No. ____

In the Supreme Court of the United States

EDISON ELECTRIC INSTITUTE, OKLAHOMA GAS AND ELECTRIC COMPANY, AND IDAHO POWER COMPANY,
Applicants,

v.

ENVIRONMENTAL PROTECTION AGENCY and MICHAEL S. REGAN, Administrator, United States Environmental Protection Agency,
Respondents.

TO THE HONORABLE JOHN G. ROBERTS, JR., CHIEF JUSTICE OF THE UNITED STATES AND CIRCUIT JUSTICE FOR THE D.C. CIRCUIT

APPENDIX TO APPLICATION FOR IMMEDIATE STAY OF FINAL AGENCY ACTION PENDING APPELLATE REVIEW

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APPENDIX A

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2023–0072; FRL–8536–01–OAR]

RIN 2060–AV09

New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing multiple actions under section 111 of the Clean Air Act (CAA) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs). First, the EPA is finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines at this time; instead, the EPA intends to take further action on the proposed emission guidelines at a later date.

DATES: This final rule is effective on July 8, 2024. The incorporation by reference of certain publications listed in the rules is approved by the Director of the Federal Register as of July 8, 2024. The incorporation by reference of certain other materials listed in the rule was approved by the Director of the Federal Register as of October 23, 2015.

ADDRESSES: The EPA has established a docket for these actions under Docket ID No. EPA–HQ–OAR–2023–0072. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: Lisa Thompson (she/her), Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5158; and email address: *thompson.lisa@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACE Affordable Clean Energy rule
BSER best system of emissions reduction
Btu British thermal unit
CAA Clean Air Act
CBI Confidential Business Information
CCS carbon capture and sequestration/storage
CCUS carbon capture, utilization, and sequestration/storage
CO_2 carbon dioxide
DER distributed energy resources
DOE Department of Energy
EEA energy emergency alert
EGU electric generating unit
EIA Energy Information Administration
EJ environmental justice
E.O. Executive Order
EPA Environmental Protection Agency
FEED front-end engineering and design
FGD flue gas desulfurization
FR Federal Register
GHG greenhouse gas
GW gigawatt
GWh gigawatt-hour
HAP hazardous air pollutant
HRSG heat recovery steam generator
IIJA Infrastructure Investment and Jobs Act
IRC Internal Revenue Code
kg kilogram
kWh kilowatt-hour
LCOE levelized cost of electricity
LNG liquefied natural gas
MATS Mercury and Air Toxics Standards
MMBtu/h million British thermal units per hour
MMT CO_2e million metric tons of carbon dioxide equivalent
MW megawatt
MWh megawatt-hour
NAAQS National Ambient Air Quality Standards
NESHAP National Emission Standards for Hazardous Air Pollutants
NGCC natural gas combined cycle
NO_X nitrogen oxides
NSPS new source performance standards
NSR New Source Review
PM particulate matter
$PM_{2.5}$ fine particulate matter
RIA regulatory impact analysis
TSD technical support document
U.S. United States

Organization of this document. The information in this preamble is organized as follows:

I. Executive Summary

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare.[1] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the destructive and worsening effects of climate change every day.[2] Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021.[3] At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources is available to the power sector—including carbon capture and sequestration/storage (CCS), co-firing with less GHG-intensive fuels, and more efficient generation. Congress has also acted to provide funding and other incentives to encourage the deployment of various technologies, including CCS, to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and new source performance standards (NSPS) that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

Specifically, the EPA is first finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines at this time and plans to expeditiously issue an additional proposal that more comprehensively addresses GHG emissions from this portion of the fleet. The EPA acknowledges that the share of GHG emissions from existing fossil fuel-fired combustion turbines has been growing and is projected to continue to do so, particularly as emissions from other portions of the fleet decline, and that it is vital to regulate the GHG emissions from these sources consistent with CAA section 111.

These final actions ensure that the new and existing fossil fuel-fired EGUs that are subject to these rules reduce their GHG emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and

[1] 74 FR 66496 (December 15, 2009).

[2] The 5th National Climate Assessment (NCA5) states that the effects of human-caused climate change are already far-reaching and worsening across every region of the United States and that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.

[3] *https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.*

welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

A. Climate Change and Fossil Fuel-Fired EGUs

These final actions reduce the emissions of GHGs from new and existing fossil fuel-fired EGUs. The increasing concentrations of GHGs in the atmosphere are, and have been, warming the planet, resulting in serious and life-threatening environmental and human health impacts. The increased concentrations of GHGs in the atmosphere and the resulting warming have led to more frequent and more intense heat waves and extreme weather events, rising sea levels, and retreating snow and ice, all of which are occurring at a pace and scale that threaten human health and welfare.

Fossil fuel-fired EGUs that are uncontrolled for GHGs are one of the biggest domestic sources of GHG emissions. At the same time, there are technologies available (including technologies that can be applied to fossil fuel-fired power plants) to significantly reduce emissions of GHGs from the power sector. Low- and zero-GHG electricity are also key enabling technologies to significantly reduce GHG emissions in almost every other sector of the economy.

In 2021, the power sector was the largest stationary source of GHGs in the United States, emitting 25 percent of overall domestic emissions.[4] In 2021, existing fossil fuel-fired steam generating units accounted for 65 percent of the GHG emissions from the sector, but only accounted for 23 percent of the total electricity generation.

Because of its outsized contributions to overall emissions, reducing emissions from the power sector is essential to addressing the challenge of climate change—and sources in the power sector also have many available options for reducing their climate-destabilizing emissions. Particularly relevant to these actions are several key technologies (CCS and co-firing of lower-GHG fuels) that allow fossil fuel-fired steam generating EGUs and stationary combustion turbines to provide power while emitting significantly lower GHG emissions. Moreover, with the increased electrification of other GHG-emitting sectors of the economy, such as personal vehicles, heavy-duty trucks, and the heating and cooling of buildings, reducing GHG emissions from these affected sources can also help reduce power sector pollution that might otherwise result from the electrification of other sectors of the economy.

B. Recent Developments in Emissions Controls and the Electric Power Sector

Several recent developments concerning emissions controls are relevant for the EPA's determination of the BSER for existing coal-fired steam generating EGUs and new natural gas-fired stationary combustion turbines. These include lower costs and continued improvements in CCS technology, alongside Federal tax incentives that allow companies to largely offset the cost of CCS. Well-established trends in the sector further inform where using such technologies is cost effective and feasible, and form part of the basis for the EPA's determination of the BSER.

In recent years, the cost of CCS has declined in part because of process improvements learned from earlier deployments and other advances in the technology. In addition, the Inflation Reduction Act (IRA), enacted in 2022, extended and significantly increased the tax credit for carbon dioxide (CO_2) sequestration under Internal Revenue Code (IRC) section 45Q. The provision of tax credits in the IRA, combined with the funding included in the Infrastructure Investment and Jobs Act (IIJA), enacted in 2021, incentivize and facilitate the deployment of CCS and other GHG emission control technologies. As explained later in this preamble, these developments support the EPA's conclusion that CCS is the BSER for certain subcategories of new and existing EGUs because it is an adequately demonstrated and available control technology that significantly reduces emissions of dangerous pollution and because the costs of its installation and operation are reasonable. Some companies have already made plans to install CCS on their units independent of the EPA's regulations.

Well documented trends in the power sector also influence the EPA's determination of the BSER. In particular, CCS entails significant capital expenditures and is only cost-reasonable for units that will operate enough to defray those capital costs. At the same time, many utilities and power generating companies have recently announced plans to accelerate changing the mix of their generating assets. The IIJA and IRA, state legislation, technology advancements, market forces, consumer demand, and the advanced age of much of the existing fossil fuel-fired generating fleet are collectively leading to, in most cases, decreased use of the fossil fuel-fired units that are the subjects of these final actions. From 2010 through 2022, fossil fuel-fired generation declined from approximately 72 percent of total net generation to approximately 60 percent, with generation from coal-fired sources dropping from 49 percent to 20 percent of net generation during this period.[5] These trends are expected to continue and are relevant to determining where capital-intensive technologies, like CCS, may be feasibly and cost-reasonably deployed to reduce emissions.

Congress has taken other recent actions to drive the reduction of GHG emissions from the power sector. As noted earlier, Congress enacted IRC section 45Q in section 115 of the Energy Improvement and Extension Act of 2008 to provide a tax credit for the sequestration of CO_2. Congress significantly amended IRC section 45Q in the Bipartisan Budget Act of 2018, and more recently in the IRA, to make this tax incentive more generous and effective in spurring long-term deployment of CCS. In addition, the IIJA provided more than $65 billion for infrastructure investments and upgrades for transmission capacity, pipelines, and low-carbon fuels.[6] Further, the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS Act) authorized billions more in funding for development of low- and non-GHG emitting energy technologies that could provide additional low-cost options for power companies to reduce overall GHG emissions.[7] As discussed in greater detail in section IV.E.1 of this preamble, the IRA, the IIJA, and CHIPS contain numerous other provisions encouraging companies to reduce their GHGs.

C. Summary of the Principal Provisions of These Regulatory Actions

These final actions include the repeal of the ACE Rule, BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, and BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired steam generating units.

[4] *https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.*

[5] U.S. Energy Information Administration (EIA). Electric Power Annual. 2010 and 2022. *https://www.eia.gov/electricity/annual/html/epa_03_01_a.html.*

[6] *https://www.congress.gov/bill/117th-congress/house-bill/3684.*

[7] *https://www.congress.gov/bill/117th-congress/house-bill/4346.*

The EPA is taking these actions consistent with its authority under CAA section 111. Under CAA section 111, once the EPA has identified a source category that contributes significantly to dangerous air pollution, it proceeds to regulate new sources and, for GHGs and certain other air pollutants, existing sources. The central requirement is that the EPA must determine the ''best system of emission reduction . . . adequately demonstrated,'' taking into account the cost of the reductions, non-air quality health and environmental impacts, and energy requirements.[8] The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER and may subcategorize sources accordingly.

Once it identifies the BSER, the EPA must determine the ''degree of emission limitation'' achievable by application of the BSER. For new sources, the EPA establishes the standard of performance with which the sources must comply, which is a standard for emissions that reflects the degree of emission limitation. For existing sources, the EPA includes the information it has developed concerning the BSER and associated degree of emission limitation in emission guidelines and directs the states to adopt state plans that contain standards of performance that are consistent with the emission guidelines.

Since the early 1970s, the EPA has promulgated regulations under CAA section 111 for more than 60 source categories, which has established a robust set of regulatory precedents that has informed the development of these final actions. During this period, the courts, primarily the U.S. Court of Appeals for the D.C. Circuit and the Supreme Court, have developed a body of caselaw interpreting CAA section 111. As the Supreme Court has recognized, the EPA has typically (and does so in these actions) determined the BSER to be ''measures that improve the pollution performance of individual sources,'' such as add-on controls and clean fuels. *West Virginia* v. *EPA,* 597 U.S. 697, 734 (2022). For present purposes, several of a BSER's key features include that it must reduce emissions, be based on ''adequately demonstrated'' technology, and have a reasonable cost of control. The case law interpreting section 111 has also recognized that the BSER can be forward-looking in nature and take into account anticipated improvements in control technologies. For example, the EPA may determine a control to be ''adequately demonstrated'' even if it is new and not yet in widespread commercial use, and, further, that the EPA may reasonably project the development of a control system at a future time and establish requirements that take effect at that time. Further, the most relevant costs under CAA section 111 are the costs to the regulated facility. The actions that the EPA is finalizing are consistent with the requirements of CAA section 111 and its regulatory history and caselaw, which is discussed in further detail in section V of this preamble.

1. Repeal of ACE Rule

The EPA is finalizing its proposed repeal of the existing ACE Rule emission guidelines. First, as a policy matter, the EPA concludes that the suite of heat rate improvements (HRI) that was identified in the ACE Rule as the BSER is not an appropriate BSER for existing coal-fired EGUs. Second, the ACE Rule rejected CCS and natural gas co-firing as the BSER for reasons that no longer apply. Third, the EPA concludes that the ACE Rule conflicted with CAA section 111 and the EPA's implementing regulations because it did not provide sufficient specificity as to the BSER the EPA had identified or the ''degree of emission limitation achievable though application of the [BSER].''

Also, the EPA is withdrawing the proposed revisions to the New Source Review (NSR) regulations that were included the ACE Rule proposal (83 FR 44773–83; August 31, 2018).

2. Emission Guidelines for Existing Fossil Fuel-Fired Steam Generating Units

The EPA is finalizing CCS with 90 percent capture as BSER for existing coal-fired steam generating units. These units have a presumptive standard[9] of an 88.4 percent reduction in annual emission rate, with a compliance deadline of January 1, 2032. As explained in detail below, CCS is an adequately demonstrated technology that achieves significant emissions reduction and is cost-reasonable, taking into account the declining costs of the technology and a substantial tax credit available to sources. In recognition of the significant capital expenditures involved in deploying CCS technology and the fact that 45 percent of regulated units already have announced retirement dates, the EPA is finalizing a separate subcategory for existing coal-fired steam generating units that demonstrate that they plan to permanently cease operation before January 1, 2039. The BSER for this subcategory is co-firing with natural gas, at a level of 40 percent of the unit's annual heat input. These units have a presumptive standard of 16 percent reduction in annual emission rate corresponding to this BSER, with a compliance deadline of January 1, 2030.

The EPA is finalizing an applicability exemption for existing coal-fired steam EGUs demonstrating that they plan to permanently cease operation prior to January 1, 2032, based on the Agency's determination that units retiring before this date generally do not have cost-reasonable options for improving their GHG emissions performance. Sources that demonstrate they will permanently cease operation before this applicability deadline will not be subject to these emission guidelines. Further, the EPA is not finalizing the proposed imminent-term or near-term subcategories.

The EPA is finalizing the proposed structure of the subcategory definitions for natural gas- and oil-fired steam generating units. The EPA is also finalizing routine methods of operation and maintenance as the BSER for intermediate load and base load natural gas- and oil-fired steam generating units. Furthermore, the EPA is finalizing presumptive standards for natural gas- and oil-fired steam generating units that are slightly higher than at proposal: base load sources (those with annual capacity factors greater than 45 percent) have a presumptive standard of 1,400 lb CO_2/MWh-gross, and intermediate load sources (those with annual capacity factors greater than 8 percent and less than or equal to 45 percent) have a presumptive standard of 1,600 lb CO_2/MWh-gross. For low load (those with annual capacity factors less than 8 percent), the EPA is finalizing a uniform fuels BSER and a presumptive input-based standard of 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources.

3. Standards of Performance for New and Reconstructed Fossil Fuel-Fired Combustion Turbines

The EPA is finalizing emission standards for three subcategories of combustion turbines—base load, intermediate load, and low load. The BSER for base load combustion turbines includes two components to be implemented initially in two phases. The first component of the BSER for base load combustion turbines is highly efficient generation (based on the emission rates that the best performing

[8] CAA section 111(a)(1).

[9] Presumptive standards of performance are discussed in detail in section X of the preamble. While states establish standards of performance for sources, the EPA provides presumptively approvable standards of performance based on the degree of emission limitation achievable through application of the BSER for each subcategory.

units are achieving) and the second component for base load combustion turbines is utilization of CCS with 90 percent capture. Recognizing the lead time that is necessary for new base load combustion turbines to plan for and install the second component of the BSER (*i.e.,* 90 percent CCS), including the time that is needed to deploy the associated infrastructure (CO_2 pipelines, storage sites, *etc.*), the EPA is finalizing a second phase compliance deadline of January 1, 2032, for this second component of the standard.

The EPA has identified highly efficient simple cycle generation as the BSER for intermediate load combustion turbines. For low load combustion turbines, the EPA is finalizing its proposed determination that the BSER is the use of lower-emitting fuels.

4. New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units

The EPA is finalizing revisions of the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.,* a modification that increases its hourly emission rate by more than 10 percent) to mirror the emission guidelines for existing coal-fired steam generators. This reflects the EPA's determination that such modified sources are capable of meeting the same presumptive standards that the EPA is finalizing for existing steam EGUs. Further, this revised standard for modified coal-fired steam EGUs will avoid creating an unjustified disparity between emission control obligations for modified and existing coal-fired steam EGUs.

The EPA did not propose, and we are not finalizing, any review or revision of the 2015 standard for large modifications of oil- or gas-fired steam generating units because we are not aware of any existing oil- or gas-fired steam generating EGUs that have undertaken such modifications or have plans to do so, and, unlike an existing coal-fired steam generating EGUs, existing oil- or gas-fired steam units have no incentive to undertake such a modification to avoid the requirements we are including in this final rule for existing oil- or gas-fired steam generating units.

As discussed in the proposal preamble, the EPA is not revising the NSPS for newly constructed or reconstructed fossil fuel-fired steam electric generating units (EGU) at this time because the EPA anticipates that few, if any, such units will be constructed or reconstructed in the foreseeable future. However, the EPA has recently become aware that a new coal-fired power plant is under consideration in Alaska. Accordingly, the EPA is not, at this time, finalizing its proposal not to review the 2015 NSPS, and, instead, will continue to consider whether to review the 2015 NSPS. As developments warrant, the EPA will determine either to conduct a review, and propose revised standards of performance, or not conduct a review.

Also, in this final action, the EPA is withdrawing the 2018 proposed amendments [10] to the NSPS for GHG emissions from coal-fired EGUs.

5. Severability

This final action is composed of four independent rules: the repeal of the ACE rule; GHG emission guidelines for existing fossil fuel-fired steam generating units; NSPS for GHG emissions from new and reconstructed fossil fuel-fired combustion turbines; and revisions to the standards of performance for new, modified, and reconstructed fossil fuel-fired steam generating units. The EPA could have finalized each of these rules in separate **Federal Register** notices as separate final actions. The Agency decided to include these four independent rules in a single **Federal Register** notice for administrative ease because they all relate to climate pollution from the fossil fuel-fired electric generating units source category. Accordingly, despite grouping these rules into one single **Federal Register** notice, the EPA intends that each of these rules described in sections I.C.1 through I.C.4 is severable from the other.

In addition, each rule is severable as a practical matter. For example, the EPA would repeal the ACE Rule separate and apart from finalizing new standards for these sources as explained herein. Moreover, the BSER and associated emission guidelines for existing fossil fuel-fired steam generating units are independent of and would have been the same regardless of whether the EPA finalized the other parts of this rule. In determining the BSER for existing fossil fuel-fired steam generating units, the EPA considered only the technologies available to reduce GHG emissions at those sources and did not take into consideration the technologies or standards of performance for new fossil fuel-fired combustion turbines. The same is true for the Agency's evaluation and determination of the BSER and associated standards of performance for new fossil fuel-fired combustion turbines. The EPA identified the BSER and established the standards of performance by examining the controls that were available for these units. That analysis can stand alone and apart from the EPA's separate analysis for existing fossil fuel-fired steam generating units. Though the record evidence (including, for example, modeling results) often addresses the availability, performance, and expected implementation of the technologies at both existing fossil fuel-fired steam generating units and new fossil fuel-fired combustion turbines in the same record documents, the evidence for each evaluation stands on its own, and is independently sufficient to support each of the final BSERs.

In addition, within section I.C.1, the final action to repeal the ACE Rule is severable from the withdrawal of the NSR revisions that were proposed in parallel with the ACE Rule proposal. Within the group of actions for existing fossil fuel-fired steam generating units in section I.C.2, the requirements for each subcategory of existing sources are severable from the requirements for each other subcategory of existing sources. For example, if a court were to invalidate the BSER and associated emission standard for units in the medium-term subcategory, the BSER and associated emission standard for units in the long-term subcategory could function sensibly because the effectiveness of the BSER for each subcategory is not dependent on the effectiveness of the BSER for other subcategories. Within the group of actions for new and reconstructed fossil fuel-fired combustion turbines in section I.C.3, the following actions are severable: the requirements for each subcategory of new and reconstructed turbines are severable from the requirements for each other subcategory; and within the subcategory for base load turbines, the requirements for each of the two components are severable from the requirements for the other component. Each of these standards can function sensibly without the others. For example, the BSER for low load, intermediate load, and base load subcategories is based on the technologies the EPA determined met the statutory standards for those subcategories and are independent from each other. And in the base load subcategory units may practically be constructed using the most efficient technology without then installing CCS and likewise may install CCS on a turbine system that was not constructed with the most efficient technology. Within the group of actions for new, modified, and reconstructed fossil fuel-fired steam generating units in section I.C.4, the revisions of the standards of performance for coal-fired steam

[10] See 83 FR 65424, December 20, 2018.

generators that undertake a large modification are severable from the withdrawal of the 2018 proposal to revise the NSPS for emissions of GHG from EGUs. Each of the actions in these final rules that the EPA has identified as severable is functionally independent—*i.e.,* may operate in practice independently of the other actions.

In addition, while the EPA is finalizing this rule at the same time as other final rules regulating different types of pollution from EGUs—specifically the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (FR 2024–09815, EPA–HQ–OW–2009–0819; FRL–8794–02–OW); National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (FR 2024–09148, EPA–HQ–OAR–2018–0794; FRL–6716.3–02–OAR); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments (FR 2024–09157, EPA–HQ–OLEM–2020–0107; FRL–7814–04–OLEM)—and has considered the interactions between and cumulative effects of these rules, each rule is based on different statutory authority, a different record, and is completely independent of the other rules.

D. Grid Reliability Considerations

The EPA is finalizing multiple adjustments to the proposed rules that ensure the requirements in these final actions can be implemented without compromising the ability of power companies, grid operators, and state and Federal energy regulators to maintain resource adequacy and grid reliability. In response to the May 2023 proposed rule, the EPA received extensive comments from balancing authorities, independent system operators and regional transmission organizations, state regulators, power companies, and other stakeholders on the need for the final rule to accommodate resource adequacy and grid reliability needs. The EPA also engaged with the balancing authorities that submitted comments to the docket, the staff and Commissioners of the Federal Energy Regulatory Commission (FERC), the Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), and other expert entities during the course of this rulemaking. Finally, at the invitation of FERC, the EPA participated in FERC's Annual Reliability Technical Conference on November 9, 2023.

These final actions respond to this input and feedback in multiple ways, including through changes to the universe of affected sources, longer compliance timeframes for CCS implementation, and other compliance flexibilities, as well as articulation of the appropriate use of RULOF to address reliability issues during state plan development and in subsequent state plan revisions. In addition to these adjustments, the EPA is finalizing several programmatic mechanisms specifically designed to address reliability concerns raised by commenters. For existing fossil fuel-fired EGUs, a short-term reliability emergency mechanism is available for states to provide more flexibility by using an alternative emission limitation during acute operational emergencies when the grid might be temporarily under heavy strain. A similar short-term reliability emergency mechanism is also available to new sources. In addition, the EPA is creating an option for states to provide for a compliance date extension for existing sources of up to 1 year under certain circumstances for sources that are installing control technologies to comply with their standards of performance. Lastly, states may also provide, by inclusion in their state plans, a reliability assurance mechanism of up to 1 year that under limited circumstances would allow existing units that had planned to cease operating by a certain date to temporarily remain available to support reliability. Any extensions exceeding 1 year must be addressed through a state plan revision. In order to utilize this reliability pathway, there must be an adequate demonstration of need and certification by a reliability authority, and approval by the appropriate EPA Regional Administrator. The EPA plans to seek the advice of FERC for extension requests exceeding 6 months. Similarly, for new fossil fuel-fired combustion turbines, the EPA is creating a mechanism whereby baseload units may request a 1-year extension of their CCS compliance deadline under certain circumstances.

The EPA has evaluated the resource adequacy implications of these actions in the final technical support document (TSD), *Resource Adequacy Analysis,* and conducted capacity expansion modeling of the final rules in a manner that takes into account resource adequacy needs. The EPA finds that resource adequacy can be maintained with the final rules. The EPA modeled a scenario that complies with the final rules and that meets resource adequacy needs. The EPA also performed a variety of other sensitivity analyses looking at higher electricity demand (load growth) and impact of the EPA's additional regulatory actions affecting the power sector. These sensitivity analyses indicate that, in the context of higher demand and other pending power sector rules, the industry has available pathways to comply with this rule that respect NERC reliability considerations and constraints.

In addition, the EPA notes that significant planning and regulatory mechanisms exist to ensure that sufficient generation resources are available to maintain reliability. The EPA's consideration of reliability in this rulemaking has also been informed by consultation with the DOE under the auspices of the March 9, 2023, memorandum of understanding (MOU)[11] signed by the EPA Administrator and the Secretary of Energy, as well as by consultation with FERC expert staff. In these final actions, the EPA has included various flexibilities that allow power companies and grid operators to plan for achieving feasible and necessary reductions of GHGs from affected sources consistent with the EPA's statutory charge while ensuring that the rule will not interfere with systems operators' ability to ensure grid reliability.

A thorough description of how adjustments in the final rules address reliability issues, the EPA's outreach to balancing authorities, EPA's supplemental notice, as well as the introduction of mechanisms to address short- and long-term reliability needs is presented in section XII.F of this preamble.

E. Environmental Justice Considerations

Consistent with Executive Order (E.O.) 14096, and the EPA's commitment to upholding environmental justice (EJ) across its policies and programs, the EPA carefully considered the impacts of these actions on communities with environmental justice concerns. As part of the regulatory development process for these rulemakings, and consistent with directives set forth in multiple Executive Orders, the EPA conducted extensive outreach with interested parties including Tribal nations and communities with environmental justice concerns. These opportunities gave the EPA a chance to hear directly from the public, including from communities potentially impacted by these final

[11] *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* (March 9, 2023). *https://www.epa.gov/power-sector/electric-reliability-mou.*

actions. The EPA took this feedback into account in its development of these final actions.[12] The EPA's analysis of environmental justice in these final actions is briefly summarized here and discussed in further detail in sections XII.E and XIII.J of the preamble and section 6 of the regulatory impact analysis (RIA).

Several environmental justice organizations and community representatives raised significant concerns about the potential health, environmental, and safety impacts of CCS. The EPA takes these concerns seriously, agrees that any impacts to historically disadvantaged and overburdened communities are important to consider, and has carefully considered these concerns as it finalized its determinations of the BSERs for these rules. The Agency acknowledges that while these final actions will result in large reductions of both GHGs and other emissions that will have significant positive benefits, there is the potential for localized increases in emissions, particularly if units installing CCS operate for more hours during the year and/or for more years than they would have otherwise. However, as discussed in section VII.C.1.a.iii(B), a robust regulatory framework exists to reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. The Council on Environmental Quality's (CEQ) February 2022 *Carbon Capture, Utilization, and Sequestration Guidance* and the EPA's evaluation of BSER recognize that multiple Federal agencies have responsibility for regulating and permitting CCS projects, along with state and tribal governments. As the CEQ has noted, Federal agencies have ''taken actions in the past decade to develop a robust carbon capture, utilization, and sequestration/storage (CCUS) regulatory framework to protect the environment and public health across multiple statutes.''[13][14] Furthermore, the EPA plans to review and update as needed its guidance on NSR permitting, specifically with respect to BACT determinations for GHG emissions and consideration of co-pollutant increases from sources installing CCS. For the reasons explained in section VII.C, the EPA is finalizing the determination that CCS is the BSER for certain subcategories of new and existing EGUs based on its consideration of all of the statutory criteria for BSER, including emission reductions, cost, energy requirements, and non-air health and environmental considerations. At the same time, the EPA recognizes the critical importance of ensuring that the regulatory framework performs as intended to protect communities.

These actions are focused on establishing NSPS and emission guidelines for GHGs that states will implement to significantly reduce GHGs and move us a step closer to avoiding the worst impacts of climate change, which is already having a disproportionate impact on communities with environmental justice concerns. The EPA analyzed several illustrative scenarios representing potential compliance outcomes and evaluated the potential impacts that these actions may have on emissions of GHG and other health-harming air pollutants from fossil fuel-fired EGUs, as well as how these changes in emissions might affect air quality and public health, particularly for communities with EJ concerns.

The EPA's national-level analysis of emission reduction and public health impacts, which is documented in section 6 of the RIA and summarized in greater detail in section XII.A and XII.D of this preamble, finds that these actions achieve nationwide reductions in EGU emissions of multiple health-harming air pollutants including nitrogen oxides (NO_X), sulfur dioxide (SO_2), and fine particulate matter ($PM_{2.5}$), resulting in public health benefits. The EPA also evaluated how the air quality impacts associated with these final actions are distributed, with particular focus on communities with EJ concerns. As discussed in the RIA, our analysis indicates that baseline ozone and $PM_{2.5}$ concentration will decline substantially relative to today's levels. Relative to these low baseline levels, ozone and $PM_{2.5}$ concentrations will decrease further in virtually all areas of the country, although some areas of the country may experience slower or faster rates of decline in ozone and $PM_{2.5}$ pollution over time due to the changes in generation and utilization resulting from these rules. Additionally, our comparison of future air quality conditions with and without these rules suggests that while these actions are anticipated to lead to modest but widespread reductions in ambient levels of $PM_{2.5}$ and ozone for a large majority of the nation's population, there is potential for some geographic areas and demographic groups to experience small increases in ozone concentrations relative to the baseline levels which are projected to be substantially lower than today's levels.

It is important to recognize that while these projections of emissions changes and resulting air quality changes under various illustrative compliance scenarios are based upon the best information available to the EPA at this time, with regard to existing sources, each state will ultimately be responsible for determining the future operation of fossil fuel-fired steam generating units located within its jurisdiction. The EPA expects that, in making these determinations, states will consider a number of factors and weigh input from the wide range of potentially affected stakeholders. The meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders—including community members adversely impacted by pollution, energy workers affected by construction and/or other changes in operation at fossil-fuel-fired power plants, consumers and other interested parties—will have an opportunity to have their concerns heard as states make decisions balancing a multitude of factors including appropriate standards of performance, compliance strategies, and compliance flexibilities for existing EGUs, as well as public health and environmental considerations. The EPA believes that these provisions, together with the protections referenced above, can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

F. Energy Workers and Communities

These final actions include requirements for meaningful engagement in development of state plans, including with energy workers and communities. These communities, including energy workers employed at affected EGUs, workers who may construct and install pollution control technology, workers employed by fuel extraction and delivery, organizations

[12] Specifically, the EPA has relied on, and is incorporating as a basis for this rulemaking, analyses regarding possible adverse environmental effects from CCS, including those highlighted by commenters. Consideration of these effects is permissible under CAA section 111(a)(1). Although the EPA also conducted analyses of disproportionate impacts pursuant to E.O. 14096, see section XII.E, the EPA did not consider or rely on these analyses as a basis for these rules.

[13] 87 FR 8808, 8809 (February 16, 2022).

[14] This framework includes, among other things, the EPA regulation of geologic sequestration wells under the Underground Injection Control (UIC) program of the Safe Drinking Water Act; required reporting and public disclosure of geologic sequestration activity, as well as implementation of rigorous monitoring, reporting, and verification of geologic sequestration under the EPA's Greenhouse Gas Reporting Program (GHGRP); and safety regulations for CO_2 pipelines administered by the Pipeline and Hazardous Materials and Safety Administration (PHMSA).

representing these workers, and communities living near affected EGUs, are impacted by power sector trends on an ongoing basis and by these final actions, and the EPA expects that states will include these stakeholders as part of their constructive engagement under the requirements in this rule.

The EPA consulted with the Federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) in development of these rules and the meaningful engagement requirements. The EPA notes that the Energy Communities IWG has provided resources to help energy communities access the expanded federal resources made available by the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act, many of which are relevant to the development of state plans.

G. Key Changes From Proposal

The key changes from proposal in these final actions are: (1) the reduction in number of subcategories for existing coal-fired steam generating units, (2) the extension of the compliance date for existing coal-fired steam generating units to meet a standard of performance based on implementation of CCS, (3) the removal of low-GHG hydrogen co-firing as a BSER pathway, and (4) the addition of two reliability-related instruments. In addition, (5), the EPA is not finalizing proposed requirements for existing fossil fuel-fired stationary combustion turbines at this time.

The reduction in number of subcategories for existing coal-fired steam generating units: The EPA proposed four subcategories for existing coal-fired steam generating units, which would have distinguished these units by operating horizon and by load level. These included subcategories for existing coal-fired EGUs planning to cease operations in the imminent-term (*i.e.,* prior to January 1, 2032) and those planning to cease operations in the near-term (*i.e.,* prior to January 1, 2035). While commenters were generally supportive of the proposed subcategorization approach, some requested that the cease-operation-by date for the imminent-term subcategory be extended and the utilization limit for the near-term subcategory be relaxed. The EPA is not finalizing the imminent-term and near-term subcategories of coal-fired steam generating units. Rather, the EPA is finalizing an applicability exemption for coal-fired steam generating units demonstrating that they plan to permanently cease operation before January 1, 2032. See section VII.B of this preamble for further discussion.

The extension of the compliance date for existing coal-fired steam generating units to meet a standard of performance based on implementation of CCS. The EPA proposed a compliance date for implementation of CCS for long-term coal-fired steam generating units of January 1, 2030. The EPA received comments asserting that this deadline did not provide adequate lead time. In consideration of those comments, and the record as a whole, the EPA is finalizing a CCS compliance date of January 1, 2032 for these sources.

The removal of low-GHG hydrogen co-firing as a BSER pathway and only use of low-GHG hydrogen as a compliance option: The EPA is not finalizing its proposed BSER pathway of low-GHG hydrogen co-firing for new and reconstructed base load and intermediate load combustion turbines in accordance with CAA section 111(a)(1). The EPA is also not finalizing its proposed requirement that only low-GHG hydrogen may be co-fired in a combustion turbine for the purpose of compliance with the standards of performance. These decisions are based on uncertainties identified for specific criteria used to evaluate low-GHG hydrogen co-firing as a potential BSER, and after further analysis in response to public comments, the EPA has determined that these uncertainties prevent the EPA from concluding that low-GHG hydrogen co-firing is a component of the ''best'' system of emission reduction at this time. Under CAA section 111, the EPA establishes standards of performance but does not mandate use of any particular technology to meet those standards. Therefore, certain sources may elect to co-fire hydrogen for compliance with the final standards of performance, even absent the technology being a BSER pathway.[15] See section VIII.F.5 of this preamble for further discussion.

The addition of two reliability-related instruments: Commenters expressed concerns that these rules, in combination with other factors, may affect the reliability of the bulk power system. In response to these comments the EPA engaged extensively with balancing authorities, power companies, reliability experts, and regulatory authorities responsible for reliability to inform its decisions in these final rules. As described later in this preamble, the EPA has made adjustments in these final rules that will support power companies, grid operators, and states in maintaining the reliability of the electric grid during the implementation of these final rules. In addition, the EPA has undertaken an analysis of the reliability and resource adequacy implications of these final rules that supports the Agency's conclusion that these final rules can be implemented without adverse consequences for grid reliability. Further, the EPA is finalizing two reliability-related instruments as an additional layer of safeguards for reliability. These instruments include a reliability mechanism for short-term emergency issues, and a reliability assurance mechanism, or compliance flexibility, for units that have chosen compliance pathways with enforceable retirement dates, provided there is a documented and verified reliability concern. In addition, the EPA is finalizing compliance extensions for unanticipated delays with control technology implementation. Specifically, as described in greater detail in section XII.F of this preamble, the EPA is finalizing the following features and changes from the proposal that will provide even greater certainty that these final rules are sensitive to reliability-related issues and constructed in a manner that does not interfere with grid operators' responsibility to deliver reliable power:

(1) longer compliance timelines for existing coal-fired steam generating units;

(2) a mechanism to extend compliance timelines by up to 1 year in the case of unforeseen circumstances, outside of an owner/operator's control, that delay the ability to apply controls (*e.g.,* supply chain challenges or permitting delays);

(3) transparent unit-specific compliance information for EGUs that will allow grid operators to plan for system changes with greater certainty and precision;

(4) a short-term reliability mechanism to allow affected EGUs to operate at

[15] The EPA is not placing qualifications on the type of hydrogen a source may elect to co-fire at this time (see section VIII.F.6.a of this preamble for further discussion). The Agency continues to recognize that even though the combustion of hydrogen is zero-GHG emitting, its production can entail a range of GHG emissions, from low to high, depending on the production method. Thus, even though the EPA is not finalizing the low-GHG hydrogen co-firing as a BSER, as proposed, it maintains that the overall GHG profile of a particular method of hydrogen production should be a primary consideration for any source that decides to co-fire hydrogen to ensure that overall GHG reductions and important climate benefits are achieved. The EPA also notes the anticipated final rule from the U.S. Department of the Treasury pertaining to clean hydrogen production tax and energy credits, which in its proposed form contains certain eligibility parameters, as well as programs administered by the U.S. Department of Energy, such as the recent H2Hubs selections.

baseline emission rates during documented reliability emergencies; and

(5) a reliability assurance mechanism to allow states to delay cease operation dates by up to 1 year in cases where the planned cease operation date is forecast to disrupt system reliability.

Not finalizing proposed requirements for existing fossil fuel-fired stationary combustion turbines at this time: The EPA proposed emission guidelines for large (*i.e.,* greater than 300 MW), frequently operated (*i.e.,* with an annual capacity factor of greater than 50 percent), existing fossil fuel-fired stationary combustion turbines. The EPA received a wide range of comments on the proposed guidelines. Multiple commenters suggested that the proposed provisions would largely result in shifting of generation away from the most efficient natural gas-fired turbines to less efficient natural gas-fired turbines. Commenters stated that, as emissions from coal-fired steam generating units decreased, existing natural gas-fired EGUs were poised to become the largest source of GHG emissions in the power sector. Commenters noted that these units play an important role in grid reliability, particularly as aging coal-fired EGUs retire. Commenters further noted that the existing fossil fuel-fired stationary combustion turbines that were not covered by the proposal (*i.e.,* the smaller and less frequently operating units) are often less efficient, less well controlled for other pollutants such as NO_X, and are more likely to be located near population centers and communities with environmental justice concerns.

The EPA agrees with commenters who observed that GHG emissions from existing natural gas-fired stationary combustion turbines are a growing portion of the emissions from the power sector. This is consistent with EPA modeling that shows that by 2030 these units will represent the largest portion of GHG emissions from the power sector. The EPA agrees that it is vital to promulgate emission guidelines to address GHG emissions from these sources, and that the EPA has a responsibility to do so under section 111(d) of the Clean Air Act. The EPA also agrees with commenters who noted that focusing only on the largest and most frequently operating units, without also addressing emissions from other units, as the May 2023 proposed rule provided, may not be the most effective way to address emissions from this sector. The EPA's modeling shows that over time as the power sector comes closer to reaching the phase-out threshold of the clean electricity incentives in the Inflation Reduction Act (IRA) (*i.e.,* a 75 percent reduction in emissions from the power sector from 2022 levels), the average capacity factor for existing natural gas-fired stationary combustion turbines decreases. Therefore, the EPA's proposal to focus only on the largest units with the highest capacity factors may not be the most effective policy design for reducing GHG emissions from these sources.

Recognizing the importance of reducing emissions from all fossil fuel-fired EGUs, the EPA is not finalizing the proposed emission guidelines for certain existing fossil fuel-fired stationary combustion turbines at this time. Instead, the EPA intends to issue a new, more comprehensive proposal to regulate GHGs from existing sources. The new proposal will focus on achieving greater emission reductions from existing stationary combustion turbines—which will soon be the largest stationary sources of GHG emissions—while taking into account other factors including the local non-GHG impacts of gas turbine generation and the need for reliable, affordable electricity.

II. General Information

A. Action Applicability

The source category that is the subject of these actions is composed of fossil fuel-fired electric utility generating units. The North American Industry Classification System (NAICS) codes for the source category are 221112 and 921150. The list of categories and NAICS codes is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that these final actions are likely to affect.

Final amendments to 40 CFR part 60, subpart TTTT, are directly applicable to affected facilities that began construction after January 8, 2014, but before May 23, 2023, and affected facilities that began reconstruction or modification after June 18, 2014, but before May 23, 2023. The NSPS codified in 40 CFR part 60, subpart TTTTa, is directly applicable to affected facilities that begin construction, reconstruction, or modification on or after May 23, 2023. Federal, state, local, and tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subpart TTTT or TTTTa, are affected by these amendments and standards.

The emission guidelines codified in 40 CFR part 60, subpart UUUUb, are for states to follow in developing, submitting, and implementing state plans to establish performance standards to reduce emissions of GHGs from designated facilities that are existing sources. Section 111(a)(6) of the CAA defines an "existing source" as "any stationary source other than a new source." Therefore, the emission guidelines would not apply to any EGUs that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT. Under the Tribal Authority Rule (TAR), eligible tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a tribal implementation plan (TIP) implementing the emission guidelines codified in 40 CFR part 60, subpart UUUUb. The TAR authorizes tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country.[16] A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities.

B. Where To Get a Copy of This Document and Other Related Information

In addition to being available in the docket, an electronic copy of these final rulemakings is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.* Following signature by the EPA Administrator, the EPA will post a copy of these final rulemakings at this same website. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rules and key technical documents at this same website.

C. Judicial Review and Administrative Review

Under CAA section 307(b)(1), judicial review of these final actions is available only by filing a petition for review in

[16] See the EPA's website, *https://www.epa.gov/tribal/tribes-approved-treatment-state-tas,* for information on those tribes that have treatment as a state for specific environmental regulatory programs, administrative functions, and grant programs.

the United States Court of Appeals for the District of Columbia Circuit by July 8, 2024. These final actions are ''standard[s] of performance or requirement[s] under section 111,'' and, in addition, are ''nationally applicable regulations promulgated, or final action taken, by the Administrator under [the CAA],'' CAA section 307(b)(1). Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment, (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

III. Climate Change Impacts

Elevated concentrations of GHGs have been warming the planet, leading to changes in the Earth's climate that are occurring at a pace and in a way that threatens human health, society, and the natural environment. While the EPA is not making any new scientific or factual findings with regard to the well-documented impact of GHG emissions on public health and welfare in support of these rules, the EPA is providing in this section a brief scientific background on climate change to offer additional context for these rulemakings and to help the public understand the environmental impacts of GHGs.

Extensive information on climate change is available in the scientific assessments and the EPA documents that are briefly described in this section, as well as in the technical and scientific information supporting them. One of those documents is the EPA's 2009 ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the CAA'' (74 FR 66496, December 15, 2009) (''2009 Endangerment Finding''). In the 2009 Endangerment Finding, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs—CO_2, methane (CH_4), nitrous oxide (N_2O), HFCs, perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—''may reasonably be anticipated to endanger the public health and welfare of current and future generations'' (74 FR 66523, December 15, 2009). The 2009 Endangerment Finding, together with the extensive scientific and technical evidence in the supporting record, documented that climate change caused by human emissions of GHGs threatens the public health of the U.S. population. It explained that by raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses (74 FR 66497, December 15, 2009). While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. (74 FR 66525, December 15, 2009). The 2009 Endangerment Finding further explained that compared with a future without climate change, climate change is expected to increase tropospheric ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst tropospheric ozone problems, and thereby increase the risk of adverse effects on public health (74 FR 66525, December 15, 2009). Climate change is also expected to cause more intense hurricanes and more frequent and intense storms of other types and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders (74 FR 66525 December 15, 2009). Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects (74 FR 66498, December 15, 2009).

The 2009 Endangerment Finding also documented, together with the extensive scientific and technical evidence in the supporting record, that climate change touches nearly every aspect of public welfare [17] in the U.S., including the following: changes in water supply and quality due to changes in drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization). These impacts are also global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S. (74 FR 66530, December 15, 2009).

In 2016, the Administrator issued a similar finding for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA.[18] In the 2016 Endangerment Finding, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Finding compellingly supported a similar endangerment finding under CAA section 231(a)(2)(A) and also found that the science assessments released between the 2009 and 2016 Findings ''strengthen and further support the judgment that GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations'' (81 FR 54424, August 15, 2016).

Since the 2016 Endangerment Finding, the climate has continued to change, with new observational records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Additionally, major scientific assessments continue to be released that further advance our understanding of the climate system and the impacts that GHGs have on public health and welfare for both current and future generations. These updated observations and projections document the rapid rate of current and future

[17] The CAA states in section 302(h) that ''[a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants.'' 42 U.S.C. 7602(h).

[18] *Finding That Greenhouse Gas Emissions From Aircraft Cause or Contribute to Air Pollution That May Reasonably Be Anticipated To Endanger Public Health and Welfare.* 81 FR 54422, August 15, 2016 (''2016 Endangerment Finding'').

climate change both globally and in the U.S.[19] [20] [21] [22] [23] [24] [25] [26] [27] [28] [29] [30] [31]

The most recent information demonstrates that the climate is continuing to change in response to the human-induced buildup of GHGs in the atmosphere. These recent assessments show that atmospheric concentrations of GHGs have risen to a level that has no precedent in human history and that they continue to climb, primarily because of both historical and current anthropogenic emissions, and that these elevated concentrations endanger our health by affecting our food and water sources, the air we breathe, the weather we experience, and our interactions with the natural and built environments. For example, atmospheric concentrations of one of these GHGs, CO_2, measured at Mauna Loa in Hawaii and at other sites around the world reached 419 parts per million (ppm) in 2022 (nearly 50 percent higher than preindustrial levels) [32] and have continued to rise at a rapid rate. Global average temperature has increased by about 1.1 °C (2.0 °F) in the 2011–2020 decade relative to 1850–1900.[33] The years 2015–2021 were the warmest 7 years in the 1880–2021 record, contributing to the warmest decade on record with a decadal temperature of 0.82 °C (1.48 °F) above the 20th century.[34] [35] The Intergovernmental Panel on Climate Change (IPCC) determined (with medium confidence) that this past decade was warmer than any multi-century period in at least the past 100,000 years.[36] Global average sea level has risen by about 8 inches (about 21 centimeters (cm)) from 1901 to 2018, with the rate from 2006 to 2018 (0.15 inches/year or 3.7 millimeters (mm)/year) almost twice the rate over the 1971 to 2006 period, and three times the rate of the 1901 to 2018 period.[37] The rate of sea level rise over the 20th century was higher than in any other century in at least the last 2,800 years.[38] Higher CO_2 concentrations have led to acidification of the surface ocean in recent decades to an extent unusual in the past 65 million years, with negative impacts on marine organisms that use calcium carbonate to build shells or skeletons.[39] Arctic sea ice extent continues to decline in all months of the year; the most rapid reductions occur in September (very likely almost a 13 percent decrease per decade between 1979 and 2018) and are unprecedented in at least 1,000 years.[40] Human-induced climate change has led to heatwaves and heavy precipitation becoming more frequent and more intense, along with increases in agricultural and ecological droughts [41] in many regions.[42]

The assessment literature demonstrates that modest additional amounts of warming may lead to a climate different from anything humans have ever experienced. The 2022 CO_2 concentration of 419 ppm is already higher than at any time in the last 2 million years.[43] If concentrations exceed 450 ppm, they would likely be higher than any time in the past 23 million years: [44] at the current rate of increase of more than 2 ppm per year, this would occur in about 15 years. While GHGs are not the only factor that controls climate, it is illustrative that 3 million years ago (the last time CO_2 concentrations were above 400 ppm) Greenland was not yet completely covered by ice and still supported forests, while 23 million years ago (the last time concentrations were above 450 ppm) the West Antarctic ice sheet was not yet developed, indicating the possibility that high GHG concentrations could lead to a world that looks very different from today and from the conditions in which human civilization has developed. If the Greenland and Antarctic ice sheets were

[19] USGCRP, 2017: *Climate Science Special Report: Fourth National Climate Assessment,* Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp, doi: 10.7930/J0J964J6.

[20] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C.

[21] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi:10.7930/NCA4.2018.

[22] IPCC, 2018: *Global Warming of 1.5 °C.* An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

[23] IPCC, 2019: *Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems* [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D.C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].

[24] IPCC, 2019: *IPCC Special Report on the Ocean and Cryosphere in a Changing Climate* [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegriía, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[25] National Academies of Sciences, Engineering, and Medicine. 2016. *Attribution of Extreme Weather Events in the Context of Climate Change.* Washington, DC: The National Academies Press. *https://dio.org/10.17226/21852.*

[26] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/24651.*

[27] National Academies of Sciences, Engineering, and Medicine. 2019. *Climate Change and Ecosystems.* Washington, DC: The National Academies Press. *https://doi.org/10.17226/25504.*

[28] Blunden, J. and T. Boyer, Eds., 2022: ''State of the Climate in 2021.'' Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1.*

[29] U.S. Environmental Protection Agency. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. EPA 430–R–21–003.

[30] Jay, A.K., A.R. Crimmins, C.W. Avery, T.A. Dahl, R.S. Dodder, B.D. Hamlington, A. Lustig, K. Marvel, P.A. Méndez-Lazaro, M.S. Osler, A. Terando, E.S. Weeks, and A. Zycherman, 2023: Ch. 1. Overview: Understanding risks, impacts, and responses. In: Fifth National Climate Assessment. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. *https://doi.org/10.7930/NCA5.2023.CH1.*

[31] IPCC, 2023: Summary for Policymakers. In: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)].

[32] *https://gml.noaa.gov/webdata/ccgg/trends/co2/co2_annmean_mlo.txt.*

[33] IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3–32, doi:10.1017/9781009157896.001.

[34] NOAA National Centers for Environmental Information, State of the Climate 2021 retrieved on August 3, 2023, from *https://www.ncei.noaa.gov/bams-state-of-climate.*

[35] Blunden, J. and T. Boyer, Eds., 2022: ''State of the Climate in 2021.'' Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate*1.

[36] IPCC, 2021.

[37] IPCC, 2021.

[38] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi:10.7930/NCA4.2018.

[39] IPCC, 2018.

[40] IPCC, 2021.

[41] These are drought measures based on soil moisture.

[42] IPCC, 2021.

[43] Annual Mauna Loa CO_2 concentration data from *https://gml.noaa.gov/webdata/ccgg/trends/co2/co2_annmean_mlo.txt*, accessed September 9, 2023.

[44] IPCC, 2013.

to melt substantially, sea levels would rise dramatically.

The NCA4 found that it is very likely (greater than 90 percent likelihood) that by mid-century, the Arctic Ocean will be almost entirely free of sea ice by late summer for the first time in about 2 million years.[45] Coral reefs will be at risk for almost complete (99 percent) losses with 1 °C (1.8 °F) of additional warming from today (2 °C or 3.6 °F since preindustrial). At this temperature, between 8 and 18 percent of animal, plant, and insect species could lose over half of the geographic area with suitable climate for their survival, and 7 to 10 percent of rangeland livestock would be projected to be lost.[46] The IPCC similarly found that climate change has caused substantial damages and increasingly irreversible losses in terrestrial, freshwater, and coastal and open ocean marine ecosystems.

Every additional increment of temperature comes with consequences. For example, the half degree of warming from 1.5 to 2 °C (0.9 °F of warming from 2.7 °F to 3.6 °F) above preindustrial temperatures is projected on a global scale to expose 420 million more people to frequent extreme heatwaves at least every five years, and 62 million more people to frequent exceptional heatwaves at least every five years (where heatwaves are defined based on a heat wave magnitude index which takes into account duration and intensity—using this index, the 2003 French heat wave that led to almost 15,000 deaths would be classified as an ''extreme heatwave'' and the 2010 Russian heatwave which led to thousands of deaths and extensive wildfires would be classified as ''exceptional''). It would increase the frequency of sea-ice-free Arctic summers from once in 100 years to once in a decade. It could lead to 4 inches of additional sea level rise by the end of the century, exposing an additional 10 million people to risks of inundation as well as increasing the probability of triggering instabilities in either the Greenland or Antarctic ice sheets. Between half a million and a million additional square miles of permafrost would thaw over several centuries. Risks to food security would increase from medium to high for several lower-income regions in the Sahel, southern Africa, the Mediterranean, central Europe, and the Amazon. In addition to food security issues, this temperature increase would have implications for human health in terms of increasing ozone concentrations, heatwaves, and vector-borne diseases (for example, expanding the range of the mosquitoes which carry dengue fever, chikungunya, yellow fever, and the Zika virus or the ticks which carry Lyme, babesiosis, or Rocky Mountain Spotted Fever).[47] Moreover, every additional increment in warming leads to larger changes in extremes, including the potential for events unprecedented in the observational record. Every additional degree will intensify extreme precipitation events by about 7 percent. The peak winds of the most intense tropical cyclones (hurricanes) are projected to increase with warming. In addition to a higher intensity, the IPCC found that precipitation and frequency of rapid intensification of these storms has already increased, the movement speed has decreased, and elevated sea levels have increased coastal flooding, all of which make these tropical cyclones more damaging.[48]

The NCA4 also evaluated a number of impacts specific to the U.S. Severe drought and outbreaks of insects like the mountain pine beetle have killed hundreds of millions of trees in the western U.S. Wildfires have burned more than 3.7 million acres in 14 of the 17 years between 2000 and 2016, and Federal wildfire suppression costs were about a billion dollars annually.[49] The National Interagency Fire Center has documented U.S. wildfires since 1983, and the 10 years with the largest acreage burned have all occurred since 2004.[50] Wildfire smoke degrades air quality, increasing health risks, and more frequent and severe wildfires due to climate change would further diminish air quality, increase incidences of respiratory illness, impair visibility, and disrupt outdoor activities, sometimes thousands of miles from the location of the fire. Meanwhile, sea level rise has amplified coastal flooding and erosion impacts, requiring the installation of costly pump stations, flooding streets, and increasing storm surge damages. Tens of billions of dollars of U.S. real estate could be below sea level by 2050 under some scenarios. Increased frequency and duration of drought will reduce agricultural productivity in some regions, accelerate depletion of water supplies for irrigation, and expand the distribution and incidence of pests and diseases for crops and livestock. The NCA4 also recognized that climate change can increase risks to national security, both through direct impacts on military infrastructure and by affecting factors such as food and water availability that can exacerbate conflict outside U.S. borders. Droughts, floods, storm surges, wildfires, and other extreme events stress nations and people through loss of life, displacement of populations, and impacts on livelihoods.[51] The NCA5 further reinforces the science showing that climate change will have many impacts on the U.S., as described above in the preamble. Particularly relevant for these rules, the NCA5 states that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.'' [52]

EPA modeling efforts can further illustrate how these impacts from climate change may be experienced across the U.S. EPA's Framework for Evaluating Damages and Impacts (FrEDI) [53] uses information from over 30 peer-reviewed climate change impact studies to project the physical and economic impacts of climate change to the U.S. resulting from future temperature changes. These impacts are projected for specific regions within the U.S. and for more than 20 impact categories, which span a large number of sectors of the U.S. economy.[54] Using

[45] USGCRP, 2018.

[46] IPCC, 2018.

[47] IPCC, 2018.

[48] IPCC, 2021.

[49] USGCRP, 2018.

[50] NIFC (National Interagency Fire Center). 2021. Total wildland fires and acres (1983–2020). Accessed August 2021. *https://www.nifc.gov/fireInfo/fireInfo_stats_totalFires.html.*

[51] USGCRP, 2018.

[52] Jay, A.K., A.R. Crimmins, C.W. Avery, T.A. Dahl, R.S. Dodder, B.D. Hamlington, A. Lustig, K. Marvel, P.A. Méndez-Lazaro, M.S. Osler, A. Terando, E.S. Weeks, and A. Zycherman, 2023: Ch. 1. Overview: Understanding risks, impacts, and responses. In: *Fifth National Climate Assessment.* Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. *https://doi.org/10.7930/NCA5.2023.CH1.*

[53] (1) Hartin, C., *et al.* (2023). Advancing the estimation of future climate impacts within the United States. Earth Syst. Dynam., 14, 1015–1037, *https://doi.org/10.5194/esd-14-1015-2023.* (2) Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,'' Docket ID No. EPA–HQ–OAR–2021–0317, November 2023, (3) *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050.* Published by the U.S. Department of State and the U.S. Executive Office of the President, Washington DC. November 2021, (4) *Climate Risk Exposure: An Assessment of the Federal Government's Financial Risks to Climate Change,* White Paper, Office of Management and Budget, April 2022.

[54] EPA (2021). Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI). U.S. Environmental Protection Agency, EPA 430–R–21–004, *https://www.epa.gov/cira/fredi.* Documentation has been subject to both a public review comment period and an independent

Continued

this framework, the EPA estimates that global emission projections, with no additional mitigation, will result in significant climate-related damages to the U.S.[55] These damages to the U.S. would mainly be from increases in lives lost due to increases in temperatures, as well as impacts to human health from increases in climate-driven changes in air quality, dust and wildfire smoke exposure, and incidence of suicide. Additional major climate-related damages would occur to U.S. infrastructure such as roads and rail, as well as transportation impacts and coastal flooding from sea level rise, increases in property damage from tropical cyclones, and reductions in labor hours worked in outdoor settings and buildings without air conditioning. These impacts are also projected to vary from region to region with the Southeast, for example, projected to see some of the largest damages from sea level rise, the West Coast projected to experience damages from wildfire smoke more than other parts of the country, and the Northern Plains states projected to see a higher proportion of damages to rail and road infrastructure. While information on the distribution of climate impacts helps to better understand the ways in which climate change may impact the U.S., recent analyses are still only a partial assessment of climate impacts relevant to U.S. interests and in addition do not reflect increased damages that occur due to interactions between different sectors impacted by climate change or all the ways in which physical impacts of climate change occurring abroad have spillover effects in different regions of the U.S.

Some GHGs also have impacts beyond those mediated through climate change. For example, elevated concentrations of CO_2 stimulate plant growth (which can be positive in the case of beneficial species, but negative in terms of weeds and invasive species, and can also lead to a reduction in plant micronutrients[56]) and cause ocean acidification. Nitrous oxide depletes the levels of protective stratospheric ozone.[57] Methane reacts to form tropospheric ozone.

Section XII.E of this preamble discusses the impacts of GHG emissions on individuals living in socially and economically vulnerable communities. While the EPA did not conduct modeling to specifically quantify changes in climate impacts resulting from these rules in terms of avoided temperature change or sea-level rise, the Agency did quantify climate benefits by monetizing the emission reductions through the application of the social cost of greenhouse gases (SC–GHGs), as described in section XII.D of this preamble.

These scientific assessments, the EPA analyses, and documented observed changes in the climate of the planet and of the U.S. present clear support regarding the current and future dangers of climate change and the importance of GHG emissions mitigation.

IV. Recent Developments in Emissions Controls and the Electric Power Sector

In this section, we discuss background information about the electric power sector and controls available to limit GHG pollution from the fossil fuel-fired power plants regulated by these final rules, and then discuss several recent developments that are relevant for determining the BSER for these sources. After giving some general background, we first discuss CCS and explain that its costs have fallen significantly. Lower costs are central for the EPA's determination that CCS is the BSER for certain existing coal-fired steam generating units and certain new natural gas-fired combustion turbines. Second, we discuss natural gas co-firing for coal-fired steam generating units and explain recent reductions in cost for this approach as well as its widespread availability and current and potential deployment within this subcategory. Third, we discuss highly efficient generation as a BSER technology for new and reconstructed simple cycle and combined cycle combustion turbine EGUs. The emission reductions achieved by highly efficient turbines are well demonstrated in the power sector, and along with operational and maintenance best practices, represent a cost-effective technology that reduces fuel consumption. Finally, we discuss key developments in the electric power sector that influence which units can feasibly and cost-effectively deploy these technologies.

A. Background

1. Electric Power Sector

Electricity in the U.S. is generated by a range of technologies, and different EGUs play different roles in providing reliable and affordable electricity. For example, certain EGUs generate base load power, which is the portion of electricity loads that are continually present and typically operate throughout all hours of the year. Intermediate EGUs often provide complementary generation to balance variable supply and demand resources. Low load ''peaking units'' provide capacity during hours of the highest daily, weekly, or seasonal net demand, and while these resources have low levels of utilization on an annual basis, they play important roles in providing generation to meet short-term demand and often must be available to quickly increase or decrease their output. Furthermore, many of these EGUs also play important roles ensuring the reliability of the electric grid, including facilitating the regulation of frequency and voltage, providing ''black start'' capability in the event the grid must be repowered after a widespread outage, and providing reserve generating capacity[58] in the event of unexpected changes in the availability of other generators.

In general, the EGUs with the lowest operating costs are dispatched first, and, as a result, an inefficient EGU with high fuel costs will typically only operate if other lower-cost plants are unavailable or are insufficient to meet demand. Units are also unavailable during both routine and unanticipated outages, which typically become more frequent as power plants age. These factors result in the mix of available generating capacity types (*e.g.,* the share of capacity of each type of generating source) being substantially different than the mix of the share of total electricity produced by each type of generating source in a given season or year.

expert peer review, following EPA peer-review guidelines.

[55] Compared to a world with no additional warming after the model baseline (1986–2005).

[56] Ziska, L., A. Crimmins, A. Auclair, S. DeGrasse, J.F. Garofalo, A.S. Khan, I. Loladze, A.A. Pérez de León, A. Showler, J. Thurston, and I. Walls, 2016: Ch. 7: *Food Safety, Nutrition, and Distribution. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* U.S. Global Change Research Program, Washington, DC, 189–216. *https://health2016.globalchange.gov/low/ClimateHealth2016_07_Food_small.pdf.*

[57] WMO (World Meteorological Organization), *Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project*—Report No. 58, 588 pp., Geneva, Switzerland, 2018.

[58] Generation and capacity are commonly reported statistics with key distinctions. Generation is the production of electricity and is a measure of an EGU's *actual* output while capacity is a measure of the maximum *potential* production of an EGU under certain conditions. There are several methods to calculate an EGU's capacity, which are suited for different applications of the statistic. Capacity is typically measured in megawatts (MW) for individual units or gigawatts (1 GW = 1,000 MW) for multiple EGUs. Generation is often measured in kilowatt-hours (1 kWh = 1,000 watt-hours), megawatt-hours (1 MWh = 1,000 kWh), gigawatt-hours (1 GWh = 1 million kWh), or terawatt-hours (1 TWh = 1 billion kWh).

Generated electricity must be transmitted over networks [59] of high voltage lines to substations where power is stepped down to a lower voltage for local distribution. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator; [60] in others, individual utilities [61] coordinate the operations of their generation and transmission to balance the system across their respective service territories.

2. Types of EGUs

There are many types of EGUs including fossil fuel-fired power plants (*i.e.,* those using coal, oil, and natural gas), nuclear power plants, renewable generating sources (such as wind and solar) and others. This rule focuses on the fossil fuel-fired portion of the generating fleet that is responsible for the vast majority of GHG emissions from the power sector. The definition of fossil fuel-fired electric utility steam generating units includes utility boilers as well as those that use gasification technology (*i.e.,* integrated gasification combined cycle (IGCC) units). While coal is the most common fuel for fossil fuel-fired utility boilers, natural gas can also be used as a fuel in these EGUs and many existing coal- and oil-fired utility boilers have refueled as natural gas-fired utility boilers. An IGCC unit gasifies fuel—typically coal or petroleum coke—to form a synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power. The heat created by these technologies produces high-pressure steam that is released to rotate turbines, which, in turn, spin an electric generator.

Stationary combustion turbine EGUs (most commonly natural gas-fired) use one of two configurations: combined cycle or simple cycle turbines. Combined cycle units have two generating components (*i.e.,* two cycles) operating from a single source of heat. Combined cycle units first generate power from a combustion turbine (*i.e.,* the combustion cycle) directly from the heat of burning natural gas or other fuel. The second cycle reuses the waste heat from the combustion turbine engine, which is routed to a heat recovery steam generator (HRSG) that generates steam, which is then used to produce additional power using a steam turbine (*i.e.,* the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Combined cycle units that fire mostly natural gas are commonly referred to as natural gas combined cycle (NGCC) units, and, with greater efficiency, are utilized at higher capacity factors to provide base load or intermediate load power. An EGU's capacity factor indicates a power plant's electricity output as a percentage of its total generation capacity. Simple cycle turbines only use a combustion turbine to produce electricity (*i.e.,* there is no heat recovery or steam cycle). These less-efficient combustion turbines are generally utilized at non-base load capacity factors and contribute to reliable operations of the grid during periods of peak demand or provide flexibility to support increased generation from variable energy sources.[62]

Other generating sources produce electricity by harnessing kinetic energy from flowing water, wind, or tides, thermal energy from geothermal wells, or solar energy primarily through photovoltaic solar arrays. Spurred by a combination of declining costs, consumer preferences, and government policies, the capacity of these renewable technologies is growing, and when considered with existing nuclear energy, accounted for 40 percent of the overall net electricity supply in 2022. Many projections show this share growing over time. For example, the EPA's Power Sector Platform 2023 using IPM (*i.e.,* the EPA's baseline projections of the power sector) projects zero-emitting sources reaching 76 percent of electricity generation by 2040. This shift is driven by multiple factors. These factors include changes in the relative economics of generating technologies, the efforts by states to reduce GHG emissions, utility and other corporate commitments, and customer preference. The shift is further promoted by provisions of Federal legislation, most notably the Clean Electricity Investment and Production tax credits included in IRC sections 48E and 45Y of the IRA, which do not begin to phase out until the later of 2032 or when power sector GHG emissions are 75 percent less than 2022 levels. (See section IV.F of this preamble and the accompanying RIA for additional discussion of projections for the power sector.) These projections are consistent with power company announcements. For example, as the Edison Electric Institute (EEI) stated in pre-proposal public comments submitted to the regulatory docket: ''Fifty EEI members have announced forward-looking carbon reduction goals, two-thirds of which include a net-zero by 2050 or earlier equivalent goal, and members are routinely increasing the ambition or speed of their goals or altogether transforming them into net-zero goals . . . . EEI's member companies see a clear path to continued emissions reductions over the next decade using current technologies, including nuclear power, natural gas-based generation, energy demand efficiency, energy storage, and deployment of new renewable energy—especially wind and solar—as older coal-based and less-efficient natural gas-based generating units retire.'' [63] The Energy Strategy Coalition similarly said in public comments that ''[a]s major electrical utilities and power producers, our top priority is providing clean, affordable, and reliable energy to our customers'' and are ''seeking to advance'' technologies ''such as a carbon capture and storage, which can significantly reduce carbon dioxide

[59] The three network interconnections are the Western Interconnection, comprising the western parts of the U.S. and Canada, the Eastern Interconnection, comprising the eastern parts of the U.S. and Canada except parts of Eastern Canada in the Quebec Interconnection, and the Texas Interconnection, encompassing the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT). See map of all NERC interconnections at *https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.*

[60] For example, PJM Interconnection, LLC, New York Independent System Operator (NYISO), Midwest Independent System Operator (MISO), California Independent System Operator (CAISO), *etc.*

[61] For example, Los Angeles Department of Power and Water, Florida Power and Light, *etc.*

[62] Non-dispatchable renewable energy (electrical output cannot be used at any given time to meet fluctuating demand) is both variable and intermittent and is often referred to as intermittent renewable energy. The variability aspect results from predictable changes in electric generation (*e.g.,* solar not generating electricity at night) that often occur on longer time periods. The intermittent aspect of renewable energy results from inconsistent generation due to unpredictable external factors outside the control of the owner/operator (*e.g.,* imperfect local weather forecasts) that often occur on shorter time periods. Since renewable energy fluctuates over multiple time periods, grid operators are required to adjust forecast and real time operating procedures. As more renewable energy is added to the electric grid and generation forecasts improve, the intermittency of renewable energy is reduced.

[63] Edison Electric Institute (EEI). (November 18, 2022). *Clean Air Act Section 111 Standards and the Power Sector: Considerations and Options for Setting Standards and Providing Compliance Flexibility to Units and States.* Public comments submitted to the EPA's pre-proposal rulemaking, Document ID No. EPA–HQ–OAR–2022–0723–0024.

emissions from fossil fuel-fired EGUs.'' [64]

B. GHG Emissions From Fossil Fuel-Fired EGUs

The principal GHGs that accumulate in the Earth's atmosphere above pre-industrial levels because of human activity are CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Of these, CO_2 is the most abundant, accounting for 80 percent of all GHGs present in the atmosphere. This abundance of CO_2 is largely due to the combustion of fossil fuels by the transportation, electricity, and industrial sectors.[65]

The amount of CO_2 produced when a fossil fuel is burned in an EGU is a function of the carbon content of the fuel relative to the size and efficiency of the EGU. Different fuels emit different amounts of CO_2 in relation to the energy they produce when combusted. The heat content, or the amount of energy produced when a fuel is burned, is mainly determined by the carbon and hydrogen content of the fuel. For example, in terms of pounds of CO_2 emitted per million British thermal units of energy produced when combusted, natural gas is the lowest compared to other fossil fuels at 117 lb CO_2/MMBtu.[66 67] The average for coal is 216 lb CO_2/MMBtu, but varies between 206 to 229 lb CO_2/MMBtu by type (*e.g.,* anthracite, lignite, subbituminous, and bituminous).[68] The value for petroleum products such as diesel fuel and heating oil is 161 lb CO_2/MMBtu.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks [69] (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It presents total U.S. anthropogenic emissions and sinks [70] of GHGs, including CO_2 emissions since 1990. According to the latest inventory of all sectors, in 2021, total U.S. GHG emissions were 6,340 million metric tons of CO_2 equivalent (MMT CO_2e).[71] The transportation sector (28.5 percent), which includes approximately 300 million vehicles, was the largest contributor to total U.S. GHG emissions with 1,804 MMT CO_2e followed by the power sector (25.0 percent) with 1,584 MMT CO_2e. In fact, GHG emissions from the power sector were higher than the GHG emissions from all other industrial sectors combined (1,487 MMT CO_2e). Specifically, the power sector's emissions were far more than petroleum and natural gas systems [72] at 301 MMT CO_2e; chemicals (71 MMT CO_2e); minerals (64 MMT CO_2e); coal mining (53 MMT CO_2e); and metals (48 MMT CO_2e). The agriculture (636 MMT CO_2e), commercial (439 MMT CO_2e), and residential (366 MMT CO_2e) sectors combined to emit 1,441 MMT CO_2e.

Fossil fuel-fired EGUs are by far the largest stationary source emitters of GHGs in the nation. For example, according to the EPA's Greenhouse Gas Reporting Program (GHGRP), of the top 100 large facilities that reported facility-level GHGs in 2022, 85 were fossil fuel-fired power plants while 10 were refineries and/or chemical plants, four were metals facilities, and one was a petroleum and natural gas systems facility.[73] Of the 85 fossil fuel-fired power plants, 81 were primarily coal-fired, including the top 41 emitters of CO_2. In addition, of the 81 coal-fired plants, 43 have no retirement planned prior to 2039. The top 10 of these plants combined to emit more than 135 MMT of CO_2e, with the top emitter (James H. Miller power plant in Alabama) reporting approximately 22 MMT of CO_2e with each of its four EGUs emitting between 5 MMT and 6 MMT CO_2e that year. The combined capacity of these 10 plants is more than 23 gigawatts (GW), and all except for the Monroe (Michigan) plant operated at annual capacity factors of 50 percent or higher.[74] For comparison, the largest GHG emitter in the U.S. that is not a fossil fuel-fired power plant is the ExxonMobil refinery and chemical plant in Baytown, Texas, which reported 12.6 MMT CO_2e (No. 6 overall in the nation) to the GHGRP in 2022. The largest metals facility in terms of GHG emissions was the U.S. Steel facility in Gary, Indiana, with 10.4 MMT CO_2e (No. 16 overall in the nation).

Overall, CO_2 emissions from the power sector have declined by 36 percent since 2005 (when the power sector reached annual emissions of 2,400 MMT CO_2, its historical peak to date).[75] The reduction in CO_2 emissions can be attributed to the power sector's ongoing trend away from carbon-intensive coal-fired generation and toward more natural gas-fired and renewable sources. In 2005, CO_2 emissions from coal-fired EGUs alone measured 1,983 MMT.[76] This total dropped to 1,351 MMT in 2015 and reached 974 MMT in 2019, the first time since 1978 that CO_2 emissions from coal-fired EGUs were below 1,000 MMT. In 2020, emissions of CO_2 from coal-fired EGUs measured 788 MMT as the result of pandemic-related closures and reduced utilization before rebounding in 2021 to 909 MMT. By contrast, CO_2 emissions from natural gas-fired generation have almost doubled since 2005, increasing from 319 MMT to 613 MMT in 2021, and CO_2 emissions from petroleum products (*i.e.,* distillate fuel oil, petroleum coke, and residual fuel oil) declined from 98 MMT in 2005 to 18 MMT in 2021.

[64] Energy Strategy Coalition Comments on EPA's proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, Document ID No. EPA–HQ–OAR–2023–0072–0672, August 14, 2023.

[65] U.S. Environmental Protection Agency (EPA). Overview of greenhouse gas emissions. July 2021. *https://www.epa.gov/ghgemissions/overview-greenhouse-gases#carbon-dioxide*.

[66] Natural gas is primarily CH_4, which has a higher hydrogen to carbon atomic ratio, relative to other fuels, and thus, produces the least CO_2 per unit of heat released. In addition to a lower CO_2 emission rate on a lb/MMBtu basis, natural gas is generally converted to electricity more efficiently than coal. According to EIA, the 2020 emissions rate for coal and natural gas were 2.23 lb CO_2/kWh and 0.91 lb CO_2/kWh, respectively. *www.eia.gov/tools/faqs/faq.php?id=74&t=11*.

[67] Values reflect the carbon content on a per unit of energy produced on a higher heating value (HHV) combustion basis and are not reflective of recovered useful energy from any particular technology.

[68] Energy Information Administration (EIA). *Carbon Dioxide Emissions Coefficients. https://www.eia.gov/environment/emissions/co2_vol_mass.php*.

[69] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021*.

[70] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep-sea reservoirs of carbon dioxide.

[71] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks*.

[72] Petroleum and natural gas systems include: offshore and onshore petroleum and natural gas production; onshore petroleum and natural gas gathering and boosting; natural gas processing; natural gas transmission/compression; onshore natural gas transmission pipelines; natural gas local distribution companies; underground natural gas storage; liquified natural gas storage; liquified natural gas import/export equipment; and other petroleum and natural gas systems.

[73] U.S. Environmental Protection Agency (EPA). Greenhouse Gas Reporting Program. Facility Level Information on Greenhouse Gases Tool (FLIGHT). *https://ghgdata.epa.gov/ghgp/main.do#*.

[74] U.S. Energy Information Administration (EIA). Preliminary Monthly Electric Generator Inventory, Form EIA–860M, November 2023. *https://www.eia.gov/electricity/data/eia860m/*.

[75] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020. https://cfpub.epa.gov/ghgdata/inventoryexplorer/#electricitygeneration/entiresector/allgas/category/all*.

[76] U.S. Energy Information Administration (EIA). Monthly Energy Review, table 11.6. September 2022. *https://www.eia.gov/totalenergy/data/monthly/pdf/sec11.pdf*.

When the EPA finalized the Clean Power Plan (CPP) in October 2015, the Agency projected that, as a result of the CPP, the power sector would reduce its annual CO_2 emissions to 1,632 MMT by 2030, or 32 percent below 2005 levels (2,400 MMT).[77] Instead, even in the absence of Federal regulations for existing EGUs, annual CO_2 emissions from sources covered by the CPP had fallen to 1,540 MMT by the end of 2021, a nearly 36 percent reduction below 2005 levels. The power sector achieved a deeper level of reductions than forecast under the CPP and approximately a decade ahead of time. By the end of 2015, several months after the CPP was finalized, those sources already had achieved CO_2 emission levels of 1,900 MMT, or approximately 21 percent below 2005 levels. However, progress in emission reductions is not uniform across all states and is not guaranteed to continue, therefore Federal policies play an essential role. As discussed earlier in this section, the power sector remains a leading emitter of CO_2 in the U.S., and, despite the emission reductions since 2005, current CO_2 levels continue to endanger human health and welfare. Further, as sources in other sectors of the economy turn to electrification to decarbonize, future CO_2 reductions from fossil fuel-fired EGUs have the potential to take on added significance and increased benefits.

C. Recent Developments in Emissions Control

This section of the preamble describes recent developments in GHG emissions control in general. Details of those controls in the context of BSER determination are provided in section VII.C.1.a for CCS on coal-fired steam generating units, section VII.C.2.a for natural gas co-firing on coal-fired steam generating units, section VIII.F.2.b for efficient generation on natural gas-fired combustion turbines, and section VIII.F.4.c.iv for CCS on natural gas-fired combustion turbines. Further details of the control technologies are available in the final TSDs, *GHG Mitigation Measures for Steam Generating Units* and *GHG Mitigation Measures—CCS for Combustion Turbines,* available in the docket for these actions.

1. CCS

One of the key GHG reduction technologies upon which the BSER determinations are founded in these final rules is CCS—a technology that can capture and permanently store CO_2 from fossil fuel-fired EGUs. CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s[78] and has been used in a variety of industrial applications for decades. Thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[79] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with enhanced oil recovery (EOR).[80] The American Petroleum Institute (API) explains that ''CCS is a proven technology'' and that ''[t]he methods that apply to [the] carbon sequestration process are not novel. The U.S. has more than 40 years of CO_2 gas injection and storage experience. During the last 40 years the U.S. gas and oil industry's (EOR) enhanced oil recovery operations) have injected more than 1 billion tonnes of CO_2.''[81 82]

In 2009, Mike Morris, then-CEO of American Electric Power (AEP), was interviewed by Reuters and the article noted that Morris's ''companies' work in West Virginia on [CCS] gave [Morris] more insight than skeptics who doubt the technology.'' In that interview, Morris explained, ''I'm convinced it will be primetime ready by 2015 and deployable.''[83] In 2011, Alstom Power, the company that developed the 30 MW pilot project upon which Morris had based his conclusions, reiterated the claim that CCS would be commercially available in 2015. A press release from Alstom Power stated that, based on the results of Alstom's ''13 pilot and demonstration projects and validated by independent experts . . . we can now be confident that CCS works and is cost effective . . . and will be available at a commercial scale in 2015 and will allow [plants] to capture 90% of the emitted CO_2.'' The press release went on to note that ''the same conclusion applies for a gas plant using CCS.''[84]

In 2011, however, AEP determined that the economic and regulatory environment at the time did not support further development of the technology. After canceling a large-scale commercial project, Morris explained, ''as a regulated utility, it is impossible to gain regulatory approval to cover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place.''[85]

Thirteen years later, the situation is fundamentally different. Since 2011, the technological advances from full-scale deployments (*e.g.,* the Petra Nova and Boundary Dam projects discussed later in this preamble) combined with supportive policies in multiple states and the financial incentives included in the IRA, mean that CCS can be deployed at scale today. In addition to applications at fossil fuel-fired EGUs, installation of CCS is poised to dramatically increase across a range of industries in the coming years, including ethanol production, natural gas processing, and steam methane reformers.[86] Many of the CCS projects across these industries, including capture systems, pipelines, and sequestration, are already in operation or are in advanced stages of deployment. There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under

[77] 80 FR 63662 (October 23, 2015).

[78] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[79] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[80] GHGRP US EPA. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[81] American Petroleum Institute (API). (2024). Carbon Capture and Storage: A Low-Carbon Solution to Economy-Wide Greenhouse Gas Emissions Reductions. *https://www.api.org/news-policy-and-issues/carbon-capture-storage.*

[82] Major energy company presidents have made similar statements. For example, in 2021, Shell Oil Company president Gretchen H. Watkins testified to Congress that ''Carbon capture and storage is a proven technology,'' and in 2022, Joe Blommaert, the president of ExxonMobil Low Carbon Solutions, stated that ''Carbon capture and storage is a readily available technology that can play a critical role in helping society reduce greenhouse gas emissions.'' See *https://www.congress.gov/117/meeting/house/114185/witnesses/HHRG-117-GO00-Wstate-WatkinsG-20211028.pdf* and *https://corporate.exxonmobil.com/news/news-releases/2022/0225_exxonmobil-to-expand-carbon-capture-and-storage-at-labarge-wyoming-facility.*

[83] Woodall, B. (June 25, 2009). AEP sees carbon capture from coal ready by 2015. Reuters. *https://www.reuters.com/article/idUSTRE55O6TS/.*

[84] Alstom Power. (June 14, 2011). Alstom Power study demonstrates carbon capture and storage (CCS) is efficient and cost competitive. *https://www.alstom.com/press-releases-news/2011/6/press-releases-3-26.*

[85] Indiana Michigan Power. (July 14, 2011). AEP Places Carbon Capture Commercialization on Hold, Citing Uncertain Status of Climate Policy, Weak Economy. Press release. *https://www.indianamichiganpower.com/company/news/view?releaseID=1206.*

[86] U.S. Department of Energy (DOE). (2023). Pathways to Commercial Liftoff: Carbon Management. *https://liftoff.energy.gov/wp-content/uploads/2024/02/20230424-Liftoff-Carbon-Management-vPUB_update4.pdf.*

construction or in advanced stages of development.[87]

Process improvements learned from earlier deployments of CCS, the availability of better solvents, and other advances have decreased the costs of CCS in recent years. As a result, the cost of CO_2 capture, excluding any tax credits, from coal-fired power generation is projected to fall by 50 percent by 2025 compared to 2010.[88] The IRA makes additional and significant reductions in the cost of implementing CCS by extending and increasing the tax credit for CO_2 sequestration under IRC section 45Q.

With this combination of polices, and the advances related to CO_2 capture, multiple projects consistent with the emission reduction requirements of a 90 percent capture amine based BSER are in advanced stages of development. These projects use a wider range of technologies, and some of them are being developed as first-of-a-kind projects and offer significant advantages over the amine-based CCS technology that the EPA is finalizing as BSER.

For instance, in North Dakota, Governor Doug Burgum announced a goal of becoming carbon neutral by 2030 while retaining the core position of its fossil fuel industries, and to do so by significant CCS implementation. Gov. Burgum explained, ''This may seem like a moonshot goal, but it's actually not. It's actually completely doable, even with the technologies that we have today.'' [89] Companies in the state are backing up this claim with projects in multiple industries in various stages of operation and development. In the power sector, two of the biggest projects under development are Project Tundra and Coal Creek. Project Tundra is a carbon capture project on Minnkota Power's 705 MW Milton R Young Power Plant in Oliver County, North Dakota. Mitsubishi Heavy Industries will be providing an advanced version of its carbon capture equipment that builds upon the lessons learned from the Petra Nova project.[90] Rainbow Energy is developing the project at the Coal Creek Station, located in McLean, North Dakota. Notably, Rainbow Energy purchased the 1,150 MW Coal Creek Station with a business model of installing CCS based on the IRC section 45Q tax credit of $50/ton that existed at the time (the IRA has since increased the amount to $85/ton).[91] Rainbow Energy explains, ''CCUS technology has been proven and is an economical option for a facility like Coal Creek Station. We see CCUS as the best way to manage emissions at our facility.'' [92]

While North Dakota has encouraged CCS on coal-fired power plants without specific mandates, Wyoming is taking a different approach. Senate Bill 42, enacted in 2024, requires utilities to generate a specified percentage of their electricity using coal-fired power plants with CCS. SB 42 updates HB 200, enacted in 2020, which required the CCS to be installed by 2030, which SB 42 extends to 2033. To comply with those requirements, PacificCorp has stated in its 2023 IRP that it intends to install CCS on two coal-fired units by 2028.[93] Rocky Mountain Power has also announced that it will explore a new carbon capture technology at either its David Johnston plant or its Wyodak plant.[94] Another CCS project is also under development at the Dry Fork Power Plant in Wyoming. Currently, a pilot project that will capture 150 tons of CO_2 per day is under construction and is scheduled to be completed in late 2024. Work has also begun on a full-scale front end engineering design (FEED) study.

Like North Dakota, West Virginia does not have a carbon capture mandate, but there are several carbon capture projects under development in the state. One is a new, 2,000 MW natural gas combined cycle plant being developed by Competitive Power Ventures that will capture 90–95 percent of the CO_2 using GE turbine and carbon capture technology.[95] A second is an Omnis Fuel Technologies project to convert the coal-fired Pleasants Power Station to run on hydrogen.[96] Omnis intends to use a pyrolysis-based process to convert coal into hydrogen and graphite. Because the graphite is a usable, solid form of carbon, no CO_2 sequestration will be required. Therefore, unlike more traditional amine-based approaches, instead of the captured CO_2 being a cost, the graphite product will provide a revenue stream.[97] Omnis states that the Pleasants Power Project broke ground in August 2023 and will be online by 2025.

It should be noted that Wyoming, West Virginia, and North Dakota represented the first-, second-, and seventh-largest coal producers, respectively, in the U.S. in 2022.[98]

In addition to the coal-based CCS projects mentioned above, multiple other projects are in advanced stages of development and/or have completed FEED studies. For instance, Linde/BASF is installing a 10 MW pilot project on the Dallman Power Plant in Illinois. Based on results from small scale pilot studies, techno economic analysis indicates that the Linde/BASF process can provide a significant reduction in capital costs compared to the NETL base case for a supercritical pulverized coal plant with carbon capture.'' [99] Multiple other FEED studies are either completed or under development, putting those projects on a path to being able to be built and to commence operation well before January 1, 2032.

In addition to the Competitive Power Partners project, there are multiple post-combustion CCS retrofit projects in various stages of development. In particular, NET Power is in advanced stages of development on a 300 MW project in west Texas using the Allam-Fetvedt cycle, which is being designed to achieve greater than 97 percent CO_2 capture. In addition to working on this first project, NET Power has indicated that it has an additional project under development and is working with

[87] Congressional Budget Office (CBO). (December 13, 2023). Carbon Capture and Storage in the United States. *https://www.cbo.gov/publication/59345*.

[88] Global CCS Institute. (March 2021). Technology Readiness and Costs of CCS. *https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf*.

[89] Willis, A. (May 12, 2021). Gov. Doug Burgum calls for North Dakota to be carbon neutral by 2030. The Dickinson Press. *https://www.thedickinsonpress.com/business/gov-doug-burgum-calls-for-north-dakota-to-be-carbon-neutral-by-2030*.

[90] Tanaka, H. et al. Advanced KM CDR Process using New Solvent. 14th International Conference on Greenhouse Gas Control Technologies, GHGT–14. *https://www.cfaenm.org/wp-content/uploads/2019/03/GHGT14_manuscript_20180913Clean-version.pdf*.

[91] Minot Daily News. (April 8, 2024). Hoeven: ND to lead country with carbon capture project at Coal Creek Station. *https://minotdailynews.com/news/local-news/2021/07/hoeven-nd-to-lead-country-with-carbon-capture-project-at-coal-creek-station/*.

[92] Rainbow Energy Center. (ND). Carbon Capture. *https://rainbowenergycenter.com/what-we-do/carbon-capture/*.

[93] PacifiCorp. (April 1, 2024). 2023 Integrated Resource Plan Update. *https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023_IRP_Update.pdf*.

[94] Rocky Mountain Power. (April 1, 2024). Rocky Mountain Power and 8 Rivers to collaborate on proposed Wyoming carbon capture project. Press release. *https://www.rockymountainpower.net/about/newsroom/news-releases/rmp-proposed-wyoming-carbon-capture-project.html*.

[95] Competitive Power Ventures (CPV). Shay Clean Energy Center. *https://www.cpv.com/our-projects/cpv-shay-energy-center/*.

[96] The Associated Press (AP). (August 30, 2023). New owner restarts West Virginia coal-fired power plant and intends to convert it to hydrogen use. *https://apnews.com/article/west-virginia-power-plant-coal-hydrogen-7b46798c8e3b093a8591f25f66340e8f*.

[97] *omnigenglobal.com*.

[98] U.S. Energy Information Administration (EIA). (October 2023). Annual Coal Report 2022. *https://www.eia.gov/coal/annual/pdf/acr.pdf*.

[99] National Energy Technology Laboratory (NETL). Large Pilot Carbon Capture Project Supported by NETL Breaks Ground in Illinois. *https://netl.doe.gov/node/12284*.

suppliers to support additional future projects.[100]

In developing these final rules, the EPA reviewed the current state and cost of CCS technology for use with both steam generating units and stationary combustion turbines. This review is reflected in the respective BSER discussions later in this preamble and is further detailed in the accompanying RIA and final TSDs, *GHG Mitigation Measures for Steam Generating Units* and *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines.* These documents are included in the rulemaking docket.

2. Natural Gas Co-Firing

For a coal-fired steam generating unit, the substitution of natural gas for some of the coal so that the unit fires a combination of coal and natural gas is known as ''natural gas co-firing.'' Existing coal-fired steam generating units can be modified to co-fire natural gas in any desired proportion with coal. Generally, the modification of existing boilers to enable or increase natural gas firing involves the installation of new gas burners and related boiler modifications and may involve the construction of a natural gas supply pipeline if one does not already exist. In recent years, the cost of natural gas co-firing has declined because the expected difference between coal and gas prices has decreased and analysis supports lower capital costs for modifying existing boilers to co-fire with natural gas, as discussed in section VII.C.2.a of this preamble.

It is common practice for steam generating units to have the capability to burn multiple fuels onsite, and of the 565 coal-fired steam generating units operating at the end of 2021, 249 of them reported use of natural gas as a primary fuel or for startup.[101] Based on hourly reported CO_2 emission rates from the start of 2015 through the end of 2020, 29 coal-fired steam generating units co-fired with natural gas at rates at or above 60 percent of capacity on an hourly basis.[102] The capability of those units on an hourly basis is indicative of the extent of boiler burner modifications and sizing and capacity of natural gas pipelines to those units, and it implies that those units are technically capable of co-firing at least 60 percent natural gas on a heat input basis on average over the course of an extended period (*e.g.,* a year). Additionally, many coal-fired steam generating EGUs have also opted to switch entirely to providing generation from the firing of natural gas. Since 2011, more than 80 coal-fired utility boilers have been converted to natural gas-fired utility boilers.[103]

In developing these final actions, the EPA reviewed in detail the current state of natural gas co-firing technology and costs. This review is reflected in the BSER discussions later in this preamble and is further detailed in the accompanying RIA and final TSD, *GHG Mitigation Measures for Steam Generating Units.* Both documents are included in the rulemaking docket.

3. Efficient Generation

Highly efficient generation is the BSER technology upon which the first phase standards of performance are based for certain new and reconstructed stationary combustion turbine EGUs. This technology is available for both simple cycle and combined cycle combustion turbines and has been demonstrated—along with best operating and maintenance practices—to reduce emissions. Generally, as the thermal efficiency of a combustion turbine increases, less fuel is burned per gross MWh of electricity produced and there is a corresponding decrease in CO_2 and other air emissions.

For simple cycle turbines, manufacturers continue to improve the efficiency by increasing firing temperature, increasing pressure ratios, using intercooling on the air compressor, and adopting other measures. Best operating practices for simple cycle turbines include proper maintenance of the combustion turbine flow path components and the use of inlet air cooling to reduce efficiency losses during periods of high ambient temperatures. For combined cycle turbines, a highly efficient combustion turbine engine is matched with a high-efficiency HRSG. High efficiency also includes, but is not limited to, the use of the most efficient steam turbine and minimizing energy losses using insulation and blowdown heat recovery. Best operating and maintenance practices include, but are not limited to, minimizing steam leaks, minimizing air infiltration, and cleaning and maintaining heat transfer surfaces.

As discussed in section VIII.F.2.b of this preamble, efficient generation technologies have been in use at facilities in the power sector for decades and the levels of efficiency that the EPA is finalizing in this rule have been achieved by many recently constructed turbines. The efficiency improvements are incremental in nature and do not change how the combustion turbine is operated or maintained and present little incremental capital or compliance costs compared to other types of technologies that may be considered for new and reconstructed sources. In addition, more efficient designs have lower fuel costs, which offset at least a portion of the increase in capital costs. For additional discussion of this BSER technology, see the final TSD, *Efficient Generation in Combustion Turbines* in the docket for this rulemaking.

Efficiency improvements are also available for fossil fuel-fired steam generating units, and as discussed further in section VII.D.4.a, the more efficiently an EGU operates the less fuel it consumes, thereby emitting lower amounts of CO_2 and other air pollutants per MWh generated. Efficiency improvements for steam generating EGUs include a variety of technology upgrades and operating practices that may achieve CO_2 emission rate reductions of 0.1 to 5 percent for individual EGUs. These reductions are small relative to the reductions that are achievable from natural gas co-firing and from CCS. Also, as efficiency increases, some facilities could increase their utilization and therefore increase their CO_2 emissions (as well as emissions of other air pollutants). This phenomenon is known as the ''rebound effect.'' Because of this potential for perverse GHG emission outcomes resulting from deployment of efficiency measures at certain steam generating units, coupled with the relatively minor overall GHG emission reductions that would be expected, the EPA is not finalizing efficiency improvements as the BSER for any subcategory of existing coal-fired steam generating units. Specific details of efficiency measures are described in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* and an updated 2023 Sargent and Lundy HRI report (*Heat Rate Improvement Method Costs and Limitations Memo*), available in the docket.

[100] Net Power. (March 11, 2024). Q4 2023 Business Update and Results. *https://d1io3yog0oux5.cloudfront.net/_cde4aad258e20f5aec49abd8654499f8/netpower/db/3583/33195/pdf/Q4_2023+Earnings+Presentation_3.11.24.pdf.*

[101] U.S. Energy Information Administration (EIA). Form 923. *https://www.eia.gov/electricity/data/eia923/.*

[102] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. *https://campd.epa.gov.*

[103] U.S. Energy Information Administration (EIA). (5 August 2020). Today in Energy. More than 100 coal-fired plants have been replaced or converted to natural gas since 2011. *https://www.eia.gov/todayinenergy/detail.php?id=44636.*

D. The Electric Power Sector: Trends and Current Structure

1. Overview

The electric power sector is experiencing a prolonged period of transition and structural change. Since the generation of electricity from coal-fired power plants peaked nearly two decades ago, the power sector has changed at a rapid pace. Today, natural gas-fired power plants provide the largest share of net generation, coal-fired power plants provide a significantly smaller share than in the recent past, renewable energy provides a steadily increasing share, and as new technologies enter the marketplace, power producers continue to replace aging assets—especially coal-fired power plants—with more efficient and lower-cost alternatives.

These developments have significant implications for the types of controls that the EPA determined to qualify as the BSER for different types of fossil fuel-fired EGUs. For example, power plant owners and operators retired an average annual coal-fired EGU capacity of 10 GW from 2015 to 2023, and coal-fired EGUs comprised 58 percent of all retired capacity in 2023.[104] While use of CCS promises significant emissions reduction from fossil fuel-fired sources, it requires substantial up-front capital expenditure. Therefore, it is not a feasible or cost-reasonable emission reduction technology for units that intend to cease operation before they would be able to amortize its costs. Industry stakeholders requested that the EPA structure these rules to avoid imposing costly control obligations on coal-fired power plants that have announced plans to voluntarily cease operations, and the EPA has determined the BSER in accordance with its understanding of which coal-fired units will be able to feasibly and cost-effectively deploy the BSER technologies. In addition, the EPA recognizes that utilities and power plant operators are building new natural gas-fired combustion turbines with plans to operate them at varying levels of utilization, in coordination with other existing and expected new energy sources. These patterns of operation are important for the type of controls that the EPA is finalizing as the BSER for these turbines.

2. Broad Trends Within the Power Sector

For more than a decade, the power sector has been experiencing substantial transition and structural change, both in terms of the mix of generating capacity and in the share of electricity generation supplied by different types of EGUs. These changes are the result of multiple factors, including normal replacements of older EGUs; technological improvements in electricity generation from both existing and new EGUs; changes in the prices and availability of different fuels; state and Federal policy; the preferences and purchasing behaviors of end-use electricity consumers; and substantial growth in electricity generation from renewable sources.

One of the most important developments of this transition has been the evolving economics of the power sector. Specifically, as discussed in section IV.D.3.b of this preamble and in the final TSD, *Power Sector Trends,* the existing fleet of coal-fired EGUs continues to age and become more costly to maintain and operate. At the same time, natural gas prices have held relatively low due to increased supply, and renewable costs have fallen rapidly with technological improvement and growing scale. Natural gas surpassed coal in monthly net electricity generation for the first time in April 2015, and since that time natural gas has maintained its position as the primary fuel for base load electricity generation, for peaking applications, and for balancing renewable generation.[105] In 2023, generation from natural gas was more than 2.5 times as much as generation from coal.[106] Additionally, there has been increased generation from investments in zero- and low-GHG emission energy technologies spurred by technological advancements, declining costs, state and Federal policies, and most recently, the IIJA and the IRA. For example, the IIJA provides investments and other policies to help commercialize, demonstrate, and deploy technologies such as small modular nuclear reactors, long-duration energy storage, regional clean hydrogen hubs, CCS and associated infrastructure, advanced geothermal systems, and advanced distributed energy resources (DER) as well as more traditional wind, solar, and battery energy storage resources. The IRA provides numerous tax and other incentives to directly spur deployment of clean energy technologies. Particularly relevant to these final actions, the incentives in the IRA,[107 108] which are discussed in detail later in this section of the preamble, support the expansion of technologies, such as CCS, that reduce GHG emissions from fossil-fired EGUs.

The ongoing transition of the power sector is illustrated by a comparison of data between 2007 and 2022. In 2007, the year of peak coal generation, approximately 72 percent of the electricity provided to the U.S. grid was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for the largest single share. By 2022, fossil fuel net generation was approximately 60 percent, less than the share in 2007 despite electricity demand remaining relatively flat over this same period. Moreover, the share of generation supplied by coal-fired EGUs fell from 49 percent in 2007 to 19 percent in 2022 while the share supplied by natural gas-fired EGUs rose from 22 to 39 percent during the same period. In absolute terms, coal-fired generation declined by 59 percent while natural gas-fired generation increased by 88 percent. This reflects both the increase in natural gas capacity as well as an increase in the utilization of new and existing natural gas-fired EGUs. The combination of wind and solar generation also grew from 1 percent of the electric power sector mix in 2007 to 15 percent in 2022.[109]

Additional analysis of the utility power sector, including projections of future power sector behavior and the impacts of these final rules, is discussed in more detail in section XII of this preamble, in the accompanying RIA, and in the final TSD, *Power Sector Trends.* The latter two documents are available in the rulemaking docket. Consistent with analyses done by other energy modelers, the information

[104] U.S. Energy Information Administration (EIA). (7 February 2023). Today in Energy. Coal and natural gas plants will account for 98 percent of U.S. capacity retirements in 2023. *https://www.eia.gov/todayinenergy/detail.php?id=55439.*

[105] U.S. Energy Information Administration (EIA). Monthly Energy Review and Short-Term Energy Outlook, March 2016. *https://www.eia.gov/todayinenergy/detail.php?id=25392.*

[106] U.S. Energy Information Administration (EIA). Electric Power Monthly, March 2024. *https://www.eia.gov/electricity/monthly/current_month/march2024.pdf.*

[107] U.S. Department of Energy (DOE). August 2022. *The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals. https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf.*

[108] U.S. Department of Energy (DOE). August 2023. Investing in American Energy. Significant Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Energy Economy and Emissions Reductions. *https://www.energy.gov/sites/default/files/2023-08/DOE%20OP%20Economy%20Wide%20Report_0.pdf.*

[109] U.S. Energy Information Administration (EIA). *Annual Energy Review,* table 8.2b Electricity net generation: electric power sector. *https://www.eia.gov/totalenergy/data/annual/.*

provided in the RIA and TSD demonstrates that the sector trend of moving away from coal-fired generation is likely to continue, the share from natural gas-fired generation is projected to decline eventually, and the share of generation from non-emitting technologies is likely to continue increasing. For instance, according to the Energy Information Administration (EIA), the net change in solar capacity has been larger than the net change in capacity for any other source of electricity for every year since 2020. In 2024, EIA projects that the actual increase in generation from solar will exceed every other source of generating capacity. This is in part because of the large amounts of new solar coming online in 2024 but is also due to the large amount of energy storage coming online, which will help reduce renewable curtailments.[110] EIA also projects that in 2024, the U.S. will see its largest year for installation of both solar and battery storage. Specifically, EIA projects that 36.4 GW of solar will be added, nearly doubling last year's record of 18.4 GW. Similarly, EIA projects 14.3 GW of new energy storage. This would more than double last year's record installation of 6.4 GW and nearly double the existing total capacity of 15.5 GW. This compares to only 2.5 GW of new natural gas turbine capacity.[111] The only year since 2013 when renewable generation did not make up the majority of new generation capacity in the U.S. was 2018.[112]

3. Coal-Fired Generation: Historical Trends and Current Structure

a. Historical Trends in Coal-Fired Generation

Coal-fired steam generating units have historically been the nation's foremost source of electricity, but coal-fired generation has declined steadily since its peak approximately 20 years ago.[113] Construction of new coal-fired steam generating units was at its highest between 1967 and 1986, with approximately 188 GW (or 9.4 GW per year) of capacity added to the grid during that 20-year period.[114] The peak annual capacity addition was 14 GW, which was added in 1980. These coal-fired steam generating units operated as base load units for decades. However, beginning in 2005, the U.S. power sector—and especially the coal-fired fleet—began experiencing a period of transition that continues today. Many of the older coal-fired steam generating units built in the 1960s, 1970s, and 1980s have retired or have experienced significant reductions in net generation due to cost pressures and other factors. Some of these coal-fired steam generating units repowered with combustion turbines and natural gas.[115] With no new coal-fired steam generating units larger than 25 MW commencing construction in the past decade—and with the EPA unaware of any plans being approved to construct a new coal-fired EGU—much of the fleet that remains is aging, expensive to operate and maintain, and increasingly uncompetitive relative to other sources of generation in many parts of the country.

Since 2007, the power sector's total installed net summer capacity[116] has increased by 167 GW (17 percent) while coal-fired steam generating unit capacity has declined by 123 GW.[117] This reduction in coal-fired steam generating unit capacity was offset by a net increase in total installed wind capacity of 125 GW, net natural gas capacity of 110 GW, and a net increase in utility-scale solar capacity of 71 GW during the same period. Additionally, significant amounts (40 GW) of DER solar were also added. At least half of these changes were in the most recent 7 years of this period. From 2015 to 2022, coal capacity was reduced by 90 GW and this reduction in capacity was offset by a net increase of 69 GW of wind capacity, 63 GW of natural gas capacity, and 59 GW of utility-scale solar capacity. Additionally, a net summer capacity of 30 GW of DER solar were added from 2015 to 2022.

b. Current Structure of Coal-Fired Generation

Although much of the fleet of coal-fired steam generating units has historically operated as base load, there can be notable differences in design and operation across various facilities. For example, coal-fired steam generating units smaller than 100 MW comprise 18 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity.[118] Moreover, average annual capacity factors for coal-fired steam generating units have declined from 74 to 50 percent since 2007.[119] These declining capacity factors indicate that a larger share of units are operating in non-base load fashion largely because they are no longer cost-competitive in many hours of the year.

Older power plants also tend to become uneconomic over time as they become more costly to maintain and operate,[120] especially when competing for dispatch against newer and more efficient generating technologies that have lower operating costs. The average coal-fired power plant that retired between 2015 and 2022 was more than 50 years old, and 65 percent of the remaining fleet of coal-fired steam generating units will be 50 years old or more within a decade.[121] To further illustrate this trend, the existing coal-fired steam generating units older than 40 years represent 71 percent (129 GW)[122] of the total remaining capacity. In fact, more than half (100 GW) of the coal-fired steam generating units still operating have already announced retirement dates prior to 2039 or conversion to gas-fired units by the

[110] U.S. Energy Information Administration (EIA). Short Term Energy Outlook, December 2023.

[111] U.S. Energy Information Administration (EIA). (February 15, 2024). Today in Energy. *Solar and Battery Storage to make up 81% of new U.S. Electric-generating capacity in 2024. https://www.eia.gov/todayinenergy/detail.php?id=61424.*

[112] U.S. Energy Information Administration (EIA). Today in Energy. *Natural gas and renewables make up most of 2018 electric capacity additions. https://www.eia.gov/todayinenergy/detail.php?id=36092.*

[113] U.S. Energy Information Administration (EIA). Today in Energy. *Natural gas expected to surpass coal in mix of fuel used for U.S. power generation in 2016.* March 2016. *https://www.eia.gov/todayinenergy/detail.php?id=25392.*

[114] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA–860M, Inventory of Operating Generators and Inventory of Retired Generators, March 2022. *https://www.eia.gov/electricity/data/eia860m/.*

[115] U.S. Energy Information Administration (EIA). Today in Energy. *More than 100 coal-fired plants have been replaced or converted to natural gas since 2011.* August 2020. *https://www.eia.gov/todayinenergy/detail.php?id=44636.*

[116] This includes generating capacity at EGUs primarily operated to supply electricity to the grid and combined heat and power (CHP) facilities classified as Independent Power Producers and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural gas information reflects data for all generating units using natural gas as the primary fossil heat source unless otherwise stated. This includes combined cycle, simple cycle, steam, and miscellaneous (<1 percent).

[117] U.S. Energy Information Administration (EIA). Electric Power Annuals 2010 (Tables 1.1.A and 1.1.B) and 2022 (Tables 4.2.A and 4.2.B).

[118] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[119] U.S. Energy Information Administration (EIA). Electric Power Annual 2021, table 1.2.

[120] U.S. Energy Information Administration (EIA). U.S. coal plant retirements linked to plants with higher operating costs. December 2019. *https://www.eia.gov/todayinenergy/detail.php?id=42155.*

[121] eGRID 2020 (January 2022 release from EPA eGRID website). Represents data from generators that came online between 1950 and 2020 (inclusive); a 71-year period. Full eGRID data includes generators that came online as far back as 1915.

[122] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form–860M, Inventory of Operating Generators and Inventory of Retired Generators. August 2022. *https://www.eia.gov/electricity/data/eia860m/.*

same year.[123] As discussed later in this section, projections anticipate that this trend will continue.

The reduction in coal-fired generation by electric utilities is also evident in data for annual U.S. coal production, which reflects reductions in international demand as well. In 2008, annual coal production peaked at nearly 1,172 million short tons (MMst) followed by sharp declines in 2015 and 2020.[124] In 2015, less than 900 MMst were produced, and in 2020, the total dropped to 535 MMst, the lowest output since 1965. Following the pandemic, in 2022, annual coal production had increased to 594 MMst. For additional analysis of the coal-fired steam generation fleet, see the final TSD, *Power Sector Trends* included in the docket for this rulemaking.

Notwithstanding these trends, in 2022, coal-fired energy sources were still responsible for 50 percent of CO_2 emissions from the electric power sector.[125]

4. Natural Gas-Fired Generation: Historical Trends and Current Structure

a. Historical Trends in Natural Gas-Fired Generation

There has been significant expansion of the natural gas-fired EGU fleet since 2000, coinciding with efficiency improvements of combustion turbine technologies, increased availability of natural gas, increased demand for flexible generation to support the expanding capacity of variable energy resources, and declining costs for all three elements. According to data from EIA, annual capacity additions for natural gas-fired EGUs peaked between 2000 and 2006, with more than 212 GW added to the grid during this period (about 35 GW per year). Of this total, approximately 147 GW (70 percent) were combined cycle capacity and 65 GW were simple cycle capacity.[126] From 2007 to 2022, more than 132 GW of capacity were constructed and approximately 77 percent of that total were combined cycle EGUs. This figure represents an average of almost 8.8 GW of new combustion turbine generation capacity per year. In 2022, the net summer capacity of combustion turbine EGUs totaled 419 GW, with 289 GW being combined cycle generation and 130 GW being simple cycle generation.

This trend away from electricity generation using coal-fired EGUs to natural gas-fired turbine EGUs is also reflected in comparisons of annual capacity factors, sizes, and ages of affected EGUs. For example, the average annual capacity factors for natural gas-fired units increased from 28 to 38 percent between 2010 and 2022. And compared with the fleet of coal-fired steam generating units, the natural gas fleet is generally smaller and newer. While 67 percent of the coal-fired steam generating unit fleet capacity is over 500 MW per unit, 75 percent of the gas fleet is between 50 and 500 MW per unit. In terms of the age of the generating units, nearly 50 percent of the natural gas capacity has been in service less than 15 years.[127]

b. Current Structure of Natural Gas-Fired Generation

In the lower 48 states, most combustion turbine EGUs burn natural gas, and some have the capability to fire distillate oil as backup for periods when natural gas is not available, such as when residential demand for natural gas is high during the winter. Areas of the country without access to natural gas often use distillate oil or some other locally available fuel. Combustion turbines have the capability to burn either gaseous or liquid fossil fuels, including but not limited to kerosene, naphtha, synthetic gas, biogases, liquified natural gas (LNG), and hydrogen.

Over the past 20 years, advances in hydraulic fracturing (*i.e.,* fracking) and horizontal drilling techniques have opened new regions of the U.S. to gas exploration. As the production of natural gas has increased, the annual average price has declined during the same period, leading to more natural gas-fired combustion turbines.[128] Natural gas net generation increased 181 percent in the past two decades, from 601 thousand gigawatt-hours (GWh) in 2000 to 1,687 thousand GWh in 2022. For additional analysis of natural gas-fired generation, see the final TSD, *Power Sector Trends* included in the docket for this rulemaking.

E. The Legislative, Market, and State Law Context

1. Recent Legislation Impacting the Power Sector

On November 15, 2021, President Biden signed the IIJA[129] (also known as the Bipartisan Infrastructure Law), which allocated more than $65 billion in funding via grant programs, contracts, cooperative agreements, credit allocations, and other mechanisms to develop and upgrade infrastructure and expand access to clean energy technologies. Specific objectives of the legislation are to improve the nation's electricity transmission capacity, pipeline infrastructure, and increase the availability of low-GHG fuels. Some of the IIJA programs[130] that will impact the utility power sector include more than $20 billion to build and upgrade the nation's electric grid, up to $6 billion in financial support for existing nuclear reactors that are at risk of closing, and more than $700 million for upgrades to the existing hydroelectric fleet. The IIJA established the Carbon Dioxide Transportation Infrastructure Finance and Innovation Program to provide flexible Federal loans and grants for building CO_2 pipelines designed with excess capacity, enabling integrated carbon capture and geologic storage. The IIJA also allocated $21.5 billion to fund new programs to support the development, demonstration, and deployment of clean energy technologies, such as $8 billion for the development of regional clean hydrogen hubs and $7 billion for the development of carbon management technologies, including regional direct air capture hubs, carbon capture large-scale pilot projects for development of transformational technologies, and carbon capture commercial-scale demonstration projects to improve efficiency and effectiveness. Other clean energy technologies with IIJA and IRA funding include industrial demonstrations, geologic sequestration, grid-scale energy storage, and advanced nuclear reactors.

The IRA, which President Biden signed on August 16, 2022,[131] has the potential for even greater impacts on the electric power sector. Energy Security and Climate Change programs in the

[123] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v6. October 2022. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[124] U.S. Energy Information Administration (EIA). (October 2023). Annual Coal Report 2022. *https://www.eia.gov/coal/annual/pdf/acr.pdf.*

[125] U.S. Energy Information Administration (EIA). U.S. CO_2 emissions from energy consumption by source and sector, 2022. *https://www.eia.gov/totalenergy/data/monthly/pdf/flow/CO2_emissions_2022.pdf.*

[126] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA–860M, Inventory of Operating Generators and Inventory of Retired Generators, July 2022. *https://www.eia.gov/electricity/data/eia860m/.*

[127] National Electric Energy Data System (NEEDS) v.6.

[128] U.S. Energy Information Administration (EIA). *Natural Gas Annual,* September 2021. *https://www.eia.gov/energyexplained/natural-gas/prices.php.*

[129] *https://www.congress.gov/bill/117th-congress/house-bill/3684/text.*

[130] *https://www.whitehouse.gov/wp-content/uploads/2022/05/BUILDING-A-BETTER-AMERICA-V2.pdf.*

[131] *https://www.congress.gov/bill/117th-congress/house-bill/5376/text.*

IRA covering grant funding and tax incentives provide significant investments in low and non GHG-emitting generation. For example, one of the conditions set by Congress for the expiration of the Clean Electricity Production Tax Credits of the IRA, found in section 13701, is a 75 percent reduction in GHG emissions from the power sector below 2022 levels. The IRA also contains the Low Emission Electricity Program (LEEP) with funding provided to the EPA with the objective to reduce GHG emissions from domestic electricity generation and use through promotion of incentives, tools to facilitate action, and use of CAA regulatory authority. In particular, CAA section 135, added by IRA section 60107, requires the EPA to conduct an assessment of the GHG emission reductions expected to occur from changes in domestic electricity generation and use through fiscal year 2031 and, further, provides the EPA $18 million ''to ensure that reductions in [GHG] emissions are achieved through use of the existing authorities of [the Clean Air Act], incorporating the assessment. . . .'' CAA section 135(a)(6).

The IRA's provisions also demonstrate an intent to support development and deployment of low-GHG emitting technologies in the power sector through a broad array of additional tax credits, loan guarantees, and public investment programs. Particularly relevant for these final actions, these provisions are aimed at reducing emissions of GHGs from new and existing generating assets, with tax credits for CCUS and clean hydrogen production, providing a pathway for the use of coal and natural gas as part of a low-GHG electricity grid.

To assist states and utilities in their decarbonizing efforts, and most germane to these final actions, the IRA increased the tax credit incentives for capturing and storing CO_2, including from industrial sources, coal-fired steam generating units, and natural gas-fired stationary combustion turbines. The increase in credit values, found in section 13104 (which revises IRC section 45Q), is 70 percent, equaling $85/metric ton for CO_2 captured and securely stored in geologic formations and $60/metric ton for CO_2 captured and utilized or securely stored incidentally in conjunction with EOR.[132] The CCUS incentives include 12 years of credits that can be claimed at the higher credit value beginning in 2023 for qualifying projects. These incentives will significantly cut costs and are expected to accelerate the adoption of CCS in the utility power and other industrial sectors. Specifically for the power sector, the IRA requires that a qualifying carbon capture facility have a CO_2 capture design capacity of not less than 75 percent of the baseline CO_2 production of the unit and that construction must begin before January 1, 2033. Tax credits under IRC section 45Q can be combined with some other tax credits, in some circumstances, and with state-level incentives, including California's low carbon fuel standard, which is a market-based program with fuel-specific carbon intensity benchmarks.[133] The magnitude of this incentive is driving investment and announcements, evidenced by the increased number of permit applications for geologic sequestration.[134]

The new provisions in section 13204 (IRC section 45V) codify production tax credits for 'clean hydrogen' as defined in the provision. The value of the credits earned by a project is tiered (four different tiers) and depends on the estimated GHG emissions of the hydrogen production process as defined in the statute. The credits range from $3/kg H_2 for less than 0.45 kilograms of CO_2-equivalent emitted per kilogram of low-GHG hydrogen produced (kg CO_2e/kg H_2) down to $0.6/kg H_2 for 2.5 to 4.0 kg CO_2e/kg H_2 (assuming wage and apprenticeship requirements are met). Projects with production related GHG emissions greater than 4.0 kg CO_2e/kg H_2 are not eligible. Future costs for clean hydrogen produced using renewable energy are anticipated to through 2030 due to these tax incentives and concurrent scaling up of manufacturing and deployment of clean hydrogen production facilities.

Both IRC section 45Q and IRC section 45V are eligible for additional provisions that increase the value and usability of the credits. Certain tax-exempt entities, such as electric co-operatives, may elect direct payment for the full 12- or 10-year lifetime of the credits to monetize the credits directly as cash refunds rather than through tax equity transactions. Tax-paying entities may elect to have direct payment of IRC section 45Q or 45V credits for 5 consecutive years. Tax-paying entities may also elect to transfer credits to unrelated taxpayers, enabling direct monetization of the credits again without relying on tax equity transactions.

In addition to provisions such as 45Q that allow for the use of fossil-generating assets in a low-GHG future, the IRA also includes significant incentives to deploy clean energy generation. For instance, the IRA provides an additional 10 percent in production tax credit (PTC) and investment tax credit (ITC) bonuses for clean energy projects located in energy communities with historic employment and tax bases related to fossil fuels.[135] The IRA's Energy Infrastructure Reinvestment Program also provides $250 billion for the DOE to finance loan guarantees that can be used to reduce both the cost of retiring existing fossil assets and of replacement generation for those assets, including updating operating energy infrastructure with emissions control technologies.[136] As a further example, the Empowering Rural America (New ERA) Program provides rural electric cooperatives with funds that can be used for a variety of purposes, including ''funding for renewable and zero emissions energy systems that eliminate aging, obsolete or expensive infrastructure'' or that allow rural cooperatives to ''change [their] purchased-power mixes to support cleaner portfolios, manage stranded assets and boost [the] transition to clean energy.''[137] The $9.7 billion New ERA program represents the single largest investment in rural energy systems since the Rural Electrification Act of 1936.[138]

On September 12, 2023, the EPA released a report assessing the impact of the IRA on the power sector. Modeling results showed that economy-wide CO_2 emissions are lower under the IRA. The

[132] 26 U.S.C. 45Q. Note, qualified facilities must meet prevailing wage and apprenticeship requirements to be eligible for the full value of the tax credit.

[133] Global CCS Institute. (2019). *The LCFS and CCS Protocol: An Overview for Policymakers and Project Developers.* Policy report. *https://www.globalccsinstitute.com/wp-content/uploads/2019/05/LCFS-and-CCS-Protocol_digital_version-2.pdf.*

[134] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[135] U.S. Department of the Treasury. (April 4, 2023). Treasury Releases Guidance to Drive Investment to Coal Communities. Press release. *https://home.treasury.gov/news/press-releases/jy1383.*

[136] Fong, C., Posner, D., Varadarajan, U. (February 16, 2024). The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy. Case studies from Missouri and Iowa. Rocky Mountain Institute (RMI). *https://rmi.org/the-energy-infrastructure-reinvestment-program-federal-financing-for-an-equitable-clean-economy/.*

[137] U.S. Department of Agriculture (USDA). Empowering Rural America New ERA Program. *https://www.rd.usda.gov/programs-services/electric-programs/empowering-rural-america-new-era-program.*

[138] Rocky Mountain Institute (RMI). (October 4, 2023). USDA $9.7B Rural Community Clean Energy Program Receives 150+ Letters of Interest. Press release. *https://rmi.org/press-release/usda-9-7b-rural-community-clean-energy-program-receives-150-letters-of-interest/.*

results from the EPA's analysis of an array of multi-sector and electric sector modeling efforts show that a wide range of emissions reductions are possible. The IRA spurs CO_2 emissions reductions from the electric power sector of 49 to 83 percent below 2005 levels in 2030. This finding reflects diversity in how the models represent the IRA, the assumptions the models use, and fundamental differences in model structures.[139]

In determining the CAA section 111 emission limitations that are included in these final actions, the EPA did not consider many of the technologies that receive investment under recent Federal legislation. The EPA's determination of the BSER focused on ''measures that improve the pollution performance of individual sources,'' [140] not generation technologies that entities could employ as alternatives to fossil fuel-fired EGUs. However, these overarching incentives and policies are important context for this rulemaking and influence where control technologies can be feasibly and cost-reasonably deployed, as well as how owners and operators of EGUs may respond to the requirements of these final actions.

2. Commitments by Utilities To Reduce GHG Emissions

Integrated resource plans (IRPs) are filed by public utilities and demonstrate how utilities plan to meet future forecasted energy demand while ensuring reliable and cost-effective service. In developing these rules, the EPA reviewed filed IRPs of companies that have publicly committed to reducing their GHGs. These IRPs demonstrate a range of strategies that public utilities are planning to adopt to reduce their GHGs, independent of these final actions. These strategies include retiring aging coal-fired steam generating EGUs and replacing them with a combination of renewable resources, energy storage, other non-emitting technologies, and natural gas-fired combustion turbines, and reducing GHGs from their natural gas-fired assets through a combination of CCS and reduced utilization. To affirm these findings, according to EIA, as of 2022 there are no new coal-fired EGUs in development. This section highlights recent actions and announced plans of many utilities across the industry to reduce GHGs from their fleets. Indeed, 50 power producers that are members of the Edison Electric Institute (EEI) have announced CO_2 reduction goals, two-thirds of which include net-zero carbon emissions by 2050.[141] The members of the Energy Strategies Coalition, a group of companies that operate and manage electricity generation facilities, as well as electricity and natural gas transmission and distribution systems, likewise are focused on investments to reduce carbon dioxide emissions from the electricity sector.[142] This trend is not unique. Smaller utilities, rural electric cooperatives, and municipal entities are also contributing to these changes.

Many electric utilities have publicly announced near- and long-term emission reduction commitments independent of these final actions. The Smart Electric Power Alliance demonstrates that the geographic footprint of commitments for 100 percent renewable, net-zero, or other carbon emission reductions by 2050 made by utilities, their parent companies, or in response to a state clean energy requirement, covers portions of 47 states and includes 80 percent of U.S. customer accounts.[143] According to this same source, 341 utilities in 26 states have similar commitments by 2040. Additional detail about emission reduction commitments from major utilities is provided in section 2.2 of the RIA and in the final TSD, *Power Sector Trends.*

3. State Actions To Reduce Power Sector GHG Emissions

States across the country have taken the lead in efforts to reduce GHG emissions from the power sector. As of mid-2023, 25 states had made commitments to reduce economy-wide GHG emissions consistent with the goals of the Paris Agreement, including reducing GHG emissions by 50 to 52 percent by 2030.[144 145 146] These actions include legislation to decarbonize state power systems as well as commitments that require utilities to expand renewable and clean energy production through the adoption of renewable portfolio standards (RPS) and clean energy standards (CES).

Several states have enacted binding economy-wide emission reduction targets that will require significant decarbonization from state power sectors, including California, Colorado, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, Vermont, and Washington.[147] These commitments are statutory emission reduction targets accompanied by mandatory agency directives to develop comprehensive implementing regulations to achieve the necessary reductions. Some of these states, along with other neighboring states, also participate in the Regional Greenhouse Gas Initiative (RGGI), a carbon market limiting pollution from power plants throughout New England.[148] The pollution limit combined with carbon price and allowance market has led member states to reduce power sector CO_2 emissions by nearly 50 percent since the start of the program in 2009. This is 10 percent more than all non-RGGI states.[149]

Other states dependent on coal-fired power generation or coal production also have significant, albeit non-

[139] U.S. Environmental Protection Agency (EPA). (September 2023). *Electricity Sector Emissions Impacts of the Inflation Reduction Act. https://www.epa.gov/system/files/documents/2023-09/Electricity_Emissions_Impacts_Inflation_Reduction_Act_Report_EPA–FINAL.pdf.*

[140] *West Virginia* v. *EPA,* 597 U.S. at 734.

[141] See Comments of Edison Electric Institute to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Document ID No. EPA–HQ–OAR–2022–0723–0024, November 18, 2022 (''Fifty EEI members have announced forward-looking carbon reduction goals, two-third of which include a net-zero by 2050 or earlier equivalent goal, and members are routinely increasing the ambition or speed of their goals or altogether transforming them into net-zero goals.'').

[142] Energy Strategy Coalition Comments on EPA's proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, Document ID No. EPA–HQ–OAR–2023–0072–0672, August 14, 2023.

[143] Smart Electric Power Alliance Utility Carbon Tracker. *https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.*

[144] Cao, L., Brindle., T., Schneer, K., and DeGolia, A. (December 2023). Turning Climate Commitments into Results: Evaluating Updated 2023 Projections vs. State Climate Targets. Environmental Defense Fund (EDF). *https://www.edf.org/sites/default/files/2023–11/EDF-State-Emissions-Gap-December-2023.pdf.*

[145] United Nations Framework Convention on Climate Change. What is the Paris Agreement? *https://unfccc.int/process-and-meetings/the-paris-agreement.*

[146] U.S. Department of State and U.S. Executive Office of the President. November 2021. The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050. *https://www.whitehouse.gov/wp-content/uploads/2021/10/us-long-term-strategy.pdf.*

[147] Cao, L., Brindle., T., Schneer, K., and DeGolia, A., December 2023. Turning Climate Commitments into Results: Evaluating Updated 2023 Projections vs. State Climate Targets. Environmental Defense Fund (EDF). *https://www.edf.org/sites/default/files/2023-11/EDF-State-Emissions-Gap-December-2023.pdf.*

[148] A full list of states currently participating in RGGI include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

[149] Note that these figures do not include Virginia and Pennsylvania, which were not members of RGGI for the full duration of 2009–2023. Acadia Center: Regional Greenhouse Gas Initiative; Findings and Recommendations for the Third Program Review. *https://acadiacenter.wpenginepowered.com/wp-content/uploads/2023/04/AC_RGGI_2023_Layout_R6.pdf.*

binding, commitments that signal broad public support for policy with emissions-based metrics and public affirmation that climate change is fundamentally linked to fossil-intensive energy sources. These states include Illinois, Michigan, Minnesota, New Mexico, North Carolina, Pennsylvania, and Virginia. States like Wyoming, the top coal producing state in the U.S., have promulgated sector-specific regulations requiring their public service commissions to implement low-carbon energy standards for public utilities.[150] [151] Specific standards are further detailed in the sections that follow and in the final TSD, *Power Sector Trends.*

Technologies like CCS provide a means to achieve significant emission reduction targets. For example, to achieve GHG emission reduction goals legislatively enacted in 2016, California Senate Bill 100, passed in 2018, requires the state to procure 60 percent of all electricity from renewable sources by 2030 and plan for 100 percent from carbon-free sources by 2045.[152] Achieving California's established goal of carbon-free electricity by 2045 requires emissions to be balanced by carbon sequestration, capture, or other technologies. Therefore, California Senate Bill 905, passed in 2022, requires the California Air Resources Board (CARB) to establish programs for permitting CCS projects while preventing the use of captured CO_2 for EOR within the state.[153] As mentioned previously, as the top coal producing state, Wyoming has been exceptionally persistent on the implementation of CCS by incentivizing the national testing of CCS at Basin Electric's coal-fired Dry Fork Station[154] and by requiring the consideration of CCS as an alternative to coal plant retirement.[155] At least five other states, including Montana and North Dakota, also have tax incentives and regulations for CCS.[156] In the case of Montana, the acquisition of an equity interest or lease of coal-fired EGUs is prohibited unless it captures and stores at least 50 percent of its CO_2 emissions.[157] These state policies have coincided with the planning and development of large CCS projects.

Other states have broad decarbonization laws that will drive significant decrease in power sector GHG emissions. In New York, The Climate Leadership and Community Protection Act, passed in 2019, sets several climate targets. The most important goals include an 85 percent reduction in GHG emissions by 2050, 100 percent zero-emission electricity by 2040, and 70 percent renewable energy by 2030. Other targets include 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, and 6,000 MW of solar by 2025.[158] Washington State's Climate Commitment Act sets a target of reducing GHG emissions by 95 percent by 2050. The state is required to reduce emissions to 1990 levels by 2020, 45 percent below 1990 levels by 2030, 70 percent below 1990 levels by 2040, and 95 percent below 1990 levels by 2050. This also includes achieving net-zero emissions by 2050.[159] Illinois' Climate and Equitable Jobs Act, enacted in September 2021, requires all private coal-fired or oil-fired power plants to reach zero carbon emissions by 2030, municipal coal-fired plants to reach zero carbon emissions by 2045, and natural gas-fired plants to reach zero carbon emissions by 2045.[160] In October 2021, North Carolina passed House Bill 951 that required the North Carolina Utilities Commission to ''take all reasonable steps to achieve a seventy percent (70 percent) reduction in emissions of carbon dioxide (CO_2) emitted in the state from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050.'' [161]

The ambition and scope of these state power sector polices will impact the electric generation fleet for decades. Seven states with 100-percent power sector decarbonization polices include a total of 20 coal-fired EGUs with slightly less than 10 GW total capacity and without announced retirement dates before 2039.[162] Virginia, which has three coal-steam units with no announced retirement dates and one with a 2045 retirement date, enacted the Clean Economy Act in 2020 to impose a 100 percent RPS requirement by 2050. The combined capacity of all four of these units in Virginia totals nearly 1.5 GW. North Carolina, which has one coal-fired unit without an announced retirement date and one with a planned 2048 retirement, as previously mentioned, enacted a state law in 2021 requiring the state's utilities commission to achieve carbon neutrality by 2050. The combined capacity of both units totals approximately 1.4 GW of capacity. Nebraska, where three public utility boards serving a large portion of the state have adopted net-zero electricity emission goals by 2040 or 2050, includes six coal-fired units with a combined capacity of 2.9 GW. The remaining eight units are in states with long-term decarbonization goals (Illinois, Louisiana, Maryland, and Wisconsin). All four of these states have set 100 percent clean energy goals by 2050.

Twenty-nine states and the District of Columbia have enforceable RPS [163] that require a percentage of electricity that utilities sell to come from eligible renewable sources like wind and solar rather than from fossil fuel-based sources like coal and natural gas. Furthermore, 20 states have adopted a CES that includes some form of clean

[150] State of Wyoming. (Adopted March 24, 2020). House Bill 200 Reliable and dispatchable low-carbon energy standards. *https://www.wyoleg.gov/Legislation/2020/HB0200.*

[151] State of Wyoming. (Adopted March 15, 2024). Senate Bill 42 Low-carbon reliable energy standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042.*

[152] Berkeley Law. *California Climate Policy Dashboard. https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard.*

[153] Berkeley Law. *California Climate Policy Dashboard. https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard.*

[154] Basin Electric Power Cooperative. (May 2023). Press Release: Carbon Capture Technology Developers Break Ground at Wyoming Integrated Test Center Located at Basin Electric's Dry Fork Station. *https://www.basinelectric.com/News-Center/news-briefs/Carbon-capture-technology-developers-break-ground-at-Wyoming-Integrated-Test-Center-located-at-Basin-Electrics-Dry-Fork-Station.*

[155] State of Wyoming. (Adopted March 15, 2024). Senate Bill 42 Low-carbon reliable energy standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042.*

[156] Sabin Center for Climate Change Law. 2019. Legal Pathways to Deep Decarbonization. Interactive Tracker for State Action on Carbon Capture. *https://cdrlaw.org/ccus-tracker/.*

[157] Sabin Center for Climate Change Law. 2019. Legal Pathways to Deep Decarbonization. Model Laws. Montana prohibition on acquiring coal plants without CCS. *https://lpdd.org/resources/montana-prohibition-on-acquiring-coal-plants-without-ccs/.*

[158] New York State. Climate Act: Progress to our Goals. *https://climate.ny.gov/Our-Impact/Our-Progress.*

[159] Department of Ecology Washington State. *Greenhouse Gases. https://ecology.wa.gov/Air-Climate/Climate-change/Tracking-greenhouse-gases.*

[160] State of Illinois General Assembly. Public Act 102–0662: Climate and Equitable Jobs Act. 2021. *https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf.*

[161] General Assembly of North Carolina, House Bill 951 (2021). *https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v5.pdf.*

[162] These estimates are based on an analysis of the EPA's NEEDS database, which contains information about EGUs across the country. The analysis includes a basic screen for units within the NEEDS database that are likely subject to the final 111(d) EGU rule, namely coal-steam units with capacity greater than 25 MW, and then removes units with an announced retirement dates prior to 2039, units with announced plans to convert from coal- to gas-fired units, and units likely to fall outside of the rule's applicability via the cogeneration exemption.

[163] DSIRE, Renewable Portfolio Standards and Clean Energy Standards (2023). *https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2023/12/RPS-CES-Dec2023-1.pdf;* LBNL, *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update. https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean.*

energy requirement or goal with a 100 percent or net-zero target.[164] A CES shifts generating fleets away from fossil fuel resources by requiring a percentage of retail electricity to come from sources that are defined as clean. Unlike an RPS, which defines eligible generation in terms of the renewable attributes of its energy source, CES eligibility is based on the GHG emission attributes of the generation itself, typically with a zero or net-zero carbon emissions requirement. Additional discussion of state actions and legislation to reduce GHG emissions from the power sector is provided in the final TSD, *Power Sector Trends.*

F. Future Projections of Power Sector Trends

Projections for the U.S. power sector—based on the landscape of market forces in addition to the known actions of Congress, utilities, and states—have indicated that the ongoing transition will continue for specific fuel types and EGUs. The EPA's Power Sector Platform 2023 using IPM reference case (*i.e.,* the EPA's projections of the power sector, which includes representation of the IRA absent further regulation), provides projections out to 2050 on future outcomes of the electric power sector. For more information on the details of this modeling, see the model documentation.[165]

Since the passage of the IRA in August 2022, the EPA has engaged with many external partners, including other governmental entities, academia, non-governmental organizations (NGOs), and industry, to understand the impacts that the IRA will have on power sector GHG emissions. In addition to engaging in several workgroups, the EPA has contributed to two separate journal articles that include multi-model comparisons of IRA impacts across several state-of-the-art models of the U.S. energy system and electricity sector [166] [167] and participated in public events exploring modeling assumptions for the IRA.[168] The EPA plans to continue collaborating with stakeholders, conducting external engagements, and using information gathered to refine modeling of the IRA.

While much of the discussion below focuses on the EPA's Power Sector Platform 2023 using IPM reference case, many other analyses show similar trends,[169] and these trends are consistent with utility IRPs and public GHG reduction commitments, as well as state actions, both of which were described in the previous sections.

1. Future Projections for Coal-Fired Generation

As described in the EPA's baseline modeling, coal-fired steam generating unit capacity is projected to fall from 181 GW in 2023 [170] to 52 GW in 2035, of which 11 GW includes retrofit CCS. Generation from coal-fired steam generating units is projected to also fall from 898 thousand GWh in 2021 [171] to 236 thousand GWh by 2035. This change in generation reflects the anticipated continued decline in projected coal-fired steam generating unit capacity as well as a steady decline in annual operation of those EGUs that remain online, with capacity factors falling from approximately 48 percent in 2022 to 45 percent in 2035 at facilities that do not install CCS. By 2050, coal-fired steam generating unit capacity is projected to diminish further, with only 28 GW, or less than 16 percent of 2023 capacity (and approximately 9 percent of the 2010 capacity), still in operation across the continental U.S.

These projections are driven by the eroding economic opportunities for coal-fired steam generating units to operate, the continued aging of the fleet of coal-fired steam generating units, and the continued availability and expansion of low-cost alternatives, like natural gas, renewable technologies, and energy storage. The projected retirements continue the trend of coal plant retirements in recent decades that is described in section IV.D.3. of this preamble (and further in the *Power Sector Trends* technical support document). The decline in coal generation capacity has generally resulted from a more competitive economic environment and increasing coal plant age. Most notably, declines in natural gas prices associated with the rise of hydraulic fracturing and horizontal drilling lowered the cost of natural gas-fired generation.[172] Lower gas generation costs reduced coal plant capacity factors and revenues. Rapid declines in the costs of renewables and battery storage have put further price pressure on coal plants, given the zero marginal cost operation of solar and wind.[173] [174] [175] In addition, most operational coal plants today were built before 2000, and many are reaching or have surpassed their expected useful lives.[176] Retiring coal plants tend to be

[164] This count is adapted from Lawrence Berkeley National Laboratory's (LBNL) *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update,* which identifies 15 states with 100 percent CES. The LBNL count includes Virginia, which the EPA omits because it considers Virginia a 100 percent RPS. Further, the LBNL count excludes Louisiana, Michigan, New Jersey, and Wisconsin because their clean energy goals are set by executive order. The EPA instead includes Louisiana, New Jersey, and Wisconsin but characterizes them as goals rather than requirements. Michigan, which enacted a CES by statute after the LBNL report's publication, is also included in the EPA count. Finally, the EPA count includes Maryland, whose December 2023 *Climate Pollution Reduction Plan* sets a goal of 100 percent clean energy by 2035, and Delaware, which enacted a statutory goal to reach net-zero GHG emissions by 2050. See LBNL, *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update, https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean*; *Maryland's Climate Pollution Reduction Plan, https://mde.maryland.gov/programs/air/ClimateChange/Maryland%20Climate%20Reduction%20Plan/Maryland%27s%20Climate%20Pollution%20Reduction%20Plan%20-%20Final%20-%20Dec%2028%202023.pdf*; and *HB 99, An Act to Amend Titles 7 and 29 of the Delaware Code Relating to Climate Change, https://legis.delaware.gov/json/BillDetail/GenerateHtmlDocumentEngrossment?engrossmentId=25785&docTypeId=6.*

[165] U.S. Environmental Protection Agency.*Power Sector Platform 2023 using IPM.* April 2024. *https://www.epa.gov/power-sector-modeling.*

[166] Bistline, *et al.* (2023). "Emissions and Energy System Impacts of the Inflation Reduction Act of 2022." *https://www.science.org/stoken/author-tokens/ST-1277/full.*

[167] Bistline, *et al.* (2023). "Power Sector Impacts of the Inflation Reduction Act of 2022."*https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b.*

[168] Resource for the Future (2023). "Future Generation: Exploring the New Baseline for Electricity in the Presence of the Inflation Reduction Act." *https://www.rff.org/events/rff-live/future-generation-exploring-the-new-baseline-for-electricity-in-the-presence-of-the-inflation-reduction-act/.*

[169] A wide variety of modeling teams have assessed baselines with IRA. The baseline estimated here is generally in line with these other estimates. Bistline, *et al.* (2023). "Power Sector Impacts of the Inflation Reduction Act of 2022." *https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b.*

[170] U.S. Energy Information Administration (EIA), Preliminary Monthly Electric Generator Inventory, December 2023. *https://www.eia.gov/electricity/data/eia860m/*

[171] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. *https://www.eia.gov/electricity/annual/.*

[172] International Energy Agency (IEA). Energy Policies of IEA Countries: United States 2019 Review. *https://iea.blob.core.windows.net/assets/7c65c270-ba15-466a-b50d-1c5cd19e359c/United_States_2019_Review.pdf.*

[173] U.S. Energy Information Administration (EIA). (April 13, 2023). U.S. Electric Capacity Mix shifts from Fossil Fuels to Renewables in AEO2023. *https://www.eia.gov/todayinenergy/detail.php?id=56160.*

[174] Solomon, M., et al. (January 2023). Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment. Energy Innovation. *https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.*

[175] Barbose, G., et al. (September 2023). Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, 2023 Edition. Lawrence Berkeley National Laboratory. *https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.*

[176] U.S. Energy Information Administration (EIA). (August 2022). Electric Generators Inventory, Form–860M, Inventory of Operating Generators and Inventory of Retired Generators. *https://www.eia.gov/electricity/data/eia860m/.*

old.[177] As plants age, their efficiency tends to decline and operations and maintenance costs increase. Older coal plant operational parameters are less aligned with current electric grid needs. Coal plants historically were used as base load power sources and can be slow (or expensive) to increase or decrease generation output throughout a typical day. That has put greater economic pressure on older coal plants, which are forced to either incur the costs of adjusting their generation or operate during less profitable hours when loads are lower or renewable generation is more plentiful.[178] All of these factors have contributed to retirements over the past 15 years, and similar underlying factors are projected to continue the trend of coal retirements in the coming years.

In 2020, there was a total of 1,439 million metric tons of CO_2 emissions from the power sector with coal-fired sources contributing to more than half of those emissions. In the EPA's Power Sector Platform 2023 using IPM reference case, power sector related CO_2 emission are projected to fall to 724 million metric tons by 2035, of which 23 percent is projected to come from coal-fired sources in 2035.

2. Future Projections for Natural Gas-Fired Generation

As described in the EPA's Power Sector Platform 2023 using IPM reference case, natural gas-fired capacity is expected to continue to build out during the next decade with 34 GW of new capacity projected to come online by 2035 and 261 GW of new capacity by 2050. By 2035, the new natural gas capacity is comprised of 14 GW of simple cycle turbines and 20 GW of combined cycle turbines. By 2050, most of the incremental new capacity is projected to come just from simple cycle turbines. This also represents a higher rate of new simple cycle turbine builds compared to the reference periods (*i.e.,* 2000–2006 and 2007–2021) discussed previously in this section.

It should be noted that despite this increase in capacity, both overall generation and emissions from the natural gas-fired capacity are projected to decline. Generation from natural gas units is projected to fall from 1,579 thousand GWh in 2021[179] to 1,344 thousand GWh by 2035. Power sector related CO_2 emissions from natural gas-fired EGUs were 615 million metric tons in 2021.[180] By 2035, emission levels are projected to reach 521 million metric tons, 96 percent of which comes from NGCC sources.

The decline in generation and emissions is driven by a projected decline in NGCC capacity factors. In model projections, NGCC units have a capacity factor early in the projection period of 59 percent, but by 2035, capacity factor projections fall to 48 percent as many of these units switch from base load operation to more intermediate load operation to support the integration of variable renewable energy resources. Natural gas-fired simple cycle turbine capacity factors also fall, although since they are used primarily as a peaking resource and their capacity factors are already below 10 percent annually, their impact on generation and emissions changes are less notable.

Some of the reasons for this anticipated continued growth in natural gas-fired capacity, coupled with a decline in generation and emissions, include the anticipated growth in peak load, retirement of older fossil generators, and growth in renewable energy coupled with the greater flexibility offered by combustion turbines. Simple cycle turbines operate at lower efficiencies than NGCC units but offer fast startup times to meet peaking load demands. In addition, combustion turbines, along with energy storage technologies and demand response strategies, support the expansion of renewable electricity by meeting demand during peak periods and providing flexibility around the variability of renewable generation and electricity demand. In the longer term, as renewables and battery storage grow, they are anticipated to outcompete the need for some natural gas-fired generation and the overall utilization of natural gas-fired capacity is expected to decline. For additional discussion and analysis of projections of future coal- and natural gas-fired generation, see the final TSD, *Power Sector Trends* in the docket for this rulemaking.

As explained in greater detail later in this preamble and in the accompanying RIA, future generation projections for natural gas-fired combustion turbines differ from those highlighted in recent historical trends. The largest source of new generation is from renewable energy, and projections show that total natural gas-fired combined cycle capacity is likely to decline after 2030 in response to increased generation from renewables, deployment of energy storage, and other technologies. Approximately 95 percent of capacity additions in 2024 are expected to be from non-emitting generation resources including solar, battery storage, wind, and nuclear.[181] The IRA is likely to influence this trend, which is also expected to impact the operation of certain combustion turbines. For example, as the electric output from additional variable renewable generating sources fluctuates daily and seasonally, flexible low and intermediate load combustion turbines will be needed to support these variable sources and provide reliability to the grid. This requires the ability to start and stop quickly and change load more frequently. Today's system includes 212 GW of intermediate and low load combustion turbines. These operational changes, alongside other tools like demand response, energy storage, and expanded transmission, will maintain reliability of the grid.

V. Statutory Background and Regulatory History for CAA Section 111

A. Statutory Authority To Regulate GHGs From EGUs Under CAA Section 111

The EPA's authority for and obligation to issue these final rules is CAA section 111, which establishes mechanisms for controlling emissions of air pollutants from new and existing stationary sources. CAA section 111(b)(1)(A) requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, and distinguish among classes, types, and sizes within categories in establishing the standards.

[177] Mills, A., et al. (November 2017). Power Plant Retirements: Trends and Possible Drivers. Lawrence Berkeley National Laboratory. *https://live-etabiblio.pantheonsite.io/sites/default/files/lbnl_retirements_data_synthesis_final.pdf.*

[178] National Association of Regulatory Utility Commissioners. (January 2020). Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices. *https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45.*

[179] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. *https://www.eia.gov/electricity/annual/.*

[180] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emission Sources and Sinks. February 2023. *https://www.epa.gov/system/files/documents/2023-02/US-GHG-Inventory-2023-Main-Text.pdf.*

[181] U.S. Energy Information Administration (EIA). Today in Energy. Solar and battery storage to make up 81 percent of new U.S. electric-generating capacity in 2024. February 2024. *https://www.eia.gov/todayinenergy/detail.php?id=61424.*

1. Regulation of Emissions From New Sources

Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for ''new sources'' in the source category. These standards are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to the sources subject to them.

Under CAA section 111(a)(1), a ''standard of performance'' is defined, in the singular, as ''a standard for emissions of air pollutants'' that is determined in a specified manner, as noted in this section, below.

Under CAA section 111(a)(2), a ''new source'' is defined, in the singular, as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source.'' Under CAA section 111(a)(3), a ''stationary source'' is defined as ''any building, structure, facility, or installation which emits or may emit any air pollutant.'' Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. While this provision treats modified sources as new sources, EPA regulations also treat a source that undergoes ''reconstruction'' as a new source. Under the provisions in 40 CFR 60.15, ''reconstruction'' means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA 111(a)(1) makes clear that the EPA is to determine both the ''best system of emission reduction . . . adequately demonstrated'' (BSER) for the regulated sources in the source category and the ''degree of emission limitation achievable through the application of the [BSER].'' *West Virginia* v. *EPA,* 597 U.S. 697, 709 (2022). To determine the BSER, the EPA first identifies the ''system[s] of emission reduction'' that are ''adequately demonstrated,'' and then determines the ''best'' of those systems, ''taking into account'' factors including ''cost,'' ''nonair quality health and environmental impact,'' and ''energy requirements.'' The EPA then derives from that system an ''achievable'' ''degree of emission limitation.'' The EPA must then, under CAA section 111(b)(1)(B), promulgate ''standard[s] for emissions''—the NSPS—that reflect that level of stringency.

2. Regulation of Emissions From Existing Sources

When the EPA establishes a standard for emissions of an air pollutant from new sources within a category, it must also, under CAA section 111(d), regulate emissions of that pollutant from *existing* sources within the same category, unless the pollutant is regulated under the National Ambient Air Quality Standards (NAAQS) program, under CAA sections 108–110, or the National Emission Standards for Hazardous Air Pollutants (NESHAP) program, under CAA section 112. See CAA section 111(d)(1)(A)(i) and (ii); *West Virginia,* 597 U.S. at 710.

CAA section 111(d) establishes a framework of ''cooperative federalism for the regulation of existing sources.'' *American Lung Ass'n,* 985 F.3d at 931. CAA sections 111(d)(1)(A)–(B) require ''[t]he Administrator . . . to prescribe regulations'' that require ''[e]ach state . . . to submit to [EPA] a plan . . . which establishes standards of performance for any existing stationary source for'' the air pollutant at issue, and which ''provides for the implementation and enforcement of such standards of performance.'' CAA section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.''

To meet these requirements, the EPA promulgates ''emission guidelines'' that identify the BSER and the degree of emission limitation achievable through the application of the BSER. Each state must then establish standards of performance for its sources that reflect that level of stringency. However, the states need not compel regulated sources to adopt the particular components of the BSER itself. The EPA's emission guidelines must also permit a state, ''in applying a standard of performance to any particular source,'' to ''take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' 42 U.S.C. 7411(d)(1). Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the source, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act. CAA section 111(d)(2)(B). If a state elects not to submit a plan or submits a plan that the EPA does not find ''satisfactory,'' the EPA must promulgate a plan that establishes Federal standards of performance for the state's existing sources. CAA section 111(d)(2)(A).

3. EPA Review of Requirements

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years, review and, if appropriate, revise'' new source performance standards. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. *Id.* When conducting a review of an NSPS, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category. CAA section 111 does not by its terms require the EPA to review emission guidelines for existing sources, but the EPA retains the authority to do so. See 81 FR 59277 (August 29, 2016) (explaining legal authority to review emission guidelines for municipal solid waste landfills).

B. History of EPA Regulation of Greenhouse Gases From Electricity Generating Units Under CAA Section 111 and Caselaw

The EPA has listed more than 60 stationary source categories under CAA section 111(b)(1)(A). See 40 CFR part 60, subparts Cb–OOOO. In 1971, the EPA listed fossil fuel-fired EGUs (which includes natural gas, petroleum, and coal) that use steam-generating boilers in a category under CAA section 111(b)(1)(A). See 36 FR 5931 (March 31, 1971) (listing ''fossil fuel-fired steam generators of more than 250 million Btu per hour heat input''). In 1977, the EPA listed fossil fuel-fired combustion turbines, which can be used in EGUs, in a category under CAA section 111(b)(1)(A). See 42 FR 53657 (October 3, 1977) (listing ''stationary gas turbines'').

Beginning in 2007, several decisions by the U.S. Supreme Court and the D.C. Circuit have made clear that under CAA section 111, the EPA has authority to regulate GHG emissions from listed source categories. The U.S. Supreme Court ruled in *Massachusetts* v. *EPA* that GHGs [182] meet the definition of ''air pollutant'' in the CAA,[183] and subsequently premised its decision in *AEP* v. *Connecticut* [184]—that the CAA displaced any Federal common law right to compel reductions in CO_2 emissions from fossil fuel-fired power plants—on its view that CAA section 111 applies to GHG emissions. The D.C. Circuit confirmed in *American Lung Ass'n* v. *EPA,* 985 F.3d 914, 977 (D.C. Cir. 2021), discussed in section V.B.5, that the EPA is authorized to promulgate requirements under CAA section 111 for GHG from the fossil fuel-fired EGU source category notwithstanding that the source category is regulated under CAA section 112. As discussed in section V.B.6, the U.S. Supreme Court did not accept certiorari on the question whether the EPA could regulate GHGs from fossil-fuel fired EGUs under CAA section 111(d) when other pollutants from fossil-fuel fired EGUs are regulated under CAA section 112 in *West Virginia* v. *EPA,* 597 U.S. 697 (2022), and so the D.C. Circuit's holding on this issue remains good law.

In 2015, the EPA promulgated two rules that addressed CO_2 emissions from fossil fuel-fired EGUs. The first promulgated standards of performance for new fossil fuel-fired EGUs. ''Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule,'' (80 FR 64510; October 23, 2015) (2015 NSPS). The second promulgated emission guidelines for existing sources. ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule,'' (80 FR 64662; October 23, 2015) (Clean Power Plan, or CPP).

1. 2015 NSPS

In 2015, the EPA promulgated an NSPS to limit emissions of GHGs, manifested as CO_2, from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units, *i.e.,* utility boilers and IGCC EGUs, and newly constructed and reconstructed stationary combustion turbine EGUs. These final standards are codified in 40 CFR part 60, subpart TTTT. In promulgating the NSPS for newly constructed fossil fuel-fired steam generating units, the EPA determined the BSER to be a new, highly efficient, supercritical pulverized coal (SCPC) EGU that implements post-combustion partial CCS technology. The EPA concluded that CCS was adequately demonstrated (including being technically feasible) and widely available and could be implemented at reasonable cost. The EPA identified natural gas co-firing and IGCC technology (either with natural gas co-firing or implementing partial CCS) as alternative methods of compliance.

The 2015 NSPS included standards of performance for steam generating units that undergo a ''reconstruction'' as well as units that implement ''large modifications,'' *(i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent). The 2015 NSPS did not establish standards of performance for steam generating units that undertake ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent), due to the limited information available to inform the analysis of a BSER and corresponding standard of performance.

The 2015 NSPS also 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 NGCC technology as the 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. The 2015 NSPS remains in effect today.

The EPA received six petitions for reconsideration of the 2015 NSPS. On May 6, 2016 (81 FR 27442), the EPA denied five of the petitions on the basis that 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. Apart from these petitions, the EPA proposed to revise the 2015 NSPS in 2018, as discussed in section V.B.2.

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 pending EPA action concerning the 2018 proposal to revise the 2015 NSPS.

In the 2015 NSPS, the EPA noted that it was authorized to regulate GHGs from the fossil fuel-fired EGU source categories because it had listed those source categories under CAA section 111(b)(1)(A). The EPA added that CAA section 111 did not require it to make a determination that GHGs from EGUs contribute significantly to dangerous air pollution (a pollutant-specific significant contribution finding), but in the alternative, the EPA did make that finding. It explained that ''[greenhouse gas] air pollution may reasonably be anticipated to endanger public health or welfare,'' 80 FR 64530 (October 23, 2015) and emphasized that power plants are ''by far the largest emitters'' of greenhouse gases among stationary sources in the U.S. *Id.* at 64522. In *American Lung Ass'n* v. *EPA,* 985 F.3d 977 (D.C. Cir. 2021), the court held that even if the EPA were required to determine that CO_2 from fossil fuel-fired EGUs contributes significantly to dangerous air pollution—and the court emphasized that it was not deciding that the EPA was required to make such a pollutant-specific determination—the determination in the alternative that the EPA made in the 2015 NSPS was not arbitrary and capricious and, accordingly, the EPA had a sufficient basis to regulate greenhouse gases from EGUs under CAA section 111(d) in the ACE Rule. This aspect of the decision remains good law. The EPA is not reopening and did not solicit comment on any of those determinations in the 2015 NSPS concerning its rational basis to regulate GHG emissions from EGUs or its alternative finding that GHG emissions from EGUs contribute significantly to dangerous air pollution.

2. 2018 NSPS Proposal To Revise the 2015 NSPS

In 2018, the EPA proposed to revise the NSPS for new, modified, and reconstructed fossil fuel-fired steam generating units and IGCC units, in the *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rule* (83 FR 65424;

[182] The EPA's 2009 endangerment finding defines the air pollution which may endanger public health and welfare as the well-mixed aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[183] 549 U.S. 497, 520 (2007).

[184] 131 S. Ct. 2527, 2537–38 (2011).

December 20, 2018) (2018 NSPS Proposal). The EPA proposed to revise the NSPS for newly constructed units, based on a revised BSER of a highly efficient SCPC, without partial CCS. The EPA also proposed to revise the NSPS for modified and reconstructed units. As discussed in IX.A, in the present action, the EPA is withdrawing this proposed rule.[185]

3. Clean Power Plan

With the promulgation of the 2015 NSPS, the EPA also incurred a statutory obligation under CAA section 111(d) to issue emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs and stationary combustion turbine EGUs, which the EPA initially fulfilled with the promulgation of the CPP. See 80 FR 64662 (October 23, 2015). The EPA first determined that the BSER included three types of measures: (1) improving heat rate (*i.e.,* the amount of fuel that must be burned to generate a unit of electricity) at coal-fired steam plants; (2) substituting increased generation from lower-emitting NGCC plants for generation from higher-emitting steam plants (which are primarily coal-fired); and (3) substituting increased generation from new renewable energy sources for generation from fossil fuel-fired steam plants and combustion turbines. See 80 FR 64667 (October 23, 2015). The latter two measures are known as ''generation shifting'' because they involve shifting electricity generation from higher-emitting sources to lower-emitting ones. See 80 FR 64728–29 (October 23, 2015).

The EPA based this BSER determination on a technical record that evaluated generation shifting, including its cost-effectiveness, against the relevant statutory criteria for BSER and on a legal interpretation that the term ''system'' in CAA section 111(a)(1) is sufficiently broad to encompass shifting of generation from higher-emitting to lower-emitting sources. See 80 FR 64720 (October 23, 2015). The EPA then determined the ''degree of emission limitation achievable through the application of the [BSER],'' CAA section 111(a)(1), expressed as emission performance rates. See 80 FR 64667 (October 23, 2015). The EPA explained that a state would ''have to ensure, through its plan, that the emission standards it establishes for its sources individually, in the aggregate, or in combination with other measures undertaken by the state, represent the equivalent of'' those performance rates (80 FR 64667; October 23, 2015). Neither states nor sources were required to apply the specific measures identified in the BSER (80 FR 64667; October 23, 2015), and states could include trading or averaging programs in their state plans for compliance. See 80 FR 64840 (October 23, 2015).

Numerous states and private parties petitioned for review of the CPP before the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court stayed the rule pending review, *West Virginia* v. *EPA,* 577 U.S. 1126 (2016). The D.C. Circuit held the litigation in abeyance, and ultimately dismissed it at the petitioners' request. *American Lung Ass'n,* 985 F.3d at 937.

4. The CPP Repeal and ACE Rule

In 2019, the EPA repealed the CPP and replaced it with the ACE Rule. In contrast to its interpretation of CAA section 111 in the CPP, in the ACE Rule the EPA determined that the statutory ''text and reasonable inferences from it'' make ''clear'' that a ''system'' of emission reduction under CAA section 111(a)(1) ''is limited to measures that can be applied to and at the level of the individual source,'' (84 FR 32529; July 8, 2019); that is, the system must be limited to control measures that could be applied at and to each source to reduce emissions at each source. See 84 FR 32523–24 (July 8, 2019). Specifically, the ACE Rule argued that the requirements in CAA sections 111(d)(1), (a)(3), and (a)(6), that each state establish a standard of performance ''for'' ''any existing source,'' defined, in general, as any ''building . . . [or] facility,'' and the requirement in CAA section 111(a)(1) that the degree of emission limitation must be ''achievable'' through the ''application'' of the BSER, by their terms, impose this limitation. The EPA concluded that generation shifting is not such a control measure. See 84 FR 32546 (July 8, 2019). Based on its view that the CPP was a ''major rule,'' the EPA further determined that, absent ''a clear statement from Congress,'' the term '' 'system of emission reduction' '' should not be read to encompass ''generation-shifting measures.'' See 84 FR 32529 (July 8, 2019). The EPA acknowledged, however, that ''[m]arket-based forces ha[d] already led to significant generation shifting in the power sector,'' (84 FR 32532; July 8, 2019), and that there was ''likely to be no difference between a world where the CPP is implemented and one where it is not.'' See 84 FR 32561 (July 8, 2019); the Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, 2–1 to 2–5.[186]

In addition, the EPA promulgated in the ACE Rule a new set of emission guidelines for existing coal-fired steam-generating EGUs. See 84 FR 32532 (July 8, 2019). In light of ''the legal interpretation adopted in the repeal of the CPP,'' (84 FR 32532; July 8, 2019)—which ''limit[ed] 'standards of performance' to systems that can be applied at and to a stationary source,'' (84 FR 32534; July 8, 2019)—the EPA found the BSER to be heat rate improvements alone. See 84 FR 32535 (July 8, 2019). The EPA listed various technologies that could improve heat rate (84 FR 32536; July 8, 2019), and identified the ''degree of emission limitation achievable'' by ''providing ranges of expected [emission] reductions associated with each of the technologies.'' See 84 FR 32537–38 (July 8, 2019).

5. D.C. Circuit Decision in American Lung Association v. EPA Concerning the CPP Repeal and ACE Rule

Numerous states and private parties petitioned for review of the CPP Repeal and ACE Rule. In 2021, the D.C. Circuit vacated the ACE Rule, including the CPP Repeal. *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021). The court held, among other things, that CAA section 111(d) does not limit the EPA, in determining the BSER, to measures applied at and to an individual source. The court noted that ''the sole ground on which the EPA defends its abandonment of the [CPP] in favor of the ACE Rule is that the text of [CAA section 111] is clear and unambiguous in constraining the EPA to use only improvements at and to existing sources in its [BSER].'' 985 F.3d at 944. The court found ''nothing in the text, structure, history, or purpose of [CAA section 111] that compels the reading the EPA adopted.'' 985 F.3d at 957. The court likewise rejected the

[185] In the 2018 NSPS Proposal, the EPA solicited comment on whether it is required to make a determination that GHGs from a source category contribute significantly to dangerous air pollution as a predicate to promulgating a NSPS for GHG emissions from that source category for the first time. 83 FR 65432 (December 20, 2018). The EPA subsequently issued a final rule that provided that it would not regulate GHGs under CAA section 111 from a source category unless the GHGs from the category exceed 3 percent of total U.S. GHG emissions, on grounds that GHGs emitted in a lesser amount do not contribute significantly to dangerous air pollution. 86 FR 2652 (January 13, 2021). Shortly afterwards, the D.C. Circuit granted an unopposed motion by the EPA for voluntary vacatur and remand of the final rule. *California* v. *EPA,* No. 21–1035, doc. 1893155 (D.C. Cir. April 5, 2021).

[186] *https://www.epa.gov/sites/default/files/2019-06/documents/utilities_ria_final_cpp_repeal_and_ace_2019-06.pdf.*

view that the CPP's use of generation-shifting implicated a ''major question'' requiring unambiguous authorization by Congress. 985 F.3d at 958–68.

The D.C. Circuit concluded that, because the EPA had relied on an ''erroneous legal premise,'' both the CPP Repeal Rule and the ACE Rule should be vacated. 985 F.3d at 995. The court did not decide, however, ''whether the approach of the ACE Rule is a permissible reading of the statute as a matter of agency discretion,'' 985 F.3d at 944, and instead ''remanded to the EPA so that the Agency may 'consider the question afresh,' '' 985 F.3d at 995 (citations omitted).

The court also rejected the arguments that the EPA cannot regulate CO_2 emissions from coal-fired power plants under CAA section 111(d) at all because it had already regulated mercury emissions from coal-fired power plants under CAA section 112. 985 F.3d at 988. In addition, the court held that that the 2015 NSPS included a valid determination that greenhouse gases from the EGU source category contributed significantly to dangerous air pollution, which provided a sufficient basis for a CAA section 111(d) rule regulating greenhouse gases from existing fossil fuel-fired EGUs. *Id.* at 977.

Because the D.C. Circuit vacated the ACE Rule on the grounds noted above, it did not address the other challenges to the ACE Rule, including the arguments by Petitioners that the heat rate improvement BSER was inadequate because of the limited number of reductions it achieved and because the ACE Rule failed to include an appropriately specific degree of emission limitation.

Upon a motion from the EPA, the D.C. Circuit agreed to stay its mandate with respect to vacatur of the CPP Repeal, *American Lung Assn* v. *EPA,* No. 19–1140, Order (February 22, 2021), so that the CPP remained repealed. Therefore, following the D.C. Circuit's decision, no EPA rule under CAA section 111 to reduce GHGs from existing fossil fuel-fired EGUs remained in place.

6. U.S. Supreme Court Decision in West Virginia v. EPA Concerning the CPP

The Supreme Court granted petitions for certiorari from the D.C. Circuit's *American Lung Association* decision, limited to the question of whether CAA section 111 authorized the EPA to determine that ''generation shifting'' was the best system of emission reduction for fossil-fuel fired EGUs. The Supreme Court did not grant certiorari on the question of whether the EPA was authorized to regulate GHG emissions from fossil-fuel fired power plants under CAA section 111, when fossil-fuel fired power plants are regulated for other pollutants under CAA section 112. In 2022, the U.S. Supreme Court reversed the D.C. Circuit's vacatur of the ACE Rule's embedded repeal of the CPP. *West Virginia* v. *EPA,* 597 U.S. 697 (2022). The Supreme Court stated that CAA section 111 authorizes the EPA to determine the BSER and the degree of emission limitation that state plans must achieve. *Id.* at 2601–02. The Supreme Court concluded, however, that the CPP's BSER of ''generation-shifting'' raised a ''major question,'' and was not clearly authorized by section 111. The Court characterized the generation-shifting BSER as ''restructuring the Nation's overall mix of electricity generation,'' and stated that the EPA's claim that CAA section 111 authorized it to promulgate generation shifting as the BSER was ''not only unprecedented; it also effected a fundamental revision of the statute, changing it from one sort of scheme of regulation into an entirely different kind.'' *Id.* at 2612 (internal quotation marks, brackets, and citation omitted). The Court explained that the EPA, in prior rules under CAA section 111, had set emissions limits based on ''measures that would reduce pollution by causing the regulated source to operate more cleanly.'' *Id.* at 2610. The Court noted with approval those ''more traditional air pollution control measures,'' and gave as examples ''fuel-switching'' and ''add-on controls,'' which, the Court observed, the EPA had considered in the CPP. *Id.* at 2611 (internal quotations marks and citation omitted). In contrast, the Court continued, generation shifting was ''unprecedented'' because ''[r]ather than focus on improving the performance of individual sources, it would improve the overall power system by lowering the carbon intensity of power generation. And it would do that by forcing a shift throughout the power grid from one type of energy source to another.'' *Id.* at 2611–12 (internal quotation marks, emphasis, and citation omitted).

The Court recognized that a rule based on traditional measures ''may end up causing an incidental loss of coal's market share,'' but emphasized that the CPP was ''obvious[ly] differen[t]'' because, with its generation-shifting BSER, it ''simply announc[ed] what the market share of coal, natural gas, wind, and solar must be, and then require[ed] plants to reduce operations or subsidize their competitors to get there.'' *Id.* at 2613 n.4. The Court also emphasized ''the magnitude and consequence'' of the CPP. *Id.* at 2616. It noted ''the magnitude of this unprecedented power over American industry,'' *id.* at 2612 (internal quotation marks and citation omitted), and added that the EPA's adoption of generation shifting ''represent[ed] a transformative expansion in its regulatory authority.'' *Id.* at 2610 (internal quotation marks and citation omitted). The Court also viewed the CPP as promulgating ''a program that . . . Congress had considered and rejected multiple times.'' *Id.* at 2614 (internal quotation marks and citation omitted). For these and related reasons, the Court viewed the CPP as raising a major question, and therefore, requiring ''clear congressional authorization'' as a basis. *Id.* (internal quotation marks and citation omitted).

The Court declined to address the D.C. Circuit's conclusion that the text of CAA section 111 did not limit the type of ''system'' the EPA could consider as the BSER to measures applied at and to an individual source. *See id.* at 2615. Nor did the Court address the scope of the states' compliance flexibilities.

7. D.C. Circuit Order Reinstating the ACE Rule

On October 27, 2022, the D.C. Circuit responded to the U.S. Supreme Court's reversal by recalling its mandate for the vacatur of the ACE Rule. *American Lung Ass'n* v. *EPA,* No. 19–1140, Order (October 27, 2022). Accordingly, at that time, the ACE Rule came back into effect. The court also revised its judgment to deny petitions for review challenging the CPP Repeal Rule, consistent with the judgment in *West Virginia,* so that the CPP remains repealed. The court took further action denying several of the petitions for review unaffected by the Supreme Court's decision in *West Virginia,* which means that certain parts of its 2021 decision in *American Lung Association* remain in effect. These parts include the holding that the EPA's prior regulation of mercury emissions from coal-fired electric power plants under CAA section 112 does not preclude the Agency from regulating CO_2 from coal-fired electric power plants under CAA section 111, and the holding, discussed above, that the 2015 NSPS included a valid significant contribution determination and therefore provided a sufficient basis for a CAA section 111(d) rule regulating greenhouse gases from existing fossil fuel-fired EGUs. The court's holding to invalidate amendments to the implementing regulations applicable to emission guidelines under CAA section 111(d) that extended the preexisting schedules for state and Federal actions and sources' compliance, also remains in force. Based on the EPA's stated intention to replace the ACE Rule, the court stayed further proceedings with respect to the ACE Rule, including the various challenges that its BSER was flawed because it did not achieve sufficient emission reductions and failed to specify an appropriately specific degree of emission limitation.

C. Detailed Discussion of CAA Section 111 Requirements

This section discusses in more detail the key requirements of CAA section 111 for both new and existing sources that are relevant for these rulemakings.

1. Approach to the Source Category and Subcategorizing

CAA section 111 requires the EPA first to list stationary source categories that cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare and then to regulate new sources within each such source category. CAA section 111(b)(2) grants the EPA discretion whether to ''distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards,'' which we refer to as ''subcategorizing.'' Whether and how to subcategorize is a decision for which the EPA is entitled to a ''high degree of deference'' because it entails ''scientific judgment.'' *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

Although CAA section 111(d)(1) does not explicitly address subcategorization, since its first regulations implementing the CAA, the EPA has interpreted it to authorize the Agency to exercise discretion as to whether and, if so, how to subcategorize, for the following reasons. CAA section 111(d)(1) grants the EPA authority to ''prescribe regulations which shall establish a procedure . . . under which each State shall submit to the Administrator a plan [with standards of performance for existing sources.]'' The EPA promulgates emission guidelines under this provision directing the states to regulate existing sources. The Supreme Court has recognized that, under CAA section 111(d), the ''Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction . . . that has been adequately demonstrated for [existing covered] facilities.' *West Virginia,* 597 U.S. at 710 (citations omitted).

The EPA's authority to determine the BSER includes the authority to create subcategories that tailor the BSER for differently situated sets of sources. Again, for new sources, CAA section 111(b)(2) confers authority for the EPA to ''distinguish among classes, types, and sizes within categories.'' Though CAA section 111(d) does not speak specifically to the creation of subcategories for a category of existing sources, the authority to identify the ''best'' system of emission reduction for existing sources includes the discretion to differentiate between differently situated sources in the category, and group those sources into subcategories in appropriate circumstances. The size, type, class, and other characteristics can make different emission controls more appropriate for different sources. A system of emission reduction that is ''best'' for some sources may not be ''best'' for others with different characteristics. For more than four decades, the EPA has interpreted CAA section 111(d) to confer authority on the Agency to create subcategories. The EPA's implementing regulations under CAA section 111(d), promulgated in 1975, 40 FR 53340 (November 17, 1975), provide that the Administrator will specify different emission guidelines or compliance times or both ''for different sizes, types, and classes of designated facilities when [based on] costs of control, physical limitations, geographical location, or [based on] similar factors.''[187] This regulation governs the EPA's general authority to subcategorize under CAA section 111(d), and the EPA is not reopening that issue here. At the time of promulgation, the EPA explained that subcategorization allows the EPA to take into account ''differences in sizes and types of facilities and similar considerations, including differences in control costs that may be involved for sources located in different parts of the country'' so that the ''EPA's emission guidelines will in effect be tailored to what is reasonably achievable by particular classes of existing sources. . . .'' *Id.* at 53343. The EPA's authority to ''distinguish among classes, types, and sizes within categories,'' as provided under CAA section 111(b)(2), generally allows the Agency to place types of sources into subcategories. This is consistent with the commonly understood meaning of the term ''type'' in CAA section 111(b)(2): ''a particular kind, class, or group,'' or ''qualities common to a number of individuals that distinguish them as an identifiable class.'' See *https://www.merriam-webster.com/dictionary/type.*

The EPA has developed subcategories in many rulemakings under CAA section 111 since the 1970s. These rulemakings have included subcategories on the basis of the size of the sources, see 40 CFR 60.40b(b)(1)–(2) (subcategorizing certain coal-fired steam generating units on the basis of heat input capacity); the types of fuel combusted, *see Sierra Club,* v. *EPA,* 657 F.2d 298, 318–19 (D.C. Cir. 1981) (upholding a rulemaking that established different NSPS ''for utility plants that burn coal of varying sulfur content''), 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (subdividing new combustion turbines on the basis of type of fuel combusted); the types of equipment used to produce products, see 81 FR 35824 (June 3, 2016) (promulgating separate NSPS for many types of oil and gas sources, such as centrifugal compressors, pneumatic controllers, and well sites); types of manufacturing processes used to produce product, see 42 FR 12022 (March 1, 1977) (announcing availability of final guideline document for control of atmospheric fluoride emissions from existing phosphate fertilizer plants) and ''Final Guideline Document: Control of Fluoride Emissions From Existing Phosphate Fertilizer Plants,'' EPA–450/2–77–005 1–7 to 1–9, including table 1–2 (applying different control requirements for different manufacturing operations for phosphate fertilizer); levels of utilization of the sources, see 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (dividing new natural gas-fired combustion turbines into the subcategories of base load and non-base load); the activity level of the sources, see 81 FR 59276, 59278–79 (August 29, 2016) (dividing municipal solid waste landfills into the subcategories of active and closed landfills); and geographic location of the sources, see 71 FR 38482 (July 6, 2006) (SO_2 NSPS for stationary combustion turbines subcategorizing turbines on the basis of whether they are located in, for example, a continental area, a non-continental area, the part of Alaska north of the Arctic Circle, and the rest of Alaska). Thus, the EPA has subcategorized many times in rulemaking under CAA sections 111(b) and 111(d) and based on a wide variety of physical, locational, and operational characteristics.

Regardless of whether the EPA subcategorizes within a source category

[187] 40 CFR 60.22(b)(5), 60.22a(b)(5). Because the definition of subcategories depends on characteristics relevant to the BSER, and because those characteristics can differ as between new and existing sources, the EPA may establish different subcategories as between new and existing sources.

for purposes of determining the BSER and the degree of emission limitation achievable, a state retains certain flexibility in assigning standards of performance to its affected EGUs. The statutory framework for CAA section 111(d) emission guidelines, and the flexibilities available to states within that framework, are discussed below.

2. Key Elements of Determining a Standard of Performance

Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. The current text of CAA section 111(a)(1) reads: ''The term 'standard of performance' means a standard for emission of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The D.C. Circuit has reviewed CAA section 111 rulemakings on numerous occasions since 1973,[188] and has developed a body of caselaw that interprets the term ''standard of performance,'' as discussed throughout this preamble.

The basis for standards of performance, whether promulgated by the EPA under CAA section 111(b) or established by the states under CAA section 111(d), is that the EPA determines the ''degree of emission limitation'' that is ''achievable'' by the sources by application of a ''system of emission reduction'' that the EPA determines is ''adequately demonstrated,'' ''taking into account'' the factors of ''cost . . . and any nonair quality health and environmental impact and energy requirements,'' and that the EPA determines to be the ''best.'' The D.C. Circuit has stated that in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution'' [189] reduced and the role of ''technological innovation.'' [190] The D.C. Circuit has also stated that to determine the ''best'' system, the EPA may weigh the various factors identified in the statute and caselaw against each other, and has emphasized that the EPA has discretion in weighing the factors.[191] [192]

The EPA's overall approach to determining the BSER and degree of emission limitation achievable, which incorporates the various elements, is as follows: The EPA identifies ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category and determines the ''best'' of these systems after evaluating the amount of emission reductions, costs, any non-air health and environmental impacts, and energy requirements. As discussed below, for each of numerous subcategories, the EPA followed this approach to determine the BSER on the basis that the identified costs are reasonable and that the BSER is rational in light of the statutory factors, including the amount of emission reductions, that the EPA examined in its BSER analysis, consistent with governing precedent.

After determining the BSER, the EPA determines an achievable emission limit based on application of the BSER.[193] For a CAA section 111(b) rule, the EPA determines the standard of performance that reflects the achievable emission limit. For a CAA section 111(d) rule, the states have the obligation of establishing standards of performance for the affected sources that reflect the degree of emission limitation that the EPA has determined. As discussed below, the EPA is finalizing these determinations in association with each of the BSER determinations.

The remainder of this subsection discusses each element in our general analytical approach.

a. System of Emission Reduction

The CAA does not define the phrase ''system of emission reduction.'' In *West Virginia* v. *EPA,* the Supreme Court recognized that historically, the EPA had looked to ''measures that improve the pollution performance of individual sources and followed a ''technology-based approach'' in identifying systems of emission reduction. In particular, the Court identified ''the sort of 'systems of emission reduction' [the EPA] had always before selected,'' which included '' 'efficiency improvements, fuel-switching,' and 'add-on controls'.'' 597 U.S. at 727 (quoting the Clean Power Plan).[194] Section 111 itself recognizes that such systems may include off-site activities that may reduce a source's pollution contribution, identifying ''precombustion cleaning or treatment of fuels'' as a ''system'' of ''emission reduction.'' 42 U.S.C. 7411(a)(7)(B). A ''system of emission reduction'' thus, at a minimum, includes measures that an individual source applies that improve the emissions performance of that source. Measures are fairly characterized as improving the pollution performance of a source where they reduce the individual source's overall contribution to pollution.

In *West Virginia,* the Supreme Court did not define the term ''system of emissions reduction,'' and so did not rule on whether ''system of emission reduction'' is limited to those measures that the EPA has historically relied upon. It did go on to apply the major questions doctrine to hold that the term ''system'' does not provide the requisite clear authorization to support the Clean Power Plan's BSER, which the Court described as ''carbon emissions caps based on a generation shifting approach.'' *Id.* at 2614. While the Court did not define the outer bounds of the meaning of ''system,'' systems of emissions reduction like fuel switching, add-on controls, and efficiency improvements fall comfortably within the scope of prior practice as recognized by the Supreme Court.

b. ''Adequately Demonstrated''

Under CAA section 111(a)(1), an essential, although not sufficient, condition for a ''system of emission

[188] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011); *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021), *rev'd in part, West Virginia* v. *EPA,* 597 U.S. 697 (2022). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

[189] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[190] *See Sierra Club* v. *Costle,* 657 F.2d at 347.

[191] *See Lignite Energy Council,* 198 F.3d at 933.

[192] CAA section 111(a)(1), by its terms states that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination. In addition, the D.C. Circuit's caselaw makes clear that the EPA may consider these same factors when it determines which adequately demonstrated system of emission reduction is the ''best.'' *See Sierra Club* v. *Costle,* 657 F.2d at 330 (recognizing that CAA section 111 gives the EPA authority ''when determining the best technological system to weigh cost, energy, and environmental impacts'').

[193] See, *e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews (77 FR 49494; August 16, 2012) (describing the three-step analysis in setting a standard of performance).

[194] As noted in section V.B.4 of this preamble, the ACE Rule adopted the interpretation that CAA section 111(a)(1), by its plain language, limits ''system of emission reduction'' to those control measures that could be applied at and to each source to reduce emissions at each source. 84 FR 32523–24 (July 8, 2019). The EPA has subsequently rejected that interpretation as too narrow. *See Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d),* 88 FR 80535 (November 17, 2023).

reduction'' to serve as the basis for an ''achievable'' emission standard is that the Administrator must determine that the system is ''adequately demonstrated.'' The concepts of adequate demonstration and achievability are closely related: as the D.C. Circuit has stated, ''[i]t is the system which must be adequately demonstrated and the standard which must be achievable,'' [195] through application of the system. An achievable standard means a standard based on the EPA's record-based finding that sufficient evidence exists to reasonably determine that the affected sources in the source category can adopt a specific system of emission reduction to achieve the specified degree of emission limitation. As discussed below, consistent with Congress's use of the word ''demonstrated,'' the caselaw has approved the EPA's ''adequately demonstrated'' determinations concerning systems utilized at test sources or other individual sources operating at commercial scale. The case law also authorizes the EPA to set an emissions standard at levels more stringent than has regularly been achieved, based on the understanding that sources will be able to adopt specific technological improvements to the system in question that will enable them to achieve the lower standard. Importantly, and contrary to some comments received on the proposed rule, CAA section 111(a)(1) does *not* require that a system of emission reduction exist in widespread commercial use in order to satisfy the ''adequately demonstrated'' requirement.[196] Instead, CAA section 111(a)(1) authorizes the EPA to establish standards which encourage the deployment of more effective systems of emission reduction that have been adequately demonstrated but that are not yet in widespread use. This aligns with Congress's purpose in enacting the CAA, in particular its recognition that polluting sources were not widely adopting emission control technology on a voluntary basis and that Federal regulation was necessary to spur the development and deployment of those technologies.[197]

i. Plain Text, Statutory Context, and Legislative History of the ''Adequately Demonstrated'' Provision in CAA Section 111(a)(1)

Analysis of the plain text, statutory context, and legislative history of CAA section 111(a)(1) establishes two primary themes. First, Congress assigned the task of determining the appropriate BSER to the Administrator, based on a reasonable review of available evidence. Second, Congress authorized the EPA to set a standard, based on the evidence, that encourages broader adoption of an emissions-reducing technological approach that may not yet be in widespread use.

The plain text of CAA section 111(a)(1), and in particular the phrase ''the Administrator determines'' and the term ''adequately,'' confer discretion to the EPA in identifying the appropriate system. Rather than providing specific criteria for determining what constitutes appropriate evidence, Congress directed the Administrator to ''determine[ ]'' that the demonstration is ''adequate[ ].'' Courts have typically deferred to the EPA's scientific and technological judgments in making such determinations.[198] Further, use of the term ''adequate'' in provisions throughout the CAA highlights EPA flexibility and discretion in setting standards and in analyzing data that forms the basis for standard setting.

In setting NAAQS under CAA section 109, for example, the EPA is directed to determine, according to ''the judgment of the Administrator,'' an ''adequate margin of safety.'' [199] The D.C. Circuit has held that the use of the term ''adequate'' confers significant deference to the Administrator's scientific and technological judgment. In *Mississippi* v. *EPA,*[200] for example, the D.C. Circuit in 2013 upheld the EPA's choice to set the NAAQS for ozone below 0.08 ppm, and noted that any disagreements with the EPA's interpretations of the scientific evidence that underlay this decision ''must come from those who are qualified to evaluate the science, not [the court].'' [201] This *Mississippi* v. *EPA* precedent aligns with the general standard for judicial review of the EPA's understanding of the evidence under CAA section 307(d)(9)(A) (''arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law'').

The plain language of the phrase ''has been adequately demonstrated,'' in context, and in light of the legislative history, further strongly indicates that the system in question need not be in widespread use at the time the EPA's rule is published. To the contrary, CAA section 111(a)(1) authorizes technology forcing, in the sense that the EPA is authorized to promote a system which is not yet in widespread use; provided the technology is in existence and the EPA has adequate evidence to extrapolate.[202]

Some commenters argued that use of the phrase ''has been'' in ''has been adequately demonstrated'' means that the system must be in widespread commercial use at the time of rule promulgation. We disagree. Considering the plain text, the use of the past tense, ''*has been* adequately demonstrated'' indicates a requirement that the technology *currently* be demonstrated. However, ''demonstrated'' in common usage at the time of enactment meant to ''explain or make clear by using examples, experiments, *etc.*'' [203] As a general matter, and as this definition indicates, the term ''to demonstrate'' suggests the need for a test or study—as in, for example, a ''demonstration

[195] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (1973) (emphasis omitted).

[196] *See, e.g., Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973) (in which the D.C. Circuit upheld a CAA section 111 standard based on a system which had been extensively used in Europe but at the time of promulgation was only in use in the United States at one plant).

[197] In introducing the respective bills which ultimately became the 1970 Clean Air Act upon Conference Committee review, both the House and Senate emphasized the urgency of the matter at hand, the intended power of the new legislation, and in particular its technology-forcing nature. The first page of the House report declared that ''[t]he purpose of the legislation reported unanimously by [Committee was] to speed up, expand, and intensify the war against air pollution in the United States . . .'' H.R. Rep. No. 17255 at 1 (1970). It was clear, stated the House report, that until that point ''the strategies which [the United States had] pursued in the war against air pollution [had] been inadequate in several important respects, and the methods employed in implementing those strategies often [had] been slow and less effective than they might have been.'' *Id.* The Senate report agreed, stating that their bill would ''provide a much more intensive and comprehensive attack on air pollution,'' 1 S. 4358 at 4 (1970), including, crucially, by increased federal involvement. *See id.*

[198] The D.C. Circuit stated in *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 786 (D.C. Cir. 1976) ''The standard of review of actions of the Administrator in setting standards of performance is an appropriately deferential one, and we are to affirm the action of the Administrator unless it is ''arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law,'' 5 U.S.C. 706(2)(A) (1970). Since this is one of those ''highly technical areas, where our understanding of the import of the evidence is attenuated, our readiness to review evidentiary support for decisions must be correspondingly restrained.'' *Ethyl Corporation* v. *EPA,* 96 S. Ct. 2663 (1976). ''Our 'expertise' is not in setting standards for emission control, but in determining if the standards as set are the result of reasoned decision-making.'' *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 434 (D.C. Cir. 1973)) (cleaned up).''

[199] 42 U.S.C. 7409(b)(1).

[200] 744 F.3d 1334 (D.C. Cir. 2013).

[201] *Id.*

[202] While not relevant here, because CCS is already in existence, the text, case law, and legislative history make a compelling case that EPA is authorized to go farther than this, and may make a projection regarding the way in which a particular system will develop to allow for greater emissions reductions in the future. *See* 80 FR 64556–58 (discussion of ''adequately demonstrated'' in 2015 NSPS).

[203] Webster's New World Dictionary: Second College Edition (David B. Guralnik, ed., 1972).

project'' or ''demonstration plant''—that is, examples of technological feasibility.

The statutory context is also useful in establishing that where Congress wanted to specify the availability of the control system, it did so. The only other use of the exact term ''adequately demonstrated'' occurs in CAA section 119, which establishes that, in order for the EPA to require a particular ''means of emission limitation'' for smelters, the Agency must establish that such means ''has been adequately demonstrated to be reasonably available. . . .'' [204] The lack of the phrase ''reasonably available'' in CAA section 111(a)(1) is notable, and suggests that a system may be ''adequately demonstrated'' under CAA section 111 even if it is not ''reasonably available'' for every single source.[205]

The term ''demonstration'' also appears in CAA section 103 in an instructive context. CAA section 103, which establishes a ''national research and development program for the prevention and control of air pollution'' directs that as part of this program, the EPA shall ''conduct, and promote the coordination and acceleration of, research, investigations, experiments, demonstrations, surveys, and studies relating to'' the issue of air pollution.[206] According to the canon of *noscitur a sociis,* associated words in a list bear on one another's meaning.[207] In CAA section 103, the word ''demonstrations'' appears alongside ''research,'' ''investigations,'' ''experiments,'' and ''studies''—all words suggesting the development of new and emerging technology. This supports interpreting CAA section 111(a)(1) to authorize the EPA to determine a system of emission reduction to be ''adequately demonstrated'' based on demonstration projects, testing, examples, or comparable evidence.

Finally, the legislative history of the CAA in general, and section 111 in particular, strongly supports the point that BSER technology need not be in widespread use at the time of rule enactment. The final language of CAA section 111(a)(1), requiring that systems of emission reduction be ''adequately demonstrated,'' was the result of compromise in the Conference Committee between the House and Senate bill language. The House bill would have required that the EPA give ''appropriate consideration to technological and economic feasibility'' when establishing standards.[208] The Senate bill would have required that standards ''reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.'' [209] Although the exact language of neither the House nor Senate bill was adopted in the final bill, both reports made clear their intent that CAA section 111 would be significantly technology-forcing. In particular, the Senate Report referred to ''available control technology''—a phrase that, as just noted, the Senate bill included—but clarified that the technology need not ''be in actual, routine use somewhere.'' [210] The House Report explained that EPA regulations would ''prevent and control such emissions to the fullest extent compatible with the available technology and economic feasibility as determined by [the EPA],'' and ''[i]n order to be considered 'available' the technology may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution.'' [211] This last statement implies that the House Report anticipated that the EPA's determination may be technology forcing. Nothing in the legislative history suggests that Congress intended that the technology already be in widespread commercial use.

ii. Caselaw

In a series of cases reviewing standards for new sources, the D.C. Circuit has held that an adequately demonstrated standard of performance may reflect the EPA's reasonable projection of what that particular system may be expected to achieve going forward, extrapolating from available data from pilot projects or individual commercial-scale sources. A standard may be considered achievable even if the system upon which the standard is based has not regularly achieved the standard in testing. See, *e.g., Essex Chem. Corp.* v. *Ruckelshaus* [212] (upholding a standard of 4.0 lbs per ton based on a system whose average control rate was 4.6 lbs per ton, and which had achieved 4.0 lbs per ton on only three occasions and '''nearly equaled' [the standard] on the average of nineteen different readings.'') [213] The *Ruckelshaus* court concluded that the EPA's extrapolation from available data was ''the result of the exercise of reasoned discretion by the Administrator'' and therefore ''[could not] be upset by [the] court.'' [214] The court also emphasized that in order to be considered achievable, the standard set by the EPA need not be regularly or even specifically achieved at the time of rule promulgation. Instead, according to the court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.'' [215]

Case law also establishes that the EPA may set a standard more stringent than has regularly been achieved based on its identification of specific available technological improvements to the system. See *Sierra Club* v. *Costle* [216] (upholding a 90 percent standard for SO_2 emissions from coal-fired steam generators despite the fact that not all plants had previously achieved this standard, based on the EPA's expectations for improved performance with specific technological fixes and the use of ''coal washing'' going forward).[217] Further, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different,

[204] The statutory text at CAA section 119 continues, ''as determined by the Administrator, taking into account the cost of compliance, nonair quality health and environmental impact, and energy consideration.'' 42 U.S.C. 7419(b)(3).

[205] It should also be noted that the section 119 language was added as part of the 1977 Clean Air Act amendments, while the section 111 language was established in 1970. Thus, Congress was aware of section 111's more permissive language when it added the ''reasonably available'' language to section 119.

[206] 42 U.S.C. 7403(a)(1).

[207] As the Supreme Court recently explained in *Dubin* v. *United States,* even words that might be indeterminate alone may be more easily interpreted in ''company,'' because per *noscitur a sociis* ''a word is known by the company it keeps.'' 599 U.S. 110, 244 (2023).

[208] H.R. Rep. No. 17255 at 921 (1970) (quoting CAA Sec. 112(a), as proposed).

[209] S. Rept. 4358 at 91 (quoting CAA Sec. 113(b)(2), as proposed).

[210] S. Rep. 4358 at 15–16 (1970). The Senate Report went on to say that the EPA should ''examine the degree of emission control that has been or can be achieved through the application of technology which is available or normally can be made available . . . at a cost and at a time which [the Agency] determines to be reasonable.'' *Id.* Again, this language rebuts any suggestion that a BSER technology must be in widespread use at the time of rule enactment—Congress assumed only that the technology would be ''available'' or even that it ''[could] be made available,'' not that it would be *already* broadly used.

[211] H.R. Rep. No. 17255 at 900.

[212] 486 F.2d 427 (D.C. Cir. 1973).

[213] *Id.* at 437.

[214] *Id.* at 437.

[215] *Id.* at 433–34 (D.C. Cir. 1973). *See also Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), which supports the point that EPA may extrapolate from testing results, rather than relying on consistent performance, to identify an appropriate system and standard based on that system. In that case, EPA analyzed scrubber performance by considering performance during short-term testing periods. *See id.* at 377.

[216] 657 F.2d 298 (D.C. Cir. 1981).

[217] *Id.* at 365, 370–73; 365.

related, source. See *Lignite Energy Council* v. *EPA* [218] (holding it permissible to base a standard for industrial boilers on application of SCR based on extrapolated information about the application of SCR on utility boilers).[219] The *Lignite* court clarified that ''where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture,'' but the ''EPA may compensate for a *shortage* of data through the use of other qualitative methods, including the reasonable extrapolation of a technology's performance in other industries.'' [220]

As a general matter, the case law is clear that at the time of Rule promulgation, the system which the EPA establishes as BSER need not be in widespread use. See, *e.g., Ruckelshaus* [221] (upholding a standard based on a relatively new system which was in use at only one United States plant at the time of rule promulgation. Although the system was in use more extensively in Europe at the time of rule promulgation, the EPA based its analysis on test results from the lone U.S. plant only.) [222] This makes good sense, because, as discussed above, CAA section 111(a)(1) authorizes a technology-forcing standard that encourages broader adoption of an emissions-reducing technological approach that is not yet broadly used. It follows that at the time of promulgation, not every source will be prepared to adopt the BSER at once. Instead, as discussed next, the EPA's responsibility is to determine that the technology can be adopted in a reasonable period of time, and to base its requirements on this understanding.

iii. Compliance Timeframe

The preceding subsections have shown various circumstances under which the EPA may determine that a system of emission reduction is ''adequately demonstrated.'' In order to establish that a system is appropriate for the source category as a whole, the EPA must also demonstrate that the industry can deploy the technology at scale in the compliance timeframe. The D.C. Circuit has stated that the EPA may determine a ''system of emission reduction'' to be ''adequately demonstrated'' if the EPA reasonably projects that it may be more broadly deployed with adequate lead time. This view is well-grounded in the purposes of CAA section 111(a)(1), discussed above, which aim to control dangerous air pollution by allowing for standards which encourage more widespread adoption of a technology demonstrated at individual plants.

As a practical matter, CAA section 111's allowance for lead time recognizes that existing pollution control systems may be complex and may require a predictable amount of time for sources across the source category to be able to design, acquire, install, test, and begin to operate them.[223] Time may also be required to allow for the development of skilled labor, and materials like steel, concrete, and speciality parts. Accordingly, in setting 111 standards for both new and existing sources, the EPA has typically allowed for some amount of time before sources must demonstrate compliance with the standards. For instance, in the 2015 NSPS for residential wood heaters, the EPA established a ''stepped compliance approach'' which phased in requirements over 5 years to ''allow manufacturers lead time to develop, test, field evaluate and certify current technologies'' across their model lines.[224] The EPA also allowed for a series of phase-ins of various requirements in the 2023 oil and gas NSPS.[225] For example: the EPA finalized a compliance deadline for process controllers allowing for 1 year from the effective date of the final rule, to allow for delays in equipment availability; [226] the EPA established a 1-year lead time period for pumps, also in response to possible equipment and labor shortages; [227] and the EPA built in 24 months between publication in the **Federal Register** and the commencement of a requirement to end routine flaring and route associated gas to a sales line.[228]

Finally, the EPA's longstanding regulations for new source performance standards under CAA section 111 specifically authorize a minimum period for lead time. Pursuant to 40 CFR 60.11, compliance with CAA section 111 standards is generally determined in accordance with performance tests conducted under 40 CFR 60.8. Both of these regulatory provisions were adopted in 1971. Under 40 CFR 60.8, source performance is generally measured via performance tests, which must typically be carried out ''within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act. . . .'' [229] The fact that this provision has been in place for over 50 years indicates that the EPA has long recognized the need for lead time for at least one component of control development.[230]

c. Costs

Under CAA section 111(a)(1), in determining whether a particular emission control is the ''best system of emission reduction . . . adequately demonstrated,'' the EPA is required to take into account ''the cost of achieving [the emission] reduction.'' Although the CAA does not describe how the EPA is to account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including stating that the EPA may not adopt a standard the cost of which would be ''excessive'' or ''unreasonable.'' [231] [232]

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[218] 198 F.3d 930 (D.C. Cir. 1999).

[219] *See id.* at 933–34.

[220] *Id.* at 934 (emphasis added).

[221] 486 F.2d 375 (D.C. Cir. 1973). *See also Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), which supports the point that EPA may extrapolate from testing results, rather than relying on consistent performance, to identify an appropriate system and standard based on that system. In that case, EPA analyzed scrubber performance by considering performance during short-term testing periods. *See id.* at 377.

[222] 486 F.2d at 435–36.

[223] As discussed above, although the EPA is not relying on this point for purposes of these rules, it should be noted that the EPA may determine a system of emission reduction to be adequately demonstrated based on some amount of projection, even if some aspects of the system are still in development. Thus, the authorization for lead time accommodates the development of projected technology.

[224] *See* Standards of Performance for New Residential Wood Heaters, New Residential Hydronic Heaters and Forced-Air Furnaces, 80 FR 13672, 13676 (March 16, 2015).

[225] *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. 89 FR 16943 (March 8, 2024).

[226] *See id.* at 16929.

[227] *See id.* at 16937.

[228] *See id.* at 16886.

[229] 40 CFR 60.8.

[230] For further discussion of lead time in the context of this rulemaking, see section VIII.F.

[231] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981). *See* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council,* 198 F.3d at 933 (costs may not be ''exorbitant''); *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975) (costs may not be ''greater than the industry could bear and survive'').

[232] These cost formulations are consistent with the legislative history of CAA section 111. The 1977 House Committee Report noted:

In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to

The EPA has discretion in its consideration of cost under section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[233] To determine the BSER, the EPA must weigh the relevant factors, including the cost of controls and the amount of emission reductions, as well as other factors.[234]

The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance. In several cases, the court upheld standards that entailed significant costs, consistent with Congress's view that ''the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.'' [235] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); [236] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding NSPS imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial. The EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.'').

In its CAA section 111 rulemakings, the EPA has frequently used a cost-effectiveness metric, which determines the cost in dollars for each ton or other quantity of the regulated air pollutant removed through the system of emission reduction. *See, e.g.,* 81 FR 35824 (June 3, 2016) (NSPS for GHG and VOC emissions for the oil and natural gas source category); 71 FR 9866, 9870 (February 27, 2006) (NSPS for NO_X, SO_2, and PM emissions from fossil fuel-fired electric utility steam generating units); 61 FR 9905, 9910 (March 12, 1996) (NSPS and emission guidelines for nonmethane organic compounds and landfill gas from new and existing municipal solid waste landfills); 50 FR 40158 (October 1, 1985) (NSPS for SO_2 emissions from sweetening and sulfur recovery units in natural gas processing plants). This metric allows the EPA to compare the amount a regulation would require sources to pay to reduce a particular pollutant across regulations and industries. In rules for the electric power sector, the EPA has also looked at a metric that determines the dollar increase in the cost of a MWh of electricity generated by the affected sources due to the emission controls, which shows the cost of controls relative to the output of electricity. *See* section VII.C.1.a.ii of this preamble, which discusses $/MWh costs of the Good Neighbor Plan for the 2015 Ozone NAAQS (88 FR 36654; June 5, 2023) and the Cross-State Air Pollution Rule (CSAPR) (76 FR 48208; August 8, 2011). This metric facilitates comparing costs across regulations and pollutants. In these final actions, as explained herein, the EPA looks at both of these metrics, in addition to other cost evaluations, to assess the cost reasonableness of the final requirements. The EPA's consideration of cost reasonableness in this way meets the statutory requirement that the EPA take into account ''the cost of achieving [the emission] reduction'' under section 111(a)(1).

d. Non-Air Quality Health and Environmental Impact and Energy Requirements

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact and energy requirements'' in determining the BSER. Non-air quality health and environmental impacts may include the impacts of the disposal of byproducts of the air pollution controls, or requirements of the air pollution control equipment for water. *Portland Cement Ass'n* v. *Ruckelshaus,* 465 F.2d 375, 387–88 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974). Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.

e. Sector or Nationwide Component of Factors in Determining the BSER

Another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[237] The D.C. Circuit based this interpretation—which it made in the 1981 *Sierra Club* v. *Costle* case regarding the NSPS for new power plants—on a review of the legislative history, stating,

> [T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[238]

The court has upheld EPA rules that the EPA ''justified . . . in terms of the policies of the Act,'' including balancing long-term national and regional impacts. For example, the court upheld a standard of performance for SO_2 emissions from new coal-fired power plants on grounds that it—

> reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . .[239]

The EPA interprets this caselaw to authorize it to assess the impacts of the controls it is considering as the BSER, including their costs and implications for the energy system, on a sector-wide, regional, or national basis, as appropriate. For example, the EPA may assess whether controls it is considering would create risks to the reliability of the electricity system in a particular area or nationwide and, if they would, to reject those controls as the BSER.

f. ''Best''

In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA has broad discretion. In *AEP* v. *Connecticut,* 564 U.S. 410, 427 (2011), the Supreme Court explained that under CAA section 111, ''[t]he appropriate amount of regulation in any particular greenhouse gas-producing sector cannot be prescribed in a vacuum: . . . informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance. The Clean Air Act entrusts such complex balancing to the EPA in the first instance, in combination with state regulators. Each ''standard of performance'' the EPA sets must ''tak[e] into account the cost of achieving [emissions] reduction and any nonair quality health and environmental impact and energy requirements.'' (paragraphing revised; citations omitted)).

prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91–1196 at 16.

[233] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[234] *Id.* (EPA's conclusion that the high cost of control was acceptable was ''a judgment call with which we are not inclined to quarrel'').

[235] 1977 House Committee Report at 184.

[236] The costs for these standards were described in the rulemakings. See 36 FR 24876 (December 23, 1971), 37 FR 5769 (March 21, 1972).

[237] See 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

[238] *Sierra Club* v. *Costle,* 657 F.2d at 331 (citations omitted) (citing legislative history).

[239] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583–84; June 11, 1979).

Likewise, in *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,'' [240] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard,'' including the amount of emission reductions, the cost of the controls, and the non-air quality environmental impacts and energy requirements.[241] And in *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them . . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant . . . . EPA [has] considerable discretion under section 111.[242]

Importantly, the courts recognize that the EPA must consider several factors and that determining what is ''best'' depends on how much weight to give the factors. In promulgating certain standards of performance, the EPA may give greater weight to particular factors than it does in promulgating other standards of performance. Thus, the determination of what is ''best'' is complex and necessarily requires an exercise of judgment. By analogy, the question of who is the ''best'' sprinter in the 100-meter dash primarily depends on only one criterion—speed—and therefore is relatively straightforward, whereas the question of who is the ''best'' baseball player depends on a more complex weighing of multiple criteria and therefore requires a greater exercise of judgment.

The term ''best'' also authorizes the EPA to consider factors in addition to the ones enumerated in CAA section 111(a)(1), that further the purpose of the statute. In *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973), the D.C. Circuit held that under CAA section 111(a)(1) as it read prior to the enactment of the 1977 CAA Amendments that added a requirement that the EPA take account of non-air quality environmental impacts, the EPA must consider ''counter-productive environmental effects'' in Determining the BSER. *Id.* at 385. The court elaborated: ''The standard of the 'best system' is comprehensive, and we cannot imagine that Congress intended that 'best' could apply to a system which did more damage to water than it prevented to air.'' *Id.,* n.42. In *Sierra Club* v. *Costle,* 657 F.2d at 326, 346–47, the court added that the EPA must consider the amount of emission reductions and technology advancement in determining BSER, as discussed in section V.C.2.g of this preamble.

The court's view that ''best'' includes additional factors that further the purpose of CAA section 111 is a reasonable interpretation of that term in its statutory context. The purpose of CAA section 111 is to reduce emissions of air pollutants that endanger public health or welfare. CAA section 111(b)(1)(A). The court reasonably surmised that the EPA's determination of whether a system of emission reduction that reduced certain air pollutants is ''best'' should be informed by impacts that the system may have on other pollutants that affect public or welfare. *Portland Cement Ass'n,* 486 F.2d at 385. The Supreme Court confirmed the D.C. Circuit's approach in *Michigan* v. *EPA,* 576 U.S. 743 (2015), explaining that administrative agencies must engage in ''reasoned decisionmaking'' that, in the case of pollution control, cannot be based on technologies that ''do even more damage to human health'' than the emissions they eliminate. *Id.* at 751–52. After *Portland Cement Ass'n,* Congress revised CAA section 111(a)(1) to make explicit that in determining whether a system of emission reduction is the ''best,'' the EPA should account for non-air quality health and environmental impacts. By the same token, the EPA takes the position that in determining whether a system of emission reduction is the ''best,'' the EPA may account for the impacts of the system on air pollutants other than the ones that are the subject of the CAA section 111 regulation.[243] We discuss immediately below other factors that the D.C. Circuit has held the EPA should account for in determining what system is the ''best.''

g. Amount of Emissions Reductions

Consideration of the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction'' is implicit in the plain language of CAA section 111(a)(1)—the EPA must choose the *best* system of *emission reduction.* Indeed, consistent with this plain language and the purpose of CAA section 111, the EPA must consider the quantity of emissions at issue. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[244] The fact that the purpose of a ''system of emission reduction'' is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the court's view that in determining whether a ''system of emission reduction'' is the ''best,'' the EPA must consider the amount of emission reductions that the system would yield. Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term ''system of emission reduction'' or the term ''best'' may reasonably be read to allow that discretion.

h. Expanded Use and Development of Technology

The D.C. Circuit has long held that Congress intended for CAA section 111

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[240] *Sierra Club* v. *Costle,* 657 F.2d at 319.

[241] *Sierra Club* v. *Costle,* 657 F.2d at 321; *see also New York* v. *Reilly,* 969 F.2d at 1150 (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, ''the Administrator is free to exercise [her] discretion'' in promulgating an NSPS).

[242] *Lignite Energy Council,* 198 F.3d at 933 (paragraphing revised for convenience). *See New York* v. *Reilly,* 969 F.2d 1147, 1150 (D.C. Cir. 1992) (''Because Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area.''); *see also NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (The EPA did not err in its final balancing because ''neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decisionmaking.'').

[243] See generally *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Supplemental Notice of Proposed Rulemaking,* 87 FR 74765 (December 6, 2022) (proposing the BSER for reducing methane and VOC emissions from natural gas-driven controllers in the oil and natural gas sector on the basis of, among other things, impacts on emissions of criteria pollutants). In this preamble, for convenience, the EPA generally discusses the effects of controls on non-GHG air pollutants along with the effects of controls on non-air quality health and environmental impacts.

[244] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system of emission reduction'' to read, ''best technological system of continuous emission reduction.'' As noted above, the 1990 CAAA deleted ''technological'' and ''continuous'' and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of the 1977 CAAA phrase in *Sierra Club* v. *Costle* to require consideration of the amount of air emissions focused on the term ''best,'' and the terms ''technological'' and ''continuous'' were irrelevant to its analysis. It thus remains valid for the 1990 CAAA phrase ''best system of emission reduction.''

to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' *See Sierra Club* v. *Costle,* 657 F.2d at 346–47. The court has grounded its reading in the statutory text of CAA 111(a)(1), defining the term ''standard of performance.'' [245] In addition, the court's interpretation finds support in the legislative history.[246] The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (1) The development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated;'' under CAA section 111(a)(1); [247] (2) the expanded use of the best demonstrated technology; [248] and (3) the development of emerging technology.[249] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it because technological innovation may be considered an element of the term ''best,'' particularly in light of Congress's emphasis on technological innovation.

i. Achievability of the Degree of Emission Limitation

For new sources, CAA section 111(b)(1)(B) and (a)(1) provides that the EPA must establish ''standards of performance,'' which are standards for emissions that reflect the degree of emission limitation that is ''achievable'' through the application of the BSER. A standard of performance is ''achievable'' if a technology can reasonably be projected to be available to an individual source at the time it is constructed that will allow it to meet the standard.[250] Moreover, according to the court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.'' [251] To be achievable, a standard ''must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance.'' [252] To show a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard.'' [253]

Although the courts have established these standards for achievability in cases concerning CAA section 111(b) new source standards of performance, generally comparable standards for achievability should apply under CAA section 111(d), although the BSER may differ in some cases as between new and existing sources due to, for example, higher costs of retrofit. 40 FR 53340 (November 17, 1975). For existing sources, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include ''standards of performance.'' As the Supreme Court has recognized, this provision requires the EPA to promulgate emission guidelines that determine the BSER for a source category and then identify the degree of emission limitation achievable by application of the BSER. *See West Virginia* v. *EPA,* 597 U.S. at 710.[254]

The EPA has promulgated emission guidelines on the basis that the existing sources can achieve the degree of emission limitation described therein, even though under the RULOF provision of CAA section 111(d)(1), the state retains discretion to apply standards of performance to individual sources that are less stringent, which indicates that Congress recognized that the EPA may promulgate emission guidelines that are consistent with CAA section 111(d) even though certain individual sources may not be able to achieve the degree of emission limitation identified therein by applying the controls that the EPA determined to be the BSER. Note further that this requirement that the emission limitation be ''achievable'' based on the ''best system of emission reduction . . . adequately demonstrated'' indicates that the technology or other measures that the EPA identifies as the BSER must be technically feasible.

3. EPA Promulgation of Emission Guidelines for States To Establish Standards of Performance

CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a procedure similar to that provided by CAA section 110 under which states submit state plans that establish ''standards of performance'' for emissions of certain air pollutants from sources which, if they were new sources, would be regulated under CAA section 111(b), and that provide for the implementation and enforcement of such standards of performance. The term ''standard of performance'' is defined under CAA section 111(a)(1), quoted above. Thus, CAA sections 111(a)(1) and (d)(1) collectively require the EPA to determine the degree of emission limitation achievable through application of the BSER to existing sources and to establish regulations under which states establish standards of performance reflecting that degree of emission limitation. The EPA addresses both responsibilities through its emission guidelines, as well as through its general implementing regulations for CAA section 111(d). Consistent with the statutory requirements, the general implementing regulations require that the EPA's emission guidelines reflect—

> the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction and any non-air quality health and environmental

[245] *Sierra Club* v. *Costle,* 657 F.2d at 346 (''Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and non-air quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.'').

[246] See S. Rep. No. 91–1196 at 16 (1970) (''Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources''); S. Rep. No. 95–127 at 17 (1977) (cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n.174) (''The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology'').

[247] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must ''look[ ] toward what may fairly be projected for the regulated future, rather than the state of the art at present'').

[248] 1970 Senate Committee Report No. 91–1196 at 15 (''The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems'').

[249] *Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

[250] *Sierra Club* v. *Costle,* 657 F.2d 298, 364, n.276 (D.C. Cir. 1981).

[251] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[252] *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).

[253] *Sierra Club* v. *Costle,* 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the '' 'feedstock, operation, size and age' of the source.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to ''generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[254] 40 CFR 60.21(e), 60.21a(e).

impact and energy requirements) the Administrator has determined has been adequately demonstrated from designated facilities.[255]

Following the EPA's promulgation of emission guidelines, each state must establish standards of performance for its existing sources, which the EPA's regulations call ''designated facilities.'' [256] Such standards of performance must reflect the degree of emission limitation achievable through application of the best system of emission reduction as determined by the EPA, which the Agency may express as a presumptive standard of performance in the applicable emission guidelines.

While the standards of performance that states establish in their plans must generally be no less stringent than the degree of emission limitation determined by the EPA,[257] CAA section 111(d)(1) also requires that the EPA's regulations ''permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' Consistent with this statutory direction, the EPA's general implementing regulations for CAA section 111(d) provide a framework for states' consideration of remaining useful life and other factors (referred to as ''RULOF'') when applying a standard of performance to a particular source. In November 2023, the EPA finalized clarifications to its regulations governing states' consideration of RULOF to apply less stringent standards of performance to particular existing sources. As amended, these regulations provide that states may apply a standard of performance to a particular designated facility that is less stringent than, or has a longer compliance schedule than, otherwise required by the applicable emission guideline taking into consideration that facility's remaining useful life and other factors.

[255] 40 CFR 60.21a(e).

[256] 40 CFR 60.21a(b), 60.24a(b).

[257] As the Supreme Court explained in *West Virginia* v. *EPA,* ''Although the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d).'' 597 U.S. at 710. The Court elaborated that ''[t]he Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction . . . that has been adequately demonstrated for [existing covered] facilities.' 40 CFR 60.22(b)(5) (2021); see also 80 FR 64664, and n.1. The States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA. See §§ 60.23, 60.24; 42 U.S.C. 7411(d)(1).'' *Id.*

To apply a less stringent standard of performance or longer compliance schedule, the state must demonstrate with respect to each facility (or class of such facilities), that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA based on unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility or technical infeasibility of installing necessary control equipment; or other circumstances specific to the facility. In doing so, the state must demonstrate that there are fundamental differences between the information specific to a facility (or class of such facilities) and the information the EPA considered in determining the degree of emission limitation achievable through application of the BSER or the compliance schedule that make achieving such degree of emission reduction or meeting such compliance schedule unreasonable for that facility.

In addition, under CAA section 116, states may establish standard of performances that are more stringent than the presumptive standards of performance contained in the EPA's emission guidelines.[258] The state must include the standards of performance in their state plans and submit the plans to the EPA for review according to the procedures established in the Agency's general implementing regulations for CAA section 111(d).[259] Under CAA section 111(d)(2)(A), the EPA approves state plans that are determined to be ''satisfactory.'' CAA section 111(d)(2)(A) also gives the Agency ''the same authority'' as under CAA section 110(c) to promulgate a Federal plan in cases where a state fails to submit a satisfactory state plan.

VI. ACE Rule Repeal

The EPA is finalizing repeal of the ACE Rule. The EPA proposed to repeal the ACE Rule and did not receive significant comments objecting to the proposal. The EPA is finalizing the proposal largely as proposed. A general summary of the ACE Rule, including its regulatory and judicial history, is included in section V.B.4 of this preamble. The EPA repeals the ACE Rule on three grounds that each independently justify the rule's repeal.

First, as a policy matter, the EPA concludes that the suite of heat rate improvements (HRI) the ACE Rule selected as the BSER is not an appropriate BSER for existing coal-fired EGUs. In the EPA's technical judgment, the suite of HRI set forth in the ACE Rule provide negligible CO_2 reductions at best and, in many cases, may increase CO_2 emissions because of the ''rebound effect,'' as explained in section VII.D.4.a.iii of this preamble. These concerns, along with the EPA's experience in implementing the ACE Rule, cast doubt that the ACE Rule would achieve emission reductions and increase the likelihood that the ACE Rule could make CO_2 pollution worse. As a result, the EPA has determined it is appropriate to repeal the rule, and to reevaluate whether other technologies constitute the BSER.

[258] 40 CFR 60.24a(i).

[259] See generally 40 CFR 60.23a–60.28a.

Second, even assuming the ACE Rule's rejection of CCS and natural gas co-firing was supported at the time, the ACE Rule's rationale for rejecting CCS and natural gas co-firing as the BSER no longer applies because of new factual developments. Since the ACE Rule was promulgated, changes in the power industry, developments in the costs of controls, and new federal subsidies have made other controls more broadly available and less expensive. Considering these developments, the EPA has determined that co-firing with natural gas and CCS are the BSER for certain subcategories of sources as described in section VII.C of this preamble, and that the HRI technologies adopted by the ACE Rule are not the BSER. Thus, repeal of the ACE Rule is proper on this ground as well.

Third, the EPA concludes that the ACE Rule conflicted with CAA section 111 and the EPA's implementing regulations because it did not specifically identify the BSER or the ''degree of emission limitation achievable though application of the [BSER].'' Instead, the ACE Rule described only a broad range of values as the ''degree of emission limitation achievable.'' In doing so, the rule did not provide the states with adequate guidance on the degree of emission limitation that must be reflected in the standards of performance so that a state plan would be approvable by the EPA. The ACE Rule is repealed for this reason also.

A. Summary of Selected Features of the ACE Rule

The ACE Rule determined that the BSER for coal-fired EGUs was a ''list of 'candidate technologies,' '' consisting of seven types of the ''most impactful HRI technologies, equipment upgrades, and best operating and maintenance practices,'' (84 FR 32536; July 8, 2019), including, among others, ''Boiler Feed Pumps'' and ''Redesign/Replace Economizer.'' *Id.* at 32537 (table 1). The rule provided a range of improvements in heat rate that each of the seven ''candidate technologies'' could achieve if applied to coal-fired EGUs of different capacities. For six of the technologies, the expected level of improvement in heat rate ranged from 0.1–0.4 percent to 1.0–2.9 percent, and for the seventh technology, ''Improved Operating and Maintenance (O&M) Practices,'' the range was ''0 to >2%.'' *Id.* The ACE Rule explained that states must review each of their designated facilities, on either a source-by-source or group-of-sources basis, and ''evaluate the applicability of each of the candidate technologies.'' *Id.* at 32550. States were to use the list of HRI technologies ''as guidance but will be expected to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies.'' *Id.* at 32538.

The ACE Rule emphasized that states had ''inherent flexibility'' in evaluating candidate technologies with ''a wide range of potential outcomes.'' *Id.* at 32542. The ACE Rule provided that states could conclude that it was not appropriate to apply some technologies. *Id.* at 32550. Moreover, if a state decided to apply a particular technology to a particular source, the state could determine the level of heat rate improvement from the technology could be anywhere within the range that the EPA had identified for that technology, or even outside that range. *Id.* at 32551. The ACE Rule stated that after the state evaluated the technologies and calculated the amount of HRI in this way, it should determine the standard of performance 0that the source could achieve, *Id.* at 32550, and then adjust that standard further based on the application of source-specific factors such as remaining useful life. *Id.* at 32551.

The ACE Rule then identified the process by which states had to take these actions. States must ''evaluat[e] each'' of the seven candidate technologies and provide a summary, which ''include[s] an evaluation of the . . . degree of emission limitation achievable through application of the technologies.'' *Id.* at 32580. Then, the state must provide a variety of information about each power plant, including, the plant's ''annual generation,'' ''CO_2 emissions,'' ''[f]uel use, fuel price, and carbon content,'' ''operation and maintenance costs,'' ''[h]eat rates,'' ''[e]lectric generating capacity,'' and the ''timeline for implementation,'' among other information. *Id.* at 32581. The EPA explained that the purpose of this data was to allow the Agency to ''adequately and appropriately review the plan to determine whether it is satisfactory.'' *Id.* at 32558.

The ACE Rule projected a very low level of overall emission reduction if states generally applied the set of candidate technologies to their sources. The rule was projected to achieve a less-than-1-percent reduction in power-sector CO_2 emissions by 2030.[260] Further, the EPA also projected that it would increase CO_2 emissions from power plants in 15 states and the District of Columbia because of the ''rebound effect'' as coal-fired sources implemented HRI measures and became more efficient. This phenomenon is explained in more detail in section VII.D.4.a.iii of this document.[261]

The ACE Rule considered several other control measures as the BSER, including co-firing with natural gas and CCS, but rejected them. The ACE Rule rejected co-firing with natural gas primarily on grounds that it was too costly in general. 84 FR 32545 (July 8, 2019). The rule also concluded that generating electricity by co-firing natural gas in a utility boiler would be an inefficient use of the gas when compared to combusting it in a combustion turbine. *Id.* The ACE Rule rejected CCS on grounds that it was too costly. *Id.* at 32548. The rule identified the high capital and operating costs of CCS and noted the fact that the IRC section 45Q tax credit, as it then applied, would provide only limited benefit to sources. *Id.* at 32548–49.

B. Developments Undermining ACE Rule's Projected Emission Reductions

The EPA's first basis for repealing the ACE Rule is that it is unlikely that—if implemented—the rule would reduce emissions, and implementation could increase CO_2 emissions instead. Thus, the EPA concludes that as a matter of policy it is appropriate to repeal the rule and evaluate anew whether other technologies qualify as the BSER.

Two factors, taken together, undermine the ACE Rule's projected emission reductions and create the risk that implementation of the ACE Rule could increase—rather than reduce—CO_2 emissions from coal-fired EGUs. First, HRI technologies achieve only limited GHG emission reductions. The ACE Rule projected that if states generally applied the set of candidate technologies to their sources, the rule would achieve a less-than-1-percent reduction in power-sector CO_2 emissions by 2030.[262] The EPA now doubts that even these minimal reductions would be achieved. The ACE Rule's projected benefits were premised in part on a 2009 technical report by Sargent & Lundy that evaluated the effects of HRI technologies. In 2023, Sargent & Lundy issued an updated report which details that the HRI selected as the BSER in the ACE Rule would bring fewer emissions reductions than estimated in 2009. The 2023 report concludes that, with few exceptions, HRI technologies are less effective at reducing CO_2 emissions than assumed in 2009. Further reinforcing the conclusion that HRIs would bring few reductions, the 2023 report also concluded that most sources had already optimized application of HRIs, and so there are fewer opportunities to reduce emissions than previously anticipated.[263]

Second, for a subset of sources, HRI are likely to cause a ''rebound effect'' leading to an increase in GHG emissions for those sources. The rebound effect is explained in detail in section VII.D.4.a.iii of this preamble. The ACE Rule's analysis projected that the rule would increase CO_2 emissions from power plants in 15 states and the District of Columbia. The EPA's modeling projections assumed that, consistent with the rule, some sources would impose a small degree of efficiency improvements. The modeling showed that, as a consequence of these improvements, the rule would increase absolute emissions at some coal-fired sources as these sources became more efficient and displaced lower emitting sources like natural gas-fired EGUs.[264]

Even though the ACE Rule was projected to increase emissions in many states, these states were nevertheless obligated under the rule to assemble detailed state plans that evaluated available technologies and the performance of each existing coal-fired power plant, as described in section IX.A of this preamble. For example, the state was required to analyze the plant's ''annual generation,'' ''CO_2 emissions,'' ''[f]uel use, fuel price, and carbon content,'' ''operation and maintenance

[260] ACE Rule RIA 3–11, table 3–3.

[261] The rebound effect becomes evident by comparing the results of the ACE Rule IPM runs for the 2018 reference case, EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case,* Document ID No. EPA–HQ–OAR–2017–0355–26720, and for the ''Illustrative ACE Scenario. *IPM State-Level Emissions: Illustrative ACE Scenario,* Document ID No. EPA–HQ–OAR–2017–0355–26724.

[262] ACE Rule RIA 3–11, table 3–3.

[263] Sargent and Lundy. Heat Rate Improvement Method Costs and Limitations Memo. Available in Docket ID No. EPA–HQ–OAR–2023–0072.

[264] See EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case,* Document ID No. EPA–HQ–OAR–2017–0355–26720 (providing ACE reference case); *IPM State-Level Emissions: Illustrative ACE Scenario,* Document ID No. EPA–HQ–OAR–2017–0355–26724 (providing illustrative scenario).

costs,'' ''[h]eat rates,'' ''[e]lectric generating capacity,'' and the ''timeline for implementation,'' among other information. 84 FR 32581 (July 8, 2019). The risk of an increase in emissions raises doubts that the HRI for coal-fired sources satisfies the statutory criteria to constitute the BSER for this category of sources. The core element of the BSER analysis is whether the emission reduction technology selected reduces emissions. *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 441 (D.C. Cir. 1973) (noting ''counter productive environmental effects'' raises questions as to whether the BSER selected was in fact the ''best''). Moreover, this evaluation and the imposition of standards of performance was mandated even though the state plan would lead to an *increase* rather than decrease CO_2 emissions. Imposing such an obligation on states under these circumstances was arbitrary.

The EPA's experience in implementing the ACE Rule reinforces these concerns. After the ACE Rule was promulgated, one state drafted a state plan that set forth a standard of performance that allowed the affected source to increase its emission rate. The draft partial plan would have applied to one source, the Longview Power, LLC facility, and would have established a standard of performance, based on the state's consideration of the ''candidate technologies,'' that was higher (*i.e.,* less stringent) than the source's historical emission rate. Thus, the draft plan would not have achieved any emission reductions from the source, and instead would have allowed the source to *increase* its emissions, if it had been finalized.[265]

Because there is doubt that the minimal reductions projected by the ACE Rule would be achieved, and because the rebound effect could lead to an increase in emissions for many sources in many states, the EPA concludes that it is appropriate to repeal the ACE Rule and reevaluate the BSER for this category of sources.

C. Developments Showing That Other Technologies Are the BSER for This Source Category

Since the promulgation of the ACE Rule in 2019, the factual underpinnings of the rule have changed in several ways and lead the EPA to determine that HRI are not the BSER for coal-fired power plants. This reevaluation is consistent with *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009). There, the Supreme Court explained that an agency issuing a new policy ''need not demonstrate to a court's satisfaction that the reasons for the new policy are *better* than the reasons for the old one.'' Instead, ''it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates.'' *Id.* at 514–16 (emphasis in original; citation omitted).

Along with changes in the anticipated reductions from HRI, it makes sense for the EPA to reexamine the BSER because the costs of two control measures, co-firing with natural gas and CCS, have fallen for sources with longer-term operating horizons. As noted, the ACE Rule rejected natural gas co-firing as the BSER on grounds that it was too costly and would lead to inefficient use of natural gas. But as discussed in section VII.C.2.b of this preamble, the costs of natural gas co-firing are presently reasonable, and the EPA concludes that the costs of co-firing 40 percent by volume natural gas are cost-effective for existing coal-fired EGUs that intend to operate after January 1, 2032, and cease operation before January 1, 2039. In addition, changed circumstances—including that natural gas is available in greater amounts, that many coal-fired EGUs have begun co-firing with natural gas or converted wholly to natural-gas, and that there are fewer coal-fired EGUs in operation—mitigate the concerns the ACE Rule identified about inefficient use of natural gas.

Similarly, the ACE Rule rejected CCS as the BSER on grounds that it was too costly. But the costs of CCS have substantially declined, as discussed in section VII.C.1.a.ii of the preamble, partly because of developments in the technology that have lowered capital costs, and partly because the IRA extended and increased the IRS section 45Q tax credit so that it defrays a higher portion of the costs of CCS. Accordingly, for coal-fired EGUs that will continue to operate past 2039, the EPA concludes that the costs of CCS are reasonable, as described in section VII.C.1.a.ii of the preamble.

The emission reductions from these two technologies are substantial. For long-term coal-fired steam generating units, the BSER of 90 percent capture CCS results in substantial CO_2 emissions reductions amounting to emission rates that are 88.4 percent lower on a lb/MWh-gross basis and 87.1 percent lower on a lb/MWh-net basis compared to units without capture, as described in section VII.C.2.b.iv of this preamble. For medium term units, the BSER of 40 percent natural gas co-firing achieves CO_2 stack emissions reductions of 16 percent, as described in section VII.C.2.b.iv of this preamble. Given the availability of more effective, cost-reasonable technology, the EPA concludes that HRIs are not the BSER for all coal-fired EGUs.

The EPA is thus finalizing a new policy for coal-fired power plants. This rule applies to those sources that intend to operate past January 1, 2032. For sources that intend to cease operations after January 1, 2032, but before January 1, 2039, the EPA concludes that the BSER is co-firing 40 percent by volume natural gas. The EPA concludes this control measure is appropriate because it achieves substantial reductions at reasonable cost. In addition, the EPA believes that because a large supply of natural gas is available, devoting part of this supply for fuel for a coal-fired steam generating unit in place of a percentage of the coal burned at the unit is an appropriate use of natural gas and will not adversely impact the energy system, as described in section VII.C.2.b.iii(B) of this preamble. For sources that intend to operate past January 1, 2039, the EPA concludes that the BSER is CCS with 90 percent capture of CO_2. The EPA believes that this control measure is appropriate because it achieves substantial reductions at reasonable cost, as described in section VII.C.1 of this preamble.

The EPA is not concluding that HRI is the BSER for any coal-fired EGUs. As discussed in section VII.D.4.a, the EPA does not consider HRIs an appropriate BSER for coal-fired EGUs because these technologies would achieve few, if any, emissions reductions and may increase emissions due to the rebound effect. Most importantly, changed circumstances show that co-firing natural gas and CCS are available at reasonable cost, and will achieve more GHG emissions reductions. Accordingly, the EPA believes that HRI do not qualify as the BSER for any coal-fired EGUs, and that other approaches meet the statutory standard. On this basis, the EPA repeals the ACE Rule.

D. Insufficiently Precise Degree of Emission Limitation Achievable From Application of the BSER

The third independent reason why the EPA is repealing the ACE Rule is that the rule did not identify with sufficient specificity the BSER or the degree of emission limitation achievable through the application of the BSER. Thus, states lacked adequate guidance on the BSER they should consider and

[265] West Virginia CAA § 111(d) Partial Plan for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs), *https://dep.wv.gov/daq/publicnoticeandcomment/Documents/Proposed%20WV%20ACE%20State%20Partial%20Plan.pdf.*

level of emission reduction that the standards of performance must achieve. The ACE Rule determined the BSER to be a suite of HRI ''candidate technologies,'' but did not identify with specificity the degree of emission limitation states should apply in developing standards of performance for their sources. As a result, the ACE Rule conflicted with CAA section 111 and the implementing regulations, and thus failed to provide states adequate guidance so that they could ensure that their state plans were satisfactory and approvable by the EPA.

CAA section 111 and the EPA's longstanding implementing regulations establish a clear process for the EPA and states to regulate emissions of certain air pollutants from existing sources. ''The statute directs the EPA to (1) 'determine[ ],' taking into account various factors, the 'best system of emission reduction which . . . has been adequately demonstrated,' (2) ascertain the 'degree of emission limitation achievable through the application' of that system, and (3) impose an emissions limit on new stationary sources that 'reflects' that amount.'' *West Virginia* v. *EPA,* 597 U.S. at 709 (quoting 42 U.S.C. 7411(d)). Further, ''[a]lthough the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d) . . . [and] decides the amount of pollution reduction that must ultimately be achieved.'' *Id.* at 2602.

Once the EPA makes these determinations, the state must establish ''standards of performance'' for its sources that are based on the degree of emission limitation that the EPA determines in the emission guidelines. CAA section 111(a)(1) makes this clear through its definition of ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER].'' After the EPA determines the BSER, 40 CFR 60.22(b)(5), and the degree of emission limitation achievable from application of the BSER, ''the States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA.'' 597 U.S. at 710 (citing 40 CFR 60.23, 60.24; 42 U.S.C. 7411(d)(1)).

The EPA then reviews the plan and approves it if the standards of performance are ''satisfactory,'' under CAA section 111(d)(2)(A). The EPA's longstanding implementing regulations make clear that the EPA's basis for determining whether the plan is ''satisfactory'' includes that the plan must contain ''emission standards . . . no less stringent than the corresponding emission guideline(s).'' 40 CFR 60.24(c), 40 CFR 60.24a(c). In addition, under CAA section 111(d)(1), in ''applying a standard of performance to any particular source'' a state may consider, ''among other factors, the remaining useful life of the existing source to which such standard applies.'' This is also known as the RULOF provision and is discussed in section X.C.2 of this preamble.

In the ACE Rule, the EPA recognized that the CAA required it to determine the BSER and identify the degree of emission limitation achievable through application of the BSER. 84 FR 32537 (July 8, 2019). But the rule did not make those determinations. Rather, the ACE Rule described the BSER as a list of ''candidate technologies.'' And the rule described the degree of emission limitation achievable by application of the BSER as ranges of reductions from the HRI technologies. The rule thus shifted the responsibility for determining the BSER and degree of emission limitation achievable from the EPA to the states. Accordingly, the ACE Rule did not meet the CAA section 111 requirement that the EPA determine the BSER or the degree of emission limitation from application of the BSER.

As described above, the ACE Rule identified the HRI in the form of a list of seven ''candidate technologies,'' accompanied by a wide range of percentage improvements to heat rate that these technologies could provide. Indeed, for one of them, improved ''O&M'' practices (that is, operation and management practices), the range was ''0 to >2%,'' which is effectively unbounded. 84 FR 32537 (table 1) (July 8, 2019). The ACE Rule was clear that this list was simply the starting point for a state to calculate the standards of performance for its sources. That is, the seven sets of technologies were ''candidate[s]'' that the state could apply to determine the standard of performance for a source, and if the state did choose to apply one or more of them, the state could do so in a manner that yielded any percentage of heat rate improvement within the range that the EPA identified, or even outside that range. Thus, as a practical matter, the ACE Rule did not determine the BSER or any degree of emission limitation from application of the BSER, and so states had no guidance on how to craft approvable state plans. In this way, the ACE Rule did not adhere to the applicable statutory obligations. See 84 FR 32537–38 (July 8, 2019).

The only constraints that the ACE Rule imposed on the states were procedural ones, and those did not give the EPA any benchmark to determine whether a plan could be approved or give the states any certainty on whether their plan would be approved. As noted above, when a state submitted its plan, it needed to show that it evaluated each candidate technology for each source or group of sources, explain how it determined the degree of emission limitation achievable, and include data about the sources. But because the ACE Rule did not identify a BSER or include a degree of emission limitation that the standards must reflect, the states lacked specific guidance on how to craft adequate standards of performance, and the EPA had no benchmark against which to evaluate whether a state's submission was ''satisfactory'' under CAA section 111(d)(2)(A). Thus, the EPA's review of state plans would be essentially a standardless exercise, notwithstanding the Agency's longstanding view that it was ''essential'' that ''EPA review . . . [state] plans for their substantive adequacy.'' 40 FR 53342–43 (November 17, 1975). In 1975, the EPA explained that it was not appropriate to limit its review based ''solely on procedural criteria'' because otherwise ''states could set extremely lenient standards . . . so long as EPA's procedural requirements were met.'' *Id.* at 53343.

Finally, the ACE Rule's approach to determining the BSER and degree of emission limitation departed from prior emission guidelines under CAA section 111(d), in which the EPA included a numeric degree of emission limitation. See, *e.g.,* 42 FR 55796, 55797 (October 18, 1977) (limiting emission rate of acid mist from sulfuric acid plants to 0.25 grams per kilogram of acid); 44 FR 29829 (May 22, 1979) (limiting concentrations of total reduced sulfur from most of the subcategories of kraft pulp mills, such as digester systems and lime kilns, to 5, 20, or 25 ppm over 12-hour averages); 61 FR 9919 (March 12, 1996) (limiting concentration of non-methane organic compounds from solid waste landfills to 20 parts per million by volume or a 98 percent reduction). The ACE Rule did not grapple with this change in position as required by *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009), or explain why it was appropriate to provide a boundless degree of emission limitation achievable in this context.

The EPA is finalizing the repeal the ACE Rule on this ground as well. The ACE Rule's failure to determine the BSER and the associated degree of emission limitation achievable from application of the BSER deviated from CAA section 111 and the implementing regulations. Without these determinations, the ACE Rule lacked any benchmark that would guide the states in developing their state plans, and by which the EPA could determine whether those state plans were satisfactory.

For each of these three, independent reasons, repeal of the ACE Rule is proper.

E. Withdrawal of Proposed NSR Revisions

In addition to repealing the ACE Rule, the Agency is withdrawing the proposed revisions to the NSR applicability provisions that were included the ACE Rule proposal (83 FR 44756, 44773–83; August 31, 2018). These proposed revisions would have included an hourly emissions rate test to determine NSR applicability for a modified EGU, with the expressed purpose of alleviating permitting burdens for sources undertaking HRI projects pursuant to the ACE Rule emission guidelines. The ACE Rule final action did not include the NSR revisions, and the EPA indicated in that preamble that it intended to take final action on the NSR proposal in a separate action at a later date. However, the EPA did not take a final action on the NSR revisions, and the EPA has decided to no longer pursue them and to withdraw the proposed revisions.

Withdrawal of the proposal to establish an hourly emissions test for NSR applicability for EGUs is appropriate because of the repeal of the ACE rule and the EPA's conclusion that HRI is not the BSER for coal-fired EGUs. The EPA's basis for proposing the NSR revisions was to ease permitting burdens for state agencies and sources that may result from implementing the ACE Rule. There was concern that, for sources that modified their EGU to improve the heat rate, if a source were to be dispatched more frequently because of improved efficiency (the ''rebound effect''), the source could experience an increase in absolute emissions for one or more pollutants and potentially trigger major NSR requirements. The hourly emissions rate test was proposed to relieve such sources that were undertaking HRI projects to comply with their state plans from the burdens of NSR permitting, particularly in cases in which a source has an increase in annual emissions of a pollutant. However, given that this final rule BSER is not based on HRIs for coal-fired EGUs, the NSR revisions proposed as part of the ACE Rule would no longer serve the purpose that the EPA expressed in that proposal preamble.

Furthermore, in the event that any sources are increasing their absolute emissions after modifying an EGU, applicability of the NSR program is beneficial as a backstop that provides review of those situations to determine if additional controls or other emission limitations are necessary on a case-by-case basis to protect air quality. In addition, given that considerable time has passed since these EGU-specific NSR applicability revisions were proposed in 2018, should the EPA decide to pursue them at a later time, it is prudent for the Agency to propose them again at that time, accompanied with the EPA's updated context and justification to support re-proposing the NSR revisions, rather than relying on the proposal from 2018. Therefore, the EPA is withdrawing these proposed NSR revisions.

VII. Regulatory Approach for Existing Fossil Fuel-Fired Steam Generating Units

Existing fossil fuel-fired steam generation units are the largest stationary source of CO_2 emissions, emitting 909 MMT CO_2e in 2021. Recent developments in control technologies offer opportunities to reduce CO_2 emissions from these sources. The EPA's regulatory approach for these units is to require emissions reduction consistent with these technologies, where their use is cost-reasonable.

A. Overview

In this section of the preamble, the EPA identifies the BSER and degree of emission limitation achievable for the regulation of GHG emissions from existing fossil fuel-fired steam generating units. As detailed in section V of this preamble, to meet the requirements of CAA section 111(d), the EPA promulgates ''emission guidelines'' that identify the BSER and the degree of emission limitation achievable through the application of the BSER, and states then establish standards of performance for affected sources that reflect that level of stringency. To determine the BSER for a source category, the EPA identifies systems of emission reduction (*e.g.,* control technologies) that have been adequately demonstrated and evaluates the potential emissions reduction, costs, any non-air health and environmental impacts, and energy requirements. As described in section V.C.1 of this preamble, the EPA has broad authority to create subcategories under CAA section 111(d). Therefore, where the sources in a category differ from each other by some characteristic that is relevant for the suitability of the emission controls, the EPA may create separate subcategories and make separate BSER determinations for those subcategories.

The EPA considered the characteristics of fossil fuel-fired steam generating units that may impact the suitability of different control measures. First, the EPA observed that the type and amounts of fossil fuels—coal, oil, and natural gas—fired in the steam generating unit affect the performance and emissions reductions achievable by different control technologies, in part due to the differences in the carbon content of those fuels. The EPA recognized that many sources fire multiple types of fossil fuel. Therefore, the EPA is finalizing subcategories of coal-fired, oil-fired, and natural gas-fired steam generating units. The EPA is basing these subcategories, in part, on the amount of fuel combusted by the steam generating unit.

The EPA then considered the BSER that may be suitable for each of those subcategories of fuel type. For coal-fired steam generating units, of the available control technologies, the EPA is determining that CCS with 90 percent capture of CO_2 meets the requirements for BSER, including being adequately demonstrated and achieving significant emission reductions at reasonable cost for units operating in the long-term, as detailed in section VII.C.1.a of this preamble. Application of this BSER results in a degree of emission limitation equivalent to an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross). The compliance date for these sources is January 1, 2032.

Typically, the EPA assumes that sources subject to controls operate in the long-term.[266] See, for example, the 2015 NSPS (80 FR 64509; October 23, 2015) or the 2011 CSAPR (76 FR 48208; August 8, 2011). Under that assumption, fleet average costs for CCS are comparable to the cost metrics the EPA has previously considered to be reasonable. However, the EPA observes that about half of the capacity (87 GW out of 181 GW) of existing coal-fired steam generating units have announced plans to permanently cease operation prior to 2039, as detailed in section IV.D.3.b of this preamble, affecting the period available for those sources to amortize the capital costs of CCS.

[266] Typically, the EPA assumes that the capital costs can be amortized over a period of 15 years. As discussed in section VII.C.1.a.ii of this preamble, in the case of CCS, the IRC section 45Q tax credit, which defrays a significant portion of the costs of CCS, is available for the first 12 years of operation. Accordingly, EPA generally assumed a 12-year amortization period in determining CCS costs.

Accordingly, the EPA evaluated the costs of CCS for different amortization periods. For an amortization period of more than 7 years—such that sources operate after January 1, 2039—annualized fleet average costs are comparable to or less than the metrics of costs for controls that the EPA has previously found to be reasonable. However, the group of sources ceasing operation prior to January 1, 2039, have less time available to amortize the capital costs of CCS, resulting in higher annualized costs.

Because the costs of CCS depend on the available amortization period, the EPA is creating a subcategory for sources demonstrating that they plan to permanently cease operation prior to January 1, 2039. Instead, for this subcategory of sources, the EPA is determining that natural gas co-firing at 40 percent of annual heat input meets the requirements of BSER. Application of the natural gas co-firing BSER results in a degree of emission limitation equivalent to a 16 percent reduction in emission rate (lb CO_2/MWh-gross). Co-firing at 40 percent entails significantly less control equipment and infrastructure than CCS, and as a result, the EPA has determined that affected sources are able to implement it more quickly than CCS, by January 1, 2030. Importantly, co-firing at 40 percent also entails significantly less capital cost than CCS, and as a result, the costs of co-firing are comparable to or less than the metrics for cost reasonableness with an amortization period that is significantly shorter than the period for CCS. The EPA has determined that the costs of co-firing meet the metrics for cost reasonableness for the majority of the capacity that permanently cease operation more than 2 years after the January 1, 2030, implementation date, or after January 1, 2032 (and up to December 31, 2038), and that therefore have an amortization period of more than 2 years (and up to 9 years).

The EPA is also determining that sources demonstrating that they plan to permanently cease operation before January 1, 2032, are not subject to the 40 percent co-firing requirement. This is because their amortization period would be so short—2 years or less—that the costs of co-firing would, in general, be less comparable to the cost metrics for reasonableness for that group of sources. Accordingly, the EPA is defining the medium-term subcategory to include those sources demonstrating that they plan to permanently cease operating after December 31, 2031, and before January 1, 2039.

Considering the limited emission reductions available in light of the cost reasonableness of controls with short amortization periods, the EPA is finalizing an applicability exemption for coal-fired steam generating units demonstrating that they plan to permanently cease operation before January 1, 2032.

For natural gas- and oil-fired steam generating units, the EPA is finalizing subcategories based on capacity factor. Because natural gas- and oil-fired steam generating units with similar annual capacity factors perform similarly to one another, the EPA is finalizing a BSER of routine methods of operation and maintenance and a degree of emission limitation of no increase in emission rate for intermediate and base load subcategories. For low load natural gas- and oil-fired steam generating units, the EPA is finalizing a BSER of uniform fuels and respective degrees of emission limitation defined on a heat input basis (130 lb CO_2/MMBtu and 170 lb CO_2/MMBtu). Furthermore, the EPA is finalizing presumptive standards for natural gas- and oil-fired steam generating units as follows: base load sources (those with annual capacity factors greater than 45 percent) have a presumptive standard of 1,400 lb CO_2/MWh-gross, intermediate load sources (those with annual capacity factors greater than 8 percent and or less than or equal to 45 percent) have a presumptive standard of 1,600 lb CO_2/MWh-gross. For low load oil-fired sources, the EPA is finalizing a presumptive standard of 170 lb CO_2/MMBtu, while for low load natural gas-fired sources the EPA is finalizing a presumptive standard of 130 lb CO_2/MMBtu. A compliance date of January 1, 2030, applies for all natural gas- and oil-fired steam generating units.

The final subcategories and BSER are summarized in table 1 of this document.

TABLE 1—SUMMARY OF FINAL BSER, SUBCATEGORIES, AND DEGREES OF EMISSION LIMITATION FOR AFFECTED EGUS

Affected EGUs	Subcategory definition	BSER	Degree of emission limitation	Presumptively approvable standard of performance *
Long-term existing coal-fired steam generating units.	Coal-fired steam generating units that are not medium-term units.	CCS with 90 percent capture of CO_2.	88.4 percent reduction in emission rate (lb CO_2/MWh-gross).	88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
Medium-term existing coal-fired steam generating units.	Coal-fired steam generating units that have demonstrated that they plan to permanently cease operations after December 31, 2031, and before January 1, 2039.	Natural gas co-firing at 40 percent of the heat input to the unit.	A 16 percent reduction in emission rate (lb CO_2/MWh-gross).	A 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
Base load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,400 lb CO_2/MWh-gross.
Intermediate load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,600 lb CO_2/MWh-gross.
Low load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor less than 8 percent.	lower-emitting fuels	170 lb CO_2/MMBtu	170 lb CO_2/MMBtu.
Base load existing natural gas-fired steam generating units.	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,400 lb CO_2/MWh-gross.
Intermediate load existing natural gas-fired steam generating units.	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,600 lb CO_2/MWh-gross.

TABLE 1—SUMMARY OF FINAL BSER, SUBCATEGORIES, AND DEGREES OF EMISSION LIMITATION FOR AFFECTED EGUs—Continued

Affected EGUs	Subcategory definition	BSER	Degree of emission limitation	Presumptively approvable standard of performance*
Low load existing natural gas-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor less than 8 percent.	lower-emitting fuels	130 lb CO_2/MMBtu	130 lb CO_2/MMBtu.

*Presumptive standards of performance are discussed in detail in section X of the preamble. While states establish standards of performance for sources, the EPA provides presumptively approvable standards of performance based on the degree of emission limitation achievable through application of the BSER for each subcategory. Inclusion in this table is for completeness.

B. Applicability Requirements and Fossil Fuel-Type Definitions for Subcategories of Steam Generating Units

In this section of the preamble, the EPA describes the rationale for the final applicability requirements for existing fossil fuel-fired steam generating units. The EPA also describes the rationale for the fuel type definitions and associated subcategories.

1. Applicability Requirements

For the emission guidelines, the EPA is finalizing that a designated facility[267] is any fossil fuel-fired electric utility steam generating unit (*i.e.,* utility boiler or IGCC unit) that: (1) was in operation or had commenced construction on or before January 8, 2014;[268] (2) serves a generator capable of selling greater than 25 MW to a utility power distribution system; and (3) has a base load rating greater than 260 GJ/h (250 million British thermal units per hour (MMBtu/h)) heat input of fossil fuel (either alone or in combination with any other fuel). Consistent with the implementing regulations, the term ''designated facility'' is used throughout this preamble to refer to the sources affected by these emission guidelines.[269] For the emission guidelines, consistent with prior CAA section 111 rulemakings concerning EGUs, the term ''designated facility'' refers to a single EGU that is affected by these emission guidelines. The rationale for the final applicability requirements is the same as that for 40 CFR part 60, subpart TTTT (80 FR 64543–44; October 23, 2015). The EPA includes that discussion by reference here.

Section 111(a)(6) of the CAA defines an ''existing source'' as ''any stationary source other than a new source.'' Therefore, the emission guidelines do not apply to any steam generating units that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT. Moreover, because the EPA is now finalizing revised standards of performance for coal-fired steam generating units that undertake a modification, a modified coal-fired steam generating unit would be considered ''new,'' and therefore not subject to these emission guidelines, if the modification occurs after the date the proposal was published in the **Federal Register** (May 23, 2023). Any coal-fired steam generating unit that has modified prior to that date would be considered an existing source that is subject to these emission guidelines.

In addition, the EPA is finalizing in the applicability requirements of the emission guidelines many of the same exemptions as discussed for 40 CFR part 60, subpart TTTT, in section VIII.E.1 of this preamble. EGUs that may be excluded from the requirement to establish standards under a state plan are: (1) units that are subject to 40 CFR part 60, subpart TTTT, as a result of commencing a qualifying modification or reconstruction; (2) steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh; (3) non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) combined heat and power (CHP) units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (5) units that serve a generator along with other affected EGU(s), where the effective generation capacity (determined based on a prorated output of the base load rating of EGU) is 25 MW or less; (6) municipal waste combustor units subject to 40 CFR part 60, subpart Eb; (7) commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; (8) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU; or (9) coal-fired steam generating units that have elected to permanently cease operation prior to January 1, 2032.

The exemptions listed above at (4), (5), (6), and (7) are among the current exemptions at 40 CFR 60.5509(b), as discussed in section VIII.E.1 of this preamble. The exemptions listed above at (2), (3), and (8) are exemptions the EPA is finalizing revisions for 40 CFR part 60, subpart TTTT, and the rationale for the exemptions is in section VIII.E.1 of this preamble. For consistency with the applicability requirements in 40 CFR part 60, subpart TTTT, and 40 CFR part 60, subpart TTTTa, the Agency is finalizing these same exemptions for the applicability of the emission guidelines.

2. Coal-Fired Units Permanently Ceasing Operation Before January 1, 2032

The EPA is not addressing existing coal-fired steam generating units demonstrating that they plan to permanently cease operating before January 1, 2032, in these emission guidelines. Sources ceasing operation before that date have far less emission reduction potential than sources that will be operating longer, because there are unlikely to be appreciable, cost-reasonable emission reductions available on average for the group of sources operating in that timeframe. This is because controls that entail capital expenditures are unlikely to be

[267] The term ''designated facility'' means ''any existing facility . . . which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility.'' See 40 CFR 60.21a(b).

[268] Under CAA section 111, the determination of whether a source is a new source or an existing source (and thus potentially a designated facility) is based on the date that the EPA proposes to establish standards of performance for new sources.

[269] The EPA recognizes, however, that the word ''facility'' is often understood colloquially to refer to a single power plant, which may have one or more EGUs co-located within the plant's boundaries.

of reasonable cost for these sources due to the relatively short period over which they could amortize the capital costs of controls.

In particular, in developing the emission guidelines, the EPA evaluated two systems of emission reduction that achieve substantial emission reductions for coal-fired steam generating units: CCS with 90 percent capture; and natural gas co-firing at 40 percent of heat input. For CCS, the EPA has determined that controls can be installed and fully operational by the compliance date of January 1, 2032, as detailed in section VII.C.1.a.i(E) of this preamble. CCS would therefore, in most cases, be unavailable to coal-fired steam generating units planning to cease operation prior to that date. Furthermore, the EPA evaluated the costs of CCS for different amortization periods. For an amortization period of more than 7 years—such that sources operate after January 1, 2039—annualized fleet average costs are comparable to or less than the costs of controls the EPA has previously determined to be reasonable ($18.50/MWh of generation and $98/ton of CO_2 reduced), as detailed in section VII.C.1.a.ii of this preamble. However, the costs for shorter amortization periods are higher. For sources ceasing operation by January 1, 2032, it would be unlikely that the annualized costs of CCS would be reasonable even were CCS installed at an earlier date (*e.g.,* by January 1, 2030) due to the shorter amortization period available.

Because the costs of CCS would be higher for shorter amortization periods, the EPA is finalizing a separate subcategory for sources demonstrating that they plan to permanently cease operating by January 1, 2039, with a BSER of 40 percent natural gas co-firing, as detailed in section VII.C.2.b.ii of this preamble. For natural gas co-firing, the EPA is finalizing a compliance date of January 1, 2030, as detailed in section VII.C.2.b.i(C) of this preamble. Therefore, the EPA assumes sources subject to a natural gas co-firing BSER can amortize costs for a period of up to 9 years. The EPA has determined that the costs of natural gas co-firing at 40 percent meet the metrics for cost reasonableness for the majority of the capacity that operate more than 2 years after the January 1, 2030, implementation date, *i.e.,* that operate after January 1, 2032 (and up to December 31, 2038), and that therefore have an amortization period of more than 2 years (and up to 9 years).

However, for sources ceasing operation prior to January 1, 2032, the EPA believes that establishing a best system of emission reduction corresponding to a substantial level of natural gas co-firing would broadly entail costs of control that are above those that the EPA is generally considering reasonable. Sources permanently ceasing operation before January 1, 2032 would have less than 2 years to amortize the capital costs, as detailed in section VII.C.2.a of this preamble. Compared to the metrics for cost reasonableness that EPA has previously deemed reasonable ($18.50/MWh of generation and $98/ton of CO_2 reduced), very few sources can co-fire 40 percent natural gas at costs comparable to these metrics with an amortization period of only one year; only 1 percent of units have costs that are below both $18.50/MWh of generation and $98/ton of CO_2 reduced. The number of sources that can co-fire lower amounts of natural gas at costs comparable to these metrics is likewise limited—only approximately 34 percent of units can co-fire with 20 percent natural gas at costs lower than both cost metrics. Furthermore, the period that these sources would operate with co-firing for would be short, so that the emission reductions from that group of sources would be limited.

By contrast, assuming a two-year amortization period, many more units can co-fire with meaningful amounts of natural gas at a cost that is consistent with the metrics EPA has previously used: 18 percent of units can co-fire with 40 percent natural gas at costs less than $98/ton and $18.50/MWh, and 50 percent of units can co-fire with 20 percent natural gas at costs lower than both metrics. Because a substantial number of sources can implement 40-percent co-firing with natural gas with an amortization period of two years or longer with reasonable costs, and even more can co-fire with lesser amounts with reasonable costs with amortization periods longer than two years,[270] the EPA determined that a technology-based BSER was available for coal-fired units operating past January 1, 2032.

Sources that retire before that date, however, are differently situated as described above. In light of the small number of sources that are planning to retire before January 1, 2032 that could cost-effectively co-fire with natural gas, coupled with the small amount of emissions reductions that can be achieved from co-firing in such a short time span, the EPA is choosing not to establish a BSER for these sources.[271]

Because, at this time, the EPA has determined that CCS and natural gas co-firing are not available at reasonable cost for sources ceasing operation before January 1, 2032, the EPA is not finalizing a BSER for such sources. Not finalizing a BSER for these sources is consistent with the Agency's discretion to take incremental steps to address CO_2 from sources in the category, and to direct the EPA's limited resources at regulation of those sources that can achieve the most emission reductions. The EPA is therefore providing that existing coal-fired steam generating EGUs that have elected to cease operating before January 1, 2032, are not regulated by these emission guidelines. This exemption applies to a source until the earlier of December 31, 2031, or the date it demonstrates in the state plan that it plans to cease operation. If a source continues to operate past this date, it is no longer exempt from these emission guidelines. See section X.E.1 of this preamble for discussion of how state plans should address sources subject to exemption (9).[272]

3. Sources Outside of the Contiguous U.S.

The EPA proposed the same emission guidelines for fossil fuel-fired steam

[270] As described in detail in section X.C.2 of this preamble, the EPA recognizes that particular affected EGUs may have characteristics that make it unreasonable to achieve the degree of emission limitation corresponding to 40 percent co-firing with natural gas. For example, a state may be able to demonstrate a fundamental difference between the costs the EPA considered in these emission guidelines and the costs to an affected EGU that plans to cease operation in late 2032. If such costs make it unreasonable for a particular unit to meet the degree of emission limitation corresponding to 40 percent co-firing with natural gas, the state may apply a less stringent standard of performance to that unit. Consistent with the requirements for calculating a less stringent standard of performance at 40 CFR 60.24a(f), under these emission guidelines states would consider whether it is reasonable for units that cannot cost-reasonably co-fire natural gas at 40 percent to co-fire at levels lower than 40 percent. It is thus appropriate that coal-fired EGUs that can reasonably co-fire any amount of natural gas be subject to these emission guidelines.

[271] For the reasons described at length in section VI.B, the EPA does not believe that heat rate improvement measures or HRI are appropriate for sources retiring before January 1, 2032 because HRI applied to coal-fired sources achieve few emission reductions, and can lead to the "rebound effect" where CO_2 emissions from the source increase rather than decrease as a consequence of imposing the technologies.

[272] The EPA notes that this applicability exemption does not conflict with states' ability to consider the remaining useful lives of "particular" sources that are subject to these emission guidelines. 42 U.S.C. 7411(d)(1). As the EPA's implementing regulations specify, the provision for states' consideration of RULOF is intended address the specific conditions of particular sources, whereas the EPA is responsible for determining generally how to regulate a source category under an emission guideline. Moreover, RULOF applies only to when a state is applying a standard of performance to an affected source—and the state would not apply a standard of performance to exempted sources.

generating units in non-continental areas (*i.e.,* Hawaii, the U.S. Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA proposed for comparable units in the contiguous 48 states. The EPA notes that the modeling that supports the final emission guidelines focus on sources in the contiguous U.S. Further, the EPA notes that few, if any, coal-fired steam generating units operate outside of the contiguous 48 states and meet the applicability criteria. Finally, the EPA notes that the proposed BSER and degree of emissions limitation for non-continental oil-fired steam generating units would have achieved few emission reductions. Therefore, the EPA is not finalizing emission guidelines for existing steam generating units in states and territories (including Alaska, Hawaii, Guam, Puerto Rico, and the U.S. Virgin Islands) that are outside of the contiguous U.S. at this time.

4. IGCC Units

The EPA notes that existing IGCC units were included in the proposed applicability requirements and that, in section VII.B of this preamble, the EPA is finalizing inclusion of those units in the subcategory of coal-fired steam generating units. IGCC units gasify coal or solid fossil fuel (*e.g.,* pet coke) to produce syngas (a mixture of carbon monoxide and hydrogen), and either burn the syngas directly in a combined cycle unit or use a catalyst for water-gas shift (WGS) to produce a pre-combustion gas stream with a higher concentration of CO_2 and hydrogen, which can be burned in a hydrogen turbine combined cycle unit. As described in section VII.C of this preamble, the final BSER for coal-fired steam generating units includes co-firing natural gas and CCS. The few IGCC units that now operate in the U.S. either burn natural gas exclusively—and as such operate as natural gas combined cycle units—or in amounts near to the 40 percent level of the natural gas co-firing BSER. Additionally, IGCC units may be suitable for pre-combustion CO_2 capture. Because the CO_2 concentration in the pre-combustion gas, after WGS, is high relative to coal-combustion flue gas, pre-combustion CO_2 capture for IGCC units can be performed using either an amine-based (or other solvent-based) capture process or a physical absorption capture process. Alternatively, post-combustion CO_2 capture can be applied to the source. The one existing IGCC unit that still uses coal was recently awarded funding from DOE for a front-end engineering design (FEED) study for CCS targeting a capture efficiency of more than 95 percent.[273] For these reasons, the EPA is not distinguishing IGCC units from other coal-fired steam generating EGUs, so that the BSER of co-firing for medium-term coal-fired units and CCS for long-term coal-fired units apply to IGCC units.[274]

5. Fossil Fuel-Type Definitions for Subcategories of Steam Generating Units

In this action, the EPA is finalizing definitions for subcategories of existing fossil fuel-fired steam generating units based on the type and amount of fossil fuel used in the unit. The EPA is finalizing separate subcategories based on fuel type because the carbon content of the fuel combusted affects the output emission rate (*i.e.,* lb CO_2/MWh). Fuels with a higher carbon content produce a greater amount of CO_2 emissions per unit of fuel combusted (on a heat input basis, MMBtu) and per unit of electricity generated (*i.e.,* MWh).

The EPA proposed fossil fuel type subcategory definitions based on the definitions in 40 CFR part 63, subpart UUUUU, and the fossil fuel definitions in 40 CFR part 60, subpart TTTT. Those proposed definitions were determined by the relative heat input contribution of the different fuels combusted in a unit during the 3 years prior to the proposed compliance date of January 1, 2030. Further, to be considered an oil-fired or natural gas-fired unit for purposes of this emission guideline, a source would no longer retain the capability to fire coal after December 31, 2029.

The EPA proposed a 3-year lookback period, so that the proposed fuel-type subcategorization would have been based, in part, on the fuel type fired between January 1, 2027, and January 1, 2030. However, the intent of the proposed fuel type subcategorization was to base the fuel type definition on the state of the source on January 1, 2030. Therefore, the EPA is finalizing the following fuel type subcategory definitions:

- A *coal-fired steam generating unit* is an electric utility steam generating unit or IGCC unit that meets the definition of ''fossil fuel-fired'' and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029, or that retains the capability to fire coal after December 31, 2029.
- An *oil-fired steam generating unit* is an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns oil for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.
- A *natural gas-fired steam generating unit* is an electric utility steam generating unit meeting the definition of ''fossil fuel-fired,'' that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.

The EPA received some comments on the fuel type definitions. Those comments and responses are as follows.

Comment: Some industry stakeholders suggested changes to the proposed definitions for fossil fuel type. Specifically, some commenters requested that the reference to the initial compliance date be removed and that the fuel type determination should instead be rolling and continually update after the initial compliance date. Those commenters suggested this would, for example, allow sources in the coal-fired subcategory that begin natural gas co-firing in 2030 to convert to the natural-gas fired subcategory prior to the proposed date of January 1, 2040, instead of ceasing operation.

Other industry commenters suggested that to be a natural gas-fired steam generating unit, a source could either meet the heat input requirements during the 3 years prior to the compliance date *or* (emphasis added) no longer retain the capability to fire coal after December 31, 2029. Those commenters noted that, as proposed, a source that had planned to convert to 100 percent natural gas-firing would essentially have to do so prior to January 1, 2027, to meet the proposed heat input-based definition, in addition to removing the capability to fire coal by the compliance date.

[273] Duke Edwardsport DOE FEED Study Fact Sheet. *https://www.energy.gov/sites/default/files/2024-01/OCED_CCFEEDs_AwardeeFactSheet_Duke_1.5.2024.pdf.*

[274] For additional details on pre-combustion CO_2 capture, please see the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

Response: Although full natural gas conversions are not a measure that the EPA considered as a potential BSER, the emission guidelines do not prohibit such conversions should a state elect to require or accommodate them. As noted above, the EPA recognizes that many steam EGUs that formerly utilized coal as a primary fuel have fully or partially converted to natural gas, and that additional steam EGUs may elect to do so during the implementation period for these emission guidelines. However, these emission guidelines place reasonable constraints on the timing of such a conversion in situations where a source seeks to be regulated as a natural gas-fired steam EGU rather than as a coal-fired steam EGU. The EPA believes that such constraints are necessary in order to avoid creating a perverse incentive for EGUs to defer conversions in a way that could undermine the emission reduction purpose of the rule. Therefore, the EPA disagrees with those commenters that suggest the EPA should, in general, allow EGUs to be regulated as natural gas-fired steam EGUs when they undertake such conversions past January 1, 2030.

However, the EPA acknowledges that the proposed subcategorization would have essentially required a unit to convert to natural gas by January 1, 2027 in order to be regulated as a natural gas-fired steam EGU. The EPA is finalizing fuel type subcategorization based on the state of the source on the compliance date of January 1, 2030, and during any period thereafter, as detailed in section VII.B of this preamble. Should a source not be able to fully convert to natural gas by this date, it would be treated as a coal-fired steam generating EGU; however, the state may be able to use the RULOF provisions, as discussed in section X.C.2 of this preamble, to particularize a standard of performance for the unit. Note that if a state relies on operating conditions within the control of the source as the basis of providing a less stringent standard of performance or longer compliance schedule, it must include those operating conditions as an enforceable requirement in the state plan. 40 CFR 60.24a(g).

C. Rationale for the BSER for Coal-Fired Steam Generating Units

This section of the preamble describes the rationale for the final BSERs for existing coal-fired steam generating units based on the criteria described in section V.C of this preamble.

At proposal, the EPA evaluated two primary control technologies as potentially representing the BSER for existing coal-fired steam generating units: CCS and natural gas co-firing. For sources operating in the long-term, the EPA proposed CCS with 90 percent capture as BSER. For sources operating in the medium-term (*i.e.,* those demonstrating that they plan to permanently cease operation by January 1, 2040), the EPA proposed 40 percent natural gas co-firing as BSER. For imminent-term and near-term sources ceasing operation earlier, the EPA proposed BSERs of routine methods of operation and maintenance.

The EPA is finalizing CCS with 90 percent capture as BSER for coal-fired steam generating units because CCS can achieve a substantial amount of emission reductions and satisfies the other BSER criteria. CCS has been adequately demonstrated and results in by far the largest emissions reductions of the available control technologies. As noted below, the EPA has also determined that the compliance date for CCS is January 1, 2032. CCS, however, entails significant up-front capital expenditures that are amortized over a period of years. The EPA evaluated the cost for different amortization periods, and the EPA has concluded that CCS is cost-reasonable for units that operate past January 1, 2039. As noted in section IV.D.3.b of this preamble, about half (87 GW out of 181 GW) of all coal-fired capacity currently in existence has announced plans to permanently cease operations by January 1, 2039, and additional sources are likely to do so because they will be older than the age at which sources generally have permanently ceased operations since 2000. The EPA has determined that the remaining sources that may operate after January 1, 2039, can, on average, install CCS at a cost that is consistent with the EPA's metrics for cost reasonableness, accounting for an amortization period for the capital costs of more than 7 years, as detailed in section VII.C.1.a.ii of this preamble. If a particular source has costs of CCS that are fundamentally different from those amounts, the state may consider it to be a candidate for a different control requirement under the RULOF provision, as detailed in section X.C.2 of this preamble. For the group of sources that permanently cease operation before January 1, 2039, the EPA has concluded that CCS would in general be of higher cost, and therefore is finalizing a subcategory for these units, termed medium-term units, and finalizing 40 percent natural gas co-firing on a heat input basis as the BSER.

These final subcategories and BSERs are largely consistent with the proposal, which included a long-term subcategory for sources that did not plan to permanently cease operations by January 1, 2040, with 90 percent capture CCS as the BSER; and a medium-term subcategory for sources that permanently cease operations by that date and were not in any of the other proposed subcategories, discussed next, with 40 percent co-firing as the BSER. For both subcategories, the compliance date was January 1, 2030. The EPA also proposed an imminent-term subcategory, for sources that planned to permanently cease operations by January 1, 2032; and a near-term subcategory, for sources that planned to permanently case operations by January 1, 2035, and that limited their annual capacity utilization to 20 percent. The EPA proposed a BSER of routine methods of operation and maintenance for these two subcategories.

The EPA is not finalizing these imminent-term and near-term subcategories. In addition, after considering the comments, the EPA acknowledges that some additional time from what was proposed may be beneficial for the planning and installation of CCS. Therefore, the EPA is finalizing a January 1, 2032, compliance date for long-term existing coal-fired steam generating units. As noted above, the EPA's analysis of the costs of CCS also indicates that CCS is cost-reasonable with a minimum amortization period of seven years; as a result, the final emission guidelines would apply a CCS-based standard only to those units that plan to operate for at least seven years after the compliance deadline (*i.e.,* units that plan to remain in operation after January 1, 2039). For medium-term sources subject to a natural gas co-firing BSER, the EPA is finalizing a January 1, 2030, compliance date because the EPA has concluded that this provides a reasonable amount of time to begin co-firing, a technology that entails substantially less up-front infrastructure and, relatedly, capital expenditure than CCS.

1. Long-Term Coal-Fired Steam Generating Units

The EPA is finalizing CCS with 90 percent capture of CO_2 at the stack as BSER for long-term coal-fired steam generating units. Coal-fired steam generating units are the largest stationary source of CO_2 in the United States. Coal-fired steam generating units have higher emission rates than other generating technologies, about twice the emission rate of a natural gas combined cycle unit. Typically, even newer, more efficient coal-fired steam generating units emit over 1,800 lb CO_2/MWh-gross, while many existing coal-fired steam generating units have emission rates of 2,200 lb CO_2/MWh-gross or higher. As noted in section IV.B of this preamble, coal-fired sources emitted 909 MMT CO_2e in 2021, 59 percent of the GHG emissions from the power sector and 14 percent of the total U.S. GHG emissions—contributing more to U.S. GHG emissions than any other sector, aside from transportation road sources.[275] Furthermore, considering the sources in the long-term subcategory will operate longer than sources with shorter operating horizons, long-term coal-fired units have the potential to emit more total CO_2.

CCS is a control technology that can be applied at the stack of a steam generating unit, achieves substantial reductions in emissions and can capture and permanently sequester more than 90 percent of CO_2 emitted by coal-fired steam generating units. The technology is adequately demonstrated, given that it has been operated at scale and is widely applicable to these sources, and there are vast sequestration opportunities across the continental U.S. Additionally, the costs for CCS are reasonable, in light of recent technology cost declines and policies including the tax credit under IRC section 45Q. Moreover, the non-air quality health and environmental impacts of CCS can be mitigated and the energy requirements of CCS are not unreasonably adverse. The EPA's weighing of these factors together provides the basis for finalizing CCS as BSER for these sources. In addition, this BSER determination aligns with the caselaw, discussed in section V.C.2.h of the preamble, stating that CAA section 111 encourages continued advancement in pollution control technology.

At proposal, the EPA also evaluated natural gas co-firing at 40 percent of heat input as a potential BSER for long-term coal-fired steam generating units. While the unit level emission rate reductions of 16 percent achieved by 40 percent natural gas co-firing are appreciable, those reductions are substantially less than CCS with 90 percent capture of CO_2. Therefore, because CCS achieves more reductions at the unit level and is cost-reasonable, the EPA is not finalizing natural gas co-firing as the BSER for these units. Further, the EPA is not finalizing partial-CCS at lower capture rates (*e.g.,* 30 percent) because it achieves substantially fewer unit-level reductions at greater cost, and because CCS at 90 percent is achievable. Notably, the IRC section 45Q tax credit may not be available to defray the costs of partial CCS and the emission reductions would be limited. And the EPA is not finalizing HRI as the BSER for these units because of the limited reductions and potential rebound effect.

a. Rationale for CCS as the BSER for Long-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA explains the rationale for CCS as the BSER for existing long-term coal-fired steam generating units. This section discusses the aspects of CCS that are relevant for existing coal-fired steam generating units and, in particular, long-term units. As noted in section VIII.F.4.c.iv of this preamble, much of this discussion is also relevant for the EPA's determination that CCS is the BSER for new base load combustion turbines.

In general, CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Detailed descriptions of these components are provided in section VII.C.1.a.i of this preamble. As an overview, post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system, such as a utility boiler or combustion turbine. This technology is referred to as ''post-combustion capture'' because CO_2 is a product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. The exhaust gases from most combustion processes are at atmospheric pressure, contain somewhat dilute concentrations of CO_2, and are moved through the flue gas duct system by fans. To separate the CO_2 contained in the flue gas, most current post-combustion capture systems utilize liquid solvents—commonly amine-based solvents—in CO_2 scrubber systems using chemical absorption (or chemisorption).[276] In a chemisorption-based separation process, the flue gas is processed through the CO_2 scrubber and the CO_2 is absorbed by the liquid solvent. The CO_2-rich solvent is then regenerated by heating the solvent to release the captured CO_2.

The high purity CO_2 is then compressed and transported, generally through pipelines, to a site for geologic sequestration (*i.e.,* the long-term containment of CO_2 in subsurface geologic formations). Pipelines are subject to Federal safety regulations administered by PHMSA. Furthermore, sequestration sites are widely available across the nation, and the EPA has developed a comprehensive regulatory structure to oversee geologic sequestration projects and assure their safety and effectiveness.[277]

i. Adequately Demonstrated

In this section of the preamble, the EPA explains the rationale for finalizing its determination that 90 percent capture applied to long-term coal-fired steam generating units is adequately demonstrated. In this section, the EPA first describes how simultaneous operation of all components of CCS functioning in concert with one another has been demonstrated, including a commercial scale application on a coal-fired steam generating unit. The demonstration of the individual components of CO_2 capture, transport, and sequestration further support that CCS is adequately demonstrated. The EPA describes how demonstrations of CO_2 capture support that 90 percent capture rates are adequately demonstrated. The EPA further describes how transport and geologic sequestration are adequately demonstrated, including the feasibility of transport infrastructure and the broad availability of geologic sequestration reservoirs in the U.S.

(A) Simultaneous Demonstration of CO_2 Capture, Transport, and Sequestration

The EPA proposed that CCS was adequately demonstrated for applications on combustion turbines and existing coal-fired steam generating units.

On reviewing the available information, all components of CCS—CO_2 capture, CO_2 transport, and CO_2 sequestration—have been demonstrated concurrently, with each component operating simultaneously and in concert with the other components.

(1) Industrial Applications of CCS

Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s[278] and has been used in a variety of industrial applications for decades. For example, since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant at Searles Valley Minerals (Trona,

[275] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. U.S. Greenhouse Gas Emissions by Inventory Sector, 2021. https://cfpub.epa.gov/ghgdata/inventoryexplorer/index.html#iallsectors/allsectors/allgas/inventsect/current.*

[276] Other technologies may be used to capture CO_2, as described in the final TSDs, *GHG Mitigation Measures for Steam Generating Units* and the *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* available in the rulemaking docket.

[277] 80 FR 64549 (October 23, 2015).

[278] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

California).[279] Furthermore, thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[280] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with EOR.[281] There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under construction or in advanced stages of development.[282] This broad application of CCS demonstrates that the components of CCS have been successfully operated simultaneously. The Shute Creek Facility has a capture capacity of 7 million metric tons per year and has been in operation since 1986.[283] The facility uses a solvent-based process to remove CO_2 from natural gas, and the captured CO_2 is stored in association with EOR. Another example of CCS in industrial applications is the Great Plains Synfuels Plant has a capture capacity of 3 million metric tons per year and has been in operation since 2000.[284] [285] The Great Plains Synfuels Plant (Beulah, North Dakota) uses a solvent-based process to remove CO_2 from lignite-derived syngas, the CO_2 is transported by the Souris Valley pipeline, and stored underground in association with EOR in the Weyburn and Midale Oil Units in Saskatchewan, Canada. Over 39 million metric tons of CO_2 has been captured since 2000.

(2) Various CO_2 capture methods are used in industrial applications and are tailored to the flue gas conditions of a particular industry (see the TSD *GHG Mitigation Measures for Steam Generating Units* for details). Of those capture technologies, amine solvent-based capture has been demonstrated for removal of CO_2 from the post-combustion flue gas of fossil fuel-fired EGUs. The Quest CO_2 capture facility in Alberta, Canada, uses amine-based CO_2 capture retrofitted to three existing steam methane reformers at the Scotford Upgrader facility (operated by Shell Canada Energy) to capture and sequester approximately 80 percent of the CO_2 in the produced syngas.[286] Amine-solvents are also applied for post-combustion capture from fossil fuel fired EGUs. The Quest facility has been operating since 2015 and captures approximately 1 million metric tons of CO_2 per year.

Applications of CCS at Coal-Fired Steam Generating Units

For electricity generation applications, this includes operation of CCS at Boundary Dam Unit 3 in Saskatchewan, Canada. CCS at Boundary Dam Unit 3 includes capture of the CO_2 from the flue-gas of the fossil fuel-fired EGU, compression of the CO_2 onsite and transport via pipeline offsite, and storage of the captured CO_2 underground. Storage of the CO_2 captured at Boundary Dam primarily occurs via EOR. Moreover, CO_2 captured from Boundary Dam Unit 3 is also stored in a deep saline aquifer at the Aquistore Deep Saline CO_2 Storage Project, which has permanently stored over 550,000 tons of CO_2 to date.[287] Other demonstrations of CCS include the 240 MWe Petra Nova CCS project at the subbituminous coal-fired W.A. Parish plant in Texas, which, because it was EPAct05-assisted, we cite as useful in section VII.C.1.a.i(B)(2) of this preamble, but not essential, corroboration. See section VII.C.1.a.i(H)(1) for a detailed description of how the EPA considers information from EPAct05-assisted projects.

Commenters stated that that all constituent components of CCS—carbon capture, transportation, and sequestration—have not been adequately demonstrated in integrated, simultaneous operation. We disagree with this comment. The record described in the preceding shows that all components have been demonstrated simultaneously. Even if the record only included demonstration of the individual components of CCS, the EPA would still determine that CCS is adequately demonstrated as it would be reasonable on a technical basis that the individual components are capable of functioning together—they have been engineered and designed to do so, and the record for the demonstration of the individual components is based on decades of direct data and experience.

(B) CO_2 Capture Technology at Coal-Fired Steam Generating Units

The EPA is finalizing the determination that the CO_2 capture component of CCS has been adequately demonstrated at a capture efficiency of 90 percent, is technically feasible, and is achievable over long periods (*e.g.,* a year) for the reasons summarized here and detailed in the following subsections of this preamble. This determination is based, in part, on the demonstration of the technology at existing coal-fired steam generating units, including the commercial-scale installation at Boundary Dam Unit 3. The application of CCS at Boundary Dam follows decades of development of CO_2 capture for coal-fired steam generating units, as well as numerous smaller-scale demonstrations that have successfully implemented this technology. Review of the available information has also identified specific, currently available, minor technological improvements that can be applied today to better the performance of new capture plant retrofits, and which can assure that the capture plants achieve 90 percent capture. The EPA's determination that 90 percent capture of CO_2 is adequately demonstrated is further corroborated by EPAct05-assisted projects, including the Petra Nova project.

Moreover, several CCS retrofit projects on coal-fired steam generating units are in progress that apply the lessons from the prior projects and use solvents that achieve higher capture rates. Technology providers that supply those solvents and the associated process technologies have made statements concluding that the technology is commercially proven and available today and have further stated that those solvents achieve capture rates of 95 percent or greater. Technology providers have decades of experience and have done the work to responsibly scale up the technology over that time across a range of flue gas compositions. Taking all of those factors into consideration, and accounting for the operation and flue gas conditions of the affected sources, solvent-based capture will consistently achieve capture rates of 90 percent or greater for the fleet of long-term coal-fired steam generating units.

Various technologies may be used to capture CO_2, the details of which are described generally in section IV.C.1 of this preamble and in more detail in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* which is

[279] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[280] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[281] GHGRP US EPA. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[282] Carbon Capture and Storage in the United States. CBO. December 13, 2023. *https://www.cbo.gov/publication/59345.*

[283] *Id.*

[284] *https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/great-plains.*

[285] *https://co2re.co/FacilityData.*

[286] Quest Carbon Capture and Storage Project Annual Summary Report, Alberta Department of Energy: 2021. *https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2021.*

[287] Aquistore Project. *https://ptrc.ca/media/whats-new/aquistore-co2-storage-project-reached-+500000-tonnes-stored.*

available in the rulemaking docket.[288] For post-combustion capture, these technologies include solvent-based methods (*e.g.,* amines, chilled ammonia), solid sorbent-based methods, membrane filtration, pressure-swing adsorption, and cryogenic methods.[289] Lastly, oxy-combustion uses a purified oxygen stream from an air separation unit (often diluted with recycled CO_2 to control the flame temperature) to combust the fuel and produce a higher concentration of CO_2 in the flue gas, as opposed to combustion with oxygen in air which contains 80 percent nitrogen. The CO_2 can then be separated by the aforementioned CO_2 capture methods. Of the available capture technologies, solvent-based processes have been the most widely demonstrated at commercial scale for post-combustion capture and are applicable to use with either combustion turbines or steam generating units.

The EPA's identification of CCS with 90 percent capture as the BSER is premised, in part, on an amine solvent-based CO_2 system. Amine solvents used for carbon capture are typically proprietary, although non-proprietary solvents (*e.g.,* monoethanolamine, MEA) may be used. Carbon capture occurs by reactive absorption of the CO_2 from the flue gas into the amine solution in an absorption column. The amine reacts with the CO_2 but will also react with impurities in the flue gas, including SO_2. PM will also affect the capture system. Adequate removal of SO_2 and PM prior to the CO_2 capture system is therefore necessary. After pretreatment of the flue gas with conventional SO_2 and PM controls, the flue gas goes through a quencher to cool the flue gas and remove further impurities before the CO_2 absorption column. After absorption, the CO_2-rich amine solution passes to the solvent regeneration column, while the treated gas passes through a water and/or acid wash column to limit emission of amines or other byproducts. In the solvent regeneration column, the solution is heated (using steam) to release the absorbed CO_2. The released CO_2 is then compressed and transported offsite, usually by pipeline. The amine solution from the regenerating column is then cooled, a portion of the lean solvent is treated in a solvent reclaiming process to mitigate degradation of the solvent, and the lean solvent streams are recombined and sent back to the absorption column.

(1) Capture Demonstrations at Coal-Fired Steam Generating Units

(a) SaskPower's Boundary Dam Unit 3

SaskPower's Boundary Dam Unit 3, a 110 MW lignite-fired unit in Saskatchewan, Canada, was designed to achieve CO_2 capture rates of 90 percent using an amine-based post-combustion capture system retrofitted to the existing steam generating unit. The capture plant, which began operation in 2014, is the first full-scale CO_2 capture system retrofit on an existing coal-fired power plant. It uses the amine-based Shell CANSOLV® process, which includes an amine-based SO_2 scrubbing process and a separate amine-based CO_2 capture process, with integrated heat and power from the steam generating unit.[290]

After undergoing maintenance and design improvements in September and October of 2015 to address technical and mechanical challenges faced in its first year of operation, Boundary Dam Unit 3 completed a 72-hour test of its design capture rate (3,240 metric tons/day), and captured 9,695 metric tons of CO_2 or 99.7 percent of the design capacity (approximately 89.7 percent capture) with a peak rate of 3,341 metric tons/day.[291] However, the capture plant has not consistently operated at this total capture efficiency. In general, the capture plant ran less than 100 percent of the flue gas through the capture equipment and the coal-fired steam generating unit also operates when the capture plant is offline for maintenance. As a result, although the capture plant has consistently achieved 90 percent capture rates of the CO_2 in the processed slipstream, the amount of CO_2 captured was less than 90 percent of the total amount of CO_2 in the flue gas of the steam generating unit. Some of the reasons for this operation were due to the economic incentives and regulatory requirements of the project, while other reasons were due to technical challenges. The EPA has reviewed the record of CO_2 capture at Boundary Dam Unit 3. While Boundary Dam is in Canada and therefore not subject to this action, these technical challenges have been sufficiently overcome or are actively mitigated so that Boundary Dam has more recently been capable of achieving capture rates of 83 percent when the capture plant is online.[292] Furthermore, the improvements already employed and identified at Boundary Dam can be readily applied during the initial construction of a new CO_2 capture plant today.

The CO_2 captured at Boundary Dam is mostly used for EOR and CO_2 is also stored geologically in a deep saline reservoir at the Aquistore site.[293] The amount of flue gas captured is based in part on economic reasons (*i.e.,* to meet related contract requirements). The incentives for CO_2 capture at Boundary Dam beyond revenue from EOR have been limited to date, and there have been limited regulatory requirements for CO_2 capture at the facility. As a result, a portion (about 25 percent on average) of the flue gas bypasses the capture plant and is emitted untreated. However, because of increasing requirements to capture CO_2 in Canada, Boundary Dam Unit 3 has more recently pursued further process optimization.

Total capture efficiencies at the plant have also been affected by technical issues, particularly with the SO_2 removal system that is upstream of the CO_2 capture system. Operation of the SO_2 removal system affects downstream CO_2 capture and the amount of flue gas that can be processed. Specifically, fly ash (PM) in the flue gas at Boundary Dam Unit 3 contributed to fouling of SO_2 system components, particularly in the SO_2 reboiler and the demisters of the SO_2 absorber column. Buildup of scale in the SO_2 reboiler limited heat transfer and regeneration of the SO_2 scrubbing amine, and high pressure drop affected the flowrate of the SO_2 lean-solvent back to the SO_2 absorber. Likewise, fouling of the demisters in the SO_2 absorber column caused high pressure drop and restricted the flow of flue gas through the system, limiting the amount of flue gas that could be processed by the downstream CO_2 capture system. To address these technical issues, additional wash systems were added, including ''demister wash systems, a pre-scrubber flue gas inlet curtain spray wash system, flue gas cooler throat sprays, and a booster fan wash system.'' [294]

[288] Technologies to capture CO_2 are also discussed in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines.*

[289] For pre-combustion capture (as is applicable to an IGCC unit), syngas produced by gasification passes through a water-gas shift catalyst to produce a gas stream with a higher concentration of hydrogen and CO_2. The higher CO_2 concentration relative to conventional combustion flue gas reduces the demands (power, heating, and cooling) of the subsequent CO_2 capture process (*e.g.,* solid sorbent-based or solvent-based capture); the treated hydrogen can then be combusted in the unit.

[290] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191.*

[291] SaskPower Annual Report (2015–16). *https://www.saskpower.com/about-us/Our-Company/~/link.aspx?_id=29E795C8C20D48398EAB5E3273C256AD&_z=z.*

[293] Aquistore. *https://ptrc.ca/aquistore.*

[294] *Id.*

Such issues will definitively not occur in a different type of SO_2 removal system (*e.g.,* wet lime scrubber flue gas desulfurization, wet-FGD). SO_2 scrubbers have been successfully operated for decades across a large number of U.S. coal-fired sources. Of the coal-fired sources with planned operation after 2039, 60 percent have wet FGD and 23 percent have a dry FGD. In section VII.C.1.a.ii of this preamble, the EPA accounts for the cost of adding a wet-FGD for those sources that do not have an FGD.

To further mitigate fouling due to fly ash, the PM controls (electrostatic precipitators) at Boundary Dam Unit 3 were upgraded in 2015/2016 by adding switch integrated rectifiers. Of the coal-fired sources with planned operation after 2039, 31 percent have baghouses and 67 percent have electrostatic precipitators. Sources with baghouses have greater or more consistent degrees of emission control, and wet FGD also provides additional PM control.

Fouling at Boundary Dam Unit 3 also affected the heat exchangers in both the SO_2 removal system and the CO_2 capture system. Additional redundancies and isolations to those key components were added in 2017 to allow for online maintenance. Damage to the capture plant's CO_2 compressor resulted in an unplanned outage in 2021, and the issue was corrected.[295] The facility reported 98.3 percent capture system availability in the third quarter of 2023.[296]

Regular maintenance further mitigates fouling in the SO_2 and CO_2 absorbers, and other challenges (*e.g.,* foaming, biological fouling) typical of gas-liquid absorbers can be mitigated by standard procedures. According to the 2022 paper co-authored by the International CCS Knowledge Centre and SaskPower, ''[a] number of initiatives are ongoing or planned with the goal of eliminating flue gas bypass as follows: Since 2016, online cleaning of demisters has been effective at controlling demister pressure; Chemical cleans and replacement of fouled packing in the absorber towers to reduce pressure losses; Optimization of antifoam injection and other aspects of amine health, to minimize foaming potential; [and] Optimization of Liquid-to-Gas (L/G) ratio in the absorber and other process parameters,'' as well as other optimization procedures.[297] While foaming is mitigated by an antifoam injection regimen, the EPA further notes that the extent of foaming that could occur may be specific to the chemistry of the solvent and the source's flue gas conditions—foaming was not reported for MHI's KS–1 solvent when treating bituminous coal post-combustion flue gas at Petra Nova. Lastly, while biological fouling in the CO_2 absorber wash water and the SO_2 absorber caustic polisher has been observed, ''the current mitigation plan is to perform chemical shocking to remove this particular buildup.'' [298]

Based on the experiences of Boundary Dam Unit 3, key improvements can be implemented in future CCS deployments during initial design and construction. Improvements to PM and SO_2 controls can be made prior to operation of the CO_2 capture system. Where fly ash is present in the flue gas, wash systems can be installed to limit associated fouling. Additional redundancies and isolations of key heat-exchangers can be made to allow for in-line cleaning during operation. Redundancy of key equipment (*e.g.,* utilizing two CO_2 compressor trains instead of one) will further improve operational availability. A feasibility study for the Shand power plant, which is also operated by SaskPower, includes many such design improvements, at an overall cost that was less than the cost for Boundary Dam.[299]

(b) Other Coal-Fired Demonstrations

Several other projects have successfully demonstrated the capture component of CCS at electricity generating plants and other industrial facilities, some of which were previously noted in the discussion in the 2015 NSPS.[300] Since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant (Trona, California).[301] Amine-based carbon capture has further been demonstrated at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) coal-fired power plants, with the captured CO_2 being sold for use in the food processing industry.[302] At the 180 MW bituminous coal-fired Warrior Run plant, approximately 10 percent of the plant's CO_2 emissions (about 110,000 metric tons of CO_2 per year) has been captured since 2000 and sold to the food and beverage industry. AES's 320 MW Shady Point plant fires subbituminous and bituminous coal, and captured CO_2 from an approximate 5 percent slipstream (about 66,000 metric tons of CO_2 per year) from 2001 through around 2019.[303] These facilities, which have operated for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

(2) EPAct05-Assisted CO_2 Capture Projects at Coal-Fired Steam Generating Units [304]

(a) Petra Nova

Petra Nova is a 240 MW-equivalent capture facility that is the first at-scale application of carbon capture at a coal-fired power plant in the U.S. The system is located at the subbituminous coal-

[295] S&P Global Market Intelligence (January 6, 2022). Only still-operating carbon capture project battled technical issues in 2021. *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/only-still-operating-carbon-capture-project-battled-technical-issues-in-2021-68302671.*

[296] SaskPower (October 18, 2022). *BD3 Status Update: Q3 2023. https://www.saskpower.com/about-us/Our-Company/Blog/2023/BD3-Status-Update-Q3-2023.*

[297] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[298] Pradoo, P., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286503.*

[299] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

[300] 80 FR 64548–54 (October 23, 2015).

[301] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[302] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[303] Shady Point Plant (River Valley) was sold to Oklahoma Gas and Electric in 2019. *https://www.oklahoman.com/story/business/columns/2019/05/23/oklahoma-gas-and-electric-acquires-aes-shady-point-after-federal-approval/60454346007/.*

[304] In the 2015 NSPS, the EPA provided a legal interpretation of the constraints on how the EPA could rely on EPAct05-assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111. Under that legal interpretation, ''these provisions [in the EPAct05] . . . preclude the EPA from relying solely on the experience of facilities that received [EPAct05] assistance, but [do] not . . . preclude the EPA from relying on the experience of such facilities in conjunction with other information.'' As part of the rulemaking action here, the EPA incorporates the legal interpretation and discussion of these EPAct05 provisions with respect the appropriateness of considering facilities that received EPAct05 assistance in determining whether CCS is adequately demonstrated, as found in the 2015 NSPS, 80 FR 64509, 64541–43 (October 23, 2015), and the supporting response to comments, EPA–HQ–OAR–2013–0495–11861 at pgs.113–134.

fired W.A. Parish Generating Station in Thompsons, Texas, and began operation in 2017, successfully capturing and sequestering CO_2 for several years. The system was put into reserve shutdown (*i.e.,* idled) in May 2020, citing the poor economics of utilizing captured CO_2 for EOR at that time. On September 13, 2023, JX Nippon announced that the carbon capture facility at Petra Nova had been restarted.[305] A final report from the National Energy Technology Laboratory (NETL) details the success of the project and what was learned from this first-of-a-kind demonstration at scale.[306] The project used Mitsubishi Heavy Industry's proprietary KM–CDR Process®, a process that is similar to an amine-based solvent process but that uses a proprietary solvent. During its operation, the project successfully captured 92.4 percent of the CO_2 from the slip stream of flue gas processed with 99.08 percent of the captured CO_2 sequestered by EOR.

The amount of flue gas treated at Petra Nova was consistent with a 240 MW size coal-fired steam EGU. The properties of the flue gas—composition, temperature, pressure, density, flowrate, *etc.*—are the same as would occur for a similarly sized coal-firing unit. Therefore, Petra Nova corroborates that the capture equipment—including the CO_2 absorption column, solvent regeneration column, balance of plant equipment, and the solvent itself—work at commercial scale and can achieve capture rates of 90 percent.

The Petra Nova project did experience periodic outages that were unrelated to the CO_2 capture facility and do not implicate the basis for the EPA's BSER determination.[307] These include outages at either the coal-fired steam generating unit (W.A. Parish Unit 8) or the auxiliary combined cycle facility, extreme weather events (Hurricane Harvey), and the operation of the EOR site and downstream oil recovery and processing. Outages at the coal-fired steam generating unit itself do not compromise the reliability of the CO_2 capture plant or the plant's ability to achieve a standard of performance based on CCS, as there would be no CO_2 to capture. Outages at the auxiliary combined cycle facility are also not relevant to the EPA's BSER determination, because the final BSER is not premised on the CO_2 capture plant using an auxiliary combined cycle plant for steam and power. Rather, the final BSER assumes the steam and power come directly from the associated steam generating unit. Extreme weather events can affect the operation of any facility. Furthermore, the BSER is not premised on EOR, and it is not dependent on downstream oil recovery or processing. Outages attributable to the CO_2 capture facility were 41 days in 2017, 34 days in 2018, and 29 days in 2019—outages decreased year-on-year and were on average less than 10 percent of the year. Planned and unplanned outages are normal for industrial processes, including steam generating units.

Petra Nova experienced some technical challenges that were addressed during its first 3 years of operation.[308] One of these issues was leaks from heat exchangers due to the properties of the gasket materials—replacement of the gaskets addressed the issue. Another issue was vibration of the flue gas blower due to build-up of slurry and solids carryover. W.A. Parish Unit 8 uses a wet limestone FGD scrubber to remove SO_2, and the flue gas connection to the capture plant is located at the bottom of the duct running from the wet-FGD to the original stack. A diversion wall and collection drains were installed to mitigate solids and slurry carryover. Regular maintenance is required to clean affected components and reduce the amount of slurry carryover to the quencher. Solids and slurry carryover also resulted in calcium scale buildup on the flue gas blower. Although calcium concentrations were observed to increase in the solvent, impacts of calcium on the quencher and capture plant chemistry were not observed. Some scaling may have been occurring in the cooling section of the quencher and would have been addressed during a planned outage in 2020. Another issue encountered was scaling related to the CO_2 compressor intercoolers, compressor dehydration system, and an associated heat exchanger. The issue was determined to be due to a material incompatibility of the CO_2 compressor intercooler, and the components were replaced during a 2018 planned outage. To mitigate the scaling prior to the replacement of those components, the compressor drain was also rerouted to the reclaimer and a backup filtering system was also installed and used, both of which proved to be effective. Some decrease in performance was also observed in heat exchangers. The presence of cooling tower fill (a solid medium used to increase surface area in cooling towers) in the cooling water system exchangers may have impacted performance. It is also possible that there could have been some fouling in heat exchangers. Fill was planned to be removed and fouling checked for during regular maintenance. Petra Nova did not observe fouling of the CO_2 absorber packing or high pressure drops across the CO_2 absorber bed, and Petra Nova also did not report any foaming of the solvent. Even with the challenges that were faced, Petra Nova was never restricted in reaching its maximum capture rate of 5,200 tons of CO_2 per day, a scale that was substantially greater than Boundary Dam Unit 3 (approximately 3,600 tons of CO_2 per day).

(b) Plant Barry

Plant Barry, a bituminous coal-fired steam generating unit in Mobile, Alabama, began using the KM–CDR Process® in 2011 for a fully integrated 25 MWe CCS project with a capture rate of 90 percent.[309] The CCS project at Plant Barry captured approximately 165,000 tons of CO_2 annually, which was then transported via pipeline and sequestered underground in geologic formations.[310]

(c) Project Tundra

Project Tundra is a carbon capture project in North Dakota at the Milton R. Young Station lignite coal-fired power plant. Project Tundra will capture up to 4 million metric tons of CO_2 per year for permanent geologic storage. One planned storage site is collocated with the power plant and is already fully permitted, while permitting for a second nearby storage site is in progress.[311] An air permit for the capture facility has also been issued by North Dakota Department of Environmental Quality. The project is designed to capture CO_2 at a rate of about 95 percent of the treated flue gas.[312] The capture plant will treat the flue gas from the 455 MW Unit 2 and additional flue gas from the 250 MW Unit 1, and will treat an equivalent capacity of 530 MW.[313] The project began a final FEED study in February 2023 with planned completion

[305] JX Nippon Oil & Gas Exploration Corporation. *Restart of the large-scale Petra Nova Carbon Capture Facility in the U.S.* (September 2023). *https://www.nex.jx-group.co.jp/english/newsrelease/upload_files/20230913EN.pdf.*

[306] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[307] *Id.*

[308] *Id.*

[309] U.S. Department of Energy (DOE). National Energy Technology Laboratory (NETL). *https://www.netl.doe.gov/node/1741.*

[310] 80 FR 64552 (October 23, 2015).

[311] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[312] See Document ID No. EPA–HQ–OAR–2023–0072–0632.

[313] *Id.*

in April 2024,[314] and, prior to selection by DOE for funding award negotiation, the project was scheduled to begin construction in 2024.[315] The project will use MHI's KS–21 solvent and the Advanced KM–CDR process. The MHI solvent KS–1 and an advanced MHI solvent (likely KS–21) were previously tested on the lignite post-combustion flue gas from the Milton R. Young Station.[316] To provide additional conditioning of the flue gas, the project is utilizing a wet electrostatic precipitator (WESP). A draft Environmental Assessment summarizing the project and potential environmental impacts was released by DOE.[317] Finally, Project Tundra was selected for award negotiation for funding from DOE.[318]

That this project has funding through the Bipartisan Infrastructure Law, and that this funding is facilitated through DOE's Office of Clean Energy Demonstration's (OCED) Carbon Capture Demonstration Projects Program, does not detract from the adequate demonstration of CCS. Rather, the goal of that program is, ''to accelerate the implementation of integrated carbon capture and storage technologies and catalyze significant follow-on investments from the private sector to mitigate carbon emissions sources in industries across America.'' [319] For the commercial scale projects, the stated requirement of the funding opportunity announcement (FOA) is not that projects demonstrate CCS in general, but that they ''demonstrate significant improvements in the efficiency, effectiveness, cost, operational and environmental performance of existing carbon capture technologies.'' [320] This implies that the basic technology already exists and is already demonstrated. The FOA further notes that the technologies used by the projects receiving funding should be proven such that, ''the technologies funded can be readily replicated and deployed into commercial practice.'' [321] The EPA also notes that this and other on-going projects were announced well in advance of the FOA. Considering these factors, Project Tundra and other similarly funded projects are supportive of the determination that CCS is adequately demonstrated.

(d) Project Diamond Vault

Project Diamond Vault will capture up to 95 percent of CO_2 emissions from the 600 MW Madison Unit 3 at Brame Energy Center in Lena, Louisiana. Madison Unit 3 fires approximately 70 percent petroleum coke and 30 percent bituminous (Illinois Basin) coal in a circulating fluidized bed. The FEED study for the project is targeted for completion on September 9, 2024.[322] [323] Construction is planned to begin by the end of 2025 with commercial operation starting in 2028.[324] From the utility: ''Government Inflation Reduction Act (IRA) funding through 45Q tax credits makes the project financially viable. With these government tax credits, the company does not expect a rate increase as a result of this project.'' [325]

(e) Other Projects

Other projects have completed or are in the process of completing feasibility work or FEED studies, or are taking other steps towards installing CCS on coal-fired steam generating units. These projects are summarized in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket. In general, these projects target capture rates of 90 percent or above and provide evidence that sources are actively pursuing the installation of CCS.

(3) CO_2 Capture Technology Vendor Statements

CO_2 capture technology providers have issued statements supportive of the application of systems and solvents for CO_2 capture at fossil fuel-fired EGUs. These statements speak to the decades of experience that technology providers have and as noted below, vendors attest, and offer guarantees that 90 percent capture rates are achievable. Generally, while there are many CO_2 capture methods available, solvent-based CO_2 capture from post-combustion flue gas is particularly applicable to fossil fuel-fired EGUs. Solvent-based CO_2 capture systems are commercially available from technology providers including Shell, Mitsubishi Heavy Industries (MHI), Linde/BASF, Fluor and ION Clean Energy.

Technology providers have made statements asserting extensive experience in CO_2 capture and the commercial availability of CO_2 capture technologies. Solvent-based CO_2 capture was first patented in the 1930s.[326] Since then, commercial solvent-based capture systems have been developed that are focused on applications to post-combustion flue gas. Several technology providers have over 30 years of experience applying solvent-based CO_2 capture to the post-combustion flue gas of fossil fuel-fired EGUs. In general, technology providers describe the technologies for CO_2 capture from post-combustion flue gas as ''proven'' or ''commercially available'' or ''commercially proven'' or ''available now'' and describe their experience with CO_2 capture from post-combustion flue gas as ''extensive.'' CO_2 capture rates of 90 percent or higher from post-combustion flue gas have been proven by CO_2 capture technology providers using several commercially available solvents. Many of the available solvent technologies have over 50,000 hours of operation, equivalent to over 5 years of operation.

Shell has decades of experience in CO_2 capture systems. Shell notes that ''[c]apturing and safely storing carbon is an option that's available now.'' [327] Shell has developed the CANSOLV® CO_2 capture system for CO_2 capture from post-combustion flue gas, a regenerable amine that the company claims has multiple advantages including ''low parasitic energy consumption, fast kinetics and extremely low volatility.'' [328] Shell further notes, ''Moreover, the technology has been designed for

[314] ''An Overview of Minnkota's Carbon Capture Initiative—Project Tundra,'' 2023 LEC Annual Meeting, October 5, 2023.

[315] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[316] Laum, Jason. Subtask 2.4—Overcoming Barriers to the Implementation of Postcombustion Carbon Capture. *https://www.osti.gov/biblio/1580659.*

[317] DOE–EA–2197 Draft Environmental Assessment, August 17, 2023. *https://www.energy.gov/nepa/listings/doeea-2197-documents-available-download.*

[318] Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[319] DOE. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-program-front-end-engineering-design-feed-studies.*

[320] DE–FOA–0002962. *https://oced-exchange.energy.gov/FileContent.aspx?FileID=86c47d5d-835c-4343-86e8-2ba27d9dc119.*

[321] *Id.*

[322] Diamond Vault Carbon Capture FEED Study. *https://netl.doe.gov/sites/default/files/netl-file/23CM_PSCC31_Bordelon.pdf.*

[323] Note that while the FEED study is EPAct05-assisted, the capture plant is not.

[324] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[325] *Id.*

[326] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[327] Shell Global—Carbon Capture and Storage. *https://www.shell.com/energy-and-innovation/carbon-capture-and-storage.html.*

[328] Shell Global—CANSOLV® CO_2 Capture System. *https://www.shell.com/business-customers/catalysts-technologies/licensed-technologies/emissions-standards/tail-gas-treatment-unit/cansolv-co2.html.*

reliability through its highly flexible turn-up and turndown capacity.'' [329] The company has stated that ''Over 90% of the CO_2 in exhaust gases can be effectively and economically removed through the implementation of Shell's carbon capture technology.'' [330] Shell also notes, ''Systems can be guaranteed for bulk CO_2 removal of over 90%.'' [331]

MHI in collaboration with Kansai Electric Power Co., Inc. began developing a solvent-based capture process (the KM CDR Process™) using the KS–1™ solvent in 1990.[332] MHI describes the extensive experience of commercial application of the solvent, ''KS–1™—a solvent whose high reliability has been confirmed by a track record of deliveries to 15 commercial plants worldwide.'' [333] Notable applications of KS–1™ and the KM–CDR Process™ include applications at Plant Barry and Petra Nova. Previously, MHI has achieved capture rates of greater than 90 percent over long periods and at full scale at the Petra Nova project where the KS–1™ solvent was used.[334] MHI has further improved on the original process and solvent by making available the Advanced KM CDR Process™ using the KS–21™ solvent. From MHI, ''Commercialization of KS–21™ solvent was completed following demonstration testing in 2021 at the Technology Centre Mongstad in Norway, one of the world's largest carbon capture demonstration facilities.'' [335] MHI has achieved CO_2 capture rates of 95 to 98 percent using both the KS–1™ and KS–21™ solvent at the Technology Centre Mongstad (TCM).[336] Higher capture rates under modified conditions were also measured, ''In addition, in testing conducted under modified operating conditions, the KS–21™ solvent delivered an industry-leading carbon capture rate was 99.8% and demonstrated the successful recovery of CO_2 from flue gas of lower concentration than the CO_2 contained in the atmosphere.'' [337]

Linde engineering in partnership with BASF has made available BASF's OASE® blue amine solvent technology for post-combustion CO_2 capture. Linde notes their experience: ''We have longstanding experience in the design and construction of chemical wash processes, providing the necessary amine-based solvent systems and the CO_2 compression, drying and purification system.'' [338] Linde also notes that ''[t]he BASF OASE® process is used successfully in more than 400 plants worldwide to scrub natural, synthesis and other industrial gases.'' [339] The OASE® blue technology has been successfully piloted at RWE Power, Niederaussem, Germany (from 2009 through 2017; 55,000 operating hours) and the National Center for Carbon Capture in Wilsonville, Alabama (January 2015 through January 2016; 3,200 operating hours). Based on the demonstrated performance, Linde concludes that ''PCC plants combining Linde's engineering skills and BASF's OASE® blue solvent technology are now commercially available for a wide range of applications.'' [340] Linde and BASF have demonstrated capture rates over 90 percent and operating availability [341] rates of more than 97 percent during 55,000 hours of operation.

Fluor provides a solvent technology (Econamine FG Plus) and EPC services for CO_2 capture. Fluor describes their technology as ''proven,'' noting that, ''Proven technology. Fluor Econamine FG Plus technology is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation.'' [342] Fluor further notes, ''The technology builds on Fluor's more than 400 CO_2 removal units in natural gas and synthesis gas processing.'' [343] Fluor further states, ''Fluor is a global leader in CO_2 capture [. . .] with long-term commercial operating experience in CO_2 recovery from flue gas.'' On the status of Econamine FG Plus, Fluor notes that the ''[the] Technology [is] commercially proven on natural gas, coal, and fuel oil flue gases,'' and further note that ''[o]perating experience includes using steam reformers, gas turbines, gas engines, and coal/natural gas boilers.''

ION Clean Energy is a company focused on post-combustion carbon capture founded in 2008. ION's ICE–21 solvent has been used at NCCC and TCM Norway.[344] ION has achieved capture rates of 98 percent using the ICE–31 solvent.

(4) CCS User Statements on CCS

A number of the companies who have either completed large scale pilot projects or who are currently developing full scale projects have also indicated that CCS technology is currently a viable technology for large coal-fired power plants. In 2011, announcing a decision not to move forward with the first full scale commercial CCS installation of a carbon capture system on a coal plant, AEP did not cite any technology concerns, but rather indicated that ''it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place.'' [345] Enchant Energy, a company developing CCS for coal-fired power plants explained that its FEED study for the San Juan Generating Station, ''shows that the technical and business case for adding carbon capture to existing coal-fired power plants is strong.'' [346] Rainbow Energy, who is developing a carbon capture project at the Coal Creek Power Station in North Dakota explains, ''CCUS technology has been proven and is an economical option for a facility like Coal Creek Station. We see CCUS as the best option to manage CO_2 emissions at our facility.'' [347]

(5) State CCS Requirements

Several states encourage or even require sources to install CCS. These state requirements further indicate that CCS is well-established and effective. These state laws include the Illinois 2021 Climate and Equitable Jobs Act, which requires privately owned coal-

[329] Shell Catalysts & Technologies—Shell CANSOLV® CO_2 Capture System. *https://catalysts.shell.com/en/Cansolv-co2-fact-sheet.*

[330] *Id.*

[331] *Id.*

[332] Mitsubishi Heavy Industries—CO_2 Capture Technology—CO_2 Capture Process. *https://www.mhi.com/products/engineering/co2plants_process.html.*

[333] *Id.*

[334] Note: Petra Nova is an EPAct05-assisted project. W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[335] *Id.*

[336] Mitsubishi Heavy Industries, ''Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New KS–21™ Solvent for CO_2 Capture,'' *https://www.mhi.com/news/211019.html.*

[337] *Id.*

[338] Linde Engineering—Post Combustion Capture. *https://www.linde-engineering.com/en/process-plants/co2-plants/carbon-capture/post-combustion-capture/index.html.*

[339] Linde and BASF—Carbon capture storage and utilisation. *https://www.linde-engineering.com/en/images/Carbon-capture-storage-utilisation-Linde-BASF_tcm19-462558.pdf.*

[340] *Id.*

[341] Operating availability is the percent of time that the CO_2 capture equipment is available relative to its planned operation.

[342] Fluor—Comprehensive Solutions for Carbon Capture. *https://www.fluor.com/client-markets/energy/production/carbon-capture.*

[343] Fluor—Econamine FG Plus℠. *https://www.fluor.com/sitecollectiondocuments/qr/econamine-fg-plus-brochure.pdf.*

[344] ION Clean Energy—Company. *https://www.ioncleanenergy.com/company.*

[345] *https://www.aep.com/news/releases/read/1206/AEP-Places-Carbon-Capture-Commercialization-On-Hold-Citing-Uncertain-Status-Of-Climate-Policy-Weak-Economy.*

[346] Enchant Energy. What is Carbon Capture and Sequestration (CCS)? *https://enchantenergy.com/carbon-capture-technology/.*

[347] Rainbow Energy Center. Carbon Capture. *https://rainbowenergycenter.com/what-we-do/carbon-capture/.*

fired units to reduce emissions to zero by 2030 and requires publicly owned coal-fired units to reduce emissions to zero by 2045.[348] Illinois has also imposed CCS-based CO_2 emission standards on new coal-fired power plants since 2009 when the state adopted its Clean Coal Portfolio Standard law.[349] The statute required an initial capture rate of 50 percent when enacted but steadily increased the capture rate requirement to 90 percent in 2017, where it remains.

Michigan in 2023 established a 100 percent clean energy requirement by 2040 with a nearer term 80 percent clean energy by 2035 requirement.[350] The statute encourages the application of CCS by defining ''clean energy'' to include generation resources that achieve 90 percent carbon capture.

California identifies carbon capture and sequestration as a necessary tool to reduce GHG emissions within its 2022 scoping plan update [351] and, that same year, enacted a statutory requirement through Assembly Bill 1279 [352] requiring the state to plan and implement policies that enable carbon capture and storage technologies.

Several states in different parts of the country have adopted strategic and planning frameworks that also encourage CCS. Louisiana, which in 2020 set an economy-wide net-zero goal by 2050, has explored policies that encourage CCS deployment in the power sector. The state's 2022 Climate Action Plan proposes a Renewable and Clean Portfolio Standard requiring 100 percent renewable or clean energy by 2035.[353] That proposal defines power plants achieving 90 percent carbon capture as a qualifying clean energy resource that can be used to meet the standard.

Pennsylvania's 2021 Climate Action Plan notes that the state is well positioned to install CCS to transition the state's electric fleet to a zero-carbon economy.[354] The state also established an interagency workgroup in 2019 to identify ways to speed the deployment of CCS.

The Governor of North Dakota announced in 2021 an economy-wide carbon neutral goal by 2030.[355] The announcement singled out the Project Tundra Initiative, which is working to apply CCS technology to the state's Milton R. Young Power Station.

The Governor of Wyoming has broadly promoted a Decarbonizing the West initiative that includes the study of CCS technologies to reduce carbon emissions from the region.[356] A 2024 Wyoming law also requires utilities in the state to install CCS technologies on a portion of their existing coal-fired power plants by 2033.[357]

(6) Variable Load and Startups and Shutdowns

In this section of the preamble, the EPA considers the effects of variable load and startups and shutdowns on the achievability of 90 percent capture. First, the coal-fired steam generating unit can itself turndown [358] to only about 40 percent of its maximum design capacity. Due to this, coal-fired EGUs have relatively high duty cycles [359]—that is, they do not cycle as frequently as other sources and typically have high average loads when operating. In 2021, coal-fired steam generating units had an average duty cycle of 70 percent, and more than 75 percent of units had duty cycles greater than 60 percent.[360] Prior demonstrations of CO_2 capture plants on coal-fired steam generating units have had turndown limits of approximately 60 percent of throughput for Boundary Dam Unit 3 [361] and about 70 percent throughput for Petra Nova.[362] Based on the technology currently available, turndown to throughputs of 50 percent [363] are achievable for a single capture train.[364] Considering that coal units can typically only turndown to 40 percent, a 50 percent turndown ratio for the CO_2 capture plant is likely sufficient for most sources, although utilizing two CO_2 capture trains would allow for turndown to as low as 25 percent of throughput. When operating at less than maximum throughputs, the CO_2 capture facility actually achieves higher capture efficiencies, as evidenced by the data collected at Boundary Dam Unit 3.[365] Data from the Shand Feasibility Report suggests that, for a solvent and design achieving 90 percent capture at 100 percent of net load, 97.5 percent capture is achievable at 62.5 percent of net load.[366] Considering these factors, CO_2 capture is, in general, able to meet the variable load of coal-fired steam generating units without any adverse impact on the CO_2 capture rate. In fact, operation at lower loads may lead to

[348] State of Illinois General Assembly. Public Act 102–0662: Climate and Equitable Jobs Act. 2021. *https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf.*

[349] State of Illinois General Assembly. Public Act 095–1027: Clean Coal Portfolio Standard Law. *https://www.ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf.*

[350] State of Michigan Legislature. Public Act 235 of 2023. Clean and Renewable Energy and Energy Waste Reduction Act. *https://legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf.*

[351] California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality. *https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.*

[352] State of California Legislature. Assembly Bill 1279 (2022). The California Climate Crisis Act. *https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1279.*

[353] Louisiana Climate Initiatives Task Force. Louisiana Climate Action Plan (February 1, 2022). *https://gov.louisiana.gov/assets/docs/CCI-Task-force/CAP/ClimateActionPlanFinal.pdf.*

[354] Pennsylvania Dept. of Environmental Protection. Pennsylvania Climate Action Plan (2021). *https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx.*

[355] *https://www.governor.nd.gov/news/updated-waudio-burgum-addresses-williston-basin-petroleum-conference-issues-carbon-neutral.*

[356] *https://westgov.org/initiatives/overview/decarbonizing-the-west.*

[357] State of Wyoming Legislature. SF0042. Low-carbon Reliable Energy Standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042.*

[358] Here, ''turndown'' is the ability of a facility to turn down some process value, such as flowrate, throughput or capacity. Typically, this is expressed as a ratio relative to operation at its maximum instantaneous capability. Because processes are designed to operate within specific ranges, turndown is typically limited by some lower threshold.

[359] Here, ''duty cycle'' is the ratio of the gross amount of electricity generated relative to the amount that could be potentially generated if the unit operated at its nameplate capacity during every hour of operation. Duty cycle is thereby an indication of the amount of cycling or load following a unit experiences (higher duty cycles indicate less cycling, *i.e.,* more time at nameplate capacity when operating). Duty cycle is different from capacity factor, as the latter also quantifies the amount that the unit spends offline.

[360] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data website: *https://campd.epa.gov.*

[361] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[362] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[363] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

[364] Here, a ''train'' in this context is a series of connected sequential process equipment. For carbon capture, a process train can include the quencher, absorber, stripper, and compressor. Rather than doubling the size of a single train of process equipment, a source could use two equivalent sized trains.

[365] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *Reducing the CO^2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[366] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

higher achievable capture rates over long periods of time.

Coal-fired steam generating units also typically have few startups and shutdowns per year, and CO_2 emissions during those periods are low. Although capacity factor has declined in recent years, as noted in section IV.D.3 of the preamble, the number of startups per year has been relatively stable. In 2011, coal-fired sources had about 10 startups on average. In 2021, coal-fired steam generating units had only 12 startups on average, see the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket. Prior to generation of electricity, coal-fired steam generating units use natural gas or distillate oil—which have a lower carbon content than coal—because of their ignition stability and low ignition temperature. Heat input rates during startup are relatively low, to slowly raise the temperature of the boiler. Existing natural gas- or oil-fired ignitors designed for startup purposes are generally sized for up to 15 percent of the maximum heat-input. Considering the low heat input rate, use of fuel with a lower carbon content, and the relatively few startups per year, the contribution of startup to total GHG emissions is relatively low. Shutdowns are relatively short events, so that the contribution to total emissions are also low. The emissions during startup and shutdown are therefore small relative to emissions during normal operation, so that any impact is averaged out over the course of a year.

Furthermore, the IRC section 45Q tax credit provides incentive for units to operate more. Sources operating at higher capacity factors are likely to have fewer startups and shutdowns and spend less time at low loads, so that their average load would be higher. This would further minimize the insubstantial contribution of startups and shutdowns to total emissions. Additionally, as noted in the preceding sections of the preamble, new solvents achieve capture rates of 95 percent at full load, and ongoing projects are targeting capture rates of 95 percent. Considering all of these factors, startup and shutdown, in general, do not affect the achievability of 90 percent capture over long periods (*i.e.,* a year).

(7) Coal Rank

CO_2 capture at coal-fired steam generating units achieves 90 percent capture, for the reasons detailed in sections VII.C.1.a.i(B)(1) through (6) of this preamble. Moreover, 90 percent capture is achievable for all coal types because amine solvents have been used to remove CO_2 from a variety of flue gas compositions including a broad range of different coal ranks, differences in CO_2 concentration are slight and the capture process can be designed to the appropriate scale, amine solvents have been used to capture CO_2 from flue gas with much lower CO_2 concentrations, and differences in flue gas impurities due to different coal compositions can be managed or mitigated by controls.

As detailed in the preceding sections, CO_2 capture has been operated on flue gas from the combustion of a broad range of coal ranks including lignite, bituminous, subbituminous, and anthracite coals. Post-combustion CO_2 capture from the flue gas of an EGU firing lignite has been demonstrated at the Boundary Dam Unit 3 EGU (Saskatchewan, Canada). Most lignites have a higher ash and moisture content than other coal types and, in that respect, the flue gas can be more challenging to manage for CO_2 capture. Amine CO_2 capture has also been used to treat lignite post-combustion flue gas in pilot studies at the Milton R. Young station (North Dakota).[367] CO_2 capture solvents have been used to treat subbituminous post-combustion flue gas from W.A. Parish Generating Station (Texas),[368] and the bituminous post-combustion flue gas from Plant Barry (Mobile, Alabama),[369] Warrior Run (Maryland),[370] and Argus Cogeneration Plant (California).[371] Amine solvents have also been used to remove CO_2 from the flue gas of the bituminous- and subbituminous-fired Shady Point plant.[372] CO_2 capture solvents have been used to treat anthracite post-combustion flue gas at the Wilhelmshaven power plant (Germany).[373] There are also ongoing projects that will apply CCS to the flue gas of coal-fired steam generating units. The EPA considers these ongoing projects to be indicative of the confidence that industry stakeholders have in CCS. These include Project Tundra at the lignite-fired Milton R. Young station (North Dakota),[374] Project Diamond Vault at the petroleum coke- and subbituminous-fired Brame Energy Center Madison Unit 3 (Louisiana)[375] and two units at the Jim Bridger Plant (Wyoming).[376]

Different coal ranks have different carbon contents, affecting the concentration of CO_2 in flue gas. In general, however, CO_2 concentration of coal combustion flue gas varies only between 13 and 15 percent. Differences in CO_2 concentration can be accounted for by appropriately designing the capture equipment, including sizing the absorber columns. As detailed in section VIII.F.4.c.iv of the preamble, CO_2 has been captured from the post-combustion flue gas of NGCCs, which typically have a CO_2 concentration of 4 percent.

Prior to emission controls and pre-conditioning, characteristics of different coal ranks and boiler design result in other differences in the flue gas composition, including in the concentration of SO_2, NO_X, PM, and trace impurities. Such impurities in the flue gas can react with the solvent or cause fouling of downstream processes. However, in general, most existing coal-fired steam generating units in the U.S. have controls that are necessary for the pre-conditioning of flue gas prior to the CO_2 capture plant, including PM and SO_2 controls. For those sources without an FGD for SO_2 control, the EPA included the costs of adding an FGD in its cost analysis. Other marginal differences in flue gas impurities can be managed by appropriately designing the polishing column (direct contact cooler) for the individual source's flue gas. Trace impurities can be mitigated using conventional controls in the solvent reclaiming process (*e.g.,* an activated carbon bed).

Considering the broad range of coal post-combustion flue gases amine solvents have been operated with, that solvents capture CO_2 from flue gases with lower CO_2 concentrations, that the capture process can be designed for different CO_2 concentrations, and that flue gas impurities that may differ by coal rank can be managed by controls, the EPA therefore concludes that 90 percent capture is achievable across all coal ranks, including waste coal.

[367] Laum, Jason. Subtask 2.4—Overcoming Barriers to the Implementation of Postcombustion Carbon Capture. *https://www.osti.gov/biblio/1580659.*

[368] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[369] U.S. Department of Energy (DOE). National Energy Technology Laboratory (NETL). *https://www.netl.doe.gov/node/1741.*

[370] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[371] *Id.*

[372] *Id.*

[373] Reddy, *et al.* Energy Procedia, 37 (2013) 6216–6225.

[374] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[375] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[376] 2023 Integrated Resource Plan Update, PacifiCorp, April 1, 2024, *https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023_IRP_Update.pdf.*

(8) Natural Gas-Fired Combustion Turbines

Additional information supporting the EPA's determination that 90 percent capture of CO_2 from steam generating units is adequately demonstrated is the experience from CO_2 capture from natural gas-fired combustion turbines. The EPA describes this information in section VIII.F.4.c.iv(B)(1), including explaining how information about CO_2 capture from coal-fired steam generating units also applies to natural gas-fired combustion turbines. The reverse is true as well; information about CO_2 capture from natural gas-fired turbines can be applied to coal fired-units, for much the same reasons.

(9) Summary of Evidence Supporting BSER Determination Without EPAct05-Assisted Projects

As noted above, under the EPA's interpretation of the EPAct05 provisions, the EPA may not rely on capture projects that received assistance under EPAct05 as the sole basis for a determination of adequate demonstration, but the EPA may rely on those projects to support or corroborate other information that supports such a determination. The information described above that supports the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated, without consideration of the EPAct05-assisted projects, includes (i) the information concerning Boundary Dam, coupled with engineering analysis concerning key improvements that can be implemented in future CCS deployments during initial design and construction (*i.e.,* all the information in section VII.C.1.a.i.(B)(1)(a) and the information concerning Boundary Dam in section VII.C.1.a.i.(B)(1)(b)); (ii) the information concerning other coal-fired demonstrations, including the Argus Cogeneration Plant and AES's Warrior Run (*i.e.,* all the information concerning those sources in section VII.C.1.a.i.(B)(1)(a)); (iii) the information concerning industrial applications of CCS (*i.e.,* all the information in section VII.C.1.a.i.(A)(1); (iv) the information concerning CO_2 capture technology vendor statements (*i.e.,* all the information in section VII.C.1.a.i.(B)(3)); (v) information concerning carbon capture at natural gas-fired combustion turbines other than EPAct05-assisted projects (*i.e.,* all the information other than information about EPAct05-assisted projects in section VIII.F.4.c.iv.(B)(1)). All this information by itself is sufficient to support the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated. Substantial additional information from EPAct05-assisted projects, as described in section VII.C.1.a.i.(B), provides additional support and confirms that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated.

(C) CO_2 Transport

The EPA is finalizing its determination that CO_2 transport by pipelines as a component of CCS is adequately demonstrated. The EPA anticipates that in the coming years, a large-scale interstate pipeline network may develop to transport CO_2. Indeed, PHMSA is currently engaged in a rulemaking to update and strengthen its safety regulations for CO_2 pipelines, which assumes that such a pipeline network will develop.[377] For purposes of determining the CCS BSER in this final action, however, the EPA did not base its analysis of the availability of CCS on the projected existence of a large-scale interstate pipeline network. Instead, the EPA adopted a more conservative approach. The BSER is premised on the construction of relatively short lateral pipelines that extend from the source to the nearest geologic storage reservoir. While the EPA anticipates that sources would likely avail themselves of an existing interstate pipeline network if one were constructed and that using an existing network would reduce costs, the EPA's analysis focuses on steps that an individual source could take to access CO_2 storage independently.

EGUs that do not currently capture and transport CO_2 will need to construct new CO_2 pipelines to access CO_2 storage sites, or make arrangements with pipeline owners and operators who can do so. Most coal-fired steam EGUs, however, are located in relatively close proximity to deep saline formations that have the potential to be used as long-term CO_2 storage sites.[378] Of existing coal-fired steam generating capacity with planned operation during or after 2039, more than 50 percent is located less than 32 km (20 miles) from potential deep saline sequestration sites, 73 percent is located within 50 km (31 miles), 80 percent is located within 100 km (62 miles), and 91 percent is within 160 km (100 miles). While the EPA's analysis focuses on the geographic availability of deep saline formations, unmineable coal seams and depleted oil and gas reservoirs could also potentially serve as storage formations depending on site-specific characteristics. Thus, for the majority of sources, only relatively short pipelines would be needed for transporting CO_2 from the source to the sequestration site. For the reasons described below, the EPA believes that both new and existing EGUs are capable of constructing CO_2 pipelines as needed. New EGUs may also be planned to be co-located with a storage site so that minimal transport of the CO_2 is required. The EPA has assurance that the necessary pipelines will be safe because the safety of existing and new supercritical CO_2 pipelines is comprehensively regulated by PHMSA.[379]

(1) CO_2 Transport Demonstrations

The majority of CO_2 transported in the United States is moved through pipelines. CO_2 pipelines have been in use across the country for nearly 60 years. Operation of this pipeline infrastructure for this period of time establishes that the design, construction, and operational requirements for CO_2 pipelines have been adequately demonstrated.[380] PHMSA reported that 8,666 km (5,385 miles) of CO_2 pipelines were in operation in 2022, a 14 percent increase in CO_2 pipeline miles since 2011.[381] This pipeline infrastructure continues to expand with a number of anticipated projects underway.

The U.S. CO_2 pipeline network includes major trunkline (*i.e.,* large capacity) pipelines as well as shorter, smaller capacity lateral pipelines connecting a CO_2 source to a larger trunkline or connecting a CO_2 source to a nearby CO_2 end use. While CO_2

[377] PHMSA submitted the associated Notice of Proposed Rulemaking to the White House Office of Management and Budget on February 1, 2024 for pre-publication review. The notice stated that the proposed rulemaking would enhance safety regulations to "accommodate an anticipated increase in the number of carbon dioxide pipelines and volume of carbon dioxide transported." Office of Management and Budget. *https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2137-AF60.*

[378] Individual saline formations would require site-specific characterization to determine their suitability for geologic sequestration and the potential capacity for storage.

[379] PHMSA additionally initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020. For more information, see: *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[380] For additional information on CO_2 transportation infrastructure project timelines, costs and other details, please see EPA's final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[381] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, "Hazardous Annual Liquid Data." 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

pipelines are generally more economical, other methods of CO_2 transport may also be used in certain circumstances and are detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

(a) Distance of CO_2 Transport for Coal-Fired Power Plants

An important factor in the consideration of the feasibility of CO_2 transport from existing coal-fired steam generating units to sequestration sites is the distance the CO_2 must be transported. As discussed in section VII.C.1.a.i(D), potential sequestration formations include deep saline formations, unmineable coal seams, and oil and gas reservoirs. Based on data from DOE/NETL studies of storage resources, of existing coal-fired steam generating capacity with planned operation during or after 2039, 80 percent is within 100 km (62 miles) of potential deep saline sequestration sites, and another 11 percent is within 160 km (100 miles).[382] In other words, 91 percent of this capacity is within 160 km (100 miles) of potential deep saline sequestration sites. In gigawatts, of the 81 GW of coal-fired steam generation capacity with planned operation during or after 2039, only 16 GW is not within 100 km (62 miles) of a potential saline sequestration site, and only 7 GW is not within 160 km (100 mi). The vast majority of these units (on the order of 80 percent) can reach these deep saline sequestration sites by building an intrastate pipeline. This distance is consistent with the distances referenced in studies that form the basis for transport cost estimates for this final rule.[383] While the EPA's analysis focuses on the geographic availability of deep saline formations, unmineable coal seams and depleted oil and gas reservoirs could also potentially serve as storage formations depending on site-specific characteristics.

Of the 9 percent of existing coal-fired steam generating capacity with planned operation during or after 2039 that is not within 160 km (100 miles) of a potential deep saline sequestration site, 5 percent is within 241 km (150 miles) of potential saline sequestration sites, an additional 3 percent is within 322 km (200 miles) of potential saline sequestration sites, and another 1 percent is within 402 km (250 miles) of potential sequestration sites. In total, assuming all existing coal-fired steam generating capacity with planned operation during or after 2039 adopts CCS, the EPA analysis shows that approximately 8,000 km (5,000 miles) of CO_2 pipelines would be constructed by 2032. This includes units located at any distance from sequestration. Note that this value is not optimized for the least total pipeline length, but rather represents the approximate total pipeline length that would be required if each power plant constructed a lateral pipeline connecting their power plant to the nearest potential saline sequestration site.[384]

Additionally, the EPA's compliance modeling projects 3,300 miles of CO_2 pipeline buildout in the baseline and 4,700 miles of pipeline buildout in the policy scenario. This is comparable to the 4,700 to 6,000 miles of CO_2 pipeline buildout estimated by other simulations examining similar scenarios of coal CCS deployment.[385] Over 5 years, this total projected CO_2 pipeline capacity would amount to about 660 to 940 miles per year on average.[386] This projected pipeline mileage is comparable to other types of pipelines that are regularly constructed in the United States each year. For example, based on data collected by EIA, the total annual mileage of natural gas pipelines constructed over the 2017–2021 period ranged from approximately 1,000 to 2,500 miles per year. The projected annual average CO_2 pipeline mileage is less than each year in this historical natural gas pipeline range, and significantly less than the upper end of this range.

The EPA also notes that the pipeline construction estimates presented in this section are not additive with the natural gas co-firing pipeline construction estimates presented below because individual sources will not elect to utilize both compliance methods. In other words, more pipeline buildout for one compliance method necessarily means less pipeline buildout for the other method. Therefore, there is no compliance scenario in which the total pipeline construction is equal to the sum of the CCS and natural gas co-firing pipeline estimates presented in this preamble.

While natural gas line construction may be easier in some circumstances given the uniform federal regulation that governs those such construction, the historical trends support the EPA's conclusion that constructing less CO_2 pipeline length over a several year period is feasible.

(b) CO_2 Pipeline Examples

PHMSA reported that 8,666 km (5,385 miles) of CO_2 pipelines were in operation in 2022.[387] Due to the unique nature of each project, CO_2 pipelines vary widely in length and capacity. Examples of projects that have utilized CO_2 pipelines include the following: Beaver Creek (76 km), Monell (52.6 km), Bairoil (258 km), Salt Creek (201 km), Sheep Mountain (656 km), Slaughter (56 km), Cortez (808 km), Central Basin (231 km), Canyon Reef Carriers (354 km), and Choctaw (294 km). These pipelines range in capacity from 1.6 million tons per year to 27 million tons per year, and transported CO_2 for uses such as EOR.[388]

Most sources deploying CCS are anticipated to construct pipelines that run from the source to the sequestration site. Similar CO_2 pipelines have been successfully constructed and operated in the past. For example, a 109 km (68 mile) CO_2 pipeline was constructed from a fertilizer plant in Coffeyville, Kansas, to the North Burbank Unit, an EOR operation in Oklahoma.[389] Chaparral Energy entered a long-term CO_2 purchase and sale agreement with a subsidiary of CVR Energy for the capture of CO_2 from CVR's nitrogen fertilizer plant in 2011.[390] The pipeline

[382] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[383] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[384] Note that multiple coal-fired EGUs may be located at each power plant.

[385] CO_2 Pipeline Analysis for Existing Coal-Fired Powerplants. Chen et. al. Los Alamos National Lab. 2024. *https://permalink.lanl.gov/object/tr?what=info:lanl-repo/lareport/LA-UR-24-23321.*

[386] In the EPA's representative timeline, the CO_2 pipeline is constructed in an 18-month period. In practice, all CO_2 pipeline construction projects would be spread over a larger time period. In the Transport and Storage Timeline Summary, ICF (2024), available in Docket ID EPA–HQ–OAR–2023–0072, permitting is 1.5 years. Some CO_2 pipeline construction would therefore likely begin by the start of 2028, or even earlier considering on-going projects. With the one-year compliance extension for delays outside of the owner/operators control that would provide extra time if there were challenges in building pipelines, the construction on CO_2 pipelines could occur during 2032.

[387] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[388] Noothout, Paul. Et. Al. (2014). ''CO_2 Pipeline infrastructure—lessons learnt.'' *https://www.sciencedirect.com/science/article/pii/S187661021402864.*

[389] Rassenfoss, Stephen. (2014). ''Carbon Dioxide: From Industry to Oil Fields.'' *ttps://jpt.spe.org/carbon-dioxide-industry-oil-fields.*

[390] GlobeNewswire. ''Chaparral Energy Agrees to a CO2 Purchase and Sale Agreement with CVR Energy for Capture of CO_2 for Enhanced Oil Recovery.'' March 29, 2011. *https://www.globenewswire.com/news-release/2011/03/29/443163/10562/en/Chaparral-Energy-Agrees-to-a-CO2-Purchase-and-Sale-Agreement-With-CVR-*

was then constructed, and operations started in 2013.[391] Furthermore, a 132 km (82 mile) pipeline was constructed from the Terrell Gas facility (formerly Val Verde) in Texas to supply CO_2 for EOR projects in the Permian Basin.[392] Additionally, the Kemper Country CCS project in Mississippi, was designed to capture CO_2 from an integrated gasification combined cycle power plant, and transport CO_2 via a 96 km (60 mile) pipeline to be used in EOR.[393] Construction for this facility commenced in 2010 and was completed in 2014.[394] Furthermore, the Citronelle Project in Alabama, which was the largest demonstration of a fully integrated, pulverized coal-fired CCS project in the United States as of 2016, utilized a dedicated 19 km (12 mile) pipeline constructed by Denbury Resources in 2011 to transport CO_2 to a saline storage site.[395]

(c) EPAct05-Assisted CO_2 Pipelines for CCS

Consistent with the EPA's legal interpretation that the Agency can rely on experience from EPAct05 funded facilities in conjunction with other information, this section provides additional examples of CO_2 pipelines with EPAct05 funding. CCS projects with EPAct05 funding have built pipelines to connect the captured CO_2 source with sequestration sites, including Illinois Industrial Carbon Capture and Storage in Illinois, Petra Nova in Texas, and Red Trail Energy in North Dakota. The Petra Nova project, which restarted operations in September 2023,[396] transports CO_2 via a 131 km (81 mile) pipeline to the injection site, while the Illinois Industrial Carbon Capture project and Red Trail Energy transport CO_2 using pipelines under 8 km (5 miles) long.[397] [398] [399] Additionally, Project Tundra, a saline sequestration project planned at the lignite-fired Milton R. Young Station in North Dakota will transport CO_2 via a 0.4 km (0.25 mile) pipeline.[400]

(d) Existing and Planned CO_2 Trunklines

Although the BSER is premised on the construction of pipelines that connect the CO_2 source to the sequestration site, in practice some sources may construct short laterals to existing CO_2 trunklines, which can reduce the number of miles of pipeline that may need to be constructed. A map displaying both existing and planned CO_2 pipelines, overlayed on potential geologic sequestration sites, is available in the final TSD, *GHG Mitigation Measures for Steam Generating Units.* Pipelines connect natural CO_2 sources in south central Colorado, northeast New Mexico, and Mississippi to oil fields in Texas, Oklahoma, New Mexico, Utah, and Louisiana. The Cortez pipeline is the longest CO_2 pipeline, and it traverses over 800 km (500) miles from southwest Colorado to Denver City, Texas CO_2 Hub, where it connects with several other CO_2 pipelines. Many existing CO_2 pipelines in the U.S. are located in the Permian Basin region of west Texas and eastern New Mexico. CO_2 pipelines in Wyoming, Texas, and Louisiana also carry CO_2 captured from natural gas processing plants and refineries to EOR projects. Additional pipelines have been constructed to meet the demand for CO_2 transportation. A 170 km (105 mile) CO_2 pipeline owned by Denbury connecting oil fields in the Cedar Creek Anticline (located along the Montana-North Dakota border) to CO_2 produced in Wyoming was completed in 2021, and a 30 km (18 mile) pipeline also owned by Denbury connects to the same oil field and was completed in 2022.[401] [402] These pipelines form a network with existing pipelines in the region—including the Denbury Greencore pipeline, which was completed in 2012 and is 232 miles long, running from the Lost Cabin gas plant in Wyoming to Bell Creek Field in Montana.[403]

In addition to the existing pipeline network, there are a number of large CO_2 trunklines that are planned or in progress, which could further reduce the number of miles of pipeline that a source may need to construct. Several major projects have recently been announced to expand the CO_2 pipeline network across the United States. For example, the Summit Carbon Solutions Midwest Carbon Express project has proposed to add more than 3,200 km (2,000) miles of dedicated CO_2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, and Minnesota. The Midwest Carbon Express is projected to begin operations in 2026. Further, Wolf Carbon Solutions has recently announced that it plans to refile permit applications for the Mt. Simon Hub, which will expand the CO_2 pipeline by 450 km (280 miles) in the Midwest. Tallgrass announced in 2022 a plan to convert an existing 630 km (392 mile) natural gas pipeline to carry CO_2 from an ADM ethanol production facility in Nebraska to a planned commercial-scale CO_2 sequestration hub in Wyoming aimed for completion in 2024.[404] Recently, as part of agreeing to a communities benefits plan, a number of community groups have agreed that they will support construction of the Tallgrass pipeline in Nebraska.[405] While the construction of larger networks of trunklines could facilitate CCS for power plants, the BSER is not predicated on the buildout of a trunkline network and the existence of future trunklines was not assumed in the EPA's feasibility or costing analysis. The EPA's analysis is conservative in that it does not presume the buildout of trunkline networks. The development of more robust and interconnected pipeline systems over the next several years would merely lower the EPA's

Energy-for-Capture-of-CO2-for-Enhanced-Oil-Recovery.html.

[391] Chaparral Energy. "A 'CO_2 Midstream' Overview: EOR Carbon Management Workshop." December 10, 2013. *https://www.co2conference.net/wp-content/uploads/2014/01/13-Chaparral-CO2-Midstream-Overview-2013.12.09new.pdf.*

[392] "Val Verde Fact Sheet: Commercial EOR using Anthropogenic Carbon Dioxide." *https://sequestration.mit.edu/tools/projects/val_verde.html.*

[393] Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project. *https://sequestration.mit.edu/tools/projects/kemper.html.*

[394] Office of Fossil Energy and Carbon Management. Southern Company—Kemper County, Mississippi. *https://www.energy.gov/fecm/southern-company-kemper-county-mississippi.*

[395] Citronelle Project. National Energy Technology Laboratory. (2018). *https://www.netl.doe.gov/sites/default/files/2018-11/Citronelle-SECARB-Project.PDF.*

[396] Jacobs, Trent. (2023). "A New Day Begins for Shuttered Petra Nova CCUS." *https://jpt.spe.org/a-new-day-begins-for-shuttered-petra-nova-ccus.*

[397] Technical Review of Subpart RR MRV Plan for Petra Nova West Ranch Unit. (2021). *https://www.epa.gov/system/files/documents/2021-09/wru_decision.pdf.*

[398] Technical Review of Subpart RR MRV Plan for Archer Daniels Midland Illinois Industrial Carbon Capture and Storage Project. (2017). *https://www.epa.gov/sites/default/files/2017-01/documents/adm_final_decision.pdf.*

[399] Red Trail Energy Subpart RR Monitoring, Reporting, and Verification (MRV) Plan. (2022). *https://www.epa.gov/system/files/documents/2022-04/rtemrvplan.pdf.*

[400] Technical Review of Subpart RR MRV Plan for Tundra SGS LLC at the Milton R. Young Station. (2022). *https://www.epa.gov/system/files/documents/2022-04/tsgsdecision.pdf.*

[401] Denbury. Detailed Pipeline and Ownership Information. (2022) *https://www.denbury.com/wp-content/uploads/2022/11/DEN-Pipeline-Schedule.pdf.*

[402] AP News. Officials mark start of CO_2 pipeline used for oil recovery. (2022) *https://apnews.com/article/business-texas-north-dakota-plano-25f1dbf9a924613a56827c1c83e4ba68.*

[403] Denbury. Detailed Pipeline and Ownership Information. (2022) *https://www.denbury.com/wp-content/uploads/2022/11/DEN-Pipeline-Schedule.pdf.*

[404] Tallgrass. Tallgrass to Capture and Sequester CO_2 Emissions from ADM Corn Processing Complex in Nebraska. (2022). *https://tallgrass.com/newsroom/press-releases/tallgrass-to-capture-and-sequester-co2-emissions-from-adm-corn-processing-complex-in-nebraska.*

[405] *https://boldnebraska.org/upcoming-meetings-understanding-the-new-tallgrass-carbon-pipeline-community-benefits-agreement/.*

cost projections and create additional CO_2 transport options for power plants that do CCS.

Moreover, pipeline projects have received funding under the IIJA to conduct front-end engineering and design (FEED) studies.[406] Carbon Solutions LLC received funding to conduct a FEED study for a commercial-scale pipeline to transport CO_2 in support of the Wyoming Trails Carbon Hub as part of a statewide pipeline system that would be capable of transporting up to 45 million metric tons of CO_2 per year from multiple sources. In addition, Howard Midstream Energy Partners LLC received funding to conduct a FEED study for a 965 km (600 mi) CO_2 pipeline system on the Gulf Coast that would be capable of moving at least 250 million metric tons of CO_2 annually and connecting carbon sources within 30 mi of the trunkline.

Other programs were created by the IIJA to facilitate the buildout of large pipelines to carry carbon dioxide from multiple sources. For example, the Carbon Dioxide Transportation Infrastructure Finance and Innovation Act (CIFIA) was incorporated into the IIJA and provided $2.1 billion to DOE to finance projects that build shared (*i.e.,* common carrier) transport infrastructure to move CO_2 from points of capture to conversion facilities and/or storage wells. The program offers direct loans, loan guarantees, and ''future growth grants'' to provide cash payments to specifically for eligible costs to build additional capacity for potential future demand.[407]

(2) Permitting and Rights of Way

The permitting process for CO_2 pipelines often involves a number of private, local, state, tribal, and/or Federal agencies. States and local governments are directly involved in siting and permitting proposed CO_2 pipeline projects. CO_2 pipeline siting and permitting authorities, landowner rights, and eminent domain laws are governed by the states and vary by state.

State laws determine pipeline siting and the process for developers to acquire rights-of-way needed to build. Pipeline developers may secure rights-of-way for proposed projects through voluntary agreements with landowners; pipeline developers may also secure rights-of-way through eminent domain authority, which typically accompanies siting permits from state utility regulators with jurisdiction over CO_2 pipeline siting.[408] The permitting process for interstate pipelines may take longer than for intrastate pipelines. Whereas multiple state regulatory agencies would be involved in the permitting process for an interstate pipeline, only one primary state regulatory agency would be involved in the permitting process for an intrastate pipeline.

Most regulation of CO_2 pipeline siting and development is conducted at the state level, and under state specific regulatory regimes. As the interest in CO_2 pipelines has grown, states have taken steps to facilitate pipeline siting and construction. State level regulation related to CO_2 sequestration and transport is an very active area of legislation across states in all parts of the country, with many states seeking to facilitate pipeline siting and construction.[409] Many states, including Kentucky, Michigan, Montana, Arkansas, and Rhode Island, treat CO_2 pipeline operators as common carriers or public utilities.[410] This is an important classification in some jurisdictions where it may be required for pipelines seeking to exercise eminent domain.[411] Currently, 17 states explicitly allow CO_2 pipeline operators to exercise eminent domain authority for acquisition of CO_2 pipeline rights-of-way, should developers not secure them through negotiation with landowners.[412] Some states have recognized the need for a streamlined CO_2 pipeline permitting process when there are multiple layers of regulation and developed joint permit applications. Illinois, Louisiana, New York, and Pennsylvania have created a joint permitting form that allows applicants to file a single application for pipeline projects covering both state and federal permitting requirements.[413] Even in states without this streamlined process, pipeline developers can pursue required state permits concurrently with federal permits, NEPA review (as applicable), and the acquisition of rights-of-way.

Pipeline developers have been able to successfully secure the necessary rights-of way for CO_2 pipeline projects. For example, Summit Carbon Solutions, which has proposed to add more than 3,200 km (2,000 mi) of dedicated CO_2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, and Minnesota, has stated that as of November 7, 2023, it had reached easement agreements with 2,100 landowners along the route.[414] As of February 23, 2024, Summit Carbon Solutions stated that it had acquired about 75 percent of the rights of way needed in Iowa, about 80 percent in North Dakota, about 75 percent in South Dakota, and about 89 percent in Minnesota. The company has successfully navigated hurdles, such as rerouting the pipelines in certain counties where necessary.[415] [416] The EPA notes that this successful acquisition of right-of-way easements for thousands of miles of pipeline across five states has taken place in just the three years since the project launched in 2021.[417] In addition, the Citronelle Project, which was constructed in Alabama in 2011, successfully acquired rights-of-way through 9 miles of forested and commercial timber land and 3 miles of emergent shrub and forested wetlands. The Citronelle Project was able to attain rights-of-way through the habitat of an endangered species by mitigating potential environmental

[406] Office of Fossil Energy and Carbon Management. ''Project Selections for FOA 2730: Carbon Dioxide Transport Engineering and Design (Round 1).'' *https://www.energy.gov/fecm/project-selections-foa-2730-carbon-dioxide-transport-engineering-and-design-round-1.*

[407] *https://www.energy.gov/lpo/carbon-dioxide-transportation-infrastructure.*

[408] Congressional Research Service.2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[409] Great Plains Institute State Legislative Tracker 2023. Carbon Management State Legislative Program Tracker. *https://www.quorum.us/spreadsheet/external/fVOjsTvwyeWkIqVlNmoq/?mc_cid=915706f2bc&.*

[410] National Association of Regulatory Utility Commissioners (NARUC). (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[411] Martin Lockman. *Permitting CO_2 Pipelines.* Sabin Center for Climate Change Law (2023). *https://scholarship.law.columbia.edu/cgi/viewcontent.cgi?article=1208&context=sabin_climate_change.*

[412] The 17 states are: Arizona, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Montana, New Mexico, North Carolina, North Dakota, Pennsylvania, South Dakota, Texas, and Wyoming. National Association of Regulatory Utility Commissioners (NARUC). (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[413] Martin Lockman. *Permitting CO_2 Pipelines.* Sabin Center for Climate Change Law (Sept. 2023). *https://scholarship.law.columbia.edu/cgi/viewcontent.cgi?article=1208&context=sabin_climate_change.*

[414] South Dakota Public Broadcasting. ''Summit reaches land deals on more than half of CO_2 pipeline route.'' (2022). *https://listen.sdpb.org/business-economics/2022-11-08/summit-reaches-land-deals-on-more-than-half-of-co2-pipeline-route.*

[415] Summit CEO: CO2 Pipeline's Time is Now. (2024). *https://www.dtnpf.com/agriculture/web/ag/news/business-inputs/article/2024/02/23/summit-ceo-blank-says-company-toward.*

[416] Summit Carbon Solutions. Summit Carbon Solutions Signs 80 Percent of North Dakota Landowners. (2023). *https://summitcarbonsolutions.com/summit-carbon-solutions-signs-80-percent-of-north-dakota-landowners/.*

[417] Summit Carbon Solutions. Summit Carbon Solutions Announces Progress on Carbon Capture and Storage Project. (2022). *https://summitcarbonsolutions.com/summit-carbon-solutions-announces-progress-on-carbon-capture-and-storage-project/.*

impacts.[418] Even projects that require rights-of-way across multiple ownership regimes including state, private, and federally owned land have been successfully developed. The 170 km (105 mile) Cedar Creek Anticline CO_2 pipeline owned by Denbury required easements for approximately 10 km (6.2 mi) to cross state school trust lands in Montana, 27 km (17 mi) across Federal land and the remaining miles across private lands.[419] [420] The pipeline was completed in 2021.[421]

Federal actions (*e.g.,* funding a CCS project) must generally comply with NEPA, which often requires that an environmental assessment (EA) or environmental impact statement (EIS) be conducted to consider environmental impacts of the proposed action, including consideration of reasonable alternatives.[422] An EA determines whether or not a Federal action has the potential to cause significant environmental effects. Each Federal agency has adopted its own NEPA procedures for the preparation of EAs.[423] If the agency determines that the action will not have significant environmental impacts, the agency will issue a Finding of No Significant Impact (FONSI). Some projects may also be ''categorically excluded'' from a detailed environmental analysis when the Federal action normally does not have a significant effect on the human environment. Federal agencies prepare an EIS if a proposed Federal action is determined to significantly affect the quality of the human environment. The regulatory requirements for an EIS are more detailed and rigorous than the requirements for an EA. The determination of the level of NEPA review depends on the potential for significant environmental impacts considering the whole project (*e.g.,* crossings of sensitive habitats, cultural resources, wetlands, public safety concerns). Consequently, whether a pipeline project is covered by NEPA and the associated permitting timelines may vary depending on site characteristics (*e.g.,* pipeline length, whether a project crosses a water of the U.S.) and funding source. Pipelines through Bureau of Land Management (BLM) land, U.S. Forest Service (USFS) land, or other Federal land would be subject to NEPA. To ensure that agencies conduct NEPA reviews as efficiently and expeditiously as practicable, the Fiscal Responsibility Act [424] amendments to NEPA established deadlines for the preparation of environmental assessments and environmental impact statements. Environmental assessments must be completed within 1 year and environmental impact statements must be completed within 2 years [425] A lead agency that determines it is not able to meet the deadline may extend the deadline, in consultation with the applicant, to establish a new deadline that provides only so much additional time as is necessary to complete such environmental impact statement or environmental assessment.[426]

As discussed above, it is anticipated that most EGUs would need shorter, intrastate pipeline segments. For example, ADM's Decatur, Illinois, pipeline, which spans 1.9 km (1.18 miles), was constructed after Decatur was selected for the DOE Phase 1 research and development grants in October 2009.[427] Construction of the CO_2 compression, dehydration, and pipeline facilities began in July 2011 and was completed in June 2013.[428] The ADM project required only an EA. Additionally, Air Products operates a large-scale system to capture CO_2 from two steam methane reformers located within the Valero Refinery in Port Arthur, Texas. The recovered and purified CO_2 is delivered by pipeline for use in enhanced oil recovery operations.[429] This 12-mile pipeline required only an EA.[430] Conversely, the Petra Nova project in Texas required an EIS to evaluate the potential environmental impacts associated with DOE's proposed action of providing financial assistance for the project. This EIS addressed potential impacts from both the associated 131 km (81 mile) pipeline and other aspects of the larger CCS system, including the post-combustion CO_2.[431] For Petra Nova, a notice of intent to issue an EIS was published on November 14, 2011, and the record of decision was issued less than 2 years later, on May 23, 2013.[432] Construction of the CO_2 pipeline for Petra Nova from the W.A. Parish Power Plant to the West Ranch Oilfield in Jackson County, TX began in July 2014 and was completed in July 2016.[433]

Compliance with section 7 of the Endangered Species Act related to Federal agency consultation and biological assessment is also required for projects on Federal lands. Specifically, the Endangered Species Act requires consultation with the Department of Interior's Fish and Wildlife Service and Department of Commerce's NOAA Fisheries, in order to avoid or mitigate impacts to any threatened or endangered species and their habitats.[434] This agency consultation process and biological assessment are generally conducted during preparation of the NEPA documentation (EIS or EA) for the Federal project and generally within the regulatory timeframes for environmental assessment or environmental impact statement preparation. Consequently, the EPA does not anticipate that compliance with the Endangered Species Act will change the anticipated timeline for most projects.

The EPA notes that the Fixing America's Surface Transportation Act (FAST Act) is also relevant to CCS projects and pipelines. Title 41 of this Act (42 U.S.C. 4370m *et seq.*), referred to as ''FAST–41,'' created a new

[418] SECARB. (2021). Final Project Report—SECARB Phase III, September 2021. *https://www.osti.gov/servlets/purl/1823250.*

[419] Great Falls Tribune. Texas company plans 110-mile CO_2 pipeline to enhance Montana oil recovery. (2018). *https://www.greatfallstribune.com/story/news/2018/10/09/texas-company-plans-co-2-pipeline-injection-free-montana-oil/1577657002/.*

[420] U.S. D.O.I B.L.M. Denbury-Green Pipeline-MT, LLC, Denbury Onshore, LLC Cedar Creek Anticline CO_2 Pipeline and EOR Development Project Scoping Report. *https://eplanning.blm.gov/public_projects/nepa/89883/137194/167548/BLM_Denbury_Projects_Scoping_Report_March2018.pdf.*

[421] AP News. Officials mark start of CO_2 pipeline used for oil recovery. (2022) *https://apnews.com/article/business-texas-north-dakota-plano-25f1dbf9a924613a56827c1c83e4ba68.*

[422] Council on Environmental Quality. (2024). CEQ NEPA Regulations. *https://ceq.doe.gov/laws-regulations/regulations.html.*

[423] Council of Environmental Quality. (2023). Agency NEPA Implementing Procedures. *https://ceq.doe.gov/laws-regulations/agency_implementing_procedures.html.*

[424] Public Law 118–5 (June 3, 2023).

[425] NEPA Sec. 107(g)(1); 42 U.S.C. 4336a(g)(1).

[426] NEPA sec. 107(g)(2); 42 U.S.C. 4336a(g)(2).

[427] Massachusetts Institute of Technology. (2014). Decatur Fact Sheet: Carbon Dioxide Capture and Storage Project. *https://sequestration.mit.edu/tools/projects/decatur.html.*

[428] NETL. ''CO2 Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone.'' Award #DE–FE0001547. *https://www.usaspending.gov/award/ASST_NON_DEFE0001547_8900.*

[429] Air Products. Carbon Capture. *https://www.airproducts.com/company/innovation/carbon-capture.*

[430] Department of Energy. (2011). Final Environmental Assessment for Air Products and Chemicals, Inc. Recovery Act: Demonstration of CO_2 Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large Scale Hydrogen Production. *https://netl.doe.gov/sites/default/files/environmental-assessments/20110622_APCI_PtA_CO2_FEA.pdf.*

[431] Department of Energy, Office of NEPA Policy and Compliance. (2013). EIS–0473: Record of Decision. *https://www.energy.gov/nepa/articles/eis-0473-record-decision.*

[432] Department of Energy. (2017). Petra Nova W.A. Parish Project. *https://www.energy.gov/fecm/petra-nova-wa-parish-project.*

[433] Kennedy, Greg. (2020). ''W.A. Parish Post Combustion CO_2 Capture and Sequestration Demonstration Project.'' Final Technical Report. *https://www.osti.gov/biblio/1608572/.*

[434] CEQ. (2021). ''Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration.'' *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

governance structure, set of procedures, and funding authorities to improve the Federal environmental review and authorization process for covered infrastructure projects.[435] The Utilizing Significant Emissions with Innovative Technologies (USE IT) Act, among other actions, clarified that CCS projects and CO_2 pipelines are eligible for this more predictable and transparent review process.[436] FAST–41 created the Federal Permitting Improvement Steering Council (Permitting Council), composed of agency Deputy Secretary-level members and chaired by an Executive Director appointed by the President. FAST–41 establishes procedures that standardize interagency consultation and coordination practices. FAST–41 codifies into law the use of the Permitting Dashboard[437] to track project timelines, including qualifying actions that must be taken by the EPA and other Federal agencies. Project sponsor participation in FAST–41 is voluntary.[438]

Community engagement also plays a role in the safe operation and construction of CO_2 pipelines. These efforts can be supported using the CCS Pipeline Route Planning Database that was developed by NETL, a public resource designed to support pipeline routing decisions and increase transportation safety.[439] The database includes state-specific regulations and restrictions, energy and social justice factors, land use requirements, existing infrastructure, and areas of potential risk. The database produces weighted values ranging from zero to one, where zero represents acceptable areas for pipeline placement and one represents areas that should be avoided.[440] The database will be a key input for the CCS Pipeline Route Planning Tool under development by NETL.[441] The purpose of the siting tool is to aid pipeline routing decisions and facilitate avoidance of areas that would pose permitting challenges.

In sum, the permitting process for CO_2 pipelines often involves private, local, state, tribal, and/or Federal agencies, and permitting timelines may vary depending on site characteristics. Projects that opt in to the FAST–41 process are eligible for a more transparent and predictable review process. EGUs can generally proceed to obtain permits and rights-of-way simultaneously, and the EPA anticipates that, in total, the permitting process would only take around 2.5 years for pipelines that only need an EA, with a possible additional year if the project requires an EIS (see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional information). This is consistent with the anticipated timelines for CCS discussed in section VII.C.1.a.i(E). Furthermore, the EPA notes that there is over 60 years of experience in the CO_2 pipeline industry designing, permitting, building and operating CO_2 pipelines, and that this expertise can be applied to the CO_2 pipelines that would be constructed to connect to sequestration sites and units.

As discussed above in section VII.C.1.a.i.(C)(1)(a), the core of the EPA's analysis of pipeline feasibility focuses on units located within 100 km (62 miles) of potential deep saline sequestration formations. The EPA notes that the majority (80 percent) of the coal-fired steam generating capacity with planned operation during or after 2039 is located within 100 km (62 miles) of the nearest potential deep saline sequestration site. For these sources, as explained, units would be required only to build relatively short pipelines, and such buildout would be feasible within the required timeframe. For the capacity that is more than 100 km (62 miles) away from sequestration, building a pipeline may become more complex. Almost all (98 percent) of this capacity's closest sequestration site is located outside state boundaries, and access to the nearest sequestration site would require building an interstate pipeline and coordinating with multiple state authorities for permitting purposes. Conversely, for capacity where the distance to the nearest potential sequestration site is less than 100 km (62 miles), only about 19 percent would require the associated pipeline to cross state boundaries. Therefore, the EPA believes that distance to the nearest sequestration site is a useful proxy for considerations related to the complexity of pipeline construction and how long it will take to build a pipeline.

A unit that is located more than 100 km away from sequestration may face complexities in pipeline construction, including additional permitting hurdles, difficulties in obtaining the necessary rights of way over such a distance, or other considerations, that may make it unreasonable for that unit to meet the compliance schedule that is generally reasonable for sources in the subcategory as a whole. Pursuant to the RULOF provisions of 40 CFR 60.2a(e)–(h), if a state can demonstrate that there is a fundamental difference between the information relevant to a particular affected EGU and the information the EPA considered in determining the compliance deadline for sources in the long-term subcategory, and that this difference makes it unreasonable for the EGU to meet the compliance deadline, a longer compliance schedule may be warranted. The EPA does not believe that the fact that a pipeline crosses state boundaries standing alone is sufficient to show that an extended timeframe would be appropriate—many such pipelines could be reasonably accomplished in the required timeframe. Rather, it is the confluence of factors, including that a pipeline crosses state boundaries, along with others that may make RULOF appropriate.

(3) Security of CO_2 Transport

As part of its analysis, the EPA also considered the safety of CO_2 pipelines. The safety of existing and new CO_2 pipelines that transport CO_2 in a supercritical state is regulated by PHMSA. These regulations include standards related to pipeline design, pipeline construction and testing, pipeline operations and maintenance, operator reporting requirements, operator qualifications, corrosion control and pipeline integrity management, incident reporting and response, and public awareness and communications. PHMSA has regulatory authority to conduct inspections of supercritical CO_2 pipeline operations and issue notices to operators in the event of operator noncompliance with regulatory requirements.[442]

CO_2 pipelines have been operating safely for more than 60 years. In the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines with zero incidents involving fatalities.[443] PHMSA reported a total of

[435] Federal Permitting Improvement Steering Council. (2022). FAST–41 Fact Sheet. *https://www.permits.performance.gov/documentation/fast-41-fact-sheet.*

[436] Galford, Chris. USE IT carbon capture bill becomes law, incentivizing development and deployment. (2020). *https://dailyenergyinsider.com/news/28522-use-it-carbon-capture-bill-becomes-law-incentivizing-development-and-deployment/.*

[437] Permitting Dashboard Federal Infrastructure Projects. *https://permits.performance.gov/.*

[438] EPA. ''FAST–41 Coordination.'' (2023). *https://www.epa.gov/sustainability/fast-41-coordination.*

[439] ''CCS Pipeline Route Planning Database V1—EDX.'' *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[440] ''CCS Pipeline Route Planning Database V1—EDX.'' *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[441] Department of Energy. ''CCS Pipeline Route Planning Database V1—EDX.'' *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[442] See generally 49 CFR 190–199.

[443] Congressional Research Service. 2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June

102 CO_2 pipeline incidents between 2003 and 2022, with one injury (requiring in-patient hospitalization) and zero fatalities.[444]

As noted previously in this preamble, a significant CO_2 pipeline rupture occurred in 2020 in Satartia, Mississippi, following heavy rains that resulted in a landslide. Although no one required in-patient hospitalization as a result of this incident, 45 people received treatment at local emergency rooms after the incident and 200 hundred residents were evacuated. Typically, when CO_2 is released into the open air, it vaporizes into a heavier-than-air gas and dissipates. During the Satartia incident, however, unique atmospheric conditions and the topographical features of the area delayed this dissipation. As a result, residents were exposed to high concentrations of CO_2 in the air after the rupture. Furthermore, local emergency responders were not informed by the operator of the rupture and the nature of the unique safety risks of the CO_2 pipeline.[445]

PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of supercritical CO_2 pipelines following the investigation into the CO_2 pipeline failure in Satartia.[446] PHMSA submitted the associated Notice of Proposed Rulemaking to the White House Office of Management and Budget on February 1, 2024 for pre-publication review.[447] Following the Satartia incident, PHMSA also issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice) to the operator related to probable violations of Federal pipeline safety regulations. The Notice was ultimately resolved through a Consent Agreement between PHMSA and the operator that includes the assessment of civil penalties and identifies actions for the operator to take to address the alleged violations and risk conditions.[448] PHMSA has further issued an updated nationwide advisory bulletin to all pipeline operators and solicited research proposals to strengthen CO_2 pipeline safety.[449] Given the Federal and state regulation of CO_2 pipelines and the steps that PHMSA is taking to further improve pipeline safety, the EPA believes CO_2 can be safely transported by pipeline.

Certain states have authority delegated from the U.S. Department of Transportation to conduct safety inspections and enforce state and Federal pipeline safety regulations for intrastate CO_2 pipelines.[450] [451] [452] PHMSA's state partners employ about 70 percent of all pipeline inspectors, which covers more than 80 percent of regulated pipelines.[453] Federal law requires certified state authorities to adopt safety standards at least as stringent as the Federal standards.[454] Further, there are required steps that CO_2 pipeline operators must take to ensure pipelines are operated safely under PHMSA standards and related state standards, such as the use of pressure monitors to detect leaks or initiate shut-off valves, and annual reporting on operations, structural integrity assessments, and inspections.[455] These CO_2 pipeline controls and PHMSA standards are designed to ensure that captured CO_2 will be securely conveyed to a sequestration site.

(4) Comments Received on CO_2 Transport and Responses

The EPA received comments on CO_2 transport, including CO_2 pipelines. Those comments, and the EPA's responses, are as follows.

Comment: Some commenters identified challenges to the deployment of a national, interstate CO_2 pipeline network. In particular, those commenters discussed the experience faced by long (*e.g.,* over 1,000 miles) CO_2 pipelines seeking permitting and right-of-way access in Midwest states including Iowa and North Dakota. Commenters claimed those challenges make CCS as BSER infeasible. Some commenters argued that the existing CO_2 pipeline capacity is not adequate to meet potential demand caused by this rule and that the ability of the network to grow and meet future potential demand is hindered by significant public opposition.

Response: The EPA acknowledges the challenges that some large multi-state pipeline projects have faced, but does not agree that those experiences show that the BSER is not adequately demonstrated or that the standards finalized in these actions are not achievable. As detailed in the preceding subsections of the preamble, the BSER is not premised on the buildout of a national, trunkline CO_2 pipeline network. Most coal-fired steam generating units are in relatively close proximity to geologic storage, and those shorter pipelines would not likely be as challenging to permit and build as demonstrated by the examples of smaller pipeline discussed above.

The EPA acknowledges that some larger trunkline CO_2 pipeline projects, specifically the Heartland Greenway project, have recently been delayed or canceled. However, many projects are still moving forward and several major projects have recently been announced to expand the CO_2 pipeline network across the United States. The EPA notes that there are often opportunities to reroute pipelines to minimize permitting challenges and landowner concerns. For example, Summit Carbon Solutions changed their planned pipeline route in North Dakota after their initial permit was denied, leading to successful acquisition of rights of way.[456] Additionally, Tallgrass, which

3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[444] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[445] Failure Investigation Report—Denbury Gulf Coast Pipeline, May 2022. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf.*

[446] PHMSA. (2022). ''PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak.'' *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[447] Columbia Law School. (2024). PHMSA Advances CO2 Pipeline Safety Regulations. *https://climate.law.columbia.edu/content/phmsa-advances-co2-pipeline-safety-regulations.*

[448] Department of Transportation. (2023). Consent Order, Denbury Gulf Coast Pipelines, LLC, CPF No. 4–2022–017–NOPV *https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_42022017NOPV.html?nocache=7208.*

[449] Ibid.

[450] New Mexico Public Regulation Commission. 2023. Transportation Pipeline Safety. New Mexico Public Regulation Commission, Bureau of Pipeline Safety. *https://www.nm-prc.org/transportation/pipeline-safety.*

[451] Texas Railroad Commission. 2023. *Oversight & Safety Division.* Texas Railroad Commission. *https://www.rrc.texas.gov/about-us/organization-and-activities/rrc-divisions/oversight-safety-division.*

[452] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[453] PHMSA. (2023). ''PHMSA Issues Letters to Wolf Carbon, Summit, and Navigator Clarifying Federal, State, and Local Government Pipeline Authorities.'' *https://www.phmsa.dot.gov/news/phmsa-issues-letters-wolf-carbon-summit-and-navigator-clarifying-federal-state-and-local.*

[454] PHMSA, ''PHMSA Issues Letters to Wolf Carbon, Summit, and Navigator Clarifying Federal, State, and Local Government Pipeline Authorities.'' 2023. *https://www.phmsa.dot.gov/news/phmsa-issues-letters-wolf-carbon-summit-and-navigator-clarifying-federal-state-and-local.*

[455] Carbon Capture Coalition. ''PHMSA/Pipeline Safety Fact Sheet,'' November 2023. *https://carboncapturecoalition.org/wp-content/uploads/2023/11/Pipeline-Safety-Fact-Sheet.pdf.*

[456] Summit Carbon Solutions. Summit Carbon Solutions Signs 80 Percent of North Dakota

Continued

is planning to convert a 630 km (392 mile) natural gas pipeline to carry CO_2, announced that they had reach a community benefits agreement, in which certain organizations have agreed not to oppose the pipeline project while Tallgrass has agreed to terms such as contributing funds to first responders along the pipeline route and providing royalty checks to landowners.[457] See section VII.C.1.a.i(C)(1)(d) for additional discussion of planned CO_2 pipelines. While access to larger trunkline projects would not be required for most EGUs, at least some larger trunkline projects are likely to be constructed, which would increase opportunities for connecting to pipeline networks.

Comment: Some commenters disagreed with the modeling assumption that 100 km is a typical pipeline distance. The commenters asserted that there is data showing the actual locations of the power plants affected by the rule, and the required pipeline distance is not always 100 km.

Response: The EPA acknowledges that the physical locations of EGUs and the physical locations of carbon sequestration capacity and corresponding pipeline distance will not be 100 km in all cases. As discussed previously in section VII.C.1.a.i(C)(1)(a), the EPA modeled the unique approximate distance from each existing coal-fired steam generating capacity with planned operation during or after 2039 to the nearest potential saline sequestration site, and found that the majority (80 percent) is within 100 km (62 miles) of potential saline sequestration sites, and another 11 percent is within 160 km (100 miles).[458] Furthermore, the EPA disagrees with the comments suggesting that the use of 100 km is an inappropriate economic modeling assumption. The 100 km assumption was not meant to encompass the physical location of every potentially affected EGU. The 100 km assumption is intended as an economic modeling assumption and is based on similar assumptions applied in NETL studies used to estimate CO_2 transport costs. The EPA carefully reviewed the assumptions on which the NETL transport cost estimates are based and continues to find them reasonable. The NETL studies referenced in section VII.C.1.a.ii based transport costs on a generic 100 km (62 mile) pipeline and a generic 80 km pipeline.[459] For most EGUs, the necessary pipeline distance is anticipated to be less than 100 km and therefore the associated costs could also be lower than these assumptions. Other published economic models applying different assumptions have also reached the conclusion that CO_2 transport and sequestration are adequately demonstrated.[460]

Comment: Commenters also stated that the permitting and construction processes can be time-consuming.

Response: The EPA acknowledges building CO_2 pipelines requires capital expenditure and acknowledges that the timeline for siting, engineering design, permitting, and construction of CO_2 pipelines depends on factors including the pipeline capacity and pipeline length, whether the pipeline route is intrastate or interstate, and the specifics of the state pipeline regulator's regulatory requirements. In the BSER analysis, individual EGUs that are subject to carbon capture requirements are assumed to take a point-to-point approach to CO_2 transport and sequestration. These smaller-scale projects require less capital and may present less complexity than larger projects. The EPA considers the timeline to permit and install such pipelines in section VII.C.1.a.i(E) of the preamble, and has determined that a compliance date of January 1, 2032 allows for a sufficient amount of time.

Comment: Some commenters expressed significant concerns about the safety of CO_2 pipelines following the CO_2 pipeline failure in Satartia, Mississippi in 2020.

Response: For a discussion of the safety of CO_2 pipelines and the Satartia pipeline failure, see section VII.C.1.a.i(C)(3). The EPA believes that the framework of Federal and state regulation of CO_2 pipelines and the steps that PHMSA is taking to further improve pipeline safety, is sufficient to ensure CO_2 can be safely transported by pipeline.

(D) Geologic Sequestration of CO_2

The EPA is finalizing its determination that geologic sequestration (*i.e.,* the long-term containment of a CO_2 stream in subsurface geologic formations) is adequately demonstrated. In this section, we provide an overview of the availability of sequestration sites in the U.S., discuss how geologic sequestration of CO_2 is well proven and broadly available throughout the U.S, explain the effectiveness of sequestration, discuss the regulatory framework for UIC wells, and discuss the timing of permitting for sequestration sites. We then provide a summary of key comments received concerning geologic sequestration and our responses to those comments.

(1) Sequestration Sites for Coal-Fired Power Plants Subject to CCS Requirements

(a) Broad Availability of Sequestration

Sequestration is broadly available in the United States, which makes clear that it is adequately demonstrated. By far the most widely available and well understood type of sequestration is that in deep saline formations. These formations are common in the U.S. These formations are numerous and only a small subset of the existing saline storage capacity would be required to store the CO_2 from EGUs. Many projects are in the process of completing thorough subsurface studies of these deep saline formations to determine their suitability for regional-scale storage. Furthermore, sequestration formations could also include unmineable coal seams and oil and gas reservoirs. CO_2 may be stored in oil and gas reservoirs in association with EOR and enhanced gas recovery (EGR) technologies, collectively referred to as enhanced recovery (ER), which include the injection of CO_2 in oil and gas reservoirs to increase production. ER is a technology that has been used for decades in states across the U.S.[461]

Geologic sequestration is based on a demonstrated understanding of the trapping and containment processes that retain CO_2 in the subsurface. The presence of a low permeability seal is an important component of demonstrating secure geologic sequestration. Analyses of the potential availability of geologic sequestration capacity in the United States have been conducted by DOE,

Landowners. (2023). *https://summitcarbonsolutions.com/summit-carbon-solutions-signs-80-percent-of-north-dakota-landowners/.*

[457] Hammel, Paul. (2024). Pipeline company, Nebraska environmental group strike unique 'community benefits' agreement. *https://www.desmoinesregister.com/story/tech/science/environment/2024/04/11/nebraska-environmentalist-forge-peace-pact-with-pipeline-company/73282852007/.*

[458] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[459] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[460] Ogland-Hand, Jonathan D. et. al. 2022. *Screening for Geologic Sequestration of CO_2: A Comparison Between SCO2TPRO and the FE/NETL CO_2 Saline Storage Cost Model.* International Journal of Greenhouse Gas Control, Volume 114, February 2022, 103557. *https://www.sciencedirect.com/science/article/pii/S175058362100308X.*

[461] NETL. (2010). Carbon Dioxide Enhanced Oil Recovery. *https://www.netl.doe.gov/sites/default/files/netl-file/co2_eor_primer.pdf.*

and the U.S. Geological Survey (USGS) has also undertaken a comprehensive assessment of geologic sequestration resources in the United States.[462] [463] Geologic sequestration potential for CO_2 is widespread and available throughout the United States. Nearly every state in the United States has or is in close proximity to formations with geologic sequestration potential, including areas offshore. There have been numerous efforts demonstrating successful geologic sequestration projects in the United States and overseas, and the United States has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. Moreover, the amount of storage potential can readily accommodate the amount of CO_2 for which sequestration could be expected under this final rule.

The EPA has performed a geographic availability analysis in which the Agency examined areas of the U.S. with sequestration potential in deep saline formations, unmineable coal seams, and oil and gas reservoirs; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100 km (62-mile) area of potential sequestration sites. This availability analysis is based on resources from the DOE, the USGS, and the EPA. The distance of 100 km is consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline. The scoping assessment by the EPA found that at least 37 states have geologic characteristics that are amenable to deep saline sequestration, and an additional 6 states are within 100 kilometers of potentially amenable deep saline formations in either onshore or offshore locations. Of the 7 states that are further than 100 km (62 mi) of onshore or offshore storage potential in deep saline formations, only New Hampshire has coal EGUs that were assumed to be in operation after 2039, with a total capacity of 534 MW. However, the EPA notes that as of March 27, 2024, the last coal-fired steam EGUs in New Hampshire announced that they would cease operation by 2028.[464] Therefore, the EPA anticipates that there will no existing coal-fired steam EGUs located in states that are further than 100 km (62 mi) of potential geologic sequestration sites. Furthermore, as described in section VII.C.1.a.i(C), new EGUs would have the ability to consider proximity and access to geologic sequestration sites or CO_2 pipelines in the siting process.

The DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration resources in the United States. The DOE estimates are compiled in the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) using volumetric models and are published in its Carbon Utilization and Sequestration Atlas (NETL Atlas). The DOE estimates that areas of the United States with appropriate geology have a sequestration potential of at least 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, unmineable coal seams, and oil and gas reservoirs. The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential across the United States. With respect to deep saline formations, the DOE estimates a sequestration potential of at least 2,200 billion metric tons of CO_2 in these formations in the United States. The EPA estimates that the CO_2 emissions reductions for this rule (which is similar to the amount of CO_2 may be sequestered under this rule) are estimated in the range of 1.3 to 1.4 billion metric tons over the 2028 to 2047 timeframe.[465] This volume of sequestered CO_2 is less than a tenth of a percent of the storage capacity in deep saline formations estimated to be available by DOE.

Unmineable coal seams offer another potential option for geologic sequestration of CO_2. Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively ''locks'' the CO_2 to the coal, where it remains stored. States with the potential for sequestration in unmineable coal seams include Iowa and Missouri, which have little to no saline sequestration potential and have existing coal-fired EGUs. Unmineable coal seams have a sequestration potential of at least 54 billion metric tons of CO_2, or 2 percent of total potential in the United States, and are located in 22 states.

The potential for CO_2 sequestration in unmineable coal seams has been demonstrated in small-scale demonstration projects, including the Allison Unit pilot project in New Mexico, which injected a total of 270,000 tons of CO_2 over a 6-year period (1995–2001). Further, DOE Regional Carbon Sequestration Partnership projects have injected CO_2 volumes in unmineable coal seams ranging from 90 tons to 16,700 tons, and completed site characterization, injection, and post-injection monitoring for sites. DOE has included unmineable coal seams in the NETL Atlas. One study estimated that in the United States, 86.16 billion tons of CO_2 could be permanently stored in unmineable coal seams.[466] Although the large-scale injection of CO_2 in coal seams can lead to swelling of coal, the literature also suggests that there are available technologies and techniques to compensate for the resulting reduction in injectivity. Further, the reduced injectivity can be anticipated and accommodated in sizing and characterizing prospective sequestration sites.

Depleted oil and gas reservoirs present additional potential for geologic sequestration. The reservoir characteristics of developed fields are well known as a result of exploration and many years of hydrocarbon production and, in many areas, infrastructure already exists which could be evaluated for conversion to CO_2 transportation and sequestration service. Other types of geologic formations such as organic rich shale and basalt may also have the ability to store CO_2, and DOE is continuing to evaluate their potential sequestration capacity and efficacy.

(b) Inventory of Coal-Fired Power Plants That Are Candidates for CCS

Sequestration potential as it relates to distance from existing coal-fired steam generating units is a key part of the EPA's regular power sector modeling, using data from DOE/NETL studies.[467] As discussed in section VII.C.1.a.i(D)(1)(a), the availability

[462] U.S. DOE NETL. (2015). Carbon Storage Atlas, Fifth Edition, September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

[463] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). National assessment of geologic carbon dioxide storage resources—Summary: U.S. Geological Survey Factsheet 2013–3020. *http://pubs.usgs.gov/fs/2013/3020/.*

[464] Vickers, Clayton. (2024). ''Last coal plants in New England to close; renewables take their place.'' *https://thehill.com/policy/energy-environment/4560375-new-hampshire-coal-plants-closing/.*

[465] For detailed information on the estimated emissions reductions from this rule, see section 3 of the RIA, available in the rulemaking docket.

[466] Godec, Koperna, and Gale. (2014). ''CO_2-ECBM: A Review of its Status and Global Potential'', Energy Procedia, Volume 63. *https://doi.org/10.1016/j.egypro.2014.11.619.*

[467] For details, please see Chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

analysis shows that of the coal-fired steam generating capacity with planned operation during or after 2039, more than 50 percent is less than 32 km (20 miles) from potential deep saline sequestration sites, 73 percent is located within 50 km (31 miles), 80 percent is located within 100 km (62 miles), and 91 percent is within 160 km (100 miles).[468]

(2) Geologic Sequestration of CO_2 Is Adequately Demonstrated

Geologic sequestration is based on a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. Existing project and regulatory experience, along with other information, indicate that geologic sequestration is a viable long-term CO_2 sequestration option. As discussed in this section, there are many examples of projects successfully injecting and containing CO_2 in the subsurface.

Research conducted through the Department of Energy's Regional Carbon Sequestration Partnerships has demonstrated geologic sequestration through a series of field research projects that increased in scale over time, injecting more than 12 million tons of CO_2 with no indications of negative impacts to either human health or the environment.[469] Building on this experience, DOE launched the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative in 2016 to demonstrate how knowledge from the Regional Carbon Sequestration Partnerships can be applied to commercial-scale safe storage. This initiative is furthering the development and refinement of technologies and techniques critical to the characterization of sites with the potential to sequester greater than 50 million tons of CO_2.[470] In Phase I of CarbonSAFE, thirteen projects conducted economic feasibility analyses, collected, analyzed, and modeled extensive regional data, evaluated multiple storage sites and infrastructure, and evaluated business plans. Six projects were funded for Phase II which involves storage complex feasibility studies. These projects evaluate initial reservoir characteristics to determine if the reservoir is suitable for geologic sequestration sites of more than 50 million tons of CO_2, address technical and non-technical challenges that may arise, develop a risk assessment and CO_2 management strategy for the project; and assist with the validation of existing tools. Five projects have been funded for CarbonSAFE Phase III and are currently performing site characterization and permitting.

The EPA notes that, while only sequestration facilities with Federal funding are currently operational in the United States, multiple commercial sequestration facilities, other than those funded under EPAct05, are in construction or advanced development, with some scheduled to open for operation as early as 2025.[471] These facilities have proposed sequestration capacities ranging from 0.03 to 6 million tons of CO_2 per year. The Great Plains Synfuel Plant currently captures 2 million metric tons of CO_2 per year, which is exported to Canada for use in EOR; a planned addition of sequestration in a saline formation for this facility is expected to increase the amount of CO_2 captured and sequestered (through both geologic sequestration and EOR) to 3.5 million metric tons of CO_2 per year.[472] The EPA and states with approved UIC Class VI programs (including Wyoming, North Dakota, and Louisiana) are currently reviewing UIC Class VI geologic sequestration well permit applications for proposed sequestration sites in fourteen states.[473] [474] [475] As of March 15, 2024, 44 projects with 130 injection wells are under review by the EPA.[476]

Currently, there are planned geologic sequestration facilities across the United States in various phases of development, construction, and operation. The Wyoming Department of Environmental Quality issued three UIC Class VI permits in December 2023 to Frontier Carbon Solutions. The Frontier Carbon Solutions project will sequester 5 million metric tons of CO_2/year.[477] Additionally, UIC Class VI permit applications have been submitted to the Wyoming Department of Environmental Quality for a proposed Eastern Wyoming Sequestration Hub project that would sequester up to 3 million metric tons of CO_2/year.[478] The North Dakota Oil and Gas Division has issued UIC Class VI permits to 6 sequestration projects that collectively will sequester 18 million metric tons of CO_2/year.[479] Since 2014, the EPA has issued two UIC Class VI permits to Archer Daniels Midland (ADM) in Decatur, Illinois, which authorize the injection of up to 7 million metric tons of CO_2. One of the AMD wells is in the injection phase while the other is in the post-injection phase. In January 2024, the EPA issued two UIC Class VI permits to Wabash Carbon Services LLC for a project that will sequester up to 1.67 million metric tons of CO_2/year over an injection period of 12 years.[480] In December 2023, the EPA released for public comment four UIC Class VI draft permits for the Carbon TerraVault projects, to be located in California.[481] These projects propose to sequester CO_2 captured from multiple different sources in California including a hydrogen plant, direct air capture, and pre-combustion gas treatment. TerraVault plans to inject 1.46 million metric tons of CO_2 annually into the four proposed wells over a 26-year injection period with a total potential capacity of 191 million metric tons.[482] [483] One of the proposed wells is

[468] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[469] Regional Sequestration Partnership Overview. *https://netl.doe.gov/carbon-management/carbon-storage/RCSP.*

[470] National Energy Technology Laboratory. CarbonSAFE Initiative. *https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe.*

[471] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[472] Basin Electric Power Cooperative. (2021). "Great Plains Synfuels Plant Potential to Be Largest Coal-Based Carbon Capture and Storage Project to Use Geologic Storage". *https://www.basinelectric.com/News-Center/news-releases/Great-Plains-Synfuels-Plant-potential-to-be-largest-coal-based-carbon-capture-and-storage-project-to-use-geologic-storage.*

[473] UIC regulations for Class VI wells authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water. The major components to be included in UIC Class VI permits are detailed further in section VII.C.1.a.i(D)(4).

[474] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 25, 2024. *https://www.epa.gov/uic/table-epas-draft-and-final-class-vi-well-permits* Last updated January 19, 2024.

[475] U.S. EPA Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[476] U.S. EPA. Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[477] Wyoming DEQ, Water Quality. Wyoming grants its first three Class VI permits. By Kimberly Mazza, December 14, 2023 *https://deq.wyoming.gov/2023/12/wyoming-grants-its-first-three-class-vi-permits/.*

[478] Wyoming DEQ Class VI Permit Applications. Trailblazer permit application. *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi.*

[479] North Dakota Oil and Gas Division, Class VI—Geologic Sequestration Wells. *https://www.dmr.nd.gov/dmr/oilgas/ClassVI.*

[480] EPA Approves Permits to Begin Construction of Wabash Carbon Services Underground Injection Wells in Indiana's Vermillion and Vigo Counties. (2024) *https://www.epa.gov/uic/epa-approves-permits-wabash-carbon-services-underground-injection-wells-indianas-vigo-and*

[481] U.S. EPA Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[482] U.S. EPA Class VI Permit Application. "Intent to Issue Four (4) Class VI Geologic Carbon Sequestration Underground Injection Control (UIC)

an existing UIC Class II well that would be converted to a UIC Class VI well for the TerraVault project.[484]

Geologic sequestration has been proven to be successful and safe in projects internationally. In Norway, facilities conduct offshore sequestration under the Norwegian continental shelf.[485] In addition, the Sleipner CO_2 Storage facility in the North Sea, which began operations in 1996, injects around 1 million metric tons of CO_2 per year from natural gas processing.[486] The Snohvit CO_2 Storage facility in the Barents Sea, which began operations in 2008, injects around 0.7 million metric tons of CO_2 per year from natural gas processing. The SaskPower carbon capture and sequestration facility at Boundary Dam Power Station in Saskatchewan, Canada had, as of the end of 2023, captured 5.6 million metric tons of CO_2 since it began operating in 2014.[487] Other international sequestration facilities in operation include Glacier Gas Plant MCCS (Canada),[488] Quest (Canada), and Qatar LNG CCS (Qatar). The CarbFix project in Iceland injects CO_2 into a geologic formation in which the CO_2 reacts with basalt rock formations to form stone. The CarbFix project has injected approximately 100,000 metric tons of CO_2 into geologic formations since 2014.[489]

EOR, the process of injecting CO_2 into oil and gas formations to extract additional oil and gas, has been successfully used for decades at numerous production fields throughout the United States to increase oil and gas recovery. The oil and gas industry in the United States has nearly 60 years of experience with EOR.[490] This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure geologic sequestration that can be used for deployment of CCS across geographically diverse areas. The amount of CO_2 that can be injected for an EOR project and the duration of operations are of similar magnitude to the duration and volume of CO_2 that is expected to be captured from fossil fuel-fired EGUs. The Farnsworth Unit, the Camrick Unit, the Shute Creek Facility, and the Core Energy CO_2-EOR facility are all examples of operations that store anthropogenic CO_2 as a part of EOR operations.[491] [492] Currently, 13 states have active EOR operations, and these states also have areas that are amenable to deep saline sequestration in either onshore or offshore locations.[493]

(3) EPAct05-Assisted Geologic Sequestration Projects

Consistent with the EPA's legal interpretation that the Agency can rely on experience from EPAct05 funded facilities in conjunction with other information, this section provides examples of EPAct05-assisted geologic sequestration projects. While the EPA has determined that the sequestration component of CCS is adequately demonstrated based on the non-EPAct05 examples discussed above, adequate demonstration of geologic sequestration is further corroborated by planned and operational geologic sequestration projects assisted by grants, loan guarantees, and the IRC section 48A federal tax credit for ''clean coal technology'' authorized by the EPAct05.[494]

At present, there are 13 operational and one post-injection phase commercial carbon sequestration facilities in the United States.[495] [496] Red Trail Energy CCS Project in North Dakota and Illinois Industrial Carbon Capture and Storage in Illinois are dedicated saline sequestration facilities, while the other facilities, including Petra Nova in Texas, are sequestration via EOR.[497] [498] Several other facilities are under development.[499] The Red Trail Energy CCS facility in North Dakota began injecting CO_2 captured from ethanol production plants in 2022.[500] This project is expected to inject 180,000 tons of CO_2 per year.[501] The Illinois Industrial Carbon Capture and Storage Project began injecting CO_2 from ethanol production into the Mount Simon Sandstone in April 2017. According to the facility's report to the EPA's Greenhouse Gas Reporting Program (GHGRP), as of 2022, 2.9 million metric tons of CO_2 had been injected into the saline reservoir.[502] CO_2 injection for one of the two permitted Class VI wells ceased in 2021 and this well is now in the post-operation data collection phase.[503]

There are additional planned geologic sequestration projects under review by the EPA and across the United States.[504] [505] Project Tundra, a saline sequestration project planned at the lignite-fired Milton R. Young Station in North Dakota is projected to capture 4 million metric tons of CO_2 annually.[506] In Wyoming, Class VI permit

Permits for Carbon TerraVault JV Storage Company Sub 1, LLC. EPA–R09–OW–2023–0623.'' *https://www.epa.gov/publicnotices/intent-issue-class-vi-underground-injection-control-permits-carbon-terravault-jv.*

[483] California Resources Corporation. ''Carbon TerraVault Potential Storage Capacity.''*https://www.crc.com/carbon-terravault/Vaults/default.aspx.*

[484] U.S. EPA Class VI Permit Application. ''Intent to Issue Four (4) Class VI Geologic Carbon Sequestration Underground Injection Control (UIC) Permits for Carbon TerraVault JV Storage Company Sub 1, LLC. EPA–R09–OW–2023–0623.

[485] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage. *https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.*

[486] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[487] BD3 Status Update: Q3 2023. *https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q3-2023.*

[488] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[489] CarbFix Operations. (2024). *https://www.carbfix.com/.*

[490] NETL. (2010). Carbon Dioxide Enhanced Oil Recovery. *https://www.netl.doe.gov/sites/default/files/netl-file/co2_eor_primer.pdf.*

[491] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[492] Greenhouse Gas Reporting Program monitoring reports for these facilities are available at *https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide#decisions.*

[493] U.S. DOE NETL, Carbon Storage Atlas, Fifth Edition, September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

[494] 80 FR 64541–42 (October 23, 2015).

[495] Clean Air Task Force. (August 3, 2023). U.S. Carbon Capture Activity and Project Map. *https://www.catf.us/ccsmapus/.*

[496] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[497] Reuters. (September 14, 2023) ''Carbon capture project back at Texas coal plant after 3-year shutdown''. *https://www.reuters.com/business/energy/carbon-capture-project-back-texas-coal-plant-after-3-year-shutdown-2023-09-14/.*

[498] Clean Air Task Force. (August 3, 2023). U.S. Carbon Capture Activity and Project Map. *https://www.catf.us/ccsmapus/.*

[499] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[500] Ibid.

[501] Ibid.

[502] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.

[503] University of Illinois Urbana-Champaign, Prairie Research Institute. (2022). Data from landmark Illinois Basin carbon storage project are now available. *https://blogs.illinois.edu/view/7447/54118905.*

[504] In addition, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year as part of a DOE Southeast Regional Carbon Sequestration Partnership study. The Texas Bureau of Economic Geology tested a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi. Texas Bureau of Economic Geology, ''Cranfield Log.'' *https://www.beg.utexas.edu/gccc/research/cranfield.*

[505] EPA Class VI Permit Tracker. *https://www.epa.gov/system/files/documents/2024-02/class-vi-permit-tracker_2-5-24.pdf.* Accessed February 5, 2024.

[506] Project Tundra. ''Project Tundra.'' *https://www.projecttundrand.com/.*

applications have been issued by the Wyoming Department of Environmental Quality for the proposed Eastern Wyoming Sequestration Hub project, a saline sequestration facility proposed to be located in Southwestern Wyoming.[507] At full capacity, the facility would permanently store up to 5 million metric tons of CO_2 captured from industrial facilities annually in the Nugget saline sandstone reservoir.[508] In Texas, three NGCCs plan to add carbon capture equipment. Deer Park NGCC plans to capture 5 million tons per year, Quail Run NGCC plans to capture 1.5 million tons of CO_2 per year, and Baytown NGCC plans to capture up to 2 million tons of CO_2 per year.[509 510]

(4) Security of Geologic Sequestration and Related Regulatory Requirements

As discussed in section VII.C.1.a.i(D)(2) of this preamble, there have been numerous instances of geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. This regulatory framework includes the UIC well regulations pursuant to SDWA authority, and the GHGRP pursuant to CAA authority.

Regulatory oversight of geologic sequestration is built upon an understanding of the proven mechanisms by which CO_2 is retained in geologic formations. These mechanisms include (1) Structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).

(a) Overview of Legal and Regulatory Framework

For the reasons detailed below, the UIC Program, the GHGRP, and other regulatory requirements comprise a detailed regulatory framework for geologic sequestration in the United States. This framework is analyzed in a 2021 report from the Council on Environmental Quality (CEQ),[511] and statutory and regulatory frameworks that may be applicable for CCS are summarized in the EPA CCS Regulations Table.[512 513] This regulatory framework includes the UIC regulations, promulgated by the EPA under the authority of the Safe Drinking Water Act (SDWA); and the GHGRP, promulgated by the EPA under the authority of the CAA. The requirements of the UIC and GHGRP programs work together to ensure that sequestered CO_2 will remain securely stored underground. Furthermore, geologic sequestration efforts on Federal lands as well as those efforts that are directly supported with Federal funds would need to comply with the NEPA and other Federal laws and regulations, depending on the nature of the project.[514] In cases where sequestration is conducted offshore, the SDWA, the Marine Protection, Research, and Sanctuaries Act (MPRSA) or the Outer Continental Shelf Lands Act (OCSLA) may apply. The Department of Interior Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management are developing new regulations and creating a program for oversight of carbon sequestration activities on the outer continental shelf.[515] Furthermore, Title V of the Federal Land Policy and Management Act of 1976 (FLPMA) and its implementing regulations, 43 CFR part 2800, authorize the Bureau of Land Management (BLM) to issue rights-of-way (ROWs) to geologically sequester CO_2 in Federal pore space, including BLM ROWs for the necessary physical infrastructure and for the use and occupancy of the pore space itself. The BLM has published a policy defining access to pore space on BLM lands, including clarification of Federal policy for situations where the surface and pore space are under the control of different Federal agencies.[516]

(b) Underground Injection Control (UIC) Program

The UIC regulations, including the Class VI program, authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water (USDW). These regulations are built upon nearly a half-century of Federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The IIJA established a $50 million grant program to assist states and tribal regulatory authorities in developing and implementing UIC Class VI programs.[517] Major components included in UIC Class VI permits are site characterization, area of review,[518] corrective action,[519] well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure. The EPA's UIC regulations are included in 40 CFR parts 144–147. The UIC regulations ensure that injected CO_2 does not migrate out of the authorized injection zone, which in turn ensures that CO_2 is securely stored underground.

Review of a UIC permit application by the permitting authority, including for Class VI geologic sequestration, entails a multidisciplinary evaluation to determine whether the application includes the required information, is technically accurate, and supports a determination that USDWs will not be endangered by the proposed injection

[507] Wyoming DEQ Class VI Permit Applications. *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/.*

[508] *Id.*

[509] Calpine. (2023). Calpine Carbon Capture, Bayton, Texas. *https://calpinecarboncapture.com/wp-content/uploads/2023/04/Calpine-Baytown-One-Pager-English-1.pdf.*

[510] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[511] CEQ. (2021). ''Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration.'' *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[512] EPA. 2023. Regulatory and Statutory Authorities Relevant to Carbon Capture and Sequestration (CCS) Projects. *https://www.epa.gov/system/files/documents/2023-10/regulatory-and-statutory-authorities-relevant-to-carbon-capture-and-sequestration-ccs-projects.pdf.*

[513] This table serves as a reference of many possible authorities that may affect a CCS project (including site selection, capture, transportation, and sequestration). Many of the authorities listed in this table would apply only in specific circumstances.

[514] CEQ. ''Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration.'' 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[515] Department of the Interior. (2023). BSEE Budget. *https://www.doi.gov/ocl/bsee-budget.*

[516] National Policy for the Right-of-Way Authorizations Necessary for Site Characterization, Capture, Transportation, Injection, and Permanent Geologic Sequestration of Carbon Dioxide in Connection with Carbon Sequestration Projects. BLM IM 2022–041 Instruction Memorandum, June 8, 2022. *https://www.blm.gov/policy/im-2022-041.*

[517] EPA. Underground Injection Control Class VI Wells Memorandum. (December 9, 2022). *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[518] Per 40 CFR 146.84(a), the area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

[519] UIC permitting authorities may require corrective action for existing wells within the area of review to ensure protection of underground sources of drinking water.

activity.[520] The EPA promulgated UIC regulations to ensure underground injection wells are constructed, operated, and closed in a manner that is protective of USDWs and to address potential risks to USDWs associated with injection activities.[521] The UIC regulations address the major pathways by which injected fluids can migrate into USDWs, including along the injection well bore, via improperly completed or plugged wells in the area near the injection well, direct injection into a USDW, faults or fractures in the confining strata, or lateral displacement into hydraulically connected USDWs. States may apply to the EPA to be the UIC permitting authority in the state and receive primary enforcement authority (primacy). Where a state has not obtained primacy, the EPA is the UIC permitting authority.

Recognizing that CO_2 injection, for the purpose of geologic sequestration, poses unique risks relative to other injection activities, the EPA promulgated Federal Requirements Under the UIC Program for Carbon Dioxide GS Wells, known as the Class VI Rule, in December 2010.[522] The Class VI Rule created and set requirements for a new class of injection wells, Class VI. The Class VI Rule builds upon the long-standing protective framework of the UIC Program, with requirements that are tailored to address issues unique to large-scale geologic sequestration, including large injection volumes, higher reservoir pressures relative to other injection formations, the relative buoyancy of CO_2, the potential presence of impurities in captured CO_2, the corrosivity of CO_2 in the presence of water, and the mobility of CO_2 within subsurface geologic formations. These additional protective requirements include more extensive geologic testing, detailed computational modeling of the project area and periodic re-evaluations, detailed requirements for monitoring and tracking the CO_2 plume and pressure in the injection zone, unique financial responsibility requirements, and extended post-injection monitoring and site care.

UIC Class VI permits are designed to ensure that geologic sequestration does not cause the movement of injected CO_2 or formation fluids outside the authorized injection zone; if monitoring indicates leakage of injected CO_2 from the injection zone, the leakage may trigger a response per the permittee's Class VI Emergency and Remedial Response Plan including halting injection, and the permitting authority may prescribe additional permit requirements necessary to prevent such movement to ensure USDWs are protected or take appropriate enforcement action if the permit has been violated.[523] Class II EOR permits are also designed to ensure the protection of USDWs with requirements appropriate for the risks of the enhanced recovery operation. In general, the EPA believes that the protection of USDWs by preventing leakage of injected CO_2 out of the injection zone will also ensure that CO_2 is sufficiently sequestered in the subsurface, and therefore will not leak from the subsurface to the atmosphere.

The UIC program works with injection well operators throughout the life of the well to confirm practices do not pose a risk to USDWs. The program conducts inspections to verify compliance with the UIC permit, including checking for leaks.[524] Inspections are only one way that programs deter noncompliance. Programs also evaluate periodic monitoring reports submitted by operators and discuss potential issues with operators. If a well is found to be out of compliance with applicable requirements in its permit or UIC regulations, the program will identify specific actions that an operator must take to address the issues. The UIC program may assist the operator in returning the well to compliance or use administrative or judicial enforcement to return a well to compliance.

UIC program requirements address potential safety concerns with induced seismicity. More specifically, through the UIC Class VI program, the EPA has put in place mechanisms to identify, monitor, and reduce risks associated with induced seismicity in any areas within or surrounding a sequestration site through permit and program requirements such as site characterization and monitoring, and the requirement for applicants to demonstrate that induced seismic activity will not endanger USDWs.[525] The National Academy of Sciences released a report in 2012 on induced seismicity from CCS and determined that with appropriate site selection, a monitoring program, a regulatory system, and the appropriate use of remediation methods, the induced seismicity risks of geologic sequestration could be mitigated.[526] Furthermore, the Ground Water Protection Council and Interstate Oil and Gas Compact Commission have published a ''Potential Induced Seismicity Guide.'' This report found that the strategies for avoiding, mitigating, and responding to potential risks of induced seismicity should be determined based on site-specific characteristics (*i.e.,* local geology). These strategies could include supplemental seismic monitoring, altering operational parameters (such as rates and pressures) to reduce the ground motion hazard and risk, permit modification, partial plug back of the well, controlled restart (if feasible), suspending or revoking injection authorization, or stopping injection and shutting in a well.[527] The EPA's UIC National Technical Workgroup released technical recommendations in 2015 to address induced seismicity concerns in Class II wells and elements of these recommendations have been utilized in developing Class VI emergency and remedial response plans for Class VI permits.[528] [529] For example, as identified

[520] EPA. EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

[521] See 40 CFR parts 124, 144–147.

[522] EPA. (2010). Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Final Rule, 75 FR 77230, December 10, 2010 (codified at 40 CFR part 146, subpart H).

[523] See 40 CFR 144.12(b) (prohibition of movement of fluid into USDWs); 40 CFR 146.86(a)(1) (Class VI injection well construction requirements); 40 CFR 146(a) (Class VI injection well operation requirements); 40 CFR 146.94 (emergency and remedial response).

[524] EPA. (2020). Underground Injection Control Program. *https://www.epa.gov/sites/default/files/2020-04/documents/uic_fact_sheet.pdf.*

[525] *See* 40 CFR 146.82(a)(3)(v) (requiring the permit applicant to submit and the permitting authority to consider information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment); EPA. (2018). Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. U.S. Environmental Protection Agency Office of Water (4606M) EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[526] National Research Council. (2013). Induced Seismicity Potential in Energy Technologies. Washington, DC: The National Academies Press. *https://doi.org/10.17226/13355.*

[527] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. (2021). Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection. *https://www.gwpc.org/wp-content/uploads/2022/12/FINAL_Induced_Seismicity_2021_Guide_33021.pdf.*

[528] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[529] EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/*

Continued

by the EPA's UIC National Technical Workgroup, sufficient pressure buildup from disposal activities, the presence of Faults of Concern (*i.e.,* a fault optimally oriented for movement and located in a critically stressed region), and the existence of a pathway for allowing the increased pressure to communicate with the fault contribute to the risk of injection-induced seismicity. The UIC requirements, including site characterization (*e.g.,* ensuring the confining zone [530] is free of faults of concern) and operating requirements (*e.g.,* ensuring injection pressure in the injection zone is below the fracture pressure), work together to address these components and reduce the risk of injection-induced seismicity, particularly any injection-induced seismicity that could be felt by people at the surface.[531] Additionally, the EPA recommends that Class VI permits include an approach for monitoring for seismicity near the site, including seismicity that cannot be felt at the surface, and that injection activities be stopped or reduced in certain situations if seismic activity is detected to ensure that no seismic activity will endanger USDWs.[532] This also reduces the likelihood of any future injection-induced seismic activity that will be felt at the surface.

Furthermore, during site characterization, if any of the geologic or seismic data obtained indicate a substantial likelihood of seismic activity, the EPA may require further analyses, potential planned operational changes, and additional monitoring.[533] The EPA has the authority to require seismic monitoring as a condition of the UIC permit if appropriate, or to deny the permit if the injection-induced seismicity risk could endanger USDWs.

The EPA believes that meaningful engagement with local communities is an important step in the development of geologic sequestration projects and has programs and public participation requirements in place to support this process. The EPA is committed to advancing EJ for overburdened communities in all its programs, including the UIC Class VI program.[534] The EPA is also committed to supporting states' and tribes' efforts to obtain UIC Class VI primacy and strongly encourages such states and tribes to incorporate environmental justice principles and equity into proposed UIC Class VI programs.[535] The EPA is taking steps to address EJ in accordance with Presidential Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All* (88 FR 25251, April 26, 2023). In 2023, the EPA released *Environmental Justice Guidance for UIC Class VI Permitting and Primacy* that builds on the 2011 *UIC Quick Reference Guide: Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process.*[536] [537] The 2023 guidance serves as an operating framework for identifying, analyzing, and addressing EJ concerns in the context of implementing and overseeing UIC permitting and primacy programs, including primacy approvals. The EPA notes that while this guidance is focused on the UIC Class VI program, EPA Regions should apply them to the other five injection well classes wherever possible, including class II. The guidance includes recommended actions across five themes to address various aspects of EJ in UIC Class VI permitting including: (1) identify communities with potential EJ concerns, (2) enhance public involvement, (3) conduct appropriately scoped EJ assessments, (4) enhance transparency throughout the permitting process, and (5) minimize adverse effects to USDWs and the communities they may serve.[538]

As a part of the UIC Class VI permit application process, applicants and the EPA Regions should complete an EJ review using the EPA's EJScreen Tool, an online mapping tool that integrates numerous demographic, socioeconomic, and environmental data sets that are overlain on an applicant's UIC Area of Review to identify whether any disadvantaged communities are encompassed.[539] If the results indicate a potential EJ impact, applicants and the EPA Regions should consider potential measures to mitigate the impacts of the UIC Class VI project on identified vulnerable communities and enhance the public participation process to be inclusive of all potentially affected communities *(e.g.,* conduct early targeted outreach to communities and identify and mitigate any communication obstacles such as language barriers or lack of technology resources).[540]

ER technologies are used in oil and gas reservoirs to increase production. Injection wells used for ER are regulated through the UIC Class II program. Injection of CO_2 is one of several techniques used in ER. Sometimes ER uses CO_2 from anthropogenic sources such as natural gas processing, ammonia and fertilizer production, and coal gasification facilities. Through the ER process, much of the injected CO_2 is recovered from production wells and can be separated and reinjected into the subsurface formation, resulting in the storage of CO_2 underground. The EPA's Class II regulations were designed to regulate ER injection wells, among other injection wells associated with oil and natural gas production. See *e.g.,* 40 CFR 144.6(b)(2). The EPA's Class II program is designed to prevent Class II injection activities from endangering USDWs. The Class II programs of states and tribes must be approved by the EPA and must meet the EPA regulatory requirements for Class II programs, 42 U.S.C. 300h–1, or otherwise represent an effective program to prevent endangerment of USDWs. 42 U.S.C 300h–4.

documents/implementation_manual_508_010318.pdf.

[530] "Confining zone" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. 40 CFR 146.3.

[531] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[532] See EPA. Emergency and Remedial Response Plan: 40 CFR 146.94(a) template. *https://www.epa.gov/system/files/documents/2022-03/err_plan_template.docx.* See also EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[533] 40 CFR 146.82(a)(3)(v).

[534] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf; see also* EPA. Letter from the EPA Administrator Michael S. Regan to U.S. State Governors. December 9, 2022. *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[535] EPA. (2023). Targeted UIC program grants for Class VI Wells. *https://www.epa.gov/uic/underground-injection-control-grants#ClassVI_Grants.*

[536] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[537] EPA. (2011). Geologic Sequestration of Carbon Dioxide—UIC Quick Reference Guide. *https://www.epa.gov/sites/default/files/2015-07/documents/epa816r11002.pdf.*

[538] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[539] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

[540] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

In promulgating the Class VI regulations, the EPA recognized that if the business model for ER shifts to focus on maximizing CO_2 injection volumes and permanent storage, then the risk of endangerment to USDWs is likely to increase. As an ER project shifts away from oil and/or gas production, injection zone pressure and carbon dioxide volumes will likely increase if carbon dioxide injection rates increase, and the dissipation of reservoir pressure will decrease if fluid production from the reservoir decreases. Therefore, the EPA's regulations require the operator of a Class II well to obtain a Class VI permit when there is an increased risk to USDWs. 40 CFR 144.19.[541] While the EPA's regulations require the Class II well operator to assess whether there is an increased risk to USDWs (considering factors identified in the EPA's regulations), the permitting authority can also make this assessment and, in the event that an operator makes changes to Class II operations such that the increased risk to USDWs warrants transition to Class VI and the operator does not notify the permitting authority, the operator may be subject to SDWA enforcement and compliance actions to protect USDWs, including cessation of injection. The determination of whether there is an increased risk to USDWs would be based on factors specified in 40 CFR 144.19(b), including increase in reservoir pressure within the injection zone; increase in CO_2 injection rates; and suitability of the Class II Area of Review (AoR) delineation.

(c) Greenhouse Gas Reporting Program (GHGRP)

The GHGRP requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States. Approximately 8,000 facilities are required to report their emissions, injection, and/or supply activity annually, and the non-confidential reported data are made available to the public around October of each year. To complement the UIC regulations, the EPA included in the GHGRP air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration. These requirements are included in 40 CFR part 98, subpart RR and subpart VV, also referred to as "GHGRP subpart RR" and "GHGRP subpart VV."

GHGRP subpart RR applies to "any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations" [542] and provides the monitoring and reporting mechanisms to quantify CO_2 storage and to identify, quantify, and address potential leakage. The EPA designed GHGRP subpart RR to complement the UIC monitoring and testing requirements. See *e.g.,* 40 CFR 146.90–91. Reporting under GHGRP subpart RR is required for, but not limited to, all facilities that have received a UIC Class VI permit for injection of CO_2.[543] Under existing GHGRP regulations, facilities that conduct ER in Class II wells are not subject to reporting data under GHGRP subpart RR unless they have chosen to submit a proposed monitoring, reporting, and verification (MRV) plan to the EPA and received an approved plan from the EPA. Facilities conducting ER and who do not choose to submit a subpart RR MRV plan to the EPA would otherwise be required to report CO_2 data under subpart UU.[544] GHGRP subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the mass of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities.[545] [546] [547] [548] Extensive subsurface monitoring is required for UIC Class VI wells at 40 CFR 146.90 and is the primary means of determining if the injected CO_2 remains in the authorized injection zone and otherwise does not endanger any USDW, and monitoring under a GHGRP subpart RR MRV Plan complements these requirements. The MRV plan includes five major components: a delineation of monitoring areas based on the CO_2 plume location; an identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways; a strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs; an approach for establishing the expected baselines for monitoring CO_2 surface leakage; and, a summary of considerations made to calculate site-specific variables for the mass balance equation.[549]

In April 2024, the EPA finalized a new GHGRP subpart, "Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery (EOR) Using ISO 27916" (or GHGRP subpart VV).[550] GHGRP subpart VV applies to facilities that quantify the geologic sequestration of CO_2 in association with EOR operations in conformance with the ISO standard designated as CSA/ANSI ISO 27916:2019, Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery. Facilities that have chosen to submit an MRV plan and report under GHGRP subpart RR must not report data under GHGRP subpart VV. GHGRP subpart VV is largely modeled after the requirements in this ISO standard and focuses on quantifying storage of CO_2. Facilities subject to GHGRP subpart VV must include in their GHGRP annual report a copy of their EOR Operations Management Plan (EOR OMP). The EOR OMP includes a description of the EOR complex and engineered system, establishes that the EOR complex is adequate to provide safe, long-term containment of CO_2, and includes site-specific and other information including a geologic characterization of the EOR complex, a description of the facilities within the EOR project, a description of all wells and other engineered features in the EOR project, and the operations history of the project reservoir.[551]

Based on the understanding developed from existing projects, the security of sequestered CO_2 is expected to increase over time after injection ceases.[552] This is due to trapping mechanisms that reduce CO_2 mobility over time (*e.g.,* physical CO_2 trapping by a low-permeability geologic seal or chemical trapping by conversion or adsorption).[553] The EPA acknowledges the potential for some leakage of CO_2 to the atmosphere at sequestration sites, primarily while injection operations are active. For example, small quantities of the CO_2 that were sent to the

[541] EPA. (2015). Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI. *https://www.epa.gov/sites/default/files/2015-07/documents/class2eorclass6memo_1.pdf.*

[542] See 40 CFR 98.440.

[543] 40 CFR 98.440.

[544] As discussed in section X.C.5.b, entities conducting CCS to comply with this rule would be required to send the captured CO_2 to a facility that reports data under subpart RR or subpart VV.

[545] 40 CFR 98.446.

[546] 40 CFR 98.448.

[547] 40 CFR 98.446(f)(9) and (10).

[548] 40 CFR 98.446(f)(12).

[549] 40 CFR 98.448(a).

[550] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[551] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[552] "Report of the Interagency Task Force on Carbon Capture and Storage." 2010. *https://www.osti.gov/servlets/purl/985209.*

[553] See, *e.g.,* Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

sequestration site may be emitted from leaks in pipes and valves that are traversed before the CO_2 actually reaches the sequestration formation. However, the EPA's robust UIC regulatory protections protect against leakage out of the injection zone. Relative to the 46.75 million metric tons of CO_2 reported as sequestered under subpart RR of the GHGRP between 2016 to 2022, only 196,060 metric tons were reported as leakage/emissions to the atmosphere in the same time period (representing less than 0.5% of the sequestration amount). Of these emissions, most were from equipment leaks and vented emissions of CO_2 from equipment located on the surface rather than leakage from the subsurface.[554] Furthermore, any leakage of CO_2 at a sequestration facility would be required to be quantified and reported under the GHGRP subpart RR or subpart VV, and such data are made publicly available on the EPA's website.

(5) Timing of Permitting for Sequestration Sites

As previously discussed, the EPA is the Class VI permitting authority for states, tribes, and territories that have not obtained primacy over their Class VI programs.[555] The EPA is committed to reviewing UIC Class VI permits as expeditiously as possible when the agency is the permitting authority. The EPA has the experience to properly regulate and review permits for UIC Class VI injection wells, and technical experts of multiple disciplines to review permit applications submitted to the EPA.

The EPA has seen a considerable uptick in Class VI permit applications over the past few years. The 2018 passage of revisions and enhancements to the IRC section 45Q tax credit that provides tax credits for carbon oxide (including CO_2) sequestration has led to an increase in Class VI permit applications submitted to the EPA. The 2022 IRA further expanded the IRC section 45Q tax credit and the 2021 IIJA established a $50 million program for grants to help states and tribes in developing and implementing a UIC Class VI primacy program, leading to even more interest in this area.[556] Between 2011, when the Class VI rule went into effect, and 2020, the EPA received a total of 8 permit applications for Class VI wells. The EPA then received 12 Class VI permit applications in 2021, 44 in 2022, and 123 in 2023. As of March 2024, the EPA has 130 Class VI permit applications under review (56 permit applications were transferred to Louisiana in February 2024 when the EPA rule granting Class VI primacy to the state became effective). The majority of those 130 permit applications (63%) were submitted to the EPA within the past 12 months. Also, as of March 2024, the EPA has issued eight Class VI permits, including six for projects in Illinois and two for projects in Indiana, and has released for public comment four additional draft permits for proposed projects in California. Two of the permits are in the pre-operation phase, one is in the injection phase, and one is in the post-injection monitoring phase.

In light of the recent flurry of interest in this area, the EPA is devoting increased resources to the Class VI program, including through increased staffing levels in order to meet the increased demand for action on Class VI permit applications.[557] Reviewing a Class VI permit application entails a multidisciplinary evaluation to determine whether the application includes the required information, is technically accurate, and supports a risk-based determination that underground sources of drinking water will not be endangered by the proposed injection activity. A wide variety of technical experts—from geologists to engineers to physical scientists—review permit applications submitted to the EPA. The EPA has been working to develop staff expertise and increase capacity in the UIC program, and the agency has effectively deployed appropriated resources over the last five years to scale UIC program staff from a few employees to the equivalent of more than 25 full-time employees across the agency's headquarters and regional offices. We expect that the additional resources and staff capacity for the Class VI program will lead to increased efficiencies in the Class VI permitting process.

In addition to increased staffing resources, the EPA has made considerable improvements to the Class VI permitting process to reduce the time needed to make final permitting decisions for Class VI wells while maintaining a robust and thorough review process that ensures USDWs are protected. The EPA has created additional resources for applicants including upgrading the Geologic Sequestration Data Tool (GSDT) to guide applicants through the application process.[558] The EPA has also created resources for permit writers including training series and guidance documents to build capacity for Class VI permitting.[559] Additionally, the EPA issued internal guidelines to streamline and create uniformity and consistency in the Class VI permitting process, which should help to reduce permitting timeframes. These internal guidelines include the expectation that EPA Regions will classify all Class VI well applications received on or after December 12, 2023, as applications for major new UIC injection wells, which requires the Regions to develop project decision schedules for reviewing Class VI permit applications. The guidelines also set target timeframes for components of the permitting process, such as the number of days EPA Regions should set for public comment periods and for developing responses to comments and final permit decisions. The EPA will continue to evaluate its internal UIC permitting processes to identify potential opportunities for streamlining and other improvements over time. Although the available data for Class VI wells is limited, the timeframe for processing Class I wells, which follows a similar regulatory structure, is typically less than 2 years.[560]

The EPA notes that a Class VI permit tracker is available on its website.[561] This tracker shows information for the 44 projects (representing 130 wells) that have submitted Class VI applications to the EPA, including details such as the current permit review stage, whether a project has been sent a Notice of Deficiency (NOD) or Request for Additional Information (RAI), and the applicant's response time to any NODs or RAIs. As mentioned above, most of the permits submitted to the EPA have been submitted within the past 12

[554] Based on subpart RR data retrieved from the EPA Facility Level Information on Greenhouse Gases Tool (FLIGHT), at *https://ghgdata.epa.gov/ghgp/main.do*. Retrieved March 2024.

[555] See 40 CFR part 145 (State UIC Program Requirements), 40 CFR part 147 (State, Tribal, and EPA-Administered Underground Injection Control Programs).

[556] EPA. (2023). Targeted UIC program grants for Class VI Wells *https://www.epa.gov/uic/underground-injection-control-grants#ClassVI_Grants*.

[557] EPA. (2023). Testimony Of Mr. Bruno Pigott, Principal Deputy Assistant Administrator for Water, U.S. Environmental Protection Agency, Hearing On Carbon Capture And Storage. *https://www.epa.gov/system/files/documents/2023-11/testimony-pigott-senr-hearing-nov-2-2023_-cleared.pdf*.

[558] EPA. (2023). Geologic Sequestration Data Tool (GSDT). *https://www.epa.gov/system/files/documents/2023-10/geologic-sequestration-data-tool_factsheet_oct2023.pdf*.

[559] EPA. (2023). Final Class VI Guidance Documents. *https://www.epa.gov/uic/final-class-vi-guidance-documents*.

[560] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf*.

[561] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa*.

months. The EPA aims to review complete Class VI applications and issue permits when appropriate within approximately 24 months. This timeframe is dependent on several factors, including the complexity of the project and the quality and completeness of the submitted application. It is important for the applicant to submit a complete application and provide any information requested by the permitting agency in a timely manner so as not to extend the overall time for the review.

States may apply to the EPA for primacy to administer the Class VI programs within their states. The primacy application process has four phases: (1) pre-application activities, (2) completeness review and determination, (3) application evaluation, and (4) rulemaking and codification. To date, three states have been granted primacy for Class VI wells, including North Dakota, Wyoming, and most recently Louisiana.[562] As discussed above, North Dakota has issued 6 Class VI permits since receiving Class VI primacy in 2018, and Wyoming issued its first three Class VI permits in December 2023.[563 564 565] The EPA finalized a rule granting Louisiana Class VI primacy in January 2024 and the state's program became effective in February 2024. At that time, EPA Region 6 transferred 56 Class VI permit applications for projects in Louisiana to the state for continued review and permit issuance if appropriate. Prior to receiving primacy, the state worked with the EPA in understanding where each application was in the evaluation process. Currently, the EPA is working with the states of Texas, Arizona, and West Virginia as they are developing their UIC primacy applications.[566] Arizona submitted a primacy application to the EPA on February 13, 2024.[567] Texas and West Virginia are engaging with the EPA to complete pre-application activities.[568] If more states apply for and receive Class VI primacy, the number of permits in EPA review is expected to be reduced. The EPA has also created resources for regulators including training series and guidance documents to build capacity for Class VI permitting within UIC programs across the U.S. Through state primacy for Class VI programs, state expertise and capacity can be leveraged to support effective and efficient permit application reviews. The IIJA established a $50 million grant program to support states, Tribes, and territories in developing and implementing UIC Class VI programs. The EPA has allocated $1,930,000 to each state, tribe, and territory that submitted letters of intent.[569]

(6) Comments Received on Geologic Sequestration and Responses

The EPA received comments on geologic sequestration. Those comments, and the EPA's responses, are as follows.

Comment: Some commenters expressed concerns that the EPA has not demonstrated the adequacy of carbon sequestration at a commercial scale.

Response: The EPA disagrees that commercial carbon sequestration capacity will be inadequate to support this rule. As detailed in section VII.C.1.a.i(D)(1), commercial geologic sequestration capacity is growing in the United States. Multiple commercial sequestration facilities, other than those funded under EPAct05, are in construction or advanced development, with some scheduled to open for operation as early as 2025.[570] These facilities have proposed sequestration capacities ranging from 0.03 to 6 million tons of CO_2 per year. The EPA and states with approved UIC Class VI programs (including Wyoming, North Dakota, and Louisiana) are currently reviewing UIC Class VI geologic sequestration well permit applications for proposed sequestration sites in fourteen states.[571 572 573] As of March 2024, there are 44 projects with 130 injection wells are under review by the EPA.[574] Furthermore, the EPA anticipates that as the demand for commercial sequestration grows, more commercial sites will be developed in response to financial incentives.

Comment: Some commenters expressed concern about leakage of CO_2 from sequestration sites.

Response: The EPA acknowledges the potential for some leakage of CO_2 to the atmosphere at sequestration sites (such as leaks through valves before the CO_2 reaches the injection formation). However, as detailed in the preceding sections of preamble, the EPA's robust UIC permitting process is adequate to protect against CO_2 escaping the authorized injection zone (and then entering the atmosphere). As discussed in the preceding section, leakage out of the injection zone could trigger emergency and remedial response action including ceasing injection, possible permit modification, and possible enforcement action. Furthermore, the GHGRP subpart RR and subpart VV regulations prescribe accounting methodologies for facilities to quantify and report any potential leakage at the surface, and the EPA makes sequestration data and related monitoring plans publicly available on its website. The reported emissions/leakage from sequestration sites under subpart RR is a comparatively small fraction (less than 0.5 percent) of the associated sequestration volumes, with most of these reported emissions attributable to leaks or vents from surface equipment.

Comment: Some commenters expressed concern over safety due to induced seismicity.

Response: The EPA believes that the UIC program requirements adequately address potential safety concerns with induced seismicity at site-adjacent communities. More specifically, through the UIC Class VI program the EPA has put in place mechanisms to identify,

[562] On December 28, 2023, the EPA Administrator signed a final rule granting Louisiana's request for primacy for UIC Class VI junction wells located within the state. See EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[563] Wyoming Department of Environmental Quality. (2023). Wyoming grants its first three Class VI permits. *https://deq.wyoming.gov/2023/12/wyoming-grants-its-first-three-class-vi-permits/.*

[564] Ibid.

[565] Arnold & Porter. (2023). EPA Provides Increased Transparency in Class VI Permitting Process; Now Incorporated in Update to Interactive CCUS State Tracker. *https://www.arnoldporter.com/en/perspectives/blogs/environmental-edge/2023/11/ccus-state-legislative-tracker.*

[566] EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[567] Arizona Department of Environmental Quality. (2024). Underground Injection Control (UIC) Program. *https://azdeq.gov/UIC.*

[568] EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[569] EPA. (2023). Underground Injection Control (UIC) Class VI Grant Program. *https://www.epa.gov/system/files/documents/2023-11/uic-class-vi-grant-fact-sheet.pdf.*

[570] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[571] UIC regulations for Class VI wells authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water. The major components to be included in UIC Class VI permits are detailed further in section VII.C.1.a.i(D)(4).

[572] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 25, 2024. *https://www.epa.gov/uic/table-epas-draft-and-final-class-vi-well-permits* Last updated January 19, 2024.

[573] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[574] Ibid.

monitor, and mitigate risks associated with induced seismicity in any areas within or surrounding a sequestration site through permit and program requirements, such as site characterization and monitoring, and the requirement for applicants to demonstrate that induced seismic activity will not endanger USDWs.[575] See section VII.C.1.a.i(D)(4)(b) for further discussion of mitigating induced seismicity risk. Although the UIC Class II program does not have specific requirements regarding seismicity, it includes discretionary authority to add additional conditions to a UIC permit on a case-by-case basis. The EPA created a document outlining practical approaches for UIC Directors to use to minimize and manage injection-induced seismicity in Class II wells.[576] Furthermore, during site characterization, if any of the geologic or seismic data obtained indicate a substantial likelihood of seismic activity, further analyses, potential planned operational changes, and additional monitoring may be required.[577] The EPA has the authority to require seismic monitoring as a condition of the UIC permit if appropriate, or to deny the permit if the injection-induced seismicity risk could endanger USDWs.

Comment: Some commenters have expressed concern that the EPA has not meaningfully engaged with historically disadvantaged and overburdened communities who may be impacted by environmental changes due to geologic sequestration.

Response: The EPA acknowledges that meaningful engagement with local communities is an important step in the development of geologic sequestration projects and has programs and public participation requirements in place to support this process. The EPA is committed to advancing environmental justice for overburdened communities in all its programs, including the UIC Class VI program.[578] The EPA's environmental justice guidance for Class VI permitting and primacy states that many of the expectations are broadly applicable, and EPA Regions should apply them to the other five injection well classes, including Class II, wherever possible.[579] See section VII.C.1.a.i(D)(4) for a detailed discussion of environmental justice requirements and guidance.

Comment: Commenters expressed concern that companies are not always in compliance with reporting requirements for subpart RR when required for other Federal programs.

Response: The EPA recognizes the need for geologic sequestration facilities to comply with the reporting requirements of the GHGRP, and acknowledges that there have been instances of entities claiming geologic sequestration under non-EPA programs (*e.g.,* to qualify for IRC section 45Q tax credits) while not having an EPA-approved MRV plan or reporting data under subpart RR.[580] The EPA does not implement the IRC section 45Q tax credit program, and it is not privy to taxpayer information. Thus, the EPA has no role in implementing or enforcing these tax credit claims, and it is unclear, for example, whether these companies would have been required by GHGRP regulations to report data under subpart RR, or if they would have been required only by the IRC section 45Q rules to opt-in to reporting under subpart RR. The EPA disagrees that compliance with the GHGRP would be a problem for this rule because the rule requires any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground to report under GHGRP subpart RR or GHGRP subpart VV. Unlike the IRC section 45Q tax credit program, which is implemented by the Internal Revenue Service (IRS), the EPA will have the information necessary to discern whether a facility is in compliance with any applicable GHGRP requirements. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility that reports in accordance with GHGRP subpart RR or GHGRP subpart VV. For more information on the relationship to GHGRP requirements, see section X.C.5 of this preamble.

Comment: Commenters expressed concerns that UIC regulations allow Class II wells to be used for long-term CO_2 storage if the operator assesses that a Class VI permit is not required and asserted that Class II regulations are less protective than Class VI regulations.

Response: The EPA acknowledges that Class II wells for EOR may be used to inject CO_2 including CO_2 captured from an EGU. However, the EPA disagrees that the use of Class II wells for ER will be less protective of human health than the use of Class VI wells for geologic sequestration. Class II wells are used only to inject fluids associated with oil and natural gas production, and Class II ER wells are used specifically for the injection of fluids, including CO_2, for the purpose of enhanced recovery of oil or natural gas. The EPA's UIC Class II program is designed to prevent Class II injection activities from endangering USDWs. Any leakage out of the designated injection zone could pose a risk to USDWs and therefore could be subject to enforcement action or permit modification. Therefore, the EPA believes that UIC protections for USDWs would also ensure that the injected CO_2 is contained in the subsurface formations. The Class II programs of states and tribes must be approved by the EPA and must meet EPA regulatory requirements for Class II programs, 42 U.S.C. 300h–1, or otherwise represent an effective program to prevent endangerment of USDWs. 42 U.S.C 300h–4. The EPA's regulations require the operator of a Class II well to obtain a Class VI permit when operations shift to geologic sequestration and there is consequently an increased risk to USDWs. 40 CFR 144.19. UIC Class VI regulations require that owners or operators must show that the injection zone has sufficient volume to contain the injected carbon dioxide stream and report any fluid migration out of the injection zone and into or between USDWs. 40 CFR 146.83 and 40 CFR 146.91. The EPA emphasizes that while CO_2 captured from an EGU can be injected into a Class II ER injection well, it cannot be injected into the other two types of Class II wells, which are Class II disposal wells and Class II wells for the storage of hydrocarbons. 40 CFR 144.6(b).

Comment: Some commenters expressed concern that because few Class VI permits have been issued, the EPA's current level of experience in properly regulating and reviewing permits for these wells is limited.

[575] EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[576] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[577] 40 CFR 146.82(a)(3)(v).

[578] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf; see also* EPA. Letter from the EPA Administrator Michael S. Regan to U.S. State Governors. December 9, 2022. *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[579] EPA. (2023). Environmental Justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[580] Letter from U.S. Treasury Inspector General for Tax Administration (TIGTA). (2020). *https://www.menendez.senate.gov/imo/media/doc/TIGTA%20IRC%2045Q%20Response%20Letter%20FINAL%2004-15-2020.pdf.*

Response: The EPA disagrees that the Agency lacks experience to properly regulate, and review permits for Class VI injection wells. We expect that the additional resources that have been allocated for the Class VI program will lead to increased efficiencies in the Class VI permitting process and timeframes. For a more detailed discussion of Class VI permitting and timeframes, see sections VII.C.1.a.i(D)(4)(b) and VII.C.1.a.i(D)(5) of this preamble. The EPA emphasizes that incomplete or insufficient application materials can result in substantially delayed permitting decisions. When the EPA receives incomplete or insufficient permit applications, the EPA communicates the deficiencies, waits to receive additional materials from the applicant, and then reviews any new data. This back and forth can result in longer permitting timeframes. The EPA therefore encourages applicants to contact their permitting authority early on so applicants can gain a thorough understanding of the Class VI permitting process and the permitting authority's expectations. To assist potential permit applicants, the EPA maintains a list of UIC contacts within each EPA Regional Office on the Agency's website.[581] The EPA has met with more than 100 companies and other interested parties.

Comment: Some commenters claimed that various legal uncertainties preclude a finding that geologic sequestration of CO_2 has been adequately demonstrated. This concern has been raised in particular with issues of pore space ownership and the lack of long-term liability insurance and noted uncertainties regarding long-term liability generally.

Response: The EPA disagrees that these uncertainties are sufficient to prohibit the development of geologic sequestration projects. An interagency CCS task force examined sequestration-related legal issues thoroughly and concluded that early CCS projects could proceed under the existing legal framework with respect to issues such as property rights and liability.[582] The development of CCS projects may be more complex in certain regions, due to distinct pore space ownership regulatory regimes at the state level, except on Federal lands.[583]

As discussed in section VII.C.1.a.i.(D)(4) of this preamble, Title V of the FLPMA and its implementing regulations, 43 CFR part 2800, authorize the BLM to issue ROWs to geologically sequester CO_2 in Federal pore space, including BLM ROWs for the necessary physical infrastructure and for the use and occupancy of the pore space itself. The BLM has published a policy defining access to pore space on BLM lands, including clarification of Federal policy for situations where the surface and pore space are under the control of different Federal agencies.[584]

States have established legislation and regulations defining pore space ownership and providing clarification to prospective users of surface pore space. For example, in North Dakota, the surface owner also owns the pore space underlying their surface estate.[585] North Dakota state courts have determined that in situations where the surface ownership and mineral ownership have been legally severed the mineral estate is the dominant estate and has the right to use as much of the surface estate as reasonably necessary. The North Dakota legislature codified this interpretation in 2019.[586] Summit Carbon Solutions, which is developing a carbon storage hub in North Dakota to store an estimated one billion tons of CO_2, indicated that they had secured the majority of the pore space needed through long term leases with landowners.[587] Wyoming defines ownership of pore space underlying surfaces within the state.[588] Other states have also established laws, implementing regulations and guidance defining ownership and access to pore space. The EPA notes that many states are actively enacting legislation addressing pore space ownership. See *e.g.,* Wyoming H.B. No. 89 (2008) (Wyo. Stat. § 34–1–152); Montana S.B. No. 498 (2009) (Mont. Code Ann. 82–11–180); North Dakota S.B. No. 2139 (2009) (N.D. Cent. Code § 47–31–03); Kentucky H.B. 259 (2011) (Ky. Rev. Stat. Ann. § 353.800); West Virginia H.B. 4491 (2022) (W. Va. Code § 22–11B–18); California S.B. No. 905 (2022) (Cal. Pub. Res. Code § 71462); Indiana Public Law 163 (2022) (Ind. Code § 14–39–2–3); Utah H.B. 244 (2022) (Utah Code § 40–6–20.5).

Liability during operation is usually assumed by the project operator, so liability concerns primarily arise after the period of operations. Research has previously shown that the environmental risk is greatest before injection stops.[589] In terms of long-term liability and permittee obligations under the SDWA, the EPA's Class VI regulations impose various requirements on permittees even after injection ceases, including regarding injection well plugging (40 CFR 146.92), post-injection site care (PISC), and site closure (40 CFR 146.93). The default time period for post-injection site care is 50 years, during which the permittee must monitor the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered. 40 CFR 146.93. The permittee must also generally maintain financial responsibility sufficient to cover injection well plugging, corrective action, emergency and remedial response, PISC, and site closure until the permitting authority approves site closure. 40 CFR 146.85(a)&(b). Even after the former permittee has fulfilled all its UIC regulatory obligations, it may still be held liable for previous regulatory noncompliance, such as where the permittee provided erroneous data to support approval of site closure. A former permittee may always be subject to an order that the EPA Administrator deems necessary to protect public health if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW. 42 U.S.C. 300i; 40 CFR 144.12(e).

The EPA notes that many states are enacting legislation addressing long term liability. See *e.g.,* Montana S.B. No. 498 (2009) (Mont. Code Ann. 82–11–183); Texas H.B. 1796 (2009) (Tex. Health & Safety Code Ann. § 382.508); North Dakota S.B. No. 2095 (2009) (N.D. Cent. Code § 38–22–17); Kansas H.B.

[581] EPA. (2023). Underground Injection Control Class VI (Geologic Sequestration) Contact Information. *https://www.epa.gov/uic/underground-injection-control-class-vi-geologic-sequestration-contact-information.*

[582] Report of the Interagency Task Force on Carbon Capture and Storage. 2010. *https://www.energy.gov/fecm/articles/ccstf-final-report.*

[583] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[584] National Policy for the Right-of-Way Authorizations Necessary for Site Characterization, Capture, Transportation, Injection, and Permanent Geologic Sequestration of Carbon Dioxide in Connection with Carbon Sequestration Projects. BLM IM 2022–041 Instruction Memorandum, June 8, 2022. *https://www.blm.gov/policy/im-2022-041.*

[585] ND DMR 2023. Pore Space in North Dakota. North Dakota Department of Mineral Resources *https://www.dmr.nd.gov/oilgas/ND_DMR_Pore_Space_Information.pdf.*

[586] Ibid.

[587] Summit Carbon Solutions. (2021). Summit Carbon Solutions Announces Significant Carbon Storage Project Milestones. (2021). *https://summitcarbonsolutions.com/summit-carbon-solutions-announces-significant-carbon-storage-project-milestones/.*

[588] Wyo. Stat § 34–1–152 (2022).

[589] Benson, S.M. (2007). Carbon dioxide capture and storage: research pathways, progress and potential. Presentation given at the Global Climate & Energy Project Annual Symposium, October 1, 2007. *https://drive.google.com/file/d/1ZvfRW92OqvBBAFs69SPHIWoYFGySMgtD/view.*

2418 (2010) (Kan. Stat. Ann. § 55–1637(h)); Wyoming S.F. No. 47 (2022) (Wyo. Stat. §§ 35–11–319); Louisiana H.B. 661 (2009) & H.B. 571 (2023) (La. Stat. Ann. § 30:1109). Because states are actively working to address pore space and liability uncertainties, the EPA does not believe these to be issues that would delay project implementation beyond the timelines discussed in this preamble.

(E) Compliance Date for Long-Term Coal-Fired Steam Generating Units

The EPA proposed a January 1, 2030 compliance date for long-term coal fired steam generating units subject to a CCS BSER. That compliance date assumed installation of CCS was concurrent with development of state plans. While several commenters were supportive of the proposed compliance date, the EPA also received comments on the proposed rule that stated that the proposed compliance date was not achievable. Commenters referenced longer project timelines for CO_2 capture. Commenters also requested that the EPA should account for the state plan process in determining the appropriate compliance date.

The EPA has considered the comments and information available and is finalizing a compliance date of January 1, 2032, for long-term coal-fired steam generating units. The EPA is also finalizing a mechanism for a 1-year compliance date extension in cases where a source faces delays outside its control, as detailed in section X.C.1.d of this preamble. The justification for the January 1, 2032 compliance date does not require substantial work to be done during the state planning process. Rather, the justification for the compliance date reflects the assumption that only the initial feasibility work which is necessary to inform the state planning process would occur during state plan development, with the start of more substantial work beginning after the due date for state plan submission, and a longer timeline for installation of CCS than at proposal. In total, this allows for 6 years and 7 months for both initial feasibility and more substantial work to occur after issuance of this rule. This is consistent with the approximately 6 years from start to finish for Boundary Dam Unit 3 and Petra Nova.

The timing for installation of CCS on existing coal-fired steam generating units is based on the baseline project schedule for the CO_2 capture plant developed by Sargent and Lundy (S&L [590] and a review of the available information for installation of CO_2 pipelines and sequestration sites.[591] Additional details on the timeline are in the TSD *GHG Mitigation Measures for Steam Generating Units,* available in the docket. The dates for intermediate steps are for reference. The specific sequencing of steps may differ slightly, and, for some sources, the duration of one step may be shorter while another may be longer, however the total duration is expected to be the same. The resulting timeline is therefore an accurate representation of the time necessary to install CCS in general.

The EPA assumes that feasibility work, amounting to less than 1 year (June 2024 through June 2025) for each component of CCS (capture, transport, and storage) occurs during the state plan development period (June 2024 through June 2026). This feasibility work is limited to initial conceptual design and other preliminary tasks, and the costs of the feasibility work in general are substantially less than other components of the project schedule. The EPA determined that it was appropriate to assume that this work would take place during the state plan development period because it is necessary for evaluating the controls that the state may determine to be appropriate for a source and is necessary for determining the resulting standard of performance that the state may apply to the source on the basis of those controls. In other words, without such feasibility and design work, it would be very difficult for a state to determine whether CCS is appropriate for a given source or the resulting standard of performance. While the EPA accounts for up to 1 year for feasibility for the capture plant, the S&L baseline schedule estimates this initial design activity can be completed in 6 months. For the capture plant, feasibility includes a preliminary technical evaluation to review the available utilities and siting footprint for the capture plant, as well as screening of the available capture technologies and vendors for the project, with an associated initial economic estimate. For sequestration, in many cases, general geologic characterization of regional areas has already been conducted by U.S. DOE and regional initiatives; however, the EPA assumes an up to 1 year period for a storage complex feasibility study. For the pipeline, the feasibility includes the initial pipeline routing analysis, taking less than 1 year. This exercise involves using software to review existing right-of-way and other considerations to develop an optimized pipeline route. Inputs to that analysis have been made publicly available by DOE in NETL's Pipeline Route Planning Database.[592]

When state plans are submitted 24 months after publication of the final rule, requirements included within those state plans should be effective at the state level. On that basis, the EPA assumes that sources installing CCS are fully committed, and more substantial work (*e.g.,* FEED study for the capture plant, permitting, land use and right-of-way acquisition) resumes in June 2026. The EPA notes, however, that it would be possible that a source installing CCS would choose to continue these activities as soon as the initial feasibility work is completed even if not yet required to do so, rather than wait for state plan submission to occur for the reasons explained in full below.

Of the components of CCS, the CO_2 capture plant is the more technically involved and time consuming, and therefore is the primary driver for determining the compliance date. The EPA assumes substantial work commences only after submission due date for state plans. The S&L baseline timeline accounts for 5.78 years (301 weeks) for final design, permitting, and installation of the CO_2 capture plant. First, the EPA describes the timeline that is consistent with the S&L baseline for substantial work. Subsequently, the EPA describes the rationale for slight adjustments that can be made to that timeline based upon an examination of actual project timelines.

In the S&L baseline, substantial work on the CO_2 capture plant begins with a 1-year FEED study (June 2026 to June 2027). The information developed in the FEED study is necessary for finalizing commercial arrangements. In the S&L baseline, the commercial arrangements can take up to 9 months (June 2027 to March 2028). Commercial arrangements include finalizing funding as well as finalizing contracts with a CO_2 capture technology provider and engineering, procurement, and construction companies. The S&L baseline accounts for 1 year for permitting, beginning when commercial arrangements are nearly complete (December 2027 to December 2028). After commercial arrangements are complete, a 2-year period for engineering and procurement begins (March 2028 to March 2030).

[590] CO_2 Capture Project Schedule and Operations Memo, Sargent & Lundy (2024). Available in Docket ID EPA–HQ–OAR–2023–0072.

[591] Transport and Storage Timeline Summary, ICF (2024). Available in Docket ID EPA–HQ–OAR–2023–0072.

[592] NETL Develops Pipeline Route Planning Database To Guide CO_2 Transport Decisions. May 31, 2023. *https://netl.doe.gov/node/12580.*

Detailed engineering starts after commercial arrangements are complete because engineers must consider details regarding the selected CO_2 capture technology, equipment providers, and coordination with construction. Shortly after permitting is complete, 6 months of sitework (March 2029 to September 2029) occur. Sitework is followed by 2 years of construction (July 2029 to July 2031). Approximately 8 months prior to the completion of construction, a roughly 14 month (60 weeks) period for startup and commissioning begins (January 2031 to March 2032).

In many cases, the EPA believes that sources are positioned to install CO_2 capture on a slightly faster timeline than the baseline S&L timeline detailed in the prior paragraph, because CCS projects have been developed in a shorter timeframe. Including these minor adjustments, the total time for detailed engineering, procurement, construction, startup and commissioning is 4 years, which is consistent with completed projects (Boundary Dam Unit 3 and Petra Nova) and project schedules developed in completed FEED studies, see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional details. In addition, the IRC tax credits incentivize sources to begin complying earlier to reap economic benefits earlier. Sources that have already completed feasibility or FEED studies, or that have FEED studies ongoing are likely to be able to have CCS fully operational well in advance of January 1, 2032. Ongoing projects have planned dates for commercial operation that are much earlier. For example, Project Diamond Vault has plans to be fully operational in 2028.[593] While the EPA assumes FEED studies start after the date for state plan submission, in practice sources are likely to install CO_2 capture as expeditiously as practicable. Moreover, the preceding timeline is derived from project schedules developed in the absence of any regulatory impetus. Considering these factors, sources have opportunities to slightly condense the duration, overlap, or sequencing of steps so that the total duration for completing substantial work on the capture plant is reduced by 2 months. For example, by expediting the duration for commercial arrangements from 9 months to 7 months, reasonably assuming sources immediately begin sitework as soon as permitting is complete, and accounting for 13 months (rather than 14) for startup and testing, the CO_2 capture plant will be fully operational by January 2032. Therefore, the EPA concludes that CO_2 capture can be fully operational by January 1, 2032. To the extent additional time is needed to take into account the particular circumstances of a particular source, the state may take those circumstances into account to provide a different compliance schedule, as detailed in section X.C.2 of this preamble.

The EPA also notes that there is additional time for permitting than described in the S&L baseline. The key permitting that affects the timeline are air permits because of the permits' impact on the ability to construct and operate the CCS capture equipment, in which the EPA is the expert in. The S&L baseline assumes permitting starts after the FEED study is complete while commercial arrangements are ongoing, however permitting can begin earlier allowing a more extended period for permitting. Examples of CCS permitting being completed while FEED studies are on-going include the air permits for Project Tundra, Baytown Energy Center, and Deer Park Energy Center. Therefore, while the FEED study is on-going, the EPA assumes that a 2-year process for permitting can begin.

The EPA's compliance deadline assumes that storage and pipelines for the captured CO_2 can be installed concurrently with deployment of the capture system. Substantial work on the storage site starts with 3 years (June 2026 to June 2029) for final site characterization, pore-space acquisition, and permitting, including at least 2 years for permitting of Class VI wells during that period. Lastly, construction for sequestration takes 1 year (June 2029 to June 2030). While the EPA assumes that storage can be permitted and constructed in 4 years, the EPA notes that there is at least an additional 12 months of time available to complete construction of the sequestration site without impacting progress of the other components.

The EPA assumes the substantial work on the pipeline lags the start of substantial work on the storage site by 6 months. After the 1 year of feasibility work prior to state plan submission, the general timeline for the CO_2 pipeline assumes up to 3 years for final routing, permitting activities, and right-of-way acquisition (December 2026 to December 2029). Lastly, there are 1.5 years for pipeline construction (December 2029 to June 2031).[594]

The EPA does not assume that CCS projects are, in general, subject to NEPA. NEPA review is required for reasons including sources receiving federal funding (*e.g.,* through USDA or DOE) or projects on federal lands. NEPA may also be triggered for a CCS project if NEPA compliance is necessary for construction of the pipeline, such as where necessary because of a Clean Water Act section 404 permit, or for sequestration. Generally, if one aspect of a project is subject to NEPA, then the other project components could be as well. In cases where a project is subject to NEPA, an environmental assessment (EA) that takes 1 year, can be finalized concurrently during the permitting periods of each component of CCS (capture, pipeline, and sequestration). However, the EPA notes that the final timeline can also accommodate a concurrent 2-year period if an EIS were required under NEPA across all components of the project. The EPA also notes that, in some circumstances, NEPA review may begin prior to completion of a FEED study. For Petra Nova, a notice of intent to issue an EIS was published on November 14, 2011, and the record of decision was issued less than 2 years later, on May 23, 2013,[595] while the FEED study was completed in 2014.

Based on this detailed analysis, the EPA has concluded that January 1, 2032, is an achievable compliance date for CCS on existing coal-fired steam generating units that takes into account the state plan development period, as well as the technical and bureaucratic steps necessary to install and implement CCS and is consistent with other expert estimates and real-world experience.

(F) Long-Term Coal-Fired Steam Generating Units Potentially Subject to This Rule

In this section of the preamble, the EPA estimates the size of the inventory of coal-fired power plants in the long-term subcategory likely subject to CCS as the BSER. Considering that capacity, the EPA also describes the distance to storage for those sources.

(1) Capacity of Units Potentially Subject to This Rule

First, the EPA estimates the total capacity of units that are currently operating and that have not announced plans to retire by 2039, or to cease firing

[593] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[594] The summary timeline for CO_2 pipelines assumes feasibility for pipelines is 1 year, followed by 1.5 years for permitting, with the pipeline feasibility beginning 1 year after permitting for sequestration starts. The EPA assumes initial pipeline feasibility occurs up-front, with a longer period for final routing, permitting, and right-of-way acquisition.

[595] Petra Nova W.A. Parish Project. *https://www.energy.gov/fecm/petra-nova-wa-parish-project.*

coal by 2030. Starting from that first estimate, the EPA then estimates the capacity of units that would likely be subject to the CCS requirement, based on unit age, industry trends, and economic factors.

Currently, there are 181 GW of coal-fired steam generating units.[596] About half of that capacity, totaling 87 GW, have announced plans to retire before 2039, and an additional 13 GW have announced plans to cease firing coal by that time. The remaining amount, 81 GW, are likely to be the most that could potentially be subject to requirements based on CCS.

However, the capacity of affected coal-fired steam generating units that would ultimately be subject to a CCS BSER is likely approximately 40 GW. This determination is supported by several lines of analysis of the historical data on the size of the fleet over the past several years. Historical trends in the coal-fired generation fleet are detailed in section IV.D.3 of this preamble. As coal-fired units age, they become less efficient and therefore the costs of their electricity go up, rendering them even more competitively disadvantaged. Further, older sources require additional investment to replace worn parts. Those circumstances are likely to continue through the 2030s and beyond and become more pronounced. These factors contribute to the historical changes in the size of the fleet.

One way to analyze historical changes in the size of the fleet is based on unit age. As the average age of the coal-fired fleet has increased, many sources have ceased operation. From 2000 to 2022, the average age of a unit that retired was 53 years. At present, the average age of the operating fleet is 45 years. Of the 81 GW that are presently operating and that have not announced plans to retire or convert to gas prior to 2039, 56 GW will be 53 years or older by 2039.[597]

Another line of analysis is based on the rate of change of the size of the fleet. The final TSD, *Power Sector Trends,* available in the rulemaking docket, includes analysis showing sharp and steady decline in the total capacity of the coal-fired steam generating fleet. Over the last 15 years (2009–2023), average annual coal retirements have been 8 GW/year. Projecting that retirements will continue at approximately the same pace from now until 2039 is reasonable because the same circumstances will likely continue or accelerate further given the incentives under the IRA. Applying this level of annual retirement would result in 45 GW of coal capacity continuing to operate by 2039. Alternatively, the TSD also includes a graph that shows what the fleet would look like assuming that coal units without an announced retirement date retire at age 53 (the average retirement age of units over the 2000–2022 period). It shows that the amount of coal-fired capacity that remains in operation by 2039 is 38 GW.

The EPA also notes that it is often the case that coal-fired units announce that they plan to retire only a few years in advance of the retirement date. For instance, of the 15 GW of coal-fired EGUs that reported a 2022 retirement year in DOE's EIA Form 860, only 0.5 GW of that capacity had announced its retirements plans when reporting in to the same EIA–860 survey 5 years earlier, in 2017.[598] Thus, although many coal-fired units have already announced plans to retire before 2039, it is likely that many others may anticipate retiring by that date but have not yet announced it.

Finally, the EPA observes that modeling the baseline circumstances, absent this final rule, shows additional retirements of coal-fired steam generating units. At the end of 2022, there were 189 GW of coal active in the U.S. By 2039, the IPM baseline projects that there will be 42 GW of operating coal-fired capacity (not including coal-to-gas conversions). Between 2023–2039, 95 GW of coal capacity have announced retirement and an additional 13 have announced they will cease firing coal. Thus, of the 81 GW that have not announced retirement or conversion to gas by 2039, the IPM baseline projects 39 GW will retire by 2039 due to economic reasons.

For all these reasons, the EPA considers that it is realistic to expect that 42 GW of coal-fired generating will be operating by 2039—based on announced retirements, historical trends, and model projections—and therefore constitutes the affected sources in the long-term subcategory that would be subject to requirements based on CCS. It should be noted that the EPA does not consider the above analysis to predict with precision which units will remain in operation by 2039. Rather, the two sets of sources should be considered to be reasonably representative of the inventory of sources that are likely to remain in operation by 2039, which is sufficient for purposes of the BSER analysis that follows.

(2) Distance to Storage for Units Potentially Subject to This Rule

The EPA believes that it is conservative to assume that all 81 GW of capacity with planned operation during or after 2039 would need to construct pipelines to connect to sequestration sites. As detailed in section VII.B.2 of this preamble, the EPA is finalizing an exemption for coal-fired sources permanently ceasing operation by January 1, 2032. About 42 percent (34 GW) of the existing coal-fired steam generation capacity that is currently in operation and has not announced plans to retire prior to 2039 will be 53 years or older by 2032. As discussed in section VII.C.1.a.i(F), from 2000 to 2022, the average age of a coal unit that retired was 53 years old. Therefore, the EPA anticipates that approximately 34 GW of the total capacity may permanently cease operation by 2032 despite not having yet announced plans to do so. Furthermore, of the coal-fired steam generation capacity that has not announced plans to cease operation before 2039 and is further than 100 km (62 miles) of a potential saline sequestration site, 45 percent (7 GW) will be over 53 years old in 2032. Therefore, it is possible that much of the capacity that is further than 100 km (62 miles) of a saline sequestration site and has not announced plans to retire will permanently cease operation due to age before 2032 and thus the rule would not apply to them. Similarly, of the coal-fired steam generation capacity that has not announced plans to cease operation before 2039 and is further than 160 km (100 miles) of a potential saline sequestration site, 56 percent (4 GW) will be over 53 years old in 2032. Therefore, the EPA notes that it is possible that the majority of capacity that is further than 160 km (100 miles) of a saline sequestration and has not announced plans to retire site will permanently cease operation due to age before 2032 and thus be exempt from the requirements of this rule.

The EPA also notes that a majority (56 GW) of the existing coal-fired steam generation capacity that is currently in operation and has not announced plans to permanently cease operation prior to 2039 will be 53 years or older by 2039. Of the coal-fired steam generation capacity with planned operation during

[596] EIA December 2023 Preliminary Monthly Electric Generator Inventory. *https://www.eia.gov/electricity/data/eia860m/.*

[597] 81 GW is derived capacity, plant type, and retirement dates as represented in EPA NEEDS database. Total amount of covered capacity in this category may ultimately be slightly less (approximately) due to CHP-related exemptions.

[598] The survey Form EIA–860 collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity. Data available at *https://www.eia.gov/electricity/data/eia860/.*

or after 2039 that is not located within 100 km (62 miles) of a potential saline sequestration site, the majority (58 percent or 9 GW) of the units will be 53 years or older in 2039.[599] Consequently, the EPA believes that many of these units may permanently cease operation due to age prior to 2039 despite not at this point having announced specific plans to do so, and thereby would likely not be subject to a CCS BSER.

(G) Resources and Workforce To Install CCS

Sufficient resources and an available workforce are required for installation and operation of CCS. Raw materials necessary for CCS are generally available and include common commodities such as steel and concrete for construction of the capture plant, pipelines, and storage wells.

Drawing on data from recently published studies, the DOE completed an order-of-magnitude assessment of the potential requirements for specialized equipment and commodity materials for retrofitting existing U.S. coal-fueled EGUs with CCS.[600] Specialized equipment analyzed included absorbers, strippers, heat exchangers, and compressors. Commodity materials analyzed included monoethanolamine (MEA) solvent for carbon capture, triethylene glycol (TEG) for carbon dioxide drying, and steel and cement for construction of certain aspects of the CCS value chain.[601] The DOE analyzed one scenario in which 42 GW of coal-fueled EGUs are retrofitted with CCS and a second scenario in which 73 GW of coal-fueled EGUs are retrofitted with CCS.[602] The analysis determined that in both scenarios, the maximum annual commodity requirements to construct and operate the CCS systems are likely to be much less than their respective global production rates. The maximum requirements are expected to be at least one order of magnitude lower than global annual production for all of the commodities considered except MEA, which was estimated to be approximately 14 percent of global annual production in the 42 GW scenario and approximately 24 percent of global annual production in the 73 GW scenario.[603] For steel and cement, the maximum annual requirements are also expected to be at least one order of magnitude lower than U.S. annual production rates. Finally, the DOE analysis determined that it is unlikely that the deployment scenarios would encounter any bottlenecks in the supplies of specialized equipment (absorbers, strippers, heat exchangers, and compressors) because of the large pool of potential suppliers.

The workforce necessary for installing and operating CCS is readily available. The required workforce includes construction, engineering, manufacturing, and other skilled labor (*e.g.,* electrical, plumbing, and mechanical trades). The existing workforce is well positioned to meet the demand for installation and operation of CCS. Many of the skills needed to build and operate carbon capture plants are similar to those used by workers in existing industries, and this experience can be leveraged to support the workforce needed to deploy CCS. In addition, government programs, industry workforce investments, and IRC section 45Q prevailing wage and apprenticeship provisions provide additional significant support to workforce development and demonstrate that the CCS industry likely has the capacity to train and expand the available workforce to meet future needs.[604]

Overall, quantitative estimates of workforce needs indicates that the total number of jobs needed for deploying CCS on coal power plants is significantly less than the size of the existing workforce in adjacent occupations with transferrable skills in the electricity generation and fuels industries. The majority of direct jobs, approximately 90 percent, are expected to be in the construction of facilities, which tend to be project-based. The remaining 10 percent of jobs are expected to be tied to ongoing facility operations and maintenance.[605] Recent project-level estimates bear this out. The Boundary Dam CCS facility in Canada employed 1,700 people at peak construction.[606] A recent workforce projection estimates average annual jobs related to investment in carbon capture retrofits at coal power plants could range from 1,070 to 1,600 jobs per plant. A DOE memorandum estimates that 71,400 to 107,100 average annual jobs resulting from CCS project investments—across construction, project management, machinery installers, sales representatives, freight, and engineering occupations—would likely be needed over a five-year construction period[607] to deploy CCS at

[599] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation available at:. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[600] DOE. Material Requirements for Carbon Capture and Storage Retrofits on Existing Coal-Fueled Electric Generating Units. *https://www.energy.gov/policy/articles/material-requirements-carbon-capture-and-storage-retrofits-existing-coal-fueled.*

[601] Steel requirements were assessed for carbon capture, transport and storage, but cement requirements were only assessed for capture and storage.

[602] DOE analyzed the resources—including specialized equipment, commodity materials, and, as discussed below, workforce, necessary for 73 GW of coal capacity to install CCS because that is the amount that has not announced plans to retire by January 1, 2040. As indicated in the final TSD, *Power Sector Trends,* a somewhat larger amount—81 GW—has not announced plans to retire or cease firing coal by January 1, 2039, and it is this latter amount that is the maximum that, at least in theory, could be subject to the CCS requirement. DOE's conclusions that sufficient resources are available also hold true for the larger amount.

[603] Although the assessment assumed that all of the CCS deployments would utilize MEA-based carbon capture technologies, future CCS deployments could potentially use different solvents, or capture technologies that do not use solvents, *e.g.,* membranes, sorbents. A number of technology providers have solvents that are commercially available, as detailed in section VII.C.1.a.i.(B)(3) of this preamble. In addition, a 2022 DOE carbon capture supply chain assessment concluded that common amines used in carbon capture have robust and resilient supply chains that could be rapidly scaled, with low supply chain risk associated with the main inputs for scale-up. See U.S. Department of Energy (DOE). Supply Chain Deep Dive Assessment: Carbon Capture, Transport & Storage. *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf.*

[604] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[605] Ibid.

[606] SaskPower, ''SaskPower CCS.'' *https://unfccc.int/files/bodies/awg/application/pdf/01_saskatchewan_environment_micheal_monea.pdf.* For corroboration, we note similar employment numbers for two EPAct-05 assisted projects: Petra Nova estimated it would need approximately 1,100 construction-related jobs and up to 20 jobs for ongoing operations. National Energy Technology Laboratory and U.S. Department of Energy. W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Final Environmental Impact Statement. *https://www.energy.gov/sites/default/files/EIS-0473-FEIS-Summary-2013_1.pdf.* Project Tundra projects a peak labor force of 600 to 700. National Energy Technology Laboratory and U.S. Department of Energy. Draft Environmental Assessment for North Dakota CarbonSAFE: Project Tundra. *https://www.energy.gov/sites/default/files/2023-08/draft-ea-2197-nd-carbonsafe-chapters-2023-08.pdf.*

[607] For the purposes of evaluating the actual workforce and resources necessary for installation of CCS, the five-year assumption in the DOE memo is reasonable. The representative timeline for CCS includes an about 3-year period for construction activities (including site work, construction, and startup and testing) across the components of CCS (capture, pipeline, and sequestration), beginning at the end of 2028. Many sources are well positioned to install CCS, having already completed feasibility work, FEED studies, and/or permitting, and could thereby reasonably start construction activities (still 3-years in duration) by the beginning of 2028 or earlier and, as a practical matter, would likely do so notwithstanding the requirements of this rule

Continued

a subset of coal power plants. The memorandum further estimates that 116,200 to 174,300 average annual jobs would likely be needed if CCS were deployed at all coal-fired EGUs that currently have no firm commitment to retire or convert to natural gas by 2040.[608] For comparison, the DOE memorandum further categorizes potential workforce needs by occupation, and estimates 11,420 to 27,890 annual jobs for construction trade workers, while the U.S. Energy and Employment Report estimates that electric power generation and fuels accounted for more than 292,000 construction jobs in 2022, which is an order of magnitude greater than the potential workforce needs for CCS deployment under this rule. Overall energy-related construction activities across the entire energy industry accounted for nearly 2 million jobs, or 25 percent of all construction jobs in 2022, indicating that there is a very large pool of workers potentially available.[609]

As noted in section VII.C.1.a.i(F), the EPA determined that the population of sources without announced plans to cease operation or discontinue coal-firing by 2039, and that is therefore potentially subject to a CCS BSER, is not more than 81 GW, as indicated in the final TSD, *Power Sector Trends.* The DOE CCS Commodity Materials and Workforce Memos evaluated material resource and workforce needs for a similar capacity (about 73 GW), and determined that the resources and workforce available are more than sufficient, in most cases by an order of magnitude. Considering these factors, and the similar scale of the population of sources considered, the EPA therefore concludes that the workforce and resources available are more than sufficient to meet the demands of coal-fired steam generating units potentially subject to a CCS BSER.

(H) Determination That CCS Is ''Adequately Demonstrated''

As discussed in detail in section V.C.2.b, pursuant to the text, context, legislative history, and judicial precedent interpreting CAA section 111(a)(1), a technology is ''adequately demonstrated'' if there is sufficient evidence that the EPA may reasonably conclude that a source that applies the technology will be able to achieve the associated standard of performance under the reasonably expected operating circumstances. Specifically, an adequately demonstrated standard of performance may reflect the EPA's reasonable expectation of what that particular system will achieve, based on analysis of available data from individual commercial scale sources, and, if necessary, identifying specific available technological improvements that are expected to improve performance.[610] The law is clear in establishing that at the time a section 111 rule is promulgated, the system that the EPA establishes as BSER need not be in widespread use. Instead, the EPA's responsibility is to determine that the demonstrated technology can be implemented at the necessary scale in a reasonable period of time, and to base its requirements on this understanding.

In this case, the EPA acknowledged in the proposed rule, and reaffirms now, that sources will require some amount of time to install CCS. Installing CCS requires the building of capture facilities and pipelines to transport captured CO_2 to sequestration sites, and the development of sequestration sites. This is true for both existing coal plants, which will need to retrofit CCS, and new gas plants, which must incorporate CCS into their construction planning. As the EPA explained at proposal, D.C. Circuit caselaw supports this approach.[611] Moreover, the EPA has determined that there will be sufficient resources for all coal-fired power plants that are reasonably expected to be operating as of January 1, 2039, to install CCS. Nothing in the comments alters the EPA's view of the relevant legal requirements related to the EPA's determination of time necessary to allow for adoption of the system.

With all of the above in mind, the preceding sections show that CCS technology with 90 percent capture is clearly adequately demonstrated for coal-fired steam generating units, that the 90 percent standard is achievable,[612] and that it is reasonable for the EPA to determine that CCS can be deployed at the necessary scale in the compliance timeframe.

(1) EPAct05

In the proposal, the EPA noted that in the 2015 NSPS, the EPA had considered coal-fired industrial projects that had installed at least some components of CCS technology. In doing so, the EPA recognized that some of those projects had received assistance in the form of grants, loan guarantees, and Federal tax credits for investment in ''clean coal technology,'' under provisions of the Energy Policy Act of 2005 (''EPAct05''). See 80 FR 64541–42 (October 23, 2015). (The EPA refers to projects that received assistance under that legislation as ''EPAct05-assisted projects.'') The EPA further recognized that the EPAct05 included provisions that constrained how the EPA could rely on EPAct05-assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111.[613]

given the strong economic incentives provided by the tax credit. The representative timeline also makes conservative assumptions about the pre-construction activities for pipelines and sequestration, and for many sources construction of those components could occur earlier. Finally, to provide greater regulatory certainty and incentivize the installation of controls, the EPA is finalizing a limited one-year compliance date extension mechanism for certain circumstances as detailed in section X.C.1.d of the preamble, and it would also be reasonable to assume that, in practice, some sources use that mechanism. Considering these factors, evaluating workforce and resource requirements over a five-year period is reasonable.

[608] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[609] U.S. Department of Energy. United States Energy & Employment Report 2023. *https://www.energy.gov/sites/default/files/2023-06/2023%20USEER%20REPORT-v2.pdf.*

[610] A line of cases establishes that the EPA may extrapolate based on its findings and project technological improvements in a variety of ways. First, the EPA may reasonably extrapolate from testing results to predict a lower emissions rate than has been regularly achieved in testing. *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973). Second, the EPA may forecast technological improvements allowing a lower emissions rate or effective control at larger plants than those previously subject to testing, provided the agency has adequate knowledge about the needed changes to make a reasonable prediction. *See Sierra Club* v. *Costle* 657 F.2d 298 (1981). Third, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different, related, source. *See Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[611] There, EPA cited *Portland Cement* v. *Ruckelshaus,* for the proposition that ''D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the 'adequately demonstrated' criterion—even if the controls require some amount of 'lead time,' which the court has defined as 'the time in which the technology will have to be available.' '' *See New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,* 88 FR 33240, 33289 (May 23, 2023) (quoting *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973)).

[612] The concepts of ''adequately demonstrated'' and ''achievable'' are closely related. As the D.C. Circuit explained in *Essex Chem. Corp.* v. *Ruckelshaus,* ''[i]t is the *system* which must be adequately demonstrated and the *standard* which must be achievable.'' 486 F.2d 427, 433 (1973).

[613] The relevant EPAct05 provisions include the following: Section 402(i) of the EPAct05, codified at 42 U.S.C. 15962(a), provides as follows: ''No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .'' IRC section 48A(g), as added by EPAct05

In the 2015 NSPS, the EPA went on to provide a legal interpretation of those constraints. Under that legal interpretation, ''these provisions [in the EPAct05] . . . preclude the EPA from relying solely on the experience of facilities that received [EPAct05] assistance, but [do] not . . . preclude the EPA from relying on the experience of such facilities in conjunction with other information.'' [614] *Id.* at 64541–42. In this action, the EPA is adhering to the interpretation of these provisions that it announced in the 2015 NSPS.

Some commenters criticized the legal interpretation that the EPA advanced in the 2015 NSPS, and others supported the interpretation. The EPA has responded to these comments in the Response to Comments Document, available in the docket for this rulemaking.

ii. Costs

The EPA has analyzed the costs of CCS for existing coal-fired long-term steam generating units, including costs for CO_2 capture, transport, and sequestration. The EPA has determined costs of CCS for these sources are reasonable. The EPA also evaluated costs assuming shorter amortization periods. As elsewhere in this section of the preamble, costs are presented in 2019 dollars. In sum, the costs of CCS are reasonable under a variety of metrics. The costs of CCS are reasonable as compared to the costs of other controls that the EPA has required for these sources. And the costs of CCS are reasonable when looking to the dollars per ton of CO_2 reduced. The reasonableness of CCS as an emission control is further reinforced by the fact that some sources are projected to install CCS even in the absence of any EPA rule addressing CO_2 emissions—11 GW of coal-fired EGUs install CCS in the modeling base case.

Specifically, the EPA assessed the average cost of CCS for the fleet of coal-fired steam generating units with no announced retirement or gas conversion prior to 2039. In evaluating costs, the EPA accounts for the IRC section 45Q tax credit of $85/metric ton (assumes prevailing wage and apprenticeship requirements are met), a detailed discussion of which is provided in section VII.C.1.a.ii(C) of this preamble. The EPA also accounts for increases in utilization that will occur for units that apply CCS due to the incentives provided by the IRC section 45Q tax credit. In other words, because the IRC section 45Q tax credit provides a significant economic benefit, sources that apply CCS will have a strong economic incentive to increase utilization and run at higher capacity factors than occurred historically. This assumption is confirmed by the modeling, which projects that sources that install CCS run at a high capacity factor—generally, about 80 percent or even higher. The EPA notes that the NETL Baseline study assumes 85 percent as the default capacity factor assumption for coal CCS retrofits, noting that coal plants in market conditions supporting baseload operation have demonstrated the ability to operate at annual capacity factors of 85 percent or higher.[615] This assumption is also supported by observations of wind generators who receive the IRC section 45 production tax credit who continue to operate even during periods of negative power prices.[616] Therefore, the EPA assessed the costs for CCS retrofitted to existing coal-fired steam generating units assuming an 80 percent annual capacity factor. Assuming an 80 percent capacity factor and 12-year amortization period,[617] the average costs of CCS for the fleet are −$5/ton of CO_2 reduced or −$4/MWh of generation. Assuming at least a 12-year amortization period is reasonable because any unit that installs CCS and seeks to maximize its profitability will be incentivized to recoup the full value of the 12-year tax credit.

Therefore for long-term coal-fired steam generating units—ones that operate after January 1, 2039—the costs of CCS are similar or better than the representative costs of controls detailed in section VII.C.1.a.ii(D) of this preamble (*i.e.,* costs for SCRs and FGDs on EGUs of $10.60 to $18.50/MWh and the costs in the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category of $98/ton of CO_2e reduced (80 FR 56627; September 18, 2015)).

The EPA also evaluated the costs for shorter amortization periods, considering the $/MWh and $/ton metrics, as well as other cost indicators, as described in section VII.C.1.a.ii.(D). Specifically, with an initial compliance date of January 1, 2032, sources operating through the end of 2039 have at least 8 years to amortize costs. For an 80 percent capacity factor and an 8-year amortization period, the average costs of CCS for the fleet are $19/ton of CO_2 reduced or $18/MWh of generation; these costs are comparable to those costs that the EPA has previously determined to be reasonable. Sources operating through the end of 2040, 2041, and beyond (*i.e.,* sources with 9, 10, or more years to amortize the costs of CCS) have even more favorable average costs per MWh and per ton of CO_2 reduced. Sources ceasing operation by January 1, 2039, have 7 years to amortize costs. For an 80 percent capacity factor and a 7-year amortization period, the fleet average costs are $29/ton of CO_2 reduced or $28/MWh of generation; these average costs are less comparable on a $/MWh of generation basis to those costs the EPA has previously determined to be reasonable, but substantially lower than costs the EPA has previously determined to be reasonable on a $/ton of CO_2 reduced basis. The EPA further notes that the costs presented are average costs for the fleet. For a substantial amount of capacity, costs assuming a 7-year amortization period are comparable to those costs the EPA has previously determined to be reasonable on both a $/MWh basis (*i.e.,* less than $18.50/MWh) and a $/ton basis (*i.e.* less than $98/ton CO2e),[618] and the EPA concludes that a substantial amount of capacity can install CCS at reasonable cost with a 7-year amortization

1307(b), provides as follows: ''No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .'' Section 421(a) states: ''No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [*sic*] of section 7411 of this title, . . . solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title.''

[614] In the 2015 NSPS, the EPA adopted several other legal interpretations of these EPAct05 provisions as well. See 80 FR 64541 (October 23, 2015).

[615] See Exhibit 2–18. *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.*

[616] If those generators were not receiving the tax credit, they otherwise would cease producing power during those periods and result in a lower overall capacity factor. As noted by EIA, ''Wind plants can offer negative prices because of the revenue stream that results from the federal production tax credit, which generates tax benefits whenever the wind plant is producing electricity, and payments from state renewable portfolio or financial incentive programs. These alternative revenue streams make it possible for wind generators to offer their wind power into the wholesale electricity market at prices lower than other generators, and even at negative prices.'' *https://www.eia.gov/todayinenergy/detail.php?id=16831.*

[617] A 12-year amortization period is consistent with the period of time during which the IRC section 45Q tax credit can be claimed.

[618] See the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional details.

period.[619] Considering that a significant number of sources can cost reasonably install CCS even assuming a 7-year amortization period, the EPA concludes that sources operating in 2039 should be subject to a CCS BSER,[620] and for this reason, is finalizing the date of January 1, 2039 as the dividing line between the medium-term and long-term subcategories. Moreover, the EPA underscores that given the strong economic incentives of the IRC section 45Q tax credit, sources that install CCS will have strong economic incentives to operate at high capacity for the full 12 years that the tax credit is available.

As discussed in the RTC section 2.16, the EPA has also examined the reasonableness of the costs of this rule in additional ways: considering the total annual costs of the rule as compared to past CAA rules for the electricity sector and as compared to the industry's annual revenues and annual capital expenditures, and considering the effects of this rule on electricity prices. Taking all of these into consideration, in addition to the cost metrics just discussed, the EPA concludes that, in general, the costs of CCS are reasonable for sources operating after January 1, 2039.

(A) Capture Costs

The EPA developed an independent engineering cost assessment for CCS retrofits, with support from Sargent and Lundy.[621] The EPA cost analysis assumes installation of one CO_2 capture plant for each coal-fired EGU, and that sources without SO_2 controls (FGD) or NO_X controls (specifically, selective catalytic reduction—SCR; or selective non-catalytic reduction—SNCR) add a wet FGD and/or SCR.[622]

(B) CO_2 Transport and Sequestration Costs

To calculate the costs of CCS for coal-fired steam generating units for purposes of determining BSER as well as for EPA modeling, the EPA relied on transportation and storage costs consistent with the cost of transporting and storing CO_2 from each power plant to the nearest saline reservoir.[623] For a power plant composed of multiple coal-fired EGUs, the EPA's cost analysis assumes installation and operation of a single, common CO_2 pipeline.

The EPA notes that NETL has also developed costs for transport and storage. NETL's ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies'' provides an estimation of transport costs based on the CO_2 Transport Cost Model.[624] The CO_2 Transport Cost Model estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.[625]

NETL's Quality Guidelines also provide an estimate of sequestration costs. These costs reflect the cost of site screening and evaluation, permitting and construction costs, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Permitting and construction costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. NETL calculates these sequestration costs on the basis of generic plant locations in the Midwest, Texas, North Dakota, and Montana, as described in the NETL energy system studies that utilize the coal found in Illinois, East Texas, Williston, and Powder River basins.[626]

There are two primary cost drivers for a CO_2 sequestration project: the rate of injection of the CO_2 into the reservoir and the areal extent of the CO_2 plume in the reservoir. The rate of injection depends, in part, on the thickness of the reservoir and its permeability. Thick, permeable reservoirs provide for better injection and fewer injection wells. The areal extent of the CO_2 plume depends on the sequestration capacity of the reservoir. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have a smaller monitoring footprint, resulting in lower monitoring costs. NETL's Quality Guidelines model costs for a given cumulative sequestration potential.[627]

In addition, provisions in the IIJA and IRA are expected to significantly increase the CO_2 pipeline infrastructure and development of sequestration sites, which, in turn, are expected to result in further cost reductions for the application of CCS at new combined cycle EGUs. The IIJA establishes a new Carbon Dioxide Transportation Infrastructure Finance and Innovation program to provide direct loans, loan guarantees, and grants to CO_2 infrastructure projects, such as pipelines, rail transport, ships and barges.[628] The IIJA also establishes a new Regional Direct Air Capture Hubs program that includes funds to support four large-scale, regional direct air capture hubs and more broadly support projects that could be developed into a regional or inter-regional network to facilitate sequestration or utilization.[629] DOE is additionally implementing IIJA section 40305 (Carbon Storage Validation and Testing) through its CarbonSAFE initiative, which aims to further develop geographically widespread, commercial-scale, safe sequestration.[630] The IRA increases and

[619] As indicated in section 4.7.5 of the final TSD, *Greenhouse Gas Mitigation Measures for Steam Generating Units,* 24 percent of all coal-fired steam generating units in the long-term subcategory would have CCS costs below both $18.50/MWh and $98/ton of CO_2 with a 7-year amortization period (Table 11), and that amount increases to 40 percent for those coal-fired units that, in light of their age and efficiency, are most likely to operate in the long term (and thus be subject to the CCS-based standards of performance) (Table 12). In addition, of the 9 units in the NEEDS data base that have announced plans to retire in 2039, and that therefore would have a 7-year amortization period if they installed CCS by January 1, 2032, 6 would have costs below both $18.50/MWh and $98/ton of CO_2.

[620] The EPA determines the BSER based on considering information on the statutory factors, including cost, on a source category or subcategory basis. However, there may be particular sources for which, based on source-specific considerations, the cost of CCS is fundamentally different from the costs the EPA considered in making its BSER determination. If such a fundamental difference makes it unreasonable for a particular source to achieve the degree of emission limitation associated with implementing CCS with 90 percent capture, a state may provide a less stringent standard of performance (and/or longer compliance schedule, if applicable) for that source pursuant to the RULOF provisions. See section X.C.2 of this preamble for further discussion.

[621] Detailed cost information, assessment of technology options, and demonstration of cost reasonableness can be found in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[622] Whether an FGD and SCR or controls with lower costs are necessary for flue gas pretreatment prior to the CO_2 capture process will in practice depend on the flue gas conditions of the source.

[623] For additional details on CO_2 transport and storage costs, see the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[624] Grant, T., *et al.* (2019). ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies.'' National Energy Technology Laboratory. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[625] Grant, T., *et al.* ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies.'' National Energy Technology Laboratory. 2019. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[626] National Energy Technology Laboratory (NETL). (2017). ''FE/NETL CO_2 Saline Storage Cost Model (2017),'' U.S. Department of Energy, DOE/NETL–2018–1871. *https://netl.doe.gov/energy-analysis/details?id=2403.*

[627] Details on CO_2 transportation and sequestration costs can be found in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[628] Department of Energy. ''Biden-Harris Administration Announces $2 Billion from Bipartisan Infrastructure Law to Finance Carbon Dioxide Transportation Infrastructure.'' (2022). *https://www.energy.gov/articles/biden-harris-administration-announces-2-billion-bipartisan-infrastructure-law-finance.*

[629] Department of Energy. ''Regional Direct Air Capture Hubs.'' (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[630] For more information, see the NETL announcement. *https://www.netl.doe.gov/node/12405.*

extends the IRC section 45Q tax credit, discussed next.

(C) IRC Section 45Q Tax Credit

In determining the cost of CCS, the EPA is taking into account the tax credit provided under IRC section 45Q, as revised by the IRA. The tax credit is available at $85/metric ton ($77/ton) and offsets a significant portion of the capture, transport, and sequestration costs noted above.

Several other aspects of the tax credit should be noted. A tax credit offsets tax liability dollar for dollar up to the amount of the taxpayer's tax liability. Any credits in excess of the taxpayer's liability are eligible to be carried back (3 years in the case of IRC section 45Q) and then carried forward up to 20 years.[631] As noted above, the IRA also enabled additional methods to monetize tax credits in the event the taxpayer does not have sufficient tax liability, such as through credit transfer.

The EPA has determined that it is likely that EGUs installing CCS will meet the 45Q prevailing wage and apprenticeship requirements. First, the requirements provide a significant economic incentive, increasing the value of the 45Q credit by five times over the base value of the credit available if the prevailing wage and apprenticeship requirements are not met. This provides a significant incentive to meet the requirements. Second, the increased cost of meeting the requirements is likely significantly less than the increase in credit value. A recent EPRI assessment found meeting the requirements for other types of power generation projects resulted in significant savings across projects,[632] and other studies indicate prevailing wage laws and requirements for construction projects in general do not significantly affect overall construction costs.[633] The EPA expects a similar dynamic for 45Q projects. Third, the use of registered apprenticeship programs for training new employees is generally well-established in the electric power generation sector, and apprenticeship programs are widely available to generate additional trained workers in this field.[634] The overall U.S. apprentice market has more than doubled between 2014 and 2023, growing at an average annual rate of more than 7 percent.[635] Additional programs support the skilled construction trade workforce required for CCS implementation and maintenance.[636]

As discussed in section V.C.2.c of this preamble, CAA section 111(a)(1) is clear that the cost that the Administrator must take into account in determining the BSER is the cost of the controls to the source. It is reasonable to take the tax credit into account because it reduces the cost of the controls to the source, which has a significant effect on the actual cost of installing and operating CCS. In addition, all sources that install CCS to meet the requirements of these final actions are eligible for the tax credit. The legislative history of the IRA makes clear that Congress was well aware that the EPA may promulgate rulemaking under CAA section 111 based on CCS and the utility of the tax credit in reducing the costs of CCUS (*i.e.,* CCS). Rep. Frank Pallone, the chair of the House Energy & Commerce Committee, included a statement in the Congressional Record when the House adopted the IRA in which he explained: ''The tax credit[ ] for CCUS . . . included in this Act may also figure into CAA Section 111 GHG regulations for new and existing industrial sources[.] . . . Congress anticipates that EPA may consider CCUS . . . as [a] candidate[ ] for BSER for electric generating plants . . . . Further, Congress anticipates that EPA may consider the impact of the CCUS . . . tax credit[ ] in lowering the costs of [that] measure[ ].'' 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone).

In the 2015 NSPS, in which the EPA determined partial CCS to be the BSER for GHGs from new coal-fired steam generating EGUs, the EPA recognized that the IRC section 45Q tax credit or other tax incentives could factor into the cost of the controls to the sources. Specifically, the EPA calculated the cost of partial CCS on the basis of cost calculations from NETL, which included ''a range of assumptions including the projected capital costs, the cost of financing the project, the fixed and variable O&M costs, the projected fuel costs, and incorporation of any incentives such as tax credits or favorable financing that may be available to the project developer.'' 80 FR 64570 (October 23, 2015).[637]

Similarly, in the 2015 NSPS, the EPA also recognized that revenues from utilizing captured CO_2 for EOR would reduce the cost of CCS to the sources, although the EPA did not account for potential EOR revenues for purposes of determining the BSER. *Id.* At 64563–64. In other rules, the EPA has considered revenues from sale of the by-products of emission controls to affect the costs of the emission controls. For example, in the 2016 Oil and Gas Methane Rule, the EPA determined that certain control requirements would reduce natural gas leaks and therefore result in the collection of recovered natural gas that could be sold; and the EPA further determined that revenues from the sale of the recovered natural gas reduces the cost of controls. See 81 FR 35824 (June 3, 2016). The EPA made the same determination in the 2024 Oil and Gas Methane Rule. See 89 FR 16820, 16865 (May 7, 2024). In a 2011 action concerning a regional haze SIP, the EPA recognized that a NO_X control would alter the chemical composition of fly ash that the source had previously sold, so that it could no longer be sold; and as a result, the EPA further determined that the cost of the NO_X control should include the foregone revenues from the fly ash sales. 76 FR 58570, 58603 (September 21, 2011). In the 2016 emission guidelines for landfill gas from municipal solid waste landfills, the EPA reduced the costs of controls by accounting for revenue from the sale of electricity produced from the landfill gas collected through the controls. 81 FR 59276, 19679 (August 29, 2016).

The amount of the IRC section 45Q tax credit that the EPA is taking into account is $85/metric ton for CO_2 that is captured and geologically stored. This amount is available to the affected source as long as it meets the prevailing wage and apprenticeship requirements of IRC section 45Q(h)(3)–(4). The legislative history to the IRA specifically stated that when the EPA considers CCS as the BSER for GHG emissions from industrial sources in CAA section 111 rulemaking, the EPA should determine the cost of CCS by assuming that the sources would meet those prevailing wage and apprenticeship requirements. 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone). If prevailing wage and apprenticeship requirements are not met, the value of the IRC section 45Q tax credit falls to $17/metric ton. The substantially higher credit available provides a considerable incentive to meeting the prevailing wage and apprenticeship requirements.

[631] IRC section 39.

[632] *https://www.epri.com/research/products/000000003002027328.*

[633] *https://journals.sagepub.com/doi/abs/10.1177/0160449X18766398.*

[634] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[635] *https://www.apprenticeship.gov/data-and-statistics.*

[636] *https://www.apprenticeship.gov/partner-finder.*

[637] In fact, because of limits on the availability of the IRC section 45Q tax credit at the time of the 2015 NSPS, the EPA did not factor it into the cost calculation for partial CCS. 80 FR 64558–64 (October 23, 2015).

Therefore, the EPA assumes that investors maximize the value of the IRC section 45Q tax credit at $85/metric ton by meeting those requirements.

(D) Comparison to Other Costs of Controls and Other Measures of Cost Reasonableness

In assessing cost reasonableness for the BSER determination for this rule, the EPA looks at a range of cost information. As discussed in Chapter 2 of the RTC, the EPA considered the total annual costs of the rule as compared to past CAA rules for the electricity sector and as compared to the industry's annual revenues and annual capital expenditures, and considered the effects of this rule on electricity prices.

For each of the BSER determinations, the EPA also considers cost metrics that it has historically considered in assessing costs to compare the costs of GHG control measures to control costs that the EPA has previously determined to be reasonable. This includes comparison to the costs of controls at EGUs for other air pollutants, such as SO_2 and NO_X, and costs of controls for GHGs in other industries. Based on these costs, the EPA has developed two metrics for assessing the cost reasonableness of controls: the increase in cost of electricity due to controls, measured in $/MWh, and the control costs of removing a ton of pollutant, measured in $/ton CO_2e. The costs presented in this section of the preamble are in 2019 dollars.[638]

In different rulemakings, the EPA has required many coal-fired steam generating units to install and operate flue gas desulfurization (FGD) equipment—that is, wet or dry scrubbers—to reduce their SO_2 emissions or SCR to reduce their NO_X emissions. The EPA compares these control costs across technologies—steam generating units and combustion turbines—because these costs are indicative of what is reasonable for the power sector in general. The facts that the EPA required these controls in prior rules, and that many EGUs subsequently installed and operated these controls, provide evidence that these costs are reasonable, and as a result, the cost of these controls provides a benchmark to assess the reasonableness of the costs of the controls in this preamble. In the 2011 CSAPR (76 FR 48208; August 8, 2011), the EPA estimated the annualized costs to install and operate wet FGD retrofits on existing coal-fired steam generating units. Using those same cost equations and assumptions (*i.e.,* a 63 percent annual capacity factor—the average value in 2011) for retrofitting wet FGD on a representative 700 to 300 MW coal-fired steam generating unit results in annualized costs of $14.80 to $18.50/MWh of generation, respectively.[639] In the Good Neighbor Plan for the 2015 Ozone NAAQS (2023 GNP), 88 FR 36654 (June 5, 2023), the EPA estimated the annualized costs to install and operate SCR retrofits on existing coal-fired steam generating units. Using those same cost equations and assumptions (including a 56 percent annual capacity factor—a representative value in that rulemaking) to retrofit SCR on a representative 700 to 300 MW coal-fired steam generating unit results in annualized costs of $10.60 to $11.80/MWh of generation, respectively.[640]

The EPA also compares costs to the costs for GHG controls in rulemakings for other industries. In the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category, the EPA found the costs of reducing methane emissions of $2,447/ton to be reasonable (80 FR 56627; September 18, 2015).[641] Converted to a ton of CO_2e reduced basis, those costs are expressed as $98/ton of CO_2e reduced.[642]

The EPA does not consider either of these metrics, $18.50/MWh and $98/ton of CO_2e, to be bright line standards that distinguish between levels of control costs that are reasonable and levels that are unreasonable. But they do usefully indicate that control costs that are generally consistent with those levels of control costs should be considered reasonable. The EPA has required controls with comparable costs in prior rules for the electric power industry and the industry has successfully complied with those rules by installing and operating the applicable controls. In the case of the $/ton metric, the EPA has required other industries—specifically, the oil and gas industry—to reduce their climate pollution at this level of cost-effectiveness. In this rulemaking, the costs of the controls that the EPA identifies as the BSER generally match up well against both of these $/MWh and $/ton metrics for the affected subcategories of sources. And looking broadly at the range of cost information and these cost metrics, the EPA concludes that the costs of these rules are reasonable.

(E) Comparison to Costs for CCS in Prior Rulemakings

In the CPP and ACE Rule, the EPA determined that CCS did not qualify as the BSER due to cost considerations. Two key developments have led the EPA to reevaluate this conclusion: the costs of CCS technology have fallen and the extension and increase in the IRC section 45Q tax credit, as included in the IRA, in effect provide a significant stream of revenue for sequestered CO_2 emissions. The CPP and ACE Rule relied on a 2015 NETL report estimating the cost of CCS. NETL has issued updated reports to incorporate the latest information available, most recently in 2022, which show significant cost reductions. The 2015 report estimated incremental levelized cost of CCS at a new pulverized coal facility relative to a new facility without CCS at $74/MWh (2022$),[643] while the 2022 report estimated incremental levelized cost at $44/MWh (2022$).[644] Additionally, the IRA increased the IRC section 45Q tax credit from $50/metric ton to $85/metric ton (and, in the case of EOR or certain industrial uses, from $35/metric ton to $60/metric ton), assuming prevailing wage and apprenticeship conditions are met. The IRA also enhanced the realized value of the tax credit through the elective pay (informally known as direct pay) and transferability monetization options described in section IV.E.1. The combination of lower costs and higher tax credits significantly improves the cost reasonableness of CCS for purposes

[638] The EPA used the NETL Baseline Report costs directly for the combustion turbine model plant BSER analysis. Even though these costs are in 2018 dollars, the adjustment to 2019 dollars (1.018 using the U.S. GDP Implicit Price Deflator) is well within the uncertainty range of the report and the minor adjustment would not impact the EPA's BSER determination.

[639] For additional details, see *https://www.epa.gov/power-sector-modeling/documentation-integrated-planning-model-ipm-base-case-v410.*

[640] For additional details, see *https://www.epa.gov/system/files/documents/2023-01/Updated%20Summer%202021%20Reference%20Case%20Incremental%20Documentation%20for%20the%202015%20Ozone%20NAAQS%20Actions_0.pdf.*

[641] The EPA finalized the 2016 NSPS GHGs for the Crude Oil and Natural Gas source category at 81 FR 35824 (June 3, 2016). The EPA included cost information in the proposed rulemaking, at 80 FR 56627 (September 18, 2015).

[642] Based on the 100-year global warming potential for methane of 25 used in the GHGRP (40 CFR 98 Subpart A, table A–1).

[643] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 3 (July 2015). *Note:* The EPA adjusted reported costs to reflect $2022. *https://www.netl.doe.gov/projects/files/CostandPerformanceBaselinefor FossilEnergyPlantsVolume1aBit CoalPCandNaturalGastoElectRev3_070615.pdf.*

[644] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022). *Note:* The EPA adjusted reported costs to reflect $2022. *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineFor FossilEnergyPlantsVolume1Bituminous CoalAndNaturalGasToElectricity_101422.pdf.*

of determining whether it qualifies as the BSER.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

The EPA considered non-GHG emissions impacts, the water use impacts, the transport and sequestration of captured CO_2, and energy requirements resulting from CCS for steam generating units. As discussed below, where the EPA has found potential for localized adverse consequences related to non-air quality health and environmental impacts or energy requirements, the EPA also finds that protections are in place to mitigate those risks. Because the non-air quality health and environmental impacts are closely related to the energy requirements, we discuss the latter first.

(A) Energy Requirements

For a steam generating unit with 90 percent amine-based CO_2 capture, parasitic/auxiliary energy demand increases and the net power output decreases. In particular, the solvent regeneration process requires heat in the form of steam and CO_2 compression requires a large amount of electricity. Heat and power for the CO_2 capture equipment can be provided either by using the steam and electricity produced by the steam generating unit or by an auxiliary cogeneration unit. However, any auxiliary source of heat and power is part of the ''designated facility,'' along with the steam generating unit. The standards of performance apply to the designated facility. Thus, any CO_2 emissions from the connected auxiliary equipment need to be captured or they will increase the facility's emission rate.

Using integrated heat and power can reduce the capacity (*i.e.,* the amount of electricity that a unit can distribute to the grid) of an approximately 474 MW-net (501 MW-gross) coal-fired steam generating unit without CCS to approximately 425 MW-net with CCS and contributes to a reduction in net efficiency of 23 percent.[645] For retrofits of CCS on existing sources, the ductwork for flue gas and piping for heat integration to overcome potential spatial constraints are a component of efficiency reduction. The EPA notes that slightly greater efficiency reductions than in the 2016 NETL retrofit report are assumed for the BSER cost analyses, as detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket. Despite decreases in efficiency, IRC section 45Q tax credit provides an incentive for increased generation with full operation of CCS because the amount of revenue from the tax credit is based on the amount of captured and sequestered CO_2 emissions and not the amount of electricity generated. In this final action, the Agency considers the energy penalty to not be unreasonable and to be relatively minor compared to the benefits in GHG reduction of CCS.

(B) Non-GHG Emissions

As a part of considering the non-air quality health and environmental impacts of CCS, the EPA considered the potential non-GHG emission impacts of CO_2 capture. The EPA recognizes that amine-based CO_2 capture can, under some circumstances, result in the increase in emission of certain co-pollutants at a coal-fired steam generating unit. However, there are protections in place that can mitigate these impacts. For example, as discussed below, CCS retrofit projects with co-pollutant increases may be subject to preconstruction permitting under the New Source Review (NSR) program, which could require the source to adopt emission limitations based on applicable NSR requirements. Sources obtaining major NSR permits would be required to either apply Lowest Achievable Emission Rate (LAER) and fully offset any anticipated increases in criteria pollutant emissions (for their nonattainment pollutants) or apply Best Available Control Technology (BACT) and demonstrate that its emissions of criteria pollutants will not cause or contribute to a violation of applicable National Ambient Air Quality Standards (for their attainment pollutants).[646] The EPA expects facility owners, states, permitting authorities, and other responsible parties will use these protections to address co-pollutant impacts in situations where individual units use CCS to comply with these emission guidelines.

The EPA also expects that the meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders, including community members who might be adversely impacted by non-GHG pollutants, will have an opportunity to raise this concern with states and permitting authorities. Additionally, state permitting authorities are, in general, required to provide notice and an opportunity for public comment on construction projects that require NSR permits. This provides additional opportunities for affected stakeholders to engage in that process, and it is the EPA's expectation that the responsible authorities will consider these concerns and take full advantage of existing protections. Moreover, the EPA through its regional offices is committed to thoroughly review draft NSR permits associated with CO_2 capture projects and provide comments as necessary to state permitting authorities to address any concerns or questions with regard to the draft permit's consideration and treatment of non-GHG pollutants.

In the following discussion, the EPA describes the potential emissions of non-GHG pollutants resulting from installation and operation of CO_2 capture plants, the protections in place such as the controls and processes for mitigating those emissions, as well as regulations and permitting that may require review and implementation of those controls. The EPA first discusses these issues in relation to criteria air pollutants and precursor pollutants (SO_2, NO_X, and PM), and subsequently provides details regarding hazardous air pollutants (HAPs) and volatile organic compounds (VOCs).

Operation of an amine-based CO_2 capture plant on a coal-fired steam generating unit can impact the emission of criteria pollutants from the facility, including SO_2 and PM, as well as precursor pollutants, like NO_X. Sources installing CCS may operate more due to the incentives provided by the IRC section 45Q tax credit, and increased utilization would—all else being equal—result in increases in SO_2, PM, and NO_X. However, certain impacts are mitigated by the flue gas conditioning required by the CO_2 capture process and by other control equipment that the units already have or may need to install to meet other CAA requirements. Substantial flue gas conditioning, particularly to remove SO_2 and PM, is critical to limiting solvent degradation and maintaining reliable operation of the capture plant. To achieve the necessary limits on SO_2 levels in the flue gas for the capture process, steam generating units will need to add an FGD scrubber, if they do not already have one, and will usually need an additional polishing column (*i.e.,* quencher), thereby further reducing the emission of SO_2. A wet FGD column and a polishing column will also reduce the emission rate of PM. Additional improvements in PM removal may also be necessary to reduce the fouling of

[645] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=d335ce79-84ee-4a0b-a27b-c1a64edbb866.*

[646] Section XI.A of this preamble provides additional information on the NSR program and how it relates to the NSPS and emission guidelines.

other components (*e.g.,* heat exchangers) of the capture process, including upgrades to existing PM controls or, where appropriate, the inclusion of various wash stages to limit fly ash carry-over to the CO_2 removal system. Although PM emissions from the steam generating unit may be reduced, PM emissions may occur from cooling towers for those sources using wet cooling for the capture process. For some sources, a WESP may be necessary to limit the amount of aerosols in the flue gas prior to the CO_2 capture process. Reducing the amount of aerosols to the CO_2 absorber will also reduce emissions of the solvent out of the top of the absorber. Controls to limit emission of aerosols installed at the outlet of the absorber could be considered, but could lead to higher pressure drops. Thus, emission increases of SO_2 and PM would be reduced through flue gas conditioning and other system requirements of the CO_2 capture process, and NSR permitting would serve as an added backstop to review remaining SO_2 and PM increases for mitigation.

NO_X emissions can cause solvent degradation and nitrosamine formation, depending on the chemical structure of the solvent. Limits on NO_X levels of the flue gas required to avoid solvent degradation and nitrosamine formation in the CO_2 scrubber vary. For most units, the requisite limits on NO_X levels to assure that the CO_2 capture process functions properly may be met by the existing NO_X combustion controls. Other units may need to install SCR to achieve the required NOx level. Most existing coal-fired steam generating units either already have SCR or will be covered by final Federal Implementation Plan (FIP) requirements regulating interstate transport of NO_X (as ozone precursors) from EGUs. See 88 FR 36654 (June 5, 2023).[647] For units not otherwise required to have SCR, an increase in utilization from a CO_2 capture retrofit could result in increased NO_X emissions at the source that, depending on the quantity of the emissions increase, may trigger major NSR permitting requirements. Under this scenario, the permitting authority may determine that the NSR permit requires the installation of SCR for those units, based on applying the control technology requirements of major NSR. Alternatively, a state could, as part of its state plan, develop enforceable conditions for a source expected to trigger major NSR that would effectively limit the unit's ability to increase its emissions in amounts that would trigger major NSR. Under this scenario, with no major NSR requirements applying due to the limit on the emissions increase, the permitting authority may conclude for the minor NSR permit that installation of SCR is not required for the units and the source is to minimize its NO_X emission increases using other techniques. Finally, a source with some lesser increase in NO_X emissions may not trigger major NSR to begin with and, as with the previous scenario, the permitting authority would determine the NO_X control requirements pursuant to its minor NSR program requirements.

Recognizing that potential emission increases of SO_2, PM, and NO_X from operating a CO_2 capture process are an area of concern for stakeholders, the EPA plans to review and update as needed its guidance on NSR permitting, specifically with respect to BACT determinations for GHG emissions and consideration of co-pollutant increases from sources installing CCS. In its analysis to support this final action, the EPA accounted for controlling these co-pollutant increases by assuming that coal-fired units that install CCS would be required to install SCR and/or FGD if they do not already have those controls installed. The costs of these controls are included in the total program compliance cost estimates through IPM modeling, as well as in the BSER cost calculations.

An amine-based CO_2 capture plant can also impact emissions of HAP and VOC (as an ozone precursor) from the coal-fired steam generating unit. Degradation of the solvent can produce HAP, and organic HAP and amine solvent emissions from the absorber would contribute to VOC emissions out of the top of the CO_2 absorber. A conventional multistage water or acid wash and mist eliminator (demister) at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.,* nitrosamine) emissions.[648] [649] The DOE's Carbon Management Pathway report notes that monitoring and emission controls for such degradation products are currently part of standard operating procedures for amine-based CO_2 capture systems.[650] Depending on the solvent properties, different amounts of aldehydes including acetaldehyde and formaldehyde may form through oxidative processes, contributing to total HAP and VOC emissions. While a water wash or acid wash can be effective at limiting emission of amines, a separate system of controls would be required to reduce aldehyde emissions; however, the low temperature and likely high water vapor content of the gas emitted out of absorber may limit the applicability of catalytic or thermal oxidation. Other controls (*e.g.,* electrochemical, ultraviolet) common to water treatment could be considered to reduce the loading of copollutants in the water wash section, although their efficacy is still in development and it is possible that partial treatment could result in the formation of additional degradation products. Apart from these potential controls, any increase in VOC emissions from a CCS retrofit project would be mitigated through NSR permitting. As such VOC increases are not expected to be large enough to trigger major NSR requirements, they would likely be reviewed and addressed under a state's minor NSR program.

There is one nitrosamine that is a listed HAP regulated under CAA section 112. Carbon capture systems that are themselves a major source of HAP should evaluate the applicability of CAA section 112(g) and conduct a case-by-case MACT analysis if required, to establish MACT for any listed HAP, including listed nitrosamines, formaldehyde, and acetaldehyde. Because of the differences in the formation and effectiveness of controls, such a case-by-case MACT analysis should evaluate the performance of controls for nitrosamines and aldehydes separately, as formaldehyde or acetaldehyde may not be a suitable surrogate for amine and nitrosamine emissions. However, measurement of nitrosamine emissions may be challenging when the concentration is low (*e.g.,* less than 1 part per billion, dry basis).

HAP emissions from the CO_2 capture plant will depend on the flue gas

[647] As of September 21, 2023, the Good Neighbor Plan "Group 3" ozone-season NO_X control program for power plants is being implemented in the following states: Illinois, Indiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and Wisconsin. Pursuant to court orders staying the Agency's FIP Disapproval action as to the following states, the EPA is not currently implementing the Good Neighbor Plan "Group 3" ozone-season NO_X control program for power plants in the following states: Alabama, Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and West Virginia.

[648] Sharma, S., Azzi, M., "A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies," *Fuel,* 121, 178 (2014).

[649] Mertens, J., *et al.,* "Understanding ethanolamine (MEA) and ammonia emissions from amine-based post combustion carbon capture: Lessons learned from field tests," *Int'l J. of GHG Control,* 13, 72 (2013).

[650] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Carbon Management. *https://liftoff.energy.gov/wp-content/uploads/2023/04/20230424-Liftoff-Carbon-Management-vPUB_update.pdf.*

conditions, solvent, size of the source, and process design. The air permit application for Project Tundra [651] includes potential-to-emit (PTE) values for CAA section 112 listed HAP specific to the 530 MW-equivalent CO_2 capture plant, including emissions of 1.75 tons per year (TPY) of formaldehyde (CASRN 50–00–0), 32.9 TPY of acetaldehyde (CASRN 75–07–0), 0.54 TPY of acetamide (CASRN 60–35–5), 0.018 TPY of ethylenimine (CASRN 151–56–4), 0.044 TPY of N-nitrosodimethylamine (CASRN 62–75–9), and 0.018 TPY of N-nitrosomorpholine (CASRN 59–89–2). Additional PTE other species that are not CAA section 112 listed HAP were also included, including 0.022 TPY of N-nitrosodiethylamine (CASRN 55–18–5). PTE values for other CO_2 capture plants may differ. To comply with North Dakota Department of Environmental Quality (ND–DEQ) Air Toxics Policy, an air toxics assessment was included in the permit application. According to that assessment, the total maximum individual carcinogenic risk was 1.02E–6 (approximately 1-in-1 million, below the ND–DEQ threshold of 1E–5) primarily driven by N-nitrosodiethylamine and N-nitrosodimethylamine. The hazard index value was 0.022 (below the ND–DEQ threshold of 1), with formaldehyde being the primary driver. Results of air toxics risk assessments for other facilities would depend on the emissions from the facility, controls in place, stack height and flue gas conditions, local ambient conditions, and the relative location of the exposed population.

Emissions of amines and nitrosamines at Project Tundra are controlled by the water wash section of the absorber column. According to the permit to construct issued by ND–DEQ, limits for formaldehyde and acetaldehyde will be established based on testing after initial operation of the CO_2 capture plant. The permit does not include a mechanism for establishing limits for nitrosamine emissions, as they may be below the limit of detection (less than 1 part per billion, dry basis).

The EPA received several comments related to the potential for non-GHG emissions associated with CCS. Those comments and the EPA's responses are as follows.

Comment: Some commenters noted that there is a potential for increases in co-pollutants when operating amine-based CO_2 capture systems. One commenter requested that the EPA proactively regulate potential nitrosamine emissions.

Response: The EPA carefully considered these concerns as it finalized its determination of the BSERs for these rules. The EPA takes these concerns seriously, agrees that any impacts to local and downwind communities are important to consider and has done so as part of its analysis discussed at section XII.E. While the EPA acknowledges that, in some circumstances, there is potential for some non-GHG emissions to increase, there are several protections in place to help mitigate these impacts. The EPA believes that these protections, along with the meaningful engagement of potentially affected communities, can facilitate a responsible deployment of this technology that mitigates the risk of any adverse impacts.

There is one nitrosamine that is a listed HAP under CAA section 112 (N-Nitrosodimethylamine; CASRN 62–75–9). Other nitrosamines would have to be listed before the EPA could establish regulations limiting their emission. Furthermore, carbon capture systems are themselves not a listed source category of HAP, and the listing of a source category under CAA section 112 would first require some number of the sources to exist for the EPA to develop MACT standards. However, if a new CO_2 capture facility were to be permitted as a separate entity (rather than as part of the EGU) then it may be subject to case-by-case MACT under section 112(g), as detailed in the preceding section of this preamble.

Comment: Commenters noted that a source could attempt to permit CO_2 facilities as separate entities to avoid triggering NSR for the EGU.

Response: For the CO_2 capture plant to be permitted as a separate entity, the source would have to demonstrate to the state permitting authority that the EGU and CO_2 capture plant are not a single stationary source under the NSR program. In determining what constitutes a stationary source, the EPA's NSR regulations set forth criteria that are to be used when determining the scope of a ''stationary source.'' [652] These criteria require the aggregation of different pollutant-emitting activities if they (1) belong to the same industrial grouping as defined by SIC codes, (2) are located on contiguous or adjacent properties, and (3) are under common control.[653] In the case of an EGU and CO_2 capture plant that are collocated, to permit them as separate sources they should not be under common control or not be defined by the same industrial grouping.

The EPA would anticipate that, in most cases, the operation of the EGU and the CO_2 capture plant will intrinsically affect one another—typically steam, electricity, and the flue gas of the EGU will be provided to the CO_2 capture plant. Conditions of the flue gas will affect the operation of the CO_2 capture plant, including its emissions, and the steam and electrical load will affect the operation of the EGU. Moreover, the emissions from the EGU will be routed through the CO_2 capture system and emitted out of the top of the CO_2 absorber. Even if the EGU and CO_2 capture plant are owned by separate entities, the CO_2 capture plant is likely to be on or directly adjacent to land owned by the owners of the EGU and contractual obligations are likely to exist between the two owners. While each of these individual factors may not ultimately determine the outcome of whether two nominally-separate facilities should be treated as a single stationary source for permitting purposes, the EPA expects that in most cases an EGU and its collocated CO_2 capture plant would meet each of the aforementioned NSR regulatory criteria necessary to make such a determination. Thus, the EPA generally would not expect an EGU and its CO_2 capture plant to be permitted as separate stationary sources.

(C) Water Use

Water consumption at the plant increases when applying carbon capture, due to solvent water makeup and cooling demand. Water consumption can increase by 36 percent on a gross basis.[654] A separate cooling water system dedicated to a CO_2 capture plant may be necessary. However, the amount of water consumption depends on the design of the cooling system. For example, the cooling system cited in the CCS feasibility study for SaskPower's Shand Power station would rely entirely on water condensed from the flue gas and thus would not require any increase in external water consumption—all while achieving higher capture rates at lower cost than Boundary Dam Unit 3.[655] Regions with limited water supply

[651] DCC East PTC Application. *https://ceris.deq.nd.gov/ext/nsite/map/results/detail/-8992368000928857057/documents*.

[652] 40 CFR 51.165(a)(1)(i) and (ii); 40 CFR 51.166(b)(5) and (6).

[653] The EPA has issued guidance to clarify these regulatory criteria of stationary source determination. See *https://www.epa.gov/nsr/single-source-determination*.

[654] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9*.

[655] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://*

Continued

may therefore rely on dry or hybrid cooling systems. Therefore, the EPA considers the water use requirements to be manageable and does not expect this consideration to preclude coal-fired power plants generally from being able to install and operate CCS.

(D) CO_2 Capture Plant Siting

With respect to siting considerations, CO_2 capture systems have a sizeable physical footprint and a consequent land-use requirement. One commenter cited their analysis showing that, for a subset of coal-fired sources greater than 300 MW, 98 percent (154 GW of the existing fleet) have adjacent land available within 1 mile of the facility, and 83 percent have adjacent land available within 100 meters of the facility. Furthermore, the cited analysis did not include land available onsite, and it is therefore possible there is even greater land availability for siting capture equipment. Qualitatively, some commenters claimed there is limited land available for siting CO_2 capture plants adjacent to coal-fired steam generating units. However, those commenters provided no data or analysis to support their assertion. The EPA has reviewed the analysis provided by the first commenter, and the approach, methods, and assumptions are logical. Further, the EPA has reviewed the available information, including the location of coal-fired steam generating units and visual inspection of the associated maps and plots. Although in some cases longer duct runs may be required, this would not preclude coal-fired power plants generally from being able to install and operate CCS. Therefore, the EPA has concluded that siting and land-use requirements for CO_2 capture are not unreasonable.

(E) Transport and Geologic Sequestration

As noted in section VII.C.1.a.i(C) of this preamble, PHMSA oversight of supercritical CO_2 pipeline safety protects against environmental release during transport. The vast majority of CO_2 pipelines have been operating safely for more than 60 years. PHMSA reported a total of 102 CO_2 pipeline incidents between 2003 and 2022, with one injury (requiring in-patient hospitalization) and zero fatalities.[656] In the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines with zero incidents involving fatalities.[657] PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of supercritical CO_2 pipelines. Furthermore, UIC Class VI and Class II regulations under the SDWA, in tandem with GHGRP subpart RR and subpart VV requirements, ensure the protection of USDWs and the security of geologic sequestration. The EPA believes these protections constitute an effective framework for addressing potential health and environmental concerns related to CO_2 transportation and sequestration, and the EPA has taken this regulatory framework into consideration in determining that CCS represents the BSER for long-term steam EGUs.

(F) Impacts on the Energy Sector

Additionally, the EPA considered the impacts on the power sector, on a nationwide and long-term basis, of determining CCS to be the BSER for long-term coal-fired steam generating units. In this final action, the EPA considers that designating CCS as the BSER for these units would have limited and non-adverse impacts on the long-term structure of the power sector or on the reliability of the power sector. Absent the requirements defined in this action, the EPA projects that 11 GW of coal-fired steam generating units would apply CCS by 2035 and an additional 30 GW of coal-fired steam generating units, without controls, would remain in operation in 2040. Designating CCS to be the BSER for existing long-term coal-fired steam generating units may result in more of the coal-fired steam generating unit capacity applying CCS. The time available before the compliance deadline of January 1, 2032, provides for adequate resource planning, including accounting for the downtime necessary to install the CO_2 capture equipment at long-term coal-fired steam generating units. For the 12-year duration that eligible EGUs earn the IRC section 45Q tax credit, long-term coal-fired steam generating units are anticipated to run at or near base load conditions in order to maximize the amount of tax credit earned through IRC section 45Q. Total generation from coal-fired steam generating units in the medium-term subcategory would gradually decrease over an extended period of time through 2039, subject to the commitments those units have chosen to adopt. Additionally, for the long-term units applying CCS, the EPA has determined that the increase in the annualized cost of generation is reasonable. Therefore, the EPA concludes that these elements of BSER can be implemented while maintaining a reliable electric grid. A broader discussion of reliability impacts of these final rules is available in section XII.F of this preamble.

iv. Extent of Reductions in CO_2 Emissions

CCS is an extremely effective technology for reducing CO_2 emissions. As of 2021, coal-fired power plants are the largest stationary source of GHG emissions by sector. Furthermore, emission rates (lb CO_2/MWh-gross) from coal-fired sources are almost twice those of natural gas-fired combined cycle units, and sources operating in the long-term have the more substantial emissions potential. CCS can be applied to coal-fired steam generating units at the source to reduce the mass of CO_2 emissions by 90 percent or more. Increased steam and power demand have a small impact on the reduction in emission rate (*i.e.,* lb CO_2/MWh-gross) that occurs with 90 percent capture. According to the 2016 NETL Retrofit report, 90 percent capture will result in emission rates that are 88.4 percent lower on a lb/MWh-gross basis and 87.1 percent lower on a lb/MWh-net basis compared to units without capture.[658] After capture, CO_2 can be transported and securely sequestered.[659] Although steam generating units with CO_2 capture will have an incentive to operate at higher utilization because the cost to install the CCS system is largely fixed and the IRC section 45Q tax credit increases based on the amount of CO_2 captured and sequestered, any increase in utilization will be far outweighed by the substantial reductions in emission rate.

v. Promotion of the Development and Implementation of Technology

The EPA considered the potential impact on technology advancement of designating CCS as the BSER for long-term coal-fired steam generating units, and in this final rule, the EPA considers

ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.

[656] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[657] Congressional Research Service. 2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[658] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9.*

[659] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

that designating CCS as the BSER will provide for meaningful advancement of CCS technology. As indicated above, the EPA's IPM modeling indicates that 11 GW of coal-fired power plants install CCS and generate 76 terawatt-hours (TWh) per year in the base case, and that another 8 GW of plants install CCS and generate another 57 TWh per year in the policy case. In this manner, this rule advances CCS technology more widely throughout the coal-fired power sector. As discussed in section VIII.F.4.c.iv(G) of this preamble, this rule advances CCS technology for new combined cycle base load combustion turbines, as well. It is also likely that this rule supports advances in the technology in other industries.

vi. Comparison With 2015 NSPS For Newly Constructed Coal-Fired EGUs

In the 2015 NSPS, the EPA determined that the BSER for newly constructed coal-fired EGUs was based on CCS with 16 to 23 percent capture, based on the type of coal combusted, and consequently, the EPA promulgated standards of performance of 1,400 lb CO_2/MWh-g. 80 FR 64512 (table 1), 64513 (October 23, 2015). The EPA made those determinations based on the costs of CCS at the time of that rulemaking. In general, those costs were significantly higher than at present, due to recent technology cost declines as well as related policies, including the IRC section 45Q tax credit for CCS, which were not available at that time for purposes of consideration during the development of the NSPS. *Id.* at 64562 (table 8). Based on of these higher costs, the EPA determined that 16–23 percent capture qualified as the BSER, rather than a significantly higher percentage of capture. Given the substantial differences in the cost of CCS during the time of the 2015 NSPS and the present time, the capture percentage of the 2015 NSPS necessarily differed from the capture percentage in this final action, and, by the same token, the associated degree of emission limitation and resulting standards of performance necessarily differ as well. If the EPA had strong evidence to indicate that new coal-fired EGUs would be built, it would propose to revise the 2015 NSPS to align the BSER and emissions standards to reflect the new information regarding the costs of CCS. Because there is no evidence to suggest that there are any firm plans to build new coal-fired EGUs in the future, however, it is not at present a good use of the EPA's limited resources to propose to update the new source standard to align with the existing source standard finalized today. While the EPA is not revising the new source standard for new coal-fired EGUs in this action, the EPA is retaining the ability to propose review in the future.

vii. Requirement That Source Must Transfer CO_2 to an Entity That Reports Under the Greenhouse Gas Reporting Program

The final rule requires that EGUs that capture CO_2 in order to meet the applicable emission standard report in accordance with the GHGRP requirements of 40 CFR part 98, including subpart PP. GHGRP subpart RR and subpart VV requirements provide the monitoring and reporting mechanisms to quantify CO_2 storage and to identify, quantify, and address potential leakage. Under existing GHGRP regulations, sequestration wells permitted as Class VI under the UIC program are required to report under subpart RR. Facilities with UIC Class II wells that inject CO_2 to enhance the recovery of oil or natural gas can opt-in to reporting under subpart RR by submitting and receiving approval for a monitoring, reporting, and verification (MRV) plan. Subpart VV applies to facilities that conduct enhanced recovery using ISO 27916 to quantify geologic storage unless they have opted to report under subpart RR. For this rule, if injection occurs on site, the EGU must report data accordingly under 40 CFR part 98 subpart RR or subpart VV. If the CO_2 is injected off site, the EGU must transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR or subpart VV. They may also transfer the captured CO_2 to a facility that has received an innovative technology waiver from the EPA.

b. Options Not Determined To Be the BSER for Long-Term Coal-Fired Steam Generating Units

In this section, we explain why CCS at 90 percent capture best balances the BSER factors and therefore why the EPA has determined it to be the best of the possible options for the BSER.

i. Partial Capture CCS

Partial capture for CCS was not determined to be BSER because the emission reductions are lower and the costs would, in general, be higher. As discussed in section IV.B of this preamble, individual coal-fired power plants are by far the highest-emitting plants in the nation, and the coal-fired power plant sector is higher-emitting than any other stationary source sector. CCS at 90 percent capture removes very high absolute amounts of emissions. Partial capture CCS would fail to capture large quantities of emissions. With respect to costs, designs for 90 percent capture in general take greater advantage of economies of scale. Eligibility for the IRC section 45Q tax credit for existing EGUs requires design capture rates equivalent to 75 percent of a baseline emission rate by mass. Even assuming partial capture rates meet that definition, lower capture rates would receive fewer returns from the IRC section 45Q tax credit (since these are tied to the amount of carbon sequestered, and all else being equal lower capture rates would result in lower amounts of sequestered carbon) and costs would thereby be higher.

ii. Natural Gas Co-Firing

(A) Reasons Why Not Selected as BSER

As discussed in section VII.C.2, the EPA is determining 40 percent natural gas co-firing to qualify as the BSER for the medium-term subcategory of coal-fired steam generating units. This subcategory consists of units that will permanently cease operation by January 1, 2039. In making this BSER determination, the EPA analyzed the ability of all existing coal-fired units—not only medium-term units—to install and operate 40 percent co-firing. As a result, all of the determinations concerning the criteria for BSER that the EPA made for 40 percent co-firing apply to all existing coal-fired units, including the units in the long-term subcategory. For example, 40 percent co-firing is adequately demonstrated for the long-term subcategory, and has reasonable energy requirements and reasonable non-air quality environmental impacts. It would also be of reasonable cost for the long-term subcategory. Although the capital expenditure for natural gas co-firing is lower than CCS, the variable costs are higher. As a result, the total costs of natural gas co-firing, in general, are higher on a $/ton basis and not substantially lower on a $/MWh basis, than for CCS. Were co-firing the BSER for long-term units, the cost that industry would bear might then be considered similar to the cost for CCS. In addition, the GHG Mitigation Measures TSD shows that all coal-fired units would be able to achieve the requisite infrastructure build-out and obtain sufficient quantities of natural gas to comply with standards of performance based on 40 percent co-firing by January 1, 2030.

The EPA is not selecting 40 percent natural gas co-firing as the BSER for the long-term subcategory, however, because it requires substantially less emission reductions at the unit-level than 90 percent capture CCS. Natural gas co-firing at 40 percent of the heat input to the steam generating unit achieves 16 percent reductions in emission rate at the stack, while CCS achieves an 88.4 percent reduction in emission rate. As discussed in section IV.B of this preamble, individual coal-fired power plants are by far the highest-emitting plants in the nation, and the coal-fired power plant sector is higher-emitting than any other stationary source sector. Because the unit-level emission reductions achievable by CCS are substantially greater, and because CCS is of reasonable cost and matches up well against the other BSER criteria, the EPA did not determine natural gas co-firing to be BSER for the long-term subcategory although, under other circumstances, it could be. Determining BSER requires the EPA to select the ''best'' of the systems of emission reduction that are adequately demonstrated, as described in section V.C.2; in this case, there are two systems of emission reduction that match up well against the BSER criteria, but based on weighing the criteria together, and in light of the substantially greater unit-level emission reductions from CCS, the EPA has determined that CCS is a better system of emission reduction than co-firing for the long-term subcategory.

The EPA notes that if a state demonstrates that a long-term coal-fired steam generating unit cannot install and operate CCS and cannot otherwise reasonably achieve the degree of emission limitation that the EPA has determined based on CCS, following the process the EPA has specified in its applicable regulations for consideration of RULOF, the state would evaluate natural gas co-firing as a potential basis for establishing a less stringent standard of performance, as detailed in section X.C.2 of this document.

iii. Heat Rate Improvements

Heat rate improvements were not considered to be BSER for long-term steam generating units because the achievable reductions are very low and may result in a rebound effect whereby total emissions from the source increase, as detailed in section VII.D.4.a of this preamble.

Comment: One commenter requested that HRI be considered as BSER in addition to CCS, so that long-term sources would be required to achieve reductions in emission rate consistent with performing HRI and adding CCS with 90 percent capture to the source.

Response: As described in section VII.D.4.a, the reductions from HRI are very low and many sources have already made HRI, so that additional reductions are not available. It is possible that a source installing CO_2 capture will make efficiency improvements as a matter of best practices. For example, Boundary Dam Unit 3 made upgrades to the existing steam generating unit when CCS was installed, including installing a new steam turbine.[660] However, the reductions from efficiency improvements would not be additive to the reductions from CCS because of the impact of the CO_2 capture plant on the efficiency of source due to the required steam and electricity load of the capture plant.

c. Conclusion

Coal-fired EGUs remain the largest stationary source of dangerous CO_2 emissions. The EPA is finalizing CCS at a capture rate of 90 percent as the BSER for long-term coal-fired steam generating units because this system satisfies the criteria for BSER as summarized here. CCS at a capture rate of 90 percent as the BSER for long-term coal-fired steam generating units is adequately demonstrated, as indicated by the facts that it has been operated at scale, is widely applicable to these sources, and that there are vast sequestration opportunities across the continental U.S. Additionally, accounting for recent technology cost declines as well as policies including the tax credit under IRC section 45Q, the costs for CCS are reasonable. Moreover, any adverse non-air quality health and environmental impacts and energy requirements of CCS, including impacts on the power sector on a nationwide basis, are limited and can be effectively avoided or mitigated. In contrast, co-firing 40 percent natural gas would achieve far fewer emission reductions without improving the cost reasonableness of the control strategy.

These considerations provide the basis for finalizing CCS as the best of the systems of emission reduction for long-term coal-fired power plants. In addition, determining CCS as the BSER promotes advancements in control technology for CO_2, which is a relevant consideration when establishing BSER under section 111 of the CAA.

i. Adequately Demonstrated

CCS with 90 percent capture is adequately demonstrated based on the information in section VII.C.1.a.i of this preamble. Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s[661] and has been used in a variety of industrial applications for decades. Thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[662] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with EOR.[663] There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under construction or in advanced stages of development.[664] This broad application of CCS demonstrates the successful operation of all three components of CCS, operating both independently and simultaneously. Various CO_2 capture methods are used in industrial applications and are tailored to the flue gas conditions of a particular industry (see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for details). Of those capture technologies, amine solvent-based capture has been demonstrated for removal of CO_2 from the post-combustion flue gas of fossil fuel-fired EGUs.

Since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant (Trona, California).[665] Amine solvent capture has been further demonstrated at coal-fired power plants including AES's Warrior Run and Shady Point. And since 2014, CCS has been applied at the commercial scale at Boundary Dam Unit 3, a 110 MW lignite coal-fired steam generating unit in Saskatchewan, Canada.

Impending increases in Canadian regulatory CO_2 emission requirements have prompted optimization of Boundary Dam Unit 3 so that the facility now captures 83 percent of its total CO_2 emissions. Moreover, from the flue gas

[660] IEAGHG Report 2015–06. Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station. August 2015. *https://ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/935-2015-06-integrated-ccs-project-at-saskpower-s-boundary-dam-power-station.*

[661] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[662] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[663] US EPA. GHGRP. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[664] Carbon Capture and Storage in the United States. CBO. December 13, 2023. *https://www.cbo.gov/publication/59345.*

[665] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

treated, Boundary Dam Unit 3 consistently captured 90 percent or more of the CO_2 over a 3-year period. The adequate demonstration of CCS is further corroborated by the EPAct05-assisted 240MW-equivalent Petra Nova CCS project at the coal-fired W.A. Parish Unit 8, which achieved over 90 percent capture from the treated flue gas during a 3-year period. Additionally, the technical improvements put in practice at Boundary Dam Unit 3 and Petra Nova can be put in place on new capture facilities during initial construction. This includes redundancies and isolations for key equipment, and spray systems to limit fly ash carryover. Projects that have announced plans to install CO_2 capture directly include these improvements in their design and employ new solvents achieving higher capture rates that are commercially available from technology providers. As a result, these projects target capture efficiencies of at least 95 percent, well above the BSER finalized here.

Precedent, building upon the statutory text and context, has established that the EPA may make a finding of adequate demonstration by drawing upon existing data from individual commercial-scale sources, including testing at these sources,[666] and that the agency may make projections based on existing data to establish a more stringent standard than has been regularly shown,[667] in particular in cases when the agency can specifically identify technological improvements that can be expected to achieve the standard in question.[668] Further, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different, related, source.[669] Following this legal standard, the available data regarding performance and testing at Boundary Dam, a commercial-scale plant, is enough, by itself, to support the EPA's adequate demonstration finding for a 90 percent standard. In addition to this, however, in the 9 years since Boundary Dam began operating, operators and the EPA have developed a clear understanding of specific technological improvements which, if implemented, the EPA can reasonably expect to lead to a 90 percent capture rate on a regular and ongoing basis. The D.C. Circuit has established that this information is more than enough to establish that a 90 percent standard is achievable.[670] And per *Lignite Energy Council,* the findings from Boundary Dam can be extrapolated to other, similarly operating power plants, including natural gas plants.[671]

Transport of CO_2 and geological storage of CO_2 have also been adequately demonstrated, as detailed in VII.C.1.a.i(B)(7) and VII.C.1.a.i(D)(2). CO_2 has been transported through pipelines for over 60 years, and in the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines. CO_2 pipeline controls and PHMSA standards ensure that captured CO_2 will be securely conveyed to a sequestration site. Due to the proximity of sources to storage, it would be feasible for most sources to build smaller and shorter source-to-sink laterals, rather than rely on a trunkline network buildout. In addition to pipelines, CO_2 can also be transported via vessel, highway, or rail. Geological storage is proven and broadly available, and of the coal-fired steam generating units with planned operation during or after 2030, 77 percent are within 40 miles of the boundary of a saline reservoir.

The EPA also considered the timelines, materials, and workforce necessary for installing CCS, and determined they are sufficient.

ii. Cost

Process improvements have resulted in a decrease in the projected costs to install CCS on existing coal-fired steam generating units. Additionally, the IRC section 45Q tax credit provides $85 per metric ton ($77 per ton) of CO_2. It is reasonable to account for the IRC section 45Q tax credit because the costs that should be accounted for are the costs to the source. For the fleet of coal-fired steam generating units with planned operation during or after 2033, and assuming a 12-year amortization period and 80 percent annual capacity factor and including source specific transport and storage costs, the average total costs of CCS are −$5/ton of CO_2 reduced and −$4/MWh. And even for shorter amortization periods, the $/MWh costs are comparable to or less than the costs for other controls ($10.60–$18.50/MWh) for a substantial number of sources. Notably, the EPA's IPM model projects that even without this final rule—that is, in the base case, without any CAA section 111 requirements—some units would deploy CCS. Similarly, the IPM model projects that even if this rule determined 40 percent co-firing to be the BSER for long-term coal, instead of CCS, some additional units would deploy CCS. Therefore, the costs of CCS with 90 percent capture are reasonable.

iii. Non-Air Quality Health and Environmental Impacts and Energy Requirements

The CO_2 capture plant requires substantial pre-treatment of the flue gas to remove SO_2 and fly ash (PM) while other controls and process designs are necessary to minimize solvent degradation and solvent loss. Although CCS has the potential to result in some increases in non-GHG emissions, a robust regulatory framework, generally implemented at the state level, is in place to mitigate other non-GHG emissions from the CO_2 capture plant. For transport, pipeline safety is regulated by PHMSA, while UIC Class VI regulations under the SDWA, in tandem with GHGRP subpart RR requirements, ensure the protection of USDWs and the security of geologic sequestration. Therefore, the potential non-air quality health and environmental impacts do not militate against designating CCS as the BSER for long-term steam EGUs. The EPA also considered energy requirements. While the CO_2 capture plant requires steam and electricity to operate, the incentives provided by the IRC section 45Q tax credit will likely result in increased total generation from the source. Therefore, the energy requirements are not unreasonable, and there would be limited, non-adverse impacts on the broader energy sector.

2. Medium-Term Coal-Fired Steam Generating Units

The EPA is finalizing its conclusion that 40 percent natural gas co-firing on a heat input basis is the BSER for medium-term coal-fired steam generating units. Co-firing 40 percent natural gas, on an annual average heat input basis, results in a 16 percent reduction in CO_2 emission rate. The technology has been adequately demonstrated, can be implemented at reasonable cost, does not have significant adverse non-air quality health and environmental impacts or energy requirements, including impacts on the energy sector, and achieves meaningful reductions in CO_2 emissions. Co-firing also advances useful control technology, which provides additional, although not essential, support for treating it as the BSER.

[666] *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775 (D.C. Cir. 1976).

[667] *See id.*

[668] *See Sierra Club* v. *Costle,* 657 F.2d 298 (1981).

[669] *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[670] *See, e.g., Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (1981).

[671] 198 F.3d 930 (D.C. Cir. 1999).

a. Rationale for the Medium-Term Coal-Fired Steam Generating Unit Subcategory

For the development of the emission guidelines, the EPA first considered CCS as the BSER for existing coal-fired steam generating units. CCS generally achieves significant emission reductions at reasonable cost. Typically, in setting the BSER, the EPA assumes that regulated units will continue to operate indefinitely. However, that assumption is not appropriate for all coal-fired steam generating units. 62 percent of existing coal-fired steam generating units greater than 25 MW have already announced that they will retire or convert from coal to gas by 2039.[672] CCS is capital cost-intensive, entailing a certain period to amortize the capital costs. Therefore, the EPA evaluated the costs of CCS for different amortization periods, as detailed in section VII.C.1.a.ii of the preamble, and determined that CCS was cost reasonable, on average, for sources operating more than 7 years after the compliance date of January 1, 2032. Accordingly, units that cease operating before January 1, 2039, will generally have less time to amortize the capital costs, and the costs for those sources would be higher and thereby less comparable to those the EPA has previously determined to be reasonable. Considering this, and the other factors evaluated in determining BSER, the EPA is not finalizing CCS as BSER for units demonstrating that they plan to permanently cease operation prior to January 1, 2039.

Instead, the EPA is subcategorizing these units into the medium-term subcategory and finalizing a BSER based on 40 percent natural gas co-firing on a heat input basis for these units. Co-firing natural gas at 40 percent has significantly lower capital costs than CCS and can be implemented by January 1, 2030. For sources that expect to continue in operation until January 1, 2039, and that therefore have a 9-year amortization period, the costs of 40 percent co-firing are $73/ton of CO_2 reduced or $13/MWh of generation, which supports their reasonableness because they are comparable to or less than the costs detailed in section VII.C.1.a.ii(D) of this preamble for other controls on EGUs ($10.60 to $18.50/MWh) and for GHGs for the Crude Oil and Natural Gas source category in the 2016 NSPS of $98/ton of CO_{2e} reduced (80 FR 56627; September 18, 2015). Co-firing is also cost-reasonable for sources permanently ceasing operations sooner, and that therefore have a shorter amortization period. As discussed in section VII.B.2 of this preamble, with a two-year amortization period, many units can co-fire with meaningful amounts of natural gas at reasonable cost. Of course, even more can co-fire at reasonable costs with amortization periods longer than two years. For example, the EPA has determined that 33 percent of sources with an amortization period of at least three years have costs for 40 percent co-firing below both of the $/ton and $/MWh metrics, and 68 percent of those sources have costs for 20 percent co-firing below both of those metrics. Therefore, recognizing that operating horizon affects the cost reasonableness of controls, the EPA is finalizing a separate subcategory for coal-fired steam generating units operating in the medium-term—those demonstrating that they plan to permanently cease operation after December 31, 2031, and before January 1, 2039—with 40 percent natural gas co-firing as the BSER.

i. Legal Basis for Establishing the Medium-Term Subcategory

As noted in section V.C.1 of this preamble, the EPA has broad authority under CAA section 111(d) to identify subcategories. As also noted in section V.C.1, the EPA's authority to ''distinguish among classes, types, and sizes within categories,'' as provided under CAA section 111(b)(2) and as we interpret CAA section 111(d) to provide as well, generally allows the Agency to place types of sources into subcategories when they have characteristics that are relevant to the controls that the EPA may determine to be the BSER for those sources. One element of the BSER is cost reasonableness. See CAA section 111(d)(1) (requiring the EPA, in setting the BSER, to ''tak[e] into account the cost of achieving such reduction''). As noted in section V, the EPA's longstanding regulations under CAA section 111(d) explicitly recognize that subcategorizing may be appropriate for sources based on the ''costs of control.''[673] Subcategorizing on the basis of operating horizon is consistent with a key characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements: A large percentage of the sources in the industry have already announced, and more are expected to announce, dates for ceasing operation, and the fact that many coal-fired steam generating units intend to cease operation in the near term affects what controls are ''best'' for different subcategories.[674] At the outset, installation of emission control technology takes time, sometimes several years. Whether the costs of control are reasonable depends in part on the period of time over which the affected sources can amortize those costs. Sources that have shorter operating horizons will have less time to amortize capital costs. Thus, the annualized cost of controls may thereby be less comparable to the costs the EPA has previously determined to be reasonable.[675]

In addition, subcategorizing by length of period of continued operation is similar to two other bases for subcategorization on which the EPA has relied in prior rules, each of which implicates the cost reasonableness of controls: The first is load level, noted in section V.C.1. of this preamble. For

[672] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs*.

[673] 40 CFR 60.22(b)(5), 60.22a(b)(5).

[674] The EPA recognizes that section 111(d) provides that in applying standards of performance, a state may take into account, among other factors, the remaining useful life of a facility. The EPA believes that provision is intended to address exceptional circumstances at particular facilities, while the EPA has the responsibility to determine how to address the source category as a whole. See 88 FR 80480, 80511 (November 17, 2023) (''Under CAA 111, EPA must provide BSER and degree of emission limitation determinations that are, to the extent reasonably practicable, applicable to all designated facilities in the source category. In many cases, this requires the EPA to create subcategories of designated facilities, each of which has a BSER and degree of emission limitation tailored to its circumstances. . . . However, as Congress recognized, this may not be possible in every instance because, for example, it is not be feasible [sic] for the Agency to know and consider the idiosyncrasies of every designated facility or because the circumstances of individual facilities change after the EPA determined the BSER.'') (internal citations omitted). That a state may take into account the remaining useful life of an individual source, however, does not bar the EPA from considering operating horizon as a factor in determining whether subcategorization is appropriate. As discussed, the authority to subcategorize is encompassed within the EPA's authority to identify the BSER. Here, where many units share similar characteristics and have announced intended shorter operating horizons, it is permissible for the EPA to take operating horizon into account in determining the BSER for this subcategory of sources. States may continue to take RULOF factors into account for particular units where the information relevant to those units is fundamentally different than the information the EPA took into account in determining the degree of emission limitation achievable through application of the BSER. Should a court conclude that the EPA does not have the authority to create a subcategory based on the date at which units intend to cease operation, then the EPA believes it would be reasonable for states to consider co-firing as an alternative to CCS as an option for these units through the states' authority to consider, among other factors, remaining useful life.

[675] Steam Electric Reconsideration Rule, 85 FR 64650, 64679 (October 13, 2020) (distinguishes between EGUs retiring before 2028 and EGUs remaining in operation after that time).

example, in the 2015 NSPS, the EPA divided new natural gas-fired combustion turbines into the subcategories of base load and non-base load. 80 FR 64602 (table 15) (October 23, 2015). The EPA did so because the control technologies that were ''best''—including consideration of feasibility and cost reasonableness—depended on how much the unit operated. The load level, which relates to the amount of product produced on a yearly or other basis, bears similarity to a limit on a period of continued operation, which concerns the amount of time remaining to produce the product. In both cases, certain technologies may not be cost-reasonable because of the capacity to produce product—*i.e.,* the costs are spread over less product produced. Subcategorization on this basis is also supported by how utilities manage their assets over the long term, and was widely supported by industry commenters.

The second basis for subcategorization on which EPA has previously relied is fuel type, as also noted in section V.C.1 of this preamble. The 2015 NSPS provides an example of this type of subcategorization as well. There, the EPA divided new combustion turbines into subcategories on the basis of type of fuel combusted. *Id.* Subcategorizing on the basis of the type of fuel combusted may be appropriate when different controls have different costs, depending on the type of fuel, so that the cost reasonableness of the control depends on the type of fuel. In that way, it is similar to subcategorizing by operating horizon because in both cases, the subcategory is based upon the cost reasonableness of controls. Subcategorizing by operating horizon is also tantamount to the length of time over which the source will continue to combust the fuel. Subcategorizing on this basis may be appropriate when different controls for a particular fuel have different costs, depending on the length of time when the fuel will continue to be combusted, so that the cost reasonableness of controls depends on that timeframe. Some prior EPA rules for coal-fired sources have made explicit the link between length of time for continued operation and type of fuel combusted by codifying federally enforceable retirement dates as the dates by which the source must ''cease burning coal.'' [676]

As noted above, creating a subcategory on the basis of operating horizon does not preclude a state from considering RULOF in applying a standard of performance to a particular source. The EPA's authority to set BSER for a source category (including subcategories) and a state's authority to invoke RULOF for individual sources within a category or subcategory are distinct. The EPA's statutory obligation is to determine a generally applicable BSER for a source category, and where that source category encompasses different classes, types, or sizes of sources, to set generally applicable BSERs for subcategories accounting for those differences. By contrast, states' authority to invoke RULOF is premised on the state's ability to take into account information relevant to individual units that is fundamentally different than the information the EPA took into account in determining BSER generally. As noted, the EPA may subcategorize on the basis of cost of controls, and operating horizon may factor into the cost of controls. Moreover, through section 111(d)(1), Congress also required the EPA to develop regulations that permit states to consider ''among other factors, the remaining useful life'' of a particular existing source. The EPA has interpreted these other factors to include costs or technical feasibility specific to a particular source, even though these are factors the EPA itself considers in setting the BSER. In other words, the factors the EPA may consider in setting the BSER and the factors the states may consider in applying standards of performance are not distinct. As noted above, the EPA is finalizing these subcategories in response to requests by power sector representatives that this rule accommodate the fact that there is a class of sources that plan to voluntarily cease operations in the near term. Although the EPA has designed the subcategories to accommodate those requests, a particular source may still present source-specific considerations—whether related to its remaining useful life or other factors—that the state may consider relevant for the application of that particular source's standard of performance, and that the state should address as described in section X.C.2 of this preamble.

ii. Comments Received on Existing Coal-Fired Subcategories

Comment: The EPA received several comments on the proposed subcategories for coal-fired steam generating units. Many commenters, including industry commenters, supported these subcategories. Some commenters opposed these proposed subcategories. They argued that the subcategories were designed to force coal-fired power plants to retire.

Response: We disagree with comments suggesting that the subcategories for existing coal-fired steam EGUs that the EPA has finalized in this rule were designed to force retirements. The subcategories were not designed for that purpose, and the commenters do not explain their allegations to the contrary. The subcategories were designed, at industry's request,[677] to ensure that subcategories of units that can feasibly and cost-reasonably employ emissions reduction technologies—and only those subcategories of units that can do so—are required to reduce their emissions commensurate with those technologies. As explained above, in determining the BSER, the EPA generally assumes that a source will operate indefinitely, and calculates expected control costs on that basis. Under that assumption, the BSER for existing fossil-fuel fired EGUs is CCS. Nevertheless, the EPA recognizes that many fossil-fuel fired EGUs have already announced plans to cease operation. In recognition of this unique, distinguishing factor, the EPA determined whether a different BSER would be appropriate for fossil fuel-fired EGUs that do not intend to operate over the long term, and concluded, for the reasons stated above, that natural gas co-firing was appropriate for these sources that intended to cease operation before 2039. This subcategory is not intended to force retirements, and the EPA is not directing any state or any unit as to the choice of when to cease operation. Rather, the EPA has created this subcategory to accommodate these sources' intended operation plans. In fact, a number of industry commenters specifically requested and supported subcategories based on retirement dates in recognition of the reality that many operators are choosing to retire these units and that whether or not a control technology is feasible and cost-reasonable depends upon how long a unit intends to operate.

Specifically, as noted in section VII.B of this preamble, in this final action, the

[676] See 79 FR 5031, 5192 (January 30, 2014) (explaining that ''[t]he construction permit issued by Wyoming requires Naughton Unit 3 to *cease burning coal* by December 31, 2017, and to be retrofitted to natural gas as its fuel source by June 30, 2018'' (emphasis added)).

[677] As described in the proposal, during the early engagement process, industry stakeholders requested that the EPA ''[p]rovide approaches that allow for the retirement of units as opposed to investments in new control technologies, which could prolong the lives of higher-emitting EGUs; this will achieve maximum and durable environmental benefits.'' Industry stakeholders also suggested that the EPA recognize that some units may remain operational for a several-year period but will do so at limited capacity (in part to assure reliability), and then voluntarily cease operations entirely. 88 FR 33245 (May 23, 2023).

medium-term subcategory includes a date for permanently ceasing operation, which applies to coal-fired plants demonstrating that they plan to permanently cease operating after December 31, 2031, and before January 1, 2039. The EPA is retaining this subcategory because 55 percent of existing coal-fired steam generating units greater than 25 MW have already announced that they will retire or convert from coal to gas by January 1, 2039.[678] Accordingly, the costs of CCS—the high capital costs of which require a lengthy amortization period from its January 1, 2032, implementation date—are higher than the traditional metric for cost reasonableness for these sources. As discussed in section VII.C.2 of this preamble, the BSER for these sources is co-firing 40 percent natural gas. This is because co-firing, which has an implementation date of January 1, 2030, has lower capital costs and is therefore cost-reasonable for sources continuing to operate on or after January 1, 2032. It is further noted that this subcategory is elective. Furthermore, states also have the authority to establish a less stringent standard through RULOF in the state plan process, as detailed in section X.C.2 of this preamble.

In sum, these emission guidelines do not require any coal-fired steam EGU to retire, nor are they intended to induce retirements. Rather, these emission guidelines simply set forth presumptive standards that are cost-reasonable and achievable for each subcategory of existing coal-fired steam EGUs. See section VII.E.1 of this preamble (responding to comments that this rule violates the major questions doctrine).

Comment: The EPA broadly solicited comment on the dates and values defining the proposed subcategories for coal-fired steam generating units. Regarding the proposed dates for the subcategories, one industry stakeholder commented that the ''EPA's proposed retirement dates for applicability of the various subcategories are appropriate and broadly consistent with system reliability needs.'' [679] More specifically, industry commenters requested that the cease-operation-by date for the imminent-term subcategory be changed from January 1, 2032, to January 1, 2033. Industry commenters also stated that the 20 percent utilization limit in the definition of the near-term subcategory was overly restrictive and inconsistent with the emissions stringency of either the proposed medium term or imminent term subcategory—commenters requested greater flexibility for the near-term subcategory. Other comments from NGOs and other groups suggested various other changes to the subcategory definitions. One commenter requested moving the cease-operation-by date for the medium-term subcategory up to January 1, 2038, while eliminating the imminent-term subcategory and extending the near-term subcategory to January 1, 2038.

Response: The EPA is not finalizing the proposed imminent-term or near-term subcategories. The EPA is finalizing an applicability exemption for sources demonstrating that they plan to permanently cease operation prior to January 1, 2032, as detailed in section VII.B of this preamble. The EPA is finalizing the cease operating by date of January 1, 2039, for medium-term coal-fired steam generating units. These dates are all based on costs of co-firing and CCS, driven by their amortization periods, as discussed in the preceding sections of this preamble.

b. Rationale for Natural Gas Co-Firing as the BSER for Medium-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA describes its rationale for natural gas co-firing as the final BSER for medium-term coal-fired steam generating units.

For a coal-fired steam generating unit, the substitution of natural gas for some of the coal, so that the unit fires a combination of coal and natural gas, is known as ''natural gas co-firing.'' The EPA is finalizing natural gas co-firing at a level of 40 percent of annual heat input as BSER for medium-term coal-fired steam generating units.

i. Adequately Demonstrated

The EPA is finalizing its determination that natural gas co-firing at the level of 40 percent of annual heat input is adequately demonstrated for coal-fired steam generating units. Many existing coal-fired steam generating units already use some amount of natural gas, and several have co-fired at relatively high levels at or above 40 percent of heat input in recent years.

(A) Boiler Modifications

Existing coal-fired steam generating units can be modified to co-fire natural gas in any desired proportion with coal, up to 100 percent natural gas. Generally, the modification of existing boilers to enable or increase natural gas firing typically involves the installation of new gas burners and related boiler modifications, including, for example, new fuel supply lines and modifications to existing air ducts. The introduction of natural gas as a fuel can reduce boiler efficiency slightly, due in large part to the relatively high hydrogen content of natural gas. However, since the reduction in coal can result in reduced auxiliary power demand, the overall impact on net heat rate can range from a 2 percent increase to a 2 percent decrease.

It is common practice for steam generating units to have the capability to burn multiple fuels onsite, and of the 565 coal-fired steam generating units operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source. Coal-fired steam generating units often use natural gas or oil as a startup fuel, to warm the units up before running them at full capacity with coal. While startup fuels are generally used at low levels (up to roughly 1 percent of capacity on an annual average basis), some coal-fired steam generating units have co-fired natural gas at considerably higher shares. Based on hourly reported CO_2 emission rates from the start of 2015 through the end of 2020, 29 coal-fired steam generating units co-fired with natural gas at rates at or above 60 percent of capacity on an hourly basis.[680] The capability of those units on an hourly basis is indicative of the extent of boiler burner modifications and sizing and capacity of natural gas pipelines to those units, and implies that those units are technically capable of co-firing at least 60 percent natural gas on a heat input basis on average over the course of an extended period (*e.g.,* a year). Additionally, during that same 2015 through 2020 period, 29 coal-fired steam generating units co-fired natural gas at over 40 percent on an annual heat input basis. Because of the number of units that have demonstrated co-firing above 40 percent of heat input, the EPA is finalizing that co-firing at 40 percent is adequately demonstrated. A more detailed discussion of the record of natural gas co-firing, including current trends, at coal-fired steam generating units is included in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

(B) Natural Gas Pipeline Development

In addition to any potential boiler modifications, the supply of natural gas is necessary to enable co-firing at existing coal-fired steam boilers. As

[678] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[679] See Document ID No. EPA–HQ–OAR–2023–0072–0772.

[680] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data website: *https://campd.epa.gov.*

discussed in the previous section, many plants already have at least some access to natural gas. In order to increase natural gas access beyond current levels, plants may find it necessary to construct natural gas supply pipelines.

The U.S. natural gas pipeline network consists of approximately 3 million miles of pipelines that connect natural gas production with consumers of natural gas. To increase natural gas consumption at a coal-fired boiler without sufficient existing natural gas access, it is necessary to connect the facility to the natural gas pipeline transmission network via the construction of a lateral pipeline. The cost of doing so is a function of the total necessary pipeline capacity (which is characterized by the length, size, and number of laterals) and the location of the plant relative to the existing pipeline transmission network. The EPA estimated the costs associated with developing new lateral pipeline capacity sufficient to meet 60 percent of the net summer capacity at each coal-fired steam generating unit that could be included in this subcategory. As discussed in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* the EPA estimates that this lateral capacity would be sufficient to enable each unit to achieve 40 percent natural gas co-firing on an annual average basis.

The EPA considered the availability of the upstream natural gas pipeline capacity to satisfy the assumed co-firing demand implied by these new laterals. This analysis included pipeline development at all EGUs that could be included in this subcategory, including those without announced plans to cease operating before January 1, 2039. The EPA's assessment reviewed the reasonableness of each assumed new lateral by determining whether the peak gas capacity of that lateral could be satisfied without modification of the transmission pipeline systems to which it is assumed to be connected. This analysis found that most, if not all, existing pipeline systems are currently able to meet the peak needs implied by these new laterals in aggregate, assuming that each existing coal-fired unit in the analysis co-fired with natural gas at a level implied by these new laterals, or 60 percent of net summer generating capacity. While this is a reasonable assumption for the analysis to support this mitigation measure in the BSER context, it is also a conservative assumption that overstates the amount of natural gas co-firing expected under the final rule.[681]

Most of these individual laterals are less than 15 miles in length. The maximum aggregate amount of pipeline capacity, if all coal-fired steam capacity that could be included in the medium-term subcategory (*i.e.,* all capacity that has not announced that it plans to retire by 2032) implemented the final BSER by co-firing 40 percent natural gas, would be comparable to pipeline capacity constructed recently. The EPA estimates that this maximum total capacity would be nearly 14.7 billion cubic feet per day, which would require about 3,500 miles of pipeline costing roughly $11.5 billion. Over 2 years,[682] this maximum total incremental pipeline capacity would amount to less than 1,800 miles per year, with a total annual capacity of roughly 7.35 billion cubic feet per day. This represents an estimated annual investment of approximately $5.75 billion per year in capital expenditures, on average. By comparison, based on data collected by EIA, the total annual mileage of natural gas pipelines constructed over the 2017–2021 period ranged from approximately 1,000 to 2,500 miles per year, with a total annual capacity of 10 to 25 billion cubic feet per day. This represents an estimated annual investment of up to nearly $15 billion. The upper end of these historical annual values is much higher than the maximum annual values that could be expected under this final BSER measure—which, as noted above, represent a conservative estimate that significantly overstates the amount of co-firing that the EPA projects would occur under this final rule.

These conservatively high estimates of pipeline requirements also compare favorably to industry projections of future pipeline capacity additions. Based on a review of a 2018 industry report, titled ''North America Midstream Infrastructure through 2035: Significant Development Continues,'' investment in midstream infrastructure development is expected to range between $10 to $20 billion per year through 2035. Approximately $5 to $10 billion annually is expected to be invested in natural gas pipelines through 2035. This report also projects that an average of over 1,400 miles of new natural gas pipeline will be built through 2035, which is similar to the approximately 1,670 miles that were built on average from 2013 to 2017. These values are consistent with the average annual expenditure of $5.75 billion on less than 1,800 miles per year of new pipeline construction that would be necessary for the entire operational fleet of existing coal-fired steam generating units to co-fire with natural gas. The actual pipeline investment for this subcategory would be substantially lower.

(C) Compliance Date for Medium-Term Coal-Fired Steam Generating Units

The EPA is finalizing a compliance date for medium-term coal-fired steam generating units of January 1, 2030.

As in the timeline for CCS for the long term coal-fired steam generating units described in section VII.C.1.a.i(E), the EPA assumes here that feasibility work occurs during the state plan development period, and that all subsequent work occurs after the state plan is submitted and thereby effective at the state level. The EPA assumes 12 months of feasibility work for the natural gas pipeline lateral and 6 months of feasibility work for boiler modifications (both to occur over June 2024 to June 2025). As with the feasibility analysis for CCS, the feasibility analysis for co-firing will inform the state plan and therefore it is reasonable to assume units will perform it during the state planning window. Feasibility for the pipeline includes a right-of-way and routing analysis. Feasibility for the boiler modifications includes conceptual studies and design basis.

The timeline for the natural gas pipeline permitting and construction is based on a review of recently completed permitting approvals and construction.[683] The average time to complete permitting and approval is less than 1.5 years, and the average time to complete actual construction is less than 1 year. Of the 31 reviewed pipeline projects, the vast majority (27 projects) took less than a total of 3 years for permitting and construction, and none took more than 3.5 years. Therefore, it is reasonable to assume that permitting and construction would take no more than 3 years for most sources (June 2026 to June 2029), noting that permitting

[681] In practice, not all sources would necessarily be subject to a natural gas co-firing BSER in compliance. *E.g.,* some portion of that population of sources could install CCS, so the resulting amount of natural gas co-firing would be less.

[682] The average time for permitting for a natural gas pipeline lateral is 1.5 years, and many sources could be permitted faster (about 1 year) so that it is reasonable to assume that many sources could begin construction by June 2027. The average time for construction of an individual pipeline is about 1 year or less. Considering this, the EPA assumes construction of all of the natural gas pipeline laterals in the analysis occurs over a 2-year period (June 2027 through June 2029), and notes that in practice some of these projects could be constructed outside of this period.

[683] Documentation for the Lateral Cost Estimation (2024), ICF International. Available in Docket ID EPA–HQ–OAR–2023–0072.

and construction for many sources would be faster.

The timeline for boiler modifications based on the baseline duration co-firing conversion project schedule developed by Sargent and Lundy.[684] The EPA assumes that, with the exception of the feasibility studies discussed above, work on the boiler modifications begins after the state plan submission due date. The EPA also assumes permitting for the boiler modifications is required and takes 12 months (June 2026 to June 2027). In the schedule developed by Sargent and Lundy, commercial arrangements for the boiler modification take about 6 months (June 2026 to December 2026). Detailed engineering and procurement takes about 7 months (December 2026 to July 2027), and begins after commercial arrangements are complete. Site work takes 3 months (July 2027 to October 2027), followed by 4 months of construction (October 2027 to February 2028). Lastly, startup and testing takes about 2 months (June 2029 to August 2029), noting that the EPA assumes this occurs after the natural gas pipeline lateral is constructed. Considering the preceding information, the EPA has determined January 1, 2030 is the compliance date for medium-term coal-fired steam generating units.

ii. Costs

The capital costs associated with the addition of new gas burners and other necessary boiler modifications depend on the extent to which the current boiler is already able to co-fire with some natural gas and on the amount of gas co-firing desired. The EPA estimates that, on average, the total capital cost associated with modifying existing boilers to operate at up to 100 percent of heat input using natural gas is approximately $52/kW. These costs could be higher or lower, depending on the equipment that is already installed and the expected impact on heat rate or steam temperature.

While fixed O&M (FOM) costs can potentially decrease as a result of decreasing the amount of coal consumed, it is common for plants to maintain operation of one coal pulverizer at all times, which is necessary for maintaining several coal burners in continuous service. In this case, coal handling equipment would be required to operate continuously and therefore natural gas co-firing would have limited effect on reducing the coal-related FOM costs. Although, as noted, coal-related FOM costs have the potential to decrease, the EPA does not anticipate a significant increase in impact on FOM costs related to co-firing with natural gas.

In addition to capital and FOM cost impacts, any additional natural gas co-firing would result in incremental costs related to the differential in fuel cost, taking into consideration the difference in delivered coal and gas prices, as well as any potential impact on the overall net heat rate. The EPA's reference case projects that in 2030, the average delivered price of coal will be $1.56/MMBtu and the average delivered price of natural gas will be $2.95/MMBtu. Thus, assuming the same level of generation and no impact on heat rate, the additional fuel cost would be $1.39/MMBtu on average in 2030. The total additional fuel cost could increase or decrease depending on the potential impact on net heat rate. An increase in net heat rate, for example, would result in more fuel required to produce a given amount of generation and thus additional cost. In the final TSD, *GHG Mitigation Measures for Steam Generating Units,* the EPA's cost estimates assume a 1 percent average increase in net heat rate.

Finally, for plants without sufficient access to natural gas, it is also necessary to construct new natural gas pipelines (''laterals''). Pipeline costs are typically expressed in terms of dollars per inch of pipeline diameter per mile of pipeline distance (*i.e.,* dollars per inch-mile), reflecting the fact that costs increase with larger diameters and longer pipelines. On average, the cost for lateral development within the contiguous U.S. is approximately $280,000 per inch-mile (2019$), which can vary based on site-specific factors. The total pipeline cost for each coal-fired steam generating unit is a function of this cost, as well as a function of the necessary pipeline capacity and the location of the plant relative to the existing pipeline transmission network. The pipeline capacity required depends on the amount of co-firing desired as well as on the desired level of generation—a higher degree of co-firing while operating at full load would require more pipeline capacity than a lower degree of co-firing while operating at partial load. It is reasonable to assume that most plant owners would develop sufficient pipeline capacity to deliver the maximum amount of desired gas use in any moment, enabling higher levels of co-firing during periods of lower fuel price differentials. Once the necessary pipeline capacity is determined, the total lateral cost can be estimated by considering the location of each plant relative to the existing natural gas transmission pipelines as well as the available excess capacity of each of those existing pipelines.

The EPA determined the costs of 40 percent co-firing based on the fleet of coal-fired steam generating units that existed in 2021 and that do not have known plans to cease operations or convert to gas by 2032, and assuming that each of those units continues to operate at the same level as it operated over 2017–2021. The EPA assessed those costs against the cost reasonableness metrics, as described in section VII.C.1.a.ii(D) of this preamble (*i.e.,* emission control costs on EGUs of $10.60 to $18.50/MWh and the costs in the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category of $98/ton of CO_{2e} reduced (80 FR 56627; September 18, 2015)). On average, the EPA estimates that the weighted average cost of co-firing with 40 percent natural gas as the BSER on an annual average basis is approximately $73/ton CO_2 reduced, or $13/MWh. The costs here reflect an amortization period of 9 years. These estimates support a conclusion that co-firing is cost-reasonable for sources that continue to operate up until the January 1, 2039, threshold date for the subcategory. The EPA also evaluated the fleet average costs of natural gas co-firing for shorter amortization periods and has determined that the costs are consistent with the cost reasonableness metrics for the majority of sources that will operate past January 1, 2032, and therefore have an amortization period of at least 2 years and up to 9 years. These estimates and all underlying assumptions are explained in detail in the final TSD, *GHG Mitigation Measures for Steam Generating Units.* Based on this cost analysis, alongside the EPA's overall assessment of the costs of this rule, the EPA is finalizing that the costs of natural gas co-firing are reasonable for the medium-term coal-fired steam generating unit subcategory. If a particular source has costs of 40 percent co-firing that are fundamentally different from the cost reasonability metrics, the state may consider this fact under the RULOF provisions, as detailed in section X.C.2 of this preamble. The EPA previously estimated the cost of natural gas co-firing in the Clean Power Plan (CPP). 80 FR 64662 (October 23, 2015). The cost-estimates for co-firing presented in this section are lower than in the CPP, for several reasons. Since then, the expected difference between coal and gas prices has decreased significantly, from over $3/MMBtu to less than $1.50/MMBtu in this final rule. Additionally,

[684] Natural Gas Co-Firing Memo, Sargent & Lundy (2023). Available in Docket ID EPA–HQ–OAR–2023–0072.

a recent analysis performed by Sargent and Lundy for the EPA supports a considerably lower capital cost for modifying existing boilers to co-fire with natural gas. The EPA also recently conducted a highly detailed facility-level analysis of natural gas pipeline costs, the median value of which is slightly lower than the value used by the EPA previously to approximate the cost of co-firing at a representative unit.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Natural gas co-firing for steam generating units is not expected to have any significant adverse consequences related to non-air quality health and environmental impacts or energy requirements.

(A) Non-GHG Emissions

Non-GHG emissions are reduced when steam generating units co-fire with natural gas because less coal is combusted. SO_2, $PM_{2.5}$, acid gas, mercury and other hazardous air pollutant emissions that result from coal combustion are reduced proportionally to the amount of natural gas consumed, *i.e.,* under this final rule, by 40 percent. Natural gas combustion does produce NO_X emissions, but in lesser amounts than from coal-firing. However, the magnitude of this reduction is dependent on the combustion system modifications that are implemented to facilitate natural gas co-firing.

Sufficient regulations also exist related to natural gas pipelines and transport that assure natural gas can be safely transported with minimal risk of environmental release. PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.6 million mile pipeline transportation system. Recently, PHMSA finalized a rule that will improve the safety and strengthen the environmental protection of more than 300,000 miles of onshore gas transmission pipelines.[685] PHMSA also recently promulgated a separate rule covering natural gas transmission,[686] as well as a rule that significantly expanded the scope of safety and reporting requirements for more than 400,000 miles of previously unregulated gas gathering lines.[687] FERC is responsible for the regulation of the siting, construction, and/or abandonment of interstate natural gas pipelines, gas storage facilities, and Liquified Natural Gas (LNG) terminals.

(B) Energy Requirements

The introduction of natural gas co-firing will cause steam boilers to be slightly less efficient due to the high hydrogen content of natural gas. Co-firing at levels between 20 percent and 100 percent can be expected to decrease boiler efficiency between 1 percent and 5 percent. However, despite the decrease in boiler efficiency, the overall net output efficiency of a steam generating unit that switches from coal- to natural gas-firing may change only slightly, in either a positive or negative direction. Since co-firing reduces coal consumption, the auxiliary power demand related to coal handling and emissions controls typically decreases as well. While a site-specific analysis would be required to determine the overall net impact of these countervailing factors, generally the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent.

The EPA previously determined in the ACE Rule (84 FR 32545; July 8, 2019) that ''co-firing natural gas in coal-fired utility boilers is not the best or most efficient use of natural gas and [. . .] can lead to less efficient operation of utility boilers.'' That determination was informed by the more limited supply of natural gas, and the larger amount of coal-fired EGU capacity and generation, in 2019. Since that determination, the expected supply of natural gas has expanded considerably, and the capacity and generation of the existing coal-fired fleet has decreased, reducing the total mass of natural gas that might be required for sources to implement this measure.

Furthermore, regarding the efficient operation of boilers, the ACE determination was based on the observation that ''co-firing can negatively impact a unit's heat rate (efficiency) due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product.'' That finding does not consider the fact that the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent, and therefore the net impact on overall utility boiler efficiency for each steam generating unit is uncertain.

For all of these reasons, the EPA is finalizing that natural gas co-firing at medium-term coal-fired steam generating units does not result in any significant adverse consequences related to energy requirements.

Additionally, the EPA considered longer term impacts on the energy sector, and the EPA is finalizing these impacts are reasonable. Designating natural gas co-firing as the BSER for medium-term coal-fired steam generating units would not have significant adverse impacts on the structure of the energy sector. Steam generating units that currently are coal-fired would be able to remain primarily coal-fired. The replacement of some coal with natural gas as fuel in these sources would not have significant adverse effects on the price of natural gas or the price of electricity.

iv. Extent of Reductions in CO_2 Emissions

One of the primary benefits of natural gas co-firing is emission reduction. CO_2 emissions are reduced by approximately 4 percent for every additional 10 percent of co-firing. When moving from 100 percent coal to 60 percent coal and 40 percent natural gas, CO_2 stack emissions are reduced by approximately 16 percent. Non-CO_2 emissions are reduced as well, as noted earlier in this preamble.

v. Technology Advancement

Natural gas co-firing is already well-established and widely used by coal-fired steam boiler generating units. As a result, this final rule is not likely to lead to technological advances or cost reductions in the components of natural gas co-firing, including modifications to boilers and pipeline construction. However, greater use of natural gas co-firing may lead to improvements in the efficiency of conducting natural gas co-firing and operating the associated equipment.

c. Options Not Determined To Be the BSER for Medium-Term Coal-Fired Steam Generating Units

i. CCS

As discussed earlier in this preamble, the compliance date for CCS is January 1, 2032. Accordingly, sources in the medium-term subcategory—which have elected to commit to permanently cease operations prior to 2039—would have less than 7 years to amortize the capital costs of CCS. As a result, for these sources, the overall costs of CCS would exceed the metrics for cost reasonableness that the EPA is using in

[685] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (87 FR 52224; August 24, 2022).

[686] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180; October 1, 2019).

[687] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments (86 FR 63266; November 15, 2021).

this rulemaking, which are detailed in section VII.C.1.a.ii(D). For this reason, the EPA is not finalizing CCS as the BSER for the medium-term subcategory.

ii. Heat Rate Improvements

Heat rate improvements were not considered to be BSER for medium-term steam generating units because the achievable reductions are low and may result in rebound effect whereby total emissions from the source increase, as detailed in section VII.D.4.a.

d. Conclusion

The EPA is finalizing that natural gas co-firing at 40 percent of heat input is the BSER for medium-term coal-fired steam generating units because natural gas co-firing is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources. Additionally, the costs for natural gas co-firing are reasonable. Moreover, natural gas co-firing can be expected to reduce emissions of several other air pollutants in addition to GHGs. Any adverse non-air quality health and environmental impacts and energy requirements of natural gas co-firing are limited. In contrast, CCS, although achieving greater emission reductions, would be of higher cost, in general, for the subcategory of medium-term units, and HRI would achieve few reductions and, in fact, may increase emissions.

3. Degree of Emission Limitation for Final Standards

Under CAA section 111(d), once the EPA determines the BSER, it must determine the ''degree of emission limitation'' achievable by the application of the BSER. States then determine standards of performance and include them in the state plans, based on the specified degree of emission limitation. Final presumptive standards of performance are detailed in section X.C.1.b of this preamble. There is substantial variation in emission rates among coal-fired steam generating units—the range is, approximately, from 1,700 lb CO_2/MWh-gross to 2,500 lb CO_2/MWh-gross—which makes it challenging to determine a single, uniform emission limit. Accordingly, the EPA is finalizing the degrees of emission limitation by a percentage change in emission rate, as follows.

a. Long-Term Coal-Fired Steam Generating Units

As discussed earlier in this preamble, the EPA is finalizing the BSER for long-term coal-fired steam generating units as ''full-capture'' CCS, defined as 90 percent capture of the CO_2 in the flue gas. The degree of emission limitation achievable by applying this BSER can be determined on a rate basis. A capture rate of 90 percent results in reductions in the emission rate of 88.4 percent on a lb CO_2/MWh-gross basis, and this reduction in emission rate can be observed over an extended period (*e.g.,* an annual calendar-year basis). Therefore, the EPA is finalizing that the degree of emission limitation for long-term units is an 88.4 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.,* an annual calendar-year basis).

b. Medium-Term Coal-Fired Steam Generating Units

As discussed earlier in this preamble, the BSER for medium-term coal-fired steam generating units is 40 percent natural gas co-firing. The application of 40 percent natural gas co-firing results in reductions in the emission rate of 16 percent. Therefore, the degree of emission limitation for these units is a 16 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.,* an annual calendar-year basis).

D. Rationale for the BSER for Natural Gas-Fired And Oil-Fired Steam Generating Units

This section of the preamble describes the rationale for the final BSERs for existing natural gas- and oil-fired steam generating units based on the criteria described in section V.C of this preamble.

1. Subcategorization of Natural Gas- and Oil-Fired Steam Generating Units

The EPA is finalizing subcategories based on load level (*i.e.,* annual capacity factor), specifically, units that are base load, intermediate load, and low load. The EPA is finalizing routine methods of operation and maintenance as BSER for intermediate and base load units. Applying that BSER would not achieve emission reductions but would prevent increases in emission rates. The EPA is finalizing presumptive standards of performance that differ between intermediate and base load units due to their differences in operation, as detailed in section X.C.1.b.iii of this preamble. The EPA proposed a separate subcategory for non-continental oil-fired steam generating units, which operate differently from continental units; however, the EPA is not finalizing emission guidelines for sources outside of the contiguous U.S., as described in section VII.B. At proposal, the EPA solicited comment on a BSER of ''uniform fuels'' for low load natural gas- and oil-fired steam generating units, and the EPA is finalizing this approach for those sources.

Natural gas- and oil-fired steam generating units combust natural gas or distillate fuel oil or residual fuel oil in a boiler to produce steam for a turbine that drives a generator to create electricity. In non-continental areas, existing natural gas- and oil-fired steam generating units may provide base load power, but in the continental U.S., most existing units operate in a load-following manner. There are approximately 200 natural gas-fired steam generating units and fewer than 30 oil-fired steam generating units in operation in the continental U.S. Fuel costs and inefficiency relative to other technologies (*e.g.,* combustion turbines) result in operation at lower annual capacity factors for most units. Based on data reported to EIA and the EPA [688] for the contiguous U.S., for natural gas-fired steam generating units in 2019, the average annual capacity factor was less than 15 percent and 90 percent of units had annual capacity factors less than 35 percent. For oil-fired steam generating units in 2019, no units had annual capacity factors above 8 percent. Additionally, their load-following method of operation results in frequent cycling and a greater proportion of time spent at low hourly capacities, when generation is less efficient. Furthermore, because startup times for most boilers are usually long, natural gas steam generating units may operate in standby mode between periods of peak demand. Operating in standby mode requires combusting fuel to keep the boiler warm, and this further reduces the efficiency of natural gas combustion.

Unlike coal-fired steam generating units, the CO_2 emission rates of oil- and natural gas-fired steam generating units that have similar annual capacity factors do not vary considerably between units. This is partly due to the more uniform qualities (*e.g.,* carbon content) of the fuel used. However, the emission rates for units that have different annual capacity factors do vary considerably, as detailed in the final TSD, *Natural Gas- and Oil-fired Steam Generating Units.* Low annual capacity factor units cycle frequently, have a greater proportion of CO_2 emissions that may be attributed to startup, and have a greater proportion of generation at inefficient hourly capacities. Intermediate annual capacity factor units operate more often at higher hourly capacities, where CO_2 emission rates are lower. High annual capacity factor units operate still more at base load conditions, where units are more

[688] Clean Air Markets Program Data at *https://campd.epa.gov.*

efficient and CO_2 emission rates are lower.

Based on these performance differences between these load levels, the EPA, in general, proposed subcategories based on dividing natural gas- and oil-fired steam generating units into three groups each—low load, intermediate load, and base load.

The EPA is finalizing subcategories for oil-fired and natural gas-fired steam generating units, based on load levels. The EPA proposed the following load levels: ''low'' load, defined by annual capacity factors less than 8 percent; ''intermediate'' load, defined by annual capacity factors greater than or equal to 8 percent and less than 45 percent; and ''base'' load, defined by annual capacity factors greater than or equal to 45 percent.

The EPA is finalizing January 1, 2030, as the compliance date for natural gas- and oil-fired steam generating units and this date is consistent with the dates in the fuel type definitions.

The EPA received comments that were generally supportive of the proposed subcategory definitions,[689] and the EPA is finalizing the subcategory definitions as proposed.

2. Options Considered for BSER

The EPA has considered various methods for controlling CO_2 emissions from natural gas- and oil-fired steam generating units to determine whether they meet the criteria for BSER. Co-firing natural gas cannot be the BSER for these units because natural gas- and oil-fired steam generating units already fire large proportions of natural gas. Most natural gas-fired steam generating units fire more than 90 percent natural gas on a heat input basis, and any oil-fired steam generating units that would potentially operate above an annual capacity factor of around 15 percent typically combust natural gas as a large proportion of their fuel as well. Nor is CCS a candidate for BSER. The utilization of most gas-fired units, and likely all oil-fired units, is relatively low, and as a result, the amount of CO_2 available to be captured is low. However, the capture equipment would still need to be sized for the nameplate capacity of the unit. Therefore, the capital and operating costs of CCS would be high relative to the amount of CO_2 available to be captured. Additionally, again due to lower utilization, the amount of IRC section 45Q tax credits that owner/operators could claim would be low. Because of the relatively high costs and the relatively low cumulative emission reduction potential for these natural gas- and oil-fired steam generating units, the EPA is not determining CCS as the BSER for them.

The EPA has reviewed other possible controls but is not finalizing any of them as the BSER for natural gas- and oil-fired units either. Co-firing hydrogen in a boiler is technically possible, but there is limited availability of hydrogen now and in the near future and it should be prioritized for more efficient units. Additionally, for natural gas-fired steam generating units, setting a future standard based on hydrogen would likely have limited GHG reduction benefits given the low utilization of natural gas- and oil-fired steam generating units. Lastly, HRI for these types of units would face many of the same issues as for coal-fired steam generating units; in particular, HRI could result in a rebound effect that would increase emissions.

However, the EPA recognizes that natural gas- and oil-fired steam generating units could possibly, over time, operate more, in response to other changes in the power sector. Additionally, some coal-fired steam generating units have converted to 100 percent natural gas-fired, and it is possible that more may do so in the future. The EPA also received several comments from industry stating plans to do so. Moreover, in part because the fleet continues to age, the plants may operate with degrading emission rates. In light of these possibilities, identifying the BSER and degrees of emission limitation for these sources would be useful to provide clarity and prevent backsliding in GHG performance. Therefore, the EPA is finalizing BSER for intermediate and base load natural gas- and oil-fired steam generating units to be routine methods of operation and maintenance, such that the sources could maintain the emission rates (on a lb/MWh-gross basis) currently maintained by the majority of the fleet across discrete ranges of annual capacity factor. The EPA is finalizing this BSER for intermediate load and base load natural gas- and oil-fired steam generating units, regardless of the operating horizon of the unit.

A BSER based on routine methods of operation and maintenance is adequately demonstrated because units already operate with those practices. There are no or negligible additional costs because there is no additional technology that units are required to apply and there is no change in operation or maintenance that units must perform. Similarly, there are no adverse non-air quality health and environmental impacts or adverse impacts on energy requirements. Nor do they have adverse impacts on the energy sector from a nationwide or long-term perspective. The EPA's modeling, which supports this final rule, indicates that by 2040, a number of natural gas-fired steam generating units will have remained in operation since 2030, although at reduced annual capacity factors. There are no CO_2 reductions that may be achieved at the unit level, but applying routine methods of operation and maintenance as the BSER prevents increases in emission rates. Routine methods of operation and maintenance do not advance useful control technology, but this point is not significant enough to offset their benefits.

At proposal, the EPA also took comment on a potential BSER of uniform fuels for low load natural gas- and oil-fired steam generating units. As noted earlier in this preamble, non-coal fossil fuels combusted in utility boilers typically include natural gas, distillate fuel oil (*i.e.,* fuel oil No. 1 and No. 2), and residual fuel oil (*i.e.,* fuel oil No. 5 and No. 6). The EPA previously established heat-input based fuel composition as BSER in the 2015 NSPS (termed ''clean fuels'' in that rulemaking) for new non-base load natural gas- and multi-fuel-fired stationary combustion turbines (80 FR 64615–17; October 23, 2015), and the EPA is similarly finalizing lower-emitting fuels as BSER for new low load combustion turbines as described in section VIII.F of this preamble. For low load natural gas- and oil-fired steam generating units, the high variability in emission rates associated with the variability of load at the lower-load levels limits the benefits of a BSER based on routine maintenance and operation. That is because the high variability in emission rates would make it challenging to determine an emission rate (*i.e.,* on a lb CO_2/MWh-gross basis) that could serve as the presumptive standard of performance that would reflect application of a BSER of routine operation and maintenance. On the other hand, for those units, a BSER of ''uniform fuels'' and an associated presumptive standard of performance based on a heat input basis, as described in section X.C.1.b.iii of this preamble, is reasonable. Therefore, the EPA is finalizing a BSER of uniform fuels for low load natural gas- and oil-fired steam generating units, with presumptive standards depending on fuel type detailed in section X.C.1.b.iii.

[689] See, for example, Document ID No. EPA–HQ–OAR–2023–0072–0583.

3. Degree of Emission Limitation

As discussed above, because the BSER for base load and intermediate load natural gas- and oil-fired steam generating units is routine operation and maintenance, which the units are, by definition, already employing, the degree of emission limitation by application of this BSER is no increase in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*e.g.,* a year).

For low load natural gas- and oil-fired steam generating units, the EPA is finalizing a BSER of uniform fuels, with a degree of emission limitation on a heat input basis consistent with a fixed 130 lb CO_2/MMBtu for natural gas-fired steam generating units and 170 lb CO_2/MMBtu for oil-fired steam generating units. The degree of emission limitation for natural gas- and oil-fired steam generating units is higher than the corresponding values under 40 CFR part 60, subpart TTTT, because steam generating units may fire fuels with slightly higher carbon contents.

4. Other Emission Reduction Measures Not Considered BSER

a. Heat Rate Improvements

Heat rate is a measure of efficiency that is commonly used in the power sector. The heat rate is the amount of energy input, measured in Btu, required to generate 1 kilowatt-hour (kWh) of electricity. The lower an EGU's heat rate, the more efficiently it operates. As a result, an EGU with a lower heat rate will consume less fuel and emit lower amounts of CO_2 and other air pollutants per kWh generated as compared to a less efficient unit. HRI measures include a variety of technology upgrades and operating practices that may achieve CO_2 emission rate reductions of 0.1 to 5 percent for individual EGUs. The EPA considered HRI to be part of the BSER in the CPP and to be the BSER in the ACE Rule. However, the reductions that may be achieved by HRI are small relative to the reductions from natural gas co-firing and CCS. Also, some facilities that apply HRI would, as a result of their increased efficiency, increase their utilization and therefore increase their CO_2 emissions (as well as emissions of other air pollutants), a phenomenon that the EPA has termed the ''rebound effect.'' Therefore, the EPA is not finalizing HRI as a part of BSER.

i. CO_2 Reductions From HRI in Prior Rulemakings

In the CPP, the EPA quantified emission reductions achievable through heat rate improvements on a regional basis by an analysis of historical emission rate data, taking into consideration operating load and ambient temperature. The Agency concluded that EGUs can achieve on average a 4.3 percent improvement in the Eastern Interconnection, a 2.1 percent improvement in the Western Interconnection, and a 2.3 percent improvement in the Texas Interconnection. See 80 FR 64789 (October 23, 2015). The Agency then applied all three of the building blocks to 2012 baseline data and quantified, in the form of CO_2 emission rates, the reductions achievable in Each interconnection in 2030, and then selected the least stringent as a national performance rate. *Id.* at 64811–19. The EPA noted that building block 1 measures could not by themselves constitute the BSER because the quantity of emission reductions achieved would be too small and because of the potential for an increase in emissions due to increased utilization (*i.e.,* the ''rebound effect'').

ii. Updated CO_2 Reductions From HRI

The HRI measures include improvements to the boiler island (*e.g.,* neural network system, intelligent sootblower system), improvements to the steam turbine (*e.g.,* turbine overhaul and upgrade), and other equipment upgrades (*e.g.,* variable frequency drives). Some regular practices that may recover degradation in heat rate to recent levels—but that do not result in upgrades in heat rate over recent design levels and are therefore not HRI measures—include practices such as in-kind replacements and regular surface cleaning (*e.g.,* descaling, fouling removal). Specific details of the HRI measures are described in the final TSD, *GHG Mitigation Measures for Steam Generating Units* and an updated 2023 Sargent and Lundy HRI report (*Heat Rate Improvement Method Costs and Limitations Memo*), available in the docket. Most HRI upgrade measures achieve reductions in heat rate of less than 1 percent. In general, the 2023 Sargent and Lundy HRI report, which updates the 2009 Sargent and Lundy HRI report, shows that HRI achieve less reductions than indicated in the 2009 report, and shows that several HRI either have limited applicability or have already been applied at many units. Steam path overhaul and upgrade may achieve reductions up to 5.15 percent, with the average being around 1.5 percent. Different combinations of HRI measures do not necessarily result in cumulative reductions in emission rate (*e.g.,* intelligent sootblowing systems combined with neural network systems). Some of the HRI measures (*e.g.,* variable frequency drives) only impact heat rate on a net generation basis by reducing the parasitic load on the unit and would thereby not be observable for emission rates measured on a gross basis. Assuming many of the HRI measures could be applied to the same unit, adding together the upper range of some of the HRI percentages could yield an emission rate reduction of around 5 percent. However, the reductions that the fleet could achieve on average are likely much smaller. As noted, the 2023 Sargent and Lundy HRI report notes that, in many cases, units have already applied HRI upgrades or that those upgrades would not be applicable to all units. The unit level reductions in emission rate from HRI are small relative to CCS or natural gas co-firing. In the CPP and ACE Rule, the EPA viewed CCS and natural gas co-firing as too costly to qualify as the BSER; those costs have fallen since those rules and, as a result, CCS and natural gas co-firing do qualify as the BSER for the long-term and medium-term subcategories, respectively.

iii. Potential for Rebound in CO_2 Emissions

Reductions achieved on a rate basis from HRI may not result in overall emission reductions and could instead cause a ''rebound effect'' from increased utilization. A rebound effect would occur where, because of an improvement in its heat rate, a steam generating unit experiences a reduction in variable operating costs that makes the unit more competitive relative to other EGUs and consequently raises the unit's output. The increase in the unit's CO_2 emissions associated with the increase in output would offset the reduction in the unit's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of output. The extent of the offset would depend on the extent to which the unit's generation increased. The CPP did not consider HRI to be BSER on its own, in part because of the potential for a rebound effect. Analysis for the ACE Rule, where HRI was the entire BSER, observed a rebound effect for certain sources in some cases.[690] In this action, where different subcategories of units are to be subject to different BSER measures, steam generating units in a hypothetical subcategory with HRI as BSER could experience a rebound effect. Because of this potential for perverse GHG emission outcomes resulting from deployment of HRI at certain steam generating units, coupled with the

[690] 84 FR 32520 (July 8, 2019).

relatively minor overall GHG emission reductions that would be expected from this measure, the EPA is not finalizing HRI as the BSER for any subcategory of existing coal-fired steam generating units.

E. Additional Comments Received on the Emission Guidelines for Existing Steam Generating Units and Responses

1. Consistency With West Virginia v. EPA and the Major Questions Doctrine

Comment: Some commenters argued that the EPA's determination that CCS is the BSER for existing coal-fired power plants is invalid under *West Virginia* v. *EPA,* 597 U.S. 697 (2022), and the major questions doctrine (MQD). Commenters state that for various reasons, coal-fired power plants will not install CCS and instead will be forced to retire their units. They point to the EPA's IPM modeling which, they say, shows that many coal-fired power plants retire rather than install CCS. They add that, in this way, the rule effectively results in the EPA's requiring generation-shifting from coal-fired generation to renewable and other generation, and thus is like the Clean Power Plan (CPP). For those reasons, they state that the rule raises a major question, and further that CAA section 111(d) does not contain a clear authorization for this type of rule.

Response: The EPA discussed *West Virginia* and its articulation of the MQD in section V.B.6 of this preamble.

The EPA disagrees with these comments. This rule is fully consistent with the Supreme Court's interpretation of the EPA's authority in *West Virginia.* The EPA's determination that CCS—a traditional, add-on emissions control—is the BSER is consistent with the plain text of section 111. As explained in detail in section VII.C.1.a, for long-term coal-fired steam generating units, CCS meets all of the BSER factors: it is adequately demonstrated, of reasonable cost, and achieves substantial emissions reductions. That some coal-fired power plants will choose not to install emission controls and will instead retire does not raise major questions concerns.

In *West Virginia,* the U.S. Supreme Court held that ''generation-shifting'' as the BSER for coal- and gas-fired units ''effected a fundamental revision of the statute, changing it from one sort of scheme of regulation into an entirely different kind.'' 597 U.S. at 728 (internal quotation marks, brackets, and citation omitted). The Court explained that prior CAA section 111 rules were premised on ''more traditional air pollution control measures'' that ''focus on improving the performance of individual sources.'' *Id.* at 727 (citing ''fuel-switching'' and ''add-on controls''). The Court said that generation-shifting as the BSER was ''unprecedented'' because it was designed to ''improve the overall power system by lowering the carbon intensity of power generation . . . by forcing a shift throughout the power grid from one type of energy source to another.'' *Id.* at 727–28 (internal quotation marks, emphasis, and citation omitted). The Court cited statements by the then-Administrator describing the CPP as ''not about pollution control so much as it was an investment opportunity for States, especially investments in renewables and clean energy.'' *Id.* at 728. The Court further concluded that the EPA's view of its authority was virtually unbounded because the ''EPA decides, for instance, how much of a switch from coal to natural gas is practically feasible by 2020, 2025, and 2030 before the grid collapses, and how high energy prices can go as a result before they become unreasonably exorbitant.'' *Id.* at 729.

Here, the EPA's determination that CCS is the BSER does not affect a fundamental revision of the statute, nor is it unbounded. CCS is not directed at improvement of the overall power system. Rather, CCS is a traditional ''add-on [pollution] control[ ]'' akin to measures that the EPA identified as BSER in prior CAA section 111 rules. *See id.* at 727. It ''focus[es] on improving the performance of individual sources''—it reduces CO_2 pollution from each individual source—because each affected source is able to apply it to its own facility to reduce its own emissions. *Id.* at 727. Further, the EPA determined that CCS qualifies as the BSER by applying the criteria specified in CAA section 111(a)(1)—including adequate demonstration, costs of control, and emissions reductions. *See* section VII.C.1.a of this preamble. Thus, CCS as the BSER does not ''chang[e]'' the statute ''from one sort of scheme of regulation into an entirely different kind.'' *Id.* at 728 (internal quotation marks, brackets, and citation omitted).

Commenters contend that notwithstanding these distinctions, the choice of CCS as the BSER has the *effect* of shifting generation because modeling projections for the rule show that coal-fired generation will become less competitive, and gas-fired and renewable-generated electricity will be more competitive and dispatched more frequently. That some coal-fired sources may retire rather than reduce their CO_2 pollution does not mean that the rule ''represents a transformative expansion [of EPA's] regulatory authority''. *Id.* at 724. To be sure, this rule's determination that CCS is the BSER imposes compliance costs on coal-fired power plants. That sources will incur costs to control their emissions of dangerous pollution is an unremarkable consequence of regulation, which, as the Supreme Court recognized, ''may end up causing an incidental loss of coal's market share.'' *Id.* at 731 n.4.[691] Indeed, ensuring that sources internalize the full costs of mitigating their impacts on human health and the environment is a central purpose of traditional environmental regulation.

In particular, for the power sector, grid operators constantly shift generation as they dispatch electricity from sources based upon their costs. The EPA's IPM modeling, which is based on the costs of the various types of electricity generation, projects these impacts. Viewed as a whole, these projected impacts show that, collectively, coal-fired power plants will likely produce less electricity, and other sources (like gas-fired units and renewable sources) will likely produce more electricity, but this pattern does not constitute a transformative expansion of statutory authority (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends.*)

These projected impacts are best understood by comparing the IPM model's ''base case,'' *i.e.,* the projected electricity generation without any rule in place, to the model's ''policy case,'' *i.e.,* the projected electricity generation expected to result from this rule. The base case projects that many coal-fired units will retire over the next 20 years (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*). Those projected retirements track trends over the past two decades where coal-fired units have retired in high numbers because gas-fired units and renewable sources have become increasingly able to generate lower-cost electricity. As more gas-fired and renewable generation sources deploy in the future, and as coal-fired units continue to age—which results in decreased efficiency and increased costs—the coal-fired units will become increasingly marginal and continue to retire (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends.*) That is true in the absence of this rule. The EPA's modeling results also project that even if the EPA had

[691] As discussed in section VII.C.1.a.ii.(D), the costs of CCS are reasonable based on the EPA's $/MWh and $/ton metrics. As discussed in RTC section 2.16, the total annual costs of this rule are a small fraction of the revenues and capital costs of the electric power industry.

determined BSER for long-term sources to be 40 percent co-firing, which requires significantly less capital investment, and not 90 percent capture CCS, a comparable number of sources would retire instead of installing controls. These results confirm that the primary cause for the projected retirements is the marginal profitability of the sources.

Importantly, the base-case projections also show that some coal-fired units install CCS and run at high capacity factors, in fact, higher than they would have had they not installed CCS. This is because the IRC section 45Q tax credit significantly reduces the variable cost of operation for qualifying sources. This incentivizes sources to increase generation to maximize the tons of CO_2 the CCS equipment captures, and thereby increase the amount of the tax credit they receive. In the ''policy case,'' beginning when the CCS requirement applies in the 2035 model year,[692] some additional coal-fired units will likely install CCS, and also run at high capacity factors, again, significantly higher than they would have without CCS. Other units may retire rather than install emission controls (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*). On balance, the coal-fired units that install CCS collectively generate nearly the same amount of electricity in the 2040 model year as do the group of coal-fired units in the base case.

The policy case also shows that in the 2045 model year, by which time the 12-year period for sources to claim the IRC section 45Q tax credit will have expired, most sources that install CCS retire due to the costs of meeting the CCS-based standards without the benefit of the tax credit. However, in fact, these projected outcomes are far from certain as the modeling results generally do not account for numerous potential changes that may occur over the next 20 or more years, any of which may enable these units to continue to operate economically for a longer period. Examples of potential changes include reductions in the operational costs of CCS through technological improvements, or the development of additional potential revenue streams for captured CO_2 as the market for beneficial uses of CO_2 continues to develop, among other possible changed economic circumstances (including the possible extension of the tax credits). In light of these potential significant developments, the EPA is committing to review and, if appropriate, revise the requirements of this rule by January 1, 2