PANEL REPORT

of the

Small Business Advocacy Review Panel on

EPA's Proposed Rule

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units

October 2023

1. INTRODUCTION

This report is presented by the Small Business Advocacy Review Panel (SBAR Panel or Panel) that the U.S. Environmental Protection Agency (EPA) convened to review the planned proposed rulemaking on the New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units (EGUs). Under section 609(b) of the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), a Panel is required to be convened prior to publication of the initial regulatory flexibility analysis (IRFA) that an agency may be required to prepare under the RFA. In addition to EPA's Small Business Advocacy Chairperson, the Panel will consist of the Director of the Sector Policies and Programs Division within the EPA's Office of Air and Radiation, the Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget, and the Chief Counsel for Advocacy of the Small Business Administration (SBA).

This Panel has not followed the normal course of events typical of an EPA Panel. Based on the information available to EPA at the time the Notice of Proposed Rulemaking (NPRM) for this action (88 FR 33240), EPA certified the proposed rule as not having a significant economic impact on a substantial number of small entities (No SISNOSE). However, EPA solicited comment on a number of more stringent policy options that may increase the impact to small businesses, and EPA received public comments raising concerns about the certification of No SISNOSE. Therefore, EPA convened a Panel. EPA will publish an Initial Regulatory Flexibility Analysis for public comment prior to issuing a final rule.

This report includes the following:

- Background information on the proposed rule;
- Information on the types of small entities that may be subject to the proposed rule;
- A description of efforts made to obtain the advice and recommendations of representatives of those small entities; and
- A summary of the comments that have been received to date from those representatives.

Section 609(b) of the RFA directs the Panel to consult with and report on the comments of small entity representatives (SERs) and make findings on issues related to elements of an IRFA under section 603 of the RFA. Those elements of an IRFA are:

- A description of, and where feasible, an estimate of the number of small entities to which the proposed rule will apply;
- A description of 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;
- An identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap, or conflict with the proposed rule;
- 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. This analysis shall discuss any 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.

Once completed, the Panel Report is provided to the agency issuing the proposed rule and is included in the rulemaking record. The agency is to consider the Panel's findings and recommendations and, "where appropriate, the agency shall modify the proposed rule, the initial regulatory flexibility analysis or the decision on whether an initial regulatory flexibility analysis is required" (5 USC 609(b)(6)).

The Panel's findings and discussion are based on the information available at the time the final Panel Report is drafted. EPA will continue to conduct analyses relevant to the proposed rule, and additional information may be developed or obtained during the remainder of the rule development process.

Any options identified by the Panel for reducing the rule's regulatory impact on small entities may require further analysis and/or data collection to ensure that the options are practicable, enforceable, environmentally sound, and consistent with the Clean Air Act (CAA) and its amendments.

2. BACKGROUND AND DESCRIPTION OF RULEMAKING

2.1 Regulatory History

In 2015, the EPA promulgated an NSPS to limit emissions of GHGs, manifested as carbon dioxide (CO_2), from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units, *i.e.,* utility boilers and integrated gasification combined cycle (IGCC) EGUs, and newly constructed and reconstructed stationary combustion turbine EGUs. These final standards are codified in 40 CFR part 60, subpart TTTT.

The 2015 NSPS finalized standards of performance for newly constructed and reconstructed stationary combustion turbine EGUs. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA finalized a standard based on efficient natural gas combined cycle (NGCC) technology as the best system of emissions reduction (BSER). For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines and for both base load and non-base load multi-fuel-fired stationary combustion turbines, the EPA finalized a heat input-based standard based on the use of lower emitting fuels (referred to as clean fuels in the 2015 NSPS). The EPA did not promulgate final standards of performance for modified stationary combustion turbines due to lack of information. These standards remain in effect today.

The EPA received six petitions for reconsideration of the 2015 NSPS. On May 6, 2016, the EPA denied five of the petitions on the basis they did not satisfy the statutory conditions for reconsideration under CAA section 307(d)(7)(B), and deferred action on one petition that raised the issue of the treatment of biomass.

Multiple parties also filed petitions for judicial review of the 2015 NSPS in the D.C. Circuit. These cases have been briefed and, on the EPA's motion, are being held in abeyance while the Agency reviews the rule and considers whether to propose revisions to it.

In 2023, EPA proposed revised new source performance standards for GHG emissions from new fossil fuel-fired stationary combustion turbine EGUs and from fossil fuel-fired steam generating units that undertake a large modification.

2.2 Description of Rulemaking and its Scope

For new and reconstructed fossil fuel-fired combustion turbines, the EPA proposed creating three subcategories based on the function the combustion turbine serves: a low load ("peaking units") subcategory that consists of combustion turbines with a capacity factor of less than 20 percent; an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine; and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines. This subcategorization approach is similar to the 2015 NSPS for these sources, which includes separate subcategories for base load and non-base load units; however, the EPA is now proposing to subdivide the non-base load subcategory into a low load subcategory and a separate intermediate load subcategory. This revised approach to subcategories is consistent with the fact that utilities and power plant operators are building new combustion turbines with plans to operate them at varying levels of capacity, in coordination with existing and expected energy sources. These patterns of operation are important for the type of controls that the EPA proposed as the BSER for these turbines, in terms of the feasibility of, emissions reductions that would be achieved by, and cost-reasonableness of, those controls.

