste has been adjusted to apply both to biogenic and non-biogenic waste

Note: To convert to carbon equivalents multiply by 12/44.

Coefficients may vary slightly with estimation method and across time.

Coefficients are based on data from 2020. EIA uses these coefficients for estimating 2021, and more recent, energy-related CO_2 emissions.

Voluntary Reporting Program emissions factors (discontinued)

Western Farmers Electric Cooperative (WFEC)

Western Farmers Electric Cooperative

Comments on

New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Proposed Rule

Submitted Electronically in response to the Small Entity Representative Panel Outreach

to:

The Environmental Protection Agency

via

Lanelle Wiggins at Wiggins.Lanelle@epa.gov

August 24, 2023

by

Laura J. Finley
Staff Attorney
3000 S. Telephone Rd
Moore, Oklahoma 73170
(405) 402-0091 / laura.finley@wfec.com

Introduction

Western Farmers Electric Cooperative ("WFEC") appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) Small Entity Representative Panel Outreach on New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Proposed Rule.

WFEC is a Generation and Transmission ("G&T") rural electric cooperative with its headquarters located in Anadarko, OK. WFEC is a small business, with under 500 employees, whose member distribution cooperatives are located in Oklahoma and New Mexico serving predominately rural low-income communities. As an electric cooperative, WFEC is a non-profit organization; WFEC allocates operating margins as equity, and when appropriate, retires them to the members of the Cooperative in the form of money or credit on their bills. Because of the significant financial impact EPA's proposal will have, the requirements would undermine small electric cooperatives' mission of providing affordable, reliable power to the communities and the consumer-members we serve.

This proposal would require the use of carbon capture and storage (CCS) and/or hydrogen co-firing technologies that are not yet commercially viable or available on an unreasonably expedited timeframe. This will force the premature closure of dispatchable and always available thermal resources while also making it harder to permit, site, and build critical new generating units. All of this will occur while the demand for electricity significantly increases as we electrify more of the American economy. Thermal resources must be readily available because they can be dispatched to provide the power needed as wind and solar resources ramp up and down. The ability to supplement power to meet load as variable resources react to fuel supply is absolutely paramount to meet the reliability needs of the American economy.

Electric cooperatives are built by, and belong to, the communities they serve. The families and businesses served by WFEC are direct stakeholders and the sole owners of the not-for-profit cooperative. The fundamental expectation of our consumers is that the lights stay on at a cost they can afford. However, recent threats to the grid serve as a dire warning that America's ability to keep the lights on is in jeopardy. According to the North American Electric Reliability Corporation, the "disorderly" retirement of existing generating assets across the country, and insufficient replacement of that power capacity, is directly impacting reliability and increasing the risk of blackouts.

EPA's regulations propose to require the use of CCS and hydrogen co-firing, which are promising technologies but are not yet commercially viable or available in most parts of the country. For a small business, investing in a burgeoning technology that has not been proven to be consistently successful on any scale is an astronomical financial risk. For WFEC, financial risks of this magnitude can have critical impacts to the retail customers as the only avenue for recouping losses is by raising rates. And, as stated above, most of the members served by WFEC distribution cooperatives live in predominantly low-income communities. For these citizens, every single dollar counts. Additionally, given the extremely tight timelines EPA has proposed, WFEC will need to start making financial and logistical plans for extremely costly controls and/or unit upgrades or begin construction on replacement generation almost immediately. Again, this demonstrates the massive financial risk that WFEC would have to take in order to comply with a rule that will most likely be challenged in court as soon as its final and for technologies that are unproven and completely unavailable in Oklahoma and New Mexico. Retrofitting with controls and building new units would require WFEC to enter into contracts that will incur significant cancellation fees and possible termination penalties if a court later overturns EPA's rules, all unrecoverable costs, all while supply chain shortages are prevalent across America.

Because CCS and hydrogen co-firing are not proven technologies, WFEC does not have a good estimate on what it would cost to install CCS or hydrogen co-firing technology on any of its units. Research has shown that it will cost approximately $275 million to install SCR on WFEC units, which is a proven technology with known pitfalls and requirements; therefore, WFEC can only *project* that CCS and hydrogen co-firing will be well above that cost as burgeoning unproven technologies.

Unproven Emission Reduction Technologies

An additional risk faced by small businesses is the risk of EPA's proposed technologies being installed at power plants and not performing as expected. There is a great likelihood of this occurring, and the end result would be a significant increase in outages, keeping the units out of the market and unavailable to compliments the variable availability of wind and solar generation, all while decreasing reliability. This would result in additional possibly catastrophic financial impacts to WFEC.

Some of the potential pitfalls of co-firing hydrogen have been documented, but because there is no unit in the world currently utilizing hydrogen at the levels EPA has proposed, the long-term effects of firing with hydrogen are speculative at best. First, a much higher volume of hydrogen will be needed because the energy density of hydrogen is 1/10 that of natural gas.[1] This will create significant logistical and financial burdens to WFEC as a small business because any unit that is to be retrofitted to co-fire hydrogen will have to undergo a lengthy and costly shut down in order to accommodate a pipe big enough to allow a sufficient volume of hydrogen to be delivered to the unit. To accommodate the hydrogen fuel, the turbines will either need to be larger, use higher max pressures to reduce the hydrogen volume or both. Because of the higher volumes and/or pressure requirements, it will be far more costly to run hydrogen fired turbines than natural gas turbines. There are also a great deal of concerns surrounding the impacts to parts of the units due to how and at what temperatures hydrogen fires.

There simply has not been enough research and real-world use of hydrogen as a fuel to answer these concerns and understand how to troubleshoot these issues. The timelines that EPA suggests in its proposal are completely unrealistic. All of these factors create a great deal of risk and possible future costs as a result of potential damage to the unit.

This is where parties interested in receiving hydrogen from the hubs being partially financially supported by DOE were required to provide notice of their interest by July 24, 2023. The timing is in no way cohesive or workable with the timeline for the GHG rule that the EPA has proposed. Unfortunately, utilities will have already missed their deadline to notify the DOE of their interest in reserving supply in the hydrogen hubs.

Therefore, the financial risk required of installing unproven technologies on critical infrastructure units will have a significant impact on not only WFEC but also the communities and citizens it serves.

Compliance Timeline for Retirement and Replacement

If WFEC decides to retire any of its units, it would need to simultaneously begin the process to secure replacement capacity. In order to meet capacity needs and comply with the Southwest Power Pool's ("SPP") Planning Reserve Margin requirement, retiring a unit would require WFEC to replace that unit's capacity with equal or greater replacement capacity. WFEC is not projected to have excess capacity within its system, at a time when load is significantly increasing. Because WFEC's decision to retire a unit is inextricably linked to securing replacement capacity, it would need to begin these processes and incur unrecoverable costs almost immediately upon rule finalization. WFEC has researched and developed a schedule to estimate a realistic timeline for retirement and replacement. According to WFEC's conservative estimate, retirement and replacement for its individual units would require at least 7 years. The retirement and replacement process requires extensive preparation, including notification to SPP,

[1] *See* Kiewit Engineering Group, Technical Comments on Hydrogen and Ammonia Firing (August 4, 2023).

a request for proposal under Rural Utility Service's ("RUS") competitive bidding rules, and an air permit application and approval. In addition, WFEC would have to conduct an engineering and technical analysis and go through an SPP generation interconnection study prior to beginning work on any replacement capacity, after which WFEC would procure equipment and begin construction.

Further, WFEC would need to secure funding from its lender for any replacement capacity and comply with lender requirements, including preparation of an Environmental Impact Statement. This process can take 6-7 years. WFEC will be required to take certain steps immediately upon rule finalization in order to have any chance of securing the needed replacement capacity in conjunction with unit retirement required to meet EPA's aggressive emission reduction timelines. All of these steps require outlays of a great deal of capital and carry with them significant financial risk due to the uncertain future of EPA's proposed rules. Again, any unrecoverable funds outlaid by WFEC would have to be recoupled by raising rates on its customers.

Cost of Retirement and Replacement
WFEC estimates that it will cost between \$15 and \$790 million to replace even one unit to secure replacement capacity necessary for retirement, depending on the size of the unit being replaced. WFEC must make a final decision on whether to begin the retirement and replacement process immediately upon rule finalization in order to provide sufficient lead time to meet its compliance obligations under the proposed rules. The replacement process will require WFEC to incur approximately \$11 million in unrecoverable expenses within 12-18 months of rule finalization, including \$60,000-100,000 for environmental permitting, \$5 million for engineering analysis, \$150,000-200,000 for preparing an Environmental Impact Statement, \$4 million for land purchases, and \$1.9 million for an SPP interconnection study. These costs are nothing if not significant.

WFEC joins electric cooperatives across the country in standing firmly against EPA's proposal. It would undermine decades of work to reliably keep the lights on across the nation and could lead to life-threatening blackouts. WFEC strongly implores EPA to seriously consider the impact its proposed rules will have on small businesses and the small communities they serve.