For the low load subcategory, the EPA is proposing that the BSER is the use of lower emitting fuels (e.g., natural gas and distillate oil) with standards of performance ranging from 120 lb CO_2 /MMBtu to 160 lb CO_2/MMBtu, depending on the type of fuel combusted. For the intermediate load and base load subcategories, the EPA is proposing an approach in which the BSER has multiple components: (1) Highly efficient generation; and (2) depending on the subcategory, use of carbon capture and storage (CCS) or co-firing low-GHG hydrogen.

These components of the BSER for the intermediate and base load subcategories form the basis of a standard of performance that applies in multiple phases. That is, affected facilities must meet the first phase of the standard of performance, which is based exclusively on application of the first component of the BSER (highly efficient generation), by the date the rule is promulgated. Affected sources in the intermediate load and base load subcategories must also meet the second and in some cases third and more stringent phases of the standard of performance, which are based on the continued application of the first component of the BSER and the application of the second and in some cases third component of the BSER. For base load units, the EPA proposed two pathways as potential BSER:

- the use of CCS to achieve a 90 percent capture of GHG emissions by 2035 and
- the co-firing of 30 percent (by volume) low-GHG hydrogen by 2032, and ramping up to 96 percent by volume low-GHG hydrogen by 2038.

These two BSER pathways both offer significant opportunities to reduce GHG emissions but, may be available on slightly different timescales. Depending upon the phase in periods for both CCS and hydrogen, the CCS pathway could provide greater cumulative emission reductions than the low GHG hydrogen pathway.

More specifically, with respect to the first phase of the standards of performance, the EPA proposed that the BSER for both the intermediate load and base load subcategories includes highly efficient generating technology (i.e., the most efficient available combustion turbines). For the intermediate load subcategory, the EPA is proposing that the BSER includes highly efficient simple cycle turbine technology with an associated first phase standard of 1,150 lb CO_2/MWh-gross. For the base load subcategory, the EPA is proposing that the BSER includes highly efficient combined cycle technology with an associated first phase standard of 770 lb CO_2/MWh-gross for larger combustion turbine EGUs with a base load rating of 2,000 MMBtu/h or more. For smaller base load combustion turbines (with a base load rating of less than 2,000 MMBtu/h), the proposed associated standard ranges from 770 to 900 lb CO_2/MWh-gross depending on the specific base load rating of the combustion turbine. These standards would apply immediately upon the effective date of the final rule.

With respect to the second phase of the standards of performance, for the intermediate load subcategory, the EPA is proposing that the BSER includes co-firing 30 percent by volume low-GHG hydrogen (unless otherwise noted, all co-firing hydrogen percentages are on a volume basis) with an associated standard of 1,000 lb CO_2/MWh-gross, compliance with which would be required starting in 2032. For the base load subcategory, to elicit comment on both pathways, the EPA is proposed to subcategorize further into base load units that are adopting the CCS pathway and base load units that are adopting the low-GHG hydrogen co-firing pathway. For the subcategory of base load units that are adopting the CCS pathway, the EPA is proposing that the BSER includes the use of CCS with 90 percent capture of CO_2 with an associated standard of 90 lb CO_2/MWh-gross, compliance with which would be required starting in 2035. For the subcategory of base load units that are adopting the low-GHG hydrogen co-firing pathway, the EPA is proposing that the BSER includes co-firing 30 percent (by volume) low-GHG hydrogen with an associated standard of 680 lb CO_2/MWh-gross, compliance with which would be required starting in 2032, and co-firing 96 percent (by volume) low-GHG hydrogen by 2038, which corresponds to a standard of performance of 90 lb CO_2/MWh-gross. In both cases, the second (and sometimes third) phase standard of performance would be applicable to all combustion turbines that were subject to the first phase standards of performance.

2.3 Overview of Revisions under Consideration

While EPA certified no SISNOSE for the proposed rule, EPA solicited comment on a number of more stringent policy options that may impact small businesses. These include:

- 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 of the BSER for intermediate load combustion turbines based on a higher percentage of hydrogen co-firing
- A third component of the BSER for intermediate load combustion turbines based on 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

2.4 Related Federal Rules

There are additional air regulations that apply to certain equipment in the power sector. These rules, listed below, address criteria air pollutants, primarily particulate matter (PM), nitrogen oxides (NO_x), and sulfur dioxide (SO_2) and air toxics, primarily mercury, acid gas hazardous air pollutants (HAP) and non-mercury HAP metals.

- Electric Utility Steam Generating Units - 40 CFR part 60, subpart Da (PM, SO_2, NO_X) (77 FR 23399, April 19, 2012)
- Stationary Combustion Turbines - 40 CFR part 60, subpart GG and subpart KKKK (NO_X) (71 FR 9453, February 24, 2006 and 74 FR 11858, March 20, 2009, respectively), 40 CFR part 63, subpart YYYY (HAP) (85 FR 13524 March 9, 2020)
- Coal- and oil-fired EGUs - 40 CFR part 63, subpart UUUUU (Mercury, HAP, and non-mercury metals) (79 FR 68795 November 19, 2014)

In addition, EPA's Class VI Underground Injection Program regulates geologic sequestration wells under the Underground Injection Control (UIC) program of the Safe Water Drinking Act. EPA's GHG Reporting Program requires reporting and public disclosure of geologic sequestration activity, as well as implementation of rigorous monitoring, reporting, and verification of geologic sequestration.

Aside from the EPA, other Federal agencies have jurisdiction over the power sector.

- The Department of Energy addresses energy, environmental, and nuclear challenges through transformative science and technology solutions.
- The Federal Energy Regulatory Commission (FERC) within the Department of Energy regulates the transmission and wholesale sale of electricity in interstate commerce.
- The Pipeline and Hazardous Materials and Safety Administration (PHMSA) within the Department of Transportation issues safety regulations for existing and new CO_2 pipelines.

3. APPLICABLE SMALL ENTITY DEFINITIONS

The RFA defines small entities as including "small businesses," "small governments," and "small organizations" (5 USC 601). The RFA references the definition of "small business" found in the Small Business Act, which authorizes the Small Business Administration to further define "small business" by regulation. The SBA definitions of small business by size standards using the North American Industry Classification System (NAICS) can be found at 13 CFR 121.201.

Table 1 is a detailed listing of SBA definitions of small business for affected industries or sectors, by NAICS code.

Table 1: Industry Sectors, Definitions & Estimated Number of Small Entities Potentially Affected by the EPA's Planned Action

Name of Industry/Sector	2022 NAICS Code	SBA Size Standard for Small Business	Estimated Number of Small Entities
Fossil Fuel Electric Power Generation	221112	950 employees	The EPA estimates that approximately 10% of potentially affected new capacity may be owned by small entities and estimates that this total will be approximately 10 small entities.
Other Electric Power Generation	221118	650 employees	
Other	Possibly a wide variety of NAICS codes if small entity parent companies have NAICS codes unrelated to Subsector 221.	There are a wide variety of dollar- and employee-based size standards depending upon the NAICS code.	

4. LIST OF SMALL ENTITY REPRESENTATIVES

The EPA consulted with SBA's Office of Advocacy to develop the list of small entity representatives (SERs) in Table 2. The EPA issued a press release inviting self-nominations by affected small entities to serve as potential SERs. The press release directed interested small entities to a web page where they could indicate their interest in serving as a SER. The EPA launched the website on August 15, 2022 and accepted self-nominations until August 29, 2022. In addition, the EPA supplemented the self-nominations by contacting industry trade organizations notifying them of the news release and website. The EPA also participated on the Small Business Environmental Assistance Program Technical Subcommittee monthly call to provide a high-level overview regarding the rulemaking and how the small entities can participate in the panel process. The EPA sent SBA's Office of Advocacy a Formal Notification with the suggested list of potential SERs on September 20, 2022, and Advocacy responded on October 3, 2022. The list of small entity representatives (SERs) is shown in Table 2.

Table 2: List of Small Entity Representatives

Organization	Contact Name
American Public Power Association	Carolyn Slaughter
Arizona Electric Power Cooperative	Michelle Freeark
Buckeye Power/Ohio's Electric Collective	Caitlin Schiebel
Cooperative Energy	Stephanie Kilgore
Dairyland Power Cooperative	Ronald Franz
Deseret Power	Jeff Peterson

Organization	Contact Name
East Kentucky Power Cooperative	Jerry Purvis
Golden Spread Electric Cooperative	Ruth Calderon
Holland Board of Public Works	Trista Gregorski
Indiana Municipal Power Agency	Peter Prettyman
Minnkota Power Cooperative	Shannon Mikula
National Rural Electric Cooperative Association	Rae Cronmiller
North Carolina Electric Cooperatives	Michael Youth
Oglethorpe Power Corporation	Craig A. Jones
Oklahoma Municipal Power Authority	Michael Watt
Power South Energy Cooperative	Keith Stephens
Seminole Electric Cooperative	David "Chris" Weber
South Texas Electric Cooperative	John Packard
Wabash Valley Power Alliance	Jason Marshall
Western Farmers Electric Cooperative	Laura Finley
Wolverine Power Supply Electric Cooperative	Joe Hazewinkel

5. SUMMARY OF PRE-PANEL SMALL ENTITY OUTREACH

EPA's Office of Air Quality Planning and Standards (OAQPS) staff participate in monthly calls with Small Business Environmental Assistance Program (SBEAP) representatives. In August 2022, OAQPS provided an update to SBEAP representatives on the proposed rule and information about the SBAR Panel process.

The EPA conducted two rounds of outreach to gather input for these proposals. In the first round of outreach, in early 2022, the EPA sought input in a variety of formats and settings from States, Tribal nations, and a broad range of stakeholders on the state of the power sector and how the Agency's regulatory actions affect those trends. This outreach included State energy and environmental regulators; Tribal air regulators; power companies and trade associations representing investor-owned utilities, rural electric cooperatives, and municipal power agencies; environmental justice and community organizations; and labor, environmental, and public health organizations. A second round of outreach took place in August and September 2022, and focused on seeking input specific to this rulemaking. The EPA asked to hear perspectives, priorities, and feedback around five guiding questions, and encouraged public input to the nonregulatory docket (Docket ID No. EPA–HQ–OAR–2022–0723) on these questions as well.

EPA conducted a meeting with potential SERs on December 14, 2022. To help SERs prepare for the meeting, on December 1, 2022, EPA sent materials to each of the potential SERs via email. A list of the materials shared with the potential SERs during the pre-Panel outreach meeting is contained in Appendix A. For the December 14, 2022 pre-Panel outreach meeting with the potential SERs, EPA also invited representatives from the Office of Advocacy of the Small Business Administration and the Office of Information and Regulatory Affairs within the Office of Management and Budget. A total of 15 potential SERs participated in the meeting. EPA presented an overview of the SBREFA process, an explanation of the planned rulemaking, and technical background.

This outreach meeting was held to solicit feedback from the potential SERs on their suggestions for the upcoming rulemaking. EPA asked the potential SERs to provide written comments by January 9, 2023. Comments raised during the pre-Panel outreach meeting and written comments submitted by the potential SERS are summarized in section 6 of this document.

6. SUMMARY OF COMMENTS FROM POTENTIAL SMALL ENTITY REPRESENTATIVES

At the conclusion of the pre-Panel Outreach Meeting, potential SERS were asked to submit written questions and comments to EPA. Three entities submitted written materials to EPA. The following subsections summarize these submissions.

6.1 Number and Types of Entities Affected

National Rural Electric Cooperative Association (NRECA) stated all but three of their 63 electric generation and transmission cooperatives and 832 distribution cooperatives are small entities.

Western Farmers Electric Cooperative (WFEC) stated that the Energy Information Administration (EIA) data, Internal Revenue Service (IRS) data, and/or possibly NRECA datasets can provide the EPA with a better estimate of the number of small entities that may be affected by this proposed action.

6.2 Potential Reporting, Recordkeeping, and Compliance Requirements

NRECA stated the rule should allow emissions averaging as an optional compliance tool.

NRECA stated the rule should allow compliance flexibility including rate-based or mass limits such as tons/year.

WFEC stated the proposed amendments would affect their business by potentially hiring additional consultants with specialized expertise as well as potentially hiring an engineering firm to determine options for compliance.

WFEC recommended aligning recordkeeping and reporting requirements with existing requirements to reduce burden. For example, make reporting requirements consistent with existing reporting requirements (quarterly reporting in electronic data reporting (EDR) or semi-annual 60.7(c) reports similar to other NSPS reporting requirements for EGUs. Energy assessments/equipment tune-ups inspections similar to National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD and/or NESHAP Subpart UUUUU).

Regarding the subpart TTTT minimum date availability requirement, WFEC stated that 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 percent monitor data availability (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.

6.3 Other Compliance Requirements

Regarding methods to determine the design efficiency of an EGU, WFEC recommended allowing 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.

Regarding monitoring useful thermal output, WFEC stated that energy balance calculations would be practical and cost-effective. Installing a thermocouple grid in the stack would be costly to do and to maintain. WFEC noted that additional costs hit small companies hard, especially those that are not-for-profit, and asked why EPA wants this monitored? Is this only for cogeneration and/or combined cycle units?

WFEC stated low-GHG fuel use can be monitored and reported using fuel flow monitoring/reporting, similar to fuel and heat input reporting in Part 75.

WFEC stated they are unaware of practical ways of measuring, monitoring, reporting, and verifying CO_2 sequestration or use in EOR. They noted carbon dioxide sequestration is not an economically or technologically feasible control strategy for EGU. A search of the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse indicated that carbon sequestration was not a control strategy employed by any facilities with a Standard Industrial Classification (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. For small entities, the cost for installing carbon sequestration is prohibitive. Additionally, methods for ensuring CO_2 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.

WFEC stated there are no control strategies proven to be technically or economically effective at reducing CO_2 emissions. Measuring and calculating efficiency information would require additional calculations and configurations to be implemented between existing Data Acquisition and Handling Systems (DAHS) and plant control systems, which would be a unique and an additional requirement.

Dairyland Power Cooperative requested flexibility on how to calculate average capacity factor in order to meet the grid of the future.

6.4 Reliability

NRECA stated that North American Electric Reliability Corporation's (NERC's) 2022 Long-Term Reliability Assessment mirrors many of their concerns over future electric reliability. NERC recommends:

- Managing 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
- Considering the impacts of electrification may have on future electric demand
- Expanding 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.

American Public Power Association (APPA) stated regulatory certainty is paramount for any small public power utility to invest hundreds of millions of dollars to construct new base-load NGCC turbines that could operate with carbon capture, utilization, and storage (CCUS) or co-fire 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 customers.

6.5 Subcategorization

NRECA stated the 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.

APPA stated they 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 combustion turbines (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.

WFEC stated their 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

Southwest Power Pool (SPP) dispatch methods. Subcategories that may be more appropriate for EGUs include: 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% +.

6.6 BSER Technologies

APPA stated advancements in CCUS and CTs co-firing with hydrogen fuel are promising; however, co-firing hydrogen and CCUS is not adequately demonstrated throughout the power sector as the 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.

NRECA and Arizona Electric Power Cooperative stated BSER technologies need to be commercially available and viable, especially for those companies that operate in very rural areas.

APPA encouraged EPA to retain NGCC technology as the BSER for base-loaded combustion turbines.

NRECA stated that CCUS or clean hydrogen are not a BSER within the context of CAA section 111. Technologies for these strategies lack necessary associated infrastructure, are too costly, and are not readily available. 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.

NRECA stated that combined cycle with heat recovery steam generation 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 small units.

NRECA stated that 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 heat recovery steam generator (HRSG) is not potentially compelling as the case may be for a coal-fired boiler. Thus far, there is no commercial demonstration of supercritical steam application on a HRSG unit.

NRECA stated that 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.

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

APPA stated 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. If these conflicts continue to develop in other regions, it will considerably impair many utilities' efforts to implement CCUS technology.

WFEC stated at anything over 55% capacity factor you would install a new combined cycle combustion turbine instead of a simple cycle combustion turbine.

Wolverine Power Supply Electric Cooperative stated that increasing hydrogen co-firing substantially increases their NO_x emissions, which is permit restricted.

Dairyland Power Cooperative stated coops might be constrained without access to carbon capture sites and recommended a regional-specific analysis.

Dairyland Power Cooperative recommended EPA consider the tradeoffs between flexibility and efficiency.

Oglethorpe Power Corporation stated there's uncertainty as to when hydrogen and CCS will be available, as well as how long permitting of CCS storage will take. Natural gas pipelines take 5-6 years to permit and construct.

6.7 BSER Costs

NRECA stated 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 financial benefits, and the presumed intent of the Congress to sustain the benefits for the duration included in the original enacting legislation.

APPA stated 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. 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.

Arizona Electric Power Cooperative stated they need technology certainty in order to secure funding loans.

6.8 Other Federal Regulations

WFEC stated 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, and regional transmission organizations (RTOs) could conflict as well. The RTO in our area, 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.

6.9 Draft White Paper

NRECA stated the draft white paper falls 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". NRECA stated that draft white paper 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. NRECA stated the white paper must be significantly revised to be used to inform state and local permit agencies of GHG mitigation technologies for EGU combustion turbine application.

NRECA stated 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, could easily 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.

NRECA stated that CCUS and hydrogen blending for gas combustion turbines requires vast new developments in infrastructure to allow broad geographic applicability needed to demonstrate BSER. For CCUS, both pipelines and sequestration fields would need 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 BSER application.

NRECA stated 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. While the concept of Hydrogen Hubs shows promise for future application, that infrastructure on a geographic basis is not available today and may not be for years.

NRECA stated the draft white paper includes projects undergoing design exercises on NGCC units. They are all presently front end engineering and design studies that are the first prerequisites to a full-scale demonstration test. In addition to these four projects, the Department of Energy (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 General Electric (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. 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.

NRECA stated 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.

NRECA stated that 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.

NRECA stated that 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 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.

NRECA stated that each technology should incorporate guidelines for qualifying and quantifying GHG reductions. For example, the draft White Paper correctly points out 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.

NRECA stated that 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.

NRECA stated that 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.

NRECA stated that 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.

NRECA stated that 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.

6.10 Power Sector Transition

WFEC stated that 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 one to two 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.

WFEC stated the IRA has provided tax incentives for not-for-profit electric cooperatives.

WFEC stated the amended NSPS could impact proposed projects that 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. 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.

WFEC stated the strategies in EPA's white paper 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.

7. SUMMARY OF PANEL OUTREACH WITH SMALL ENTITY REPRESENTATIVES

The Panel conducted a meeting with SERs on August 10, 2023. To help SERs prepare for the meeting, EPA sent materials to each of the SERs via email on July 27, 2023. The materials shared with SERs during the Panel outreach meeting are included in Appendix A. A total of 20 SERs participated in the meeting. EPA presented an overview of the SBAR Panel process, an explanation of the rulemaking, and technical background. A discussion session was held to obtain advice and recommendations from the individual SERs about the potential impacts of the proposed rule, related Federal rules, and any significant alternatives that may minimize any significant impacts on small entities while accomplishing the stated objectives of the Clean Air Act. EPA asked the SERs to provide written comments by August 24, 2023.

Comments raised during the August 10, 2023, Panel Outreach meeting and written comments submitted by the SERS are summarized in section 8 of this document. The SERs' written comments are included in their entirety in Appendix B.

8. SUMMARY OF COMMENTS FROM SMALL ENTITY REPRESENTATIVES

At the conclusion of the Panel Outreach Meeting, SERS were asked to submit written questions and comments to EPA. Six entities submitted written materials to EPA. The following subsections summarize these submissions.

8.1 Number and Types of Entities Affected

Minnkota stated that 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.

NRECA stated EPA should reassess its initial conclusion that no small entity would be saddled with significant costs associated with this proposal's compliance.

NRECA stated all but two of their 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.

NRECA stated more cooperative entities and generating units are affected than one, as EPA presumes. At least seven small cooperative entities plan ten new natural gas combined cycle units totaling 4000 MWs and 16 new combustion turbines totaling 2400 MWs over the next five to seven-year planning period. 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.

East Kentucky Power Cooperative (EKPC) stated EPA's screening analysis is flawed because it doesn't include any costs to small entities to comply with the CAA section 111(d) portion of the rule. The analysis undercounts the number of affected entities by failing to consider the baseload replacement needs of cooperatives with coal-fired assets, driven by CAA section 111(d), and instead relies on historical data to project future generation projects. The analysis also fails to consider all the costs of the CAA section 111(b) portion of the rule.

EKPC stated all but the three largest electric cooperatives qualify as small businesses under SBA standards.

NRECA stated that EPA's no SISNOSE certification lacks a factual basis. EPA did not correctly determine which small entities would be subject to the rule's requirements and did not properly estimate costs. The supporting spreadsheet for EPA's RFA screening analysis only includes two electric cooperatives, Basin Electric Power Cooperative and Old Dominion Electric Cooperative, in the spreadsheet labeled "Small Entities." Inexplicably, EPA's sheet labeled "Final" only identifies PowerSouth Energy Cooperative, an electric cooperative that was not included in the "Small Entities" spreadsheet, as the sole affected electric cooperative. These estimates are particularly surprising given that ten electric cooperatives participated in the Pre-Panel Outreach meeting, an indication these cooperatives potentially have interest in building new natural gas units that may be covered by the Proposed Rules. In addition, for several North American Industry Classification Codes, EPA applied outdated SBA size standards. In February 2023, SBA issued a final rule updating these size standards.

8.2 Regulatory Flexibility Alternatives

APPA stated EPA should 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, 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.

APPA stated 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.

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.

APPA stated that 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.

APPA stated EPA should consider relaxing the compliance deadlines for all new CT categories as applied to small entities via a new subcategory or 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.

APPA stated the combined heat and power (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.

EKPC stated the only viable regulatory flexibility is for EPA to revise the BSER in the proposed rule. They concluded that 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 the 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 provide significant relief. EPA should refrain from implementing any of the more stringent options presented in the preamble for the same reasons.

EKPC stated EPA should revise the BSER to consider the following items:

- Timelines that can be met
- Exclusions for smaller new gas-fired units and peaking units
- Exclusions for all existing-gas fired units
- Subcategory development for cooperatives
- Fleet-wide generation averaging of emissions inside the fence
- A mechanism for reliability relief

EKPC stated EPA should refrain from devising a trading program like the Good Neighbor Federal Implementation Plan for GHGs. Trading is not a workable flexibility, and this should be considered during this process. Trading programs and averaging are often not useful for cooperative systems that have fewer units in these programs.

Golden Spread Electric Cooperative (GSEC) stated the operating ceiling for "low load" natural gas-fired 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.

Minnkota stated 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 with 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 CO_2 limitations that EPA proposed. More critically, baseload generation should be permitted to operate unless there is sufficient time to bring new replacement generation on-line. The gap in 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.

8.3 Reliability

EKPC stated the new generation timelines do not permit new generation to be built in time to replace retiring generation. 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, Rural Utilities Service 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). Small entities would be hard-pressed financially to shoulder multiple projects concurrently.

EKPC stated that 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 stated transmission systems require time and substantial costs to upgrade. Until that happens, assets in constrained areas are essential and cannot be retired by EPA.

GSEC stated that 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).

NRECA stated that NERC's 2022 Long-Term Reliability Assessment mirrors many of their concerns over future electric reliability. NERC recommends:

- Managing 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

- Considering the impacts of electrification may have on future electric demand
- Expanding 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.

NRECA stated joint comments by four Regional Transmission Organizations amplify and add to these reliability and cost concerns. The RTOs comments address among various other issues "overarching reliability concerns" and "shortcomings in EPA's reliability analysis assumptions" in connection with this rulemaking.

NRECA stated 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.

APPA stated 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 CCS and hydrogen are not resolved in a timely manner.

GSEC stated 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. 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.

GSEC stated the 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., NO_x, SO_x, 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. 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's or independent system operator's (ISO's) RUC instructions. 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.

GSEC stated that 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.

Minnkota requested EPA conduct a resource adequacy analysis on rural generation and transmission cooperatives (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.

Minnkota stated 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 Milton R. Young Station (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.

WFEC stated, 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.

8.4 BSER Technologies

EKPC stated 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 CO_2 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. EPA did not offer a direct solution except to turn community-specific concerns over to states for engagement.

GSEC stated co-firing CTs with hydrogen, or CCS of greenhouse emissions from CTs, is not the 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.

GSEC stated their 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. 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.

Minnkota stated they are sponsoring the development of a CCS project called Project Tundra, estimated to capture 95% of 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.

Minnkota stated EPA'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. 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.

Minnkota stated the 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. 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.

NRECA stated the proposal's assumption that existing natural gas pipelines can be used to transport hydrogen safely is flatly wrong. The safe hydrogen blend with natural gas in existing pipelines is 5 to 10%, which is wholly inadequate for even a 30% hydrogen blend needed in 2032. Moreover, even a 5% hydrogen blend present safety concerns with natural gas residential use. So 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.

NRECA stated the proposal appears to ignore costs associated with supplying the required amount hydrogen needed for reliable turbine electric generation. Storing enough hydrogen on site for one to five days of operation, as required for reliable power, would require significant underground or surface storage. 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. 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 Regulatory Impact Analysis (RIA).

NRECA stated 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.

NRECA stated 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. 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. 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.

WFEC stated CCS and hydrogen co-firing are not yet commercially viable or available on EPA's unreasonably expedited timeframe. 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. In addition, these technologies have unproven emission reductions and may not perform as expected.

WFEC stated that 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. 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.

8.5 Costs

APPA has consulted with several members who are investigating the potential to add new CTs that would fall into the proposed new source performance standards for low-load and intermediate-load subcategories and are considering major modifications. 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 EGUs under CAA 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 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 stated EPA must consider the costs of the CAA section 111(d) requirements because they are inextricably linked to the NSPS.

APPA stated 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 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, gas-line and hydrogen infrastructure expenses, and other ancillary costs of CCS and hydrogen projects.

APPA stated 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. 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.

APPA stated that 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.

EKPC stated the proposed rule would require major capital investments in new generation and large retrofit projects, and cooperatives must be afforded 18 to 24 months of additional time to pursue financing.

EKPC stated EPA should consider the cumulative cost impacts of EPA's suite of power sector rules.

EKPC stated the BSER technologies are more costly for cooperatives with transmission-heavy systems.

EKPC stated EPA should consider the cost of stranded assets in its cost impact analysis. The Proposed Rule requires utilities to strand generation assets even though they are still paying on environmental compliance financial obligations. EKPC incurred substantial debt through 2049 to enable the installation of NO_x and SO_2 air pollution controls at its coal-fired units between 2007 and 2012. To achieve compliance with EPA's recent revisions to the Coal Combustion Residuals rule and Effluent Limitations Guidelines, 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.

EKPC stated 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.

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

Minnkota stated 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. 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." 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.

Minnkota stated that 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 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 capital and operating expenditures 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.

Minnkota stated that 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.

Minnkota stated 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 G&Ts that may qualify for funding under the program. The program provides that no one G&T can get more than \$970M. 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 capital expenditure 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 Milton R. Young Station 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.

NRECA stated 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.

NRECA stated 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. Due to 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.

NRECA stated the proposal's hydrogen production costs are way off the mark. 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.

WFEC stated the financial impact of EPA's proposed will undermine their mission of providing affordable, reliable power to their members.

WFEC stated 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.

WFEC stated they do 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.

WFEC estimated 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.

8.6 Impacts

APPA stated 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. 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 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.

APPA stated 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.

APPA stated that to date, EPA's answer to challenging financial scenarios is the 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, 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.

EKPC stated 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 CO_2 than one baseload gas-fired new unit.

WFEC stated EPA's proposal will force premature closure of dispatchable and always available thermal resources while also making it harder to permit, site, and build critical new generating units.

WFEC stated they cannot retire a unit without replacing that unit's capacity, and they do not have any excess capacity within its system. Retirement and replacement for its individual units would require at least seven years.

NRECA and WFEC stated they 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 six to seven 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.

9. PANEL FINDINGS

9.1 Number and Types of Entities Affected

As described in Section 3, EPA estimates in the proposed rule that approximately 10% of potentially affected new capacity may be owned by small entities and estimates that this total will be approximately ten small entities. SERs commented that EPA should update the SBA size standards used in its analysis, and provided specific data corrections EPA should make in its underlying unit-level data.

The Panel recommends that EPA consider the unique circumstances faced by small rural cooperatives and municipalities. These small entities may face significant challenges in planning, investment, and financing. An impact that may not be significant for a for-profit company, whether privately owned or public, could have a more significant economic impact. Where the information is available, EPA should consider small entities' debt as a factor in determining whether costs to rural cooperatives as a percentage of revenue are significant.

The Panel recommends EPA review its database of electricity generators and validate the size of the operators against the current SBA size standards for for-profit businesses and the standards in the RFA for nonprofit businesses (see 5 USC 601(4)). The Panel further recommends EPA make appropriate data corrections and reevaluate the screening analysis.

9.2 Related Federal Rules

EGUs are subject to multiple EPA Clean Air Act regulations, including NSPS under section 111 and NESHAP under section 112. EGUs are also the subject of regulation due to National Ambient Air Quality Standards (NAAQS), including the rules addressing transport of pollutants between states. EGUs are also subject to Effluent Limitation Guidelines under the Clean Water Act. Coal-fired power plants are subject to regulation of coal combustion residuals under the Resource Conservation and Recovery Act (RCRA) and the Clean Water Act. Small entities have made multiple investments to come into compliance with these requirements over the past decade. One SER noted that they were incurring debt through 2050 to finance these compliance efforts.

SERs note that EPA's determination of BSER relies heavily on the development and accessibility of infrastructure that is subject to multiple federal authorities. If facilities must be sited based on availability for geologic carbon sequestration, additional natural gas pipelines and transmission lines will be necessary. If facilities are placed based on the availability of natural gas and transmissions lines, then additional carbon pipelines or hydrogen pipelines will be necessary. These investments will be subject to permitting review by FERC, which includes environmental reviews under the National Environmental Policy Act (NEPA), and safety regulation by PHMSA. To the extent that highway vehicles are used in the transport of hydrogen, these activities are subject to regulation by the Federal Motor Carrier Safety Administration (FMCSA). In the Western United States, significant pipeline investment will also likely involve permits by federal land management agencies. Carbon sequestration is subject to EPA regulation under the Clean Water Act and is subject to the Underground Injection Control Program. EPA has published multiple guidance documents specific to carbon sequestration.

The Panel recommends EPA continue consulting with DOE, FERC, and PHMSA staff to ensure there are no overlapping or contradictory requirements on these sources.

9.3 Regulatory Flexibility Alternatives

The Panel has reviewed the information provided by EPA to the SERs and the SERs' oral and written comments from the pre-Panel and Panel outreach. In response to this consultation, the Panel identifies the following significant alternatives for consideration by the Administrator of EPA which accomplish the stated objectives of the Clean Air Act, and which minimize any significant economic impact of the proposed rule on small entities.

9.3.1 Subcategorization

SERs stated EPA should 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. Additionally, SERs stated hydrogen and CCS are not BSER because they are not commercially available and viable in very rural areas.

The Panel recommends EPA consider and request comment on potential exclusions or subcategories for small entities that would be based on the class, type, or size of the source and be consistent with the Clean Air Act.

The Panel understands that current technology for CCS and clean hydrogen generation can require significant water resources, and CCS requires geologic sequestration. Small entity generating units located far from either one of these resources are likely to incur higher costs and at higher rates of uncertainty due to the need for infrastructure investment. The Panel recommends that EPA consider such costs, and other factors including distance from storage, regional renewable energy resource potential, fuel costs, and capital costs for new additions and retrofits, to small entities in its final rule analysis.

The Panel recommends EPA solicit comment on whether rural electric cooperatives and small utility distribution systems (serving 50,000 customers or less) can expect to have access to hydrogen and CCS infrastructure, and if a subcategory for these units is appropriate.

9.3.2 Reliability

SERs stated EPA's proposed rule will have significant reliability impacts, including that areas with transmission system limitations and energy market constraints risk power interruption if replacement generation cannot be put in place before retirements. SERs recommended that RTOs be involved to evaluate safety and reliability concerns.

SERs expressed concern that EPA's proposal relies on the continued development of technologies not currently in wide use and large-scale investments in new infrastructure and pushes these technologies significantly faster than the infrastructure will be ready and sooner than they can justify investment to their stakeholders and ratepayers. This is of particular concern for small entities that are retiring generation in response to other regulatory mandates and need to replace that generation to continue serving their customers.

The Panel recommends EPA solicit comment on a mechanism for reliability relief. Such a mechanism should be easily implementable and straightforward to address electric reliability concerns. The Panel also recommends EPA solicit comments on other mechanisms in the event RTO, ISO or other relevant authorities identify reliability issues; comment solicitation should also include phase-in considerations for small entities, implementation flexibilities for certain circumstances that may be outside the control of affected sources, and lessons learned from past reliability mechanisms in light of the proposed rule.

9.3.3 Analysis

SERs took issue with aspects of EPA's screening analysis, including relying on historical build patterns to project future investments, and recommending that this record be further strengthened by including additional planned builds by small entities. In addition, SERs commented that EPA should consider the impacts of the proposed requirements on existing sources, in addition to new sources, when evaluating the impacts on small entities, in particular accounting for the need for replacement capacity as a result of existing source requirements and the potential for requiring additional power purchases.

The Panel recognizes that many SERs have identified analytical concerns, and makes the following recommendations for EPA's analysis of small entities impacts in its final rule:

- EPA should consider economic projections of the price of hydrogen as an input in its analysis of small entities impacts and consider sensitivity analyses that address the uncertainty in this future market. EPA should consider comments on availability and cost assumptions for hydrogen. EPA should incorporate this information as relevant within the modeling for the final rule.
- EPA's analysis should consider access to natural resources, including regionalized renewable energy resource potential, fuel costs, and capital costs for both fossil fuel and renewable energy technologies, in the development of estimates of small entities impacts.
- EPA should consider the supporting infrastructure and the logistics of on-site storage of carbon or hydrogen in its analysis of small entities impacts.
- EPA's modeling should capture a representation of the distance from source to sink for carbon storage and sequestration, and include these costs in the compliance cost estimates for the final rule.
- EPA should consider the effects of the final rule on communities that small entities serve, and whether there would be disproportionate effects across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation.

9.4 Advocacy Recommendations

9.4.1 Number and Types of Entities Affected

Advocacy recommends EPA include SER-provided information about intended future investments in generating capacity by small entities. EPA should consider that these investments may be driven by retirement decisions and thus not necessarily based on historical patterns of investment, particularly for those small entities that must close coal-fired power plants. EPA should also consider whether the requirements proposed under 111(d) for existing sources may lead small entities to retire existing generation capacity and seek to replace it with new generation, further raising the number of impacted small entities above the baseline investment and making the historical data a less useful indicator of future investment.

9.4.2 Subcategorization

Advocacy recommends EPA additionally take comment on an exclusion from CCS or hydrogen co-firing for smaller power plants associated with renewable energy investments and the appropriate mechanisms to identify and maintain such an association.

Advocacy recommends EPA propose alternative thresholds between low, intermediate, and base load, in response to SER concerns that the threshold for low load does not provide sufficient flexibility and could hinder operation of more efficient peaking units in circumstances that do not rise to a "system emergency."

Appendix A: List of Materials shared with Potential Small Entity Representatives

Appendix A1 is a compilation of all outreach materials shared with potential SERs for the Pre-Panel Outreach meeting. Below is a list of those materials.

- Pre-Panel Outreach Meeting Agenda
- SBAR Panel Process Presentation
- Pre-Panel Outreach Rulemaking Presentation
- Questions for Small Entity Representatives

Appendix A2 is a compilation of all outreach materials shared with SERs for the Panel Outreach meeting. Below is a list of those materials.

- Panel Outreach Meeting Agenda
- Panel Outreach Rulemaking Presentation

Appendix B: Written Comments Submitted by Potential Small Entity Representatives

Appendix B1 is a compilation of all written comments submitted by potential SERs following the Pre-Panel Outreach meeting. Below are the SERs that submitted comments.

- American Public Power Association (APPA)
- National Rural Electric Cooperative Association (NRECA)
- Western Farmers Electric Cooperative (WFEC)

Appendix B2 is a compilation of all written comments submitted by SERs following the Panel Outreach meeting. Below are the SERs that submitted comments.

- American Public Power Association (APPA)
- East Kentucky Power Cooperative (EKPC)
- Golden Spread Electric Cooperative (GSEC)
- Minnkota Power Cooperative (Minnkota)
- National Rural Electric Cooperative Association (NRECA)
- Western Farmers Electric Cooperative (WFEC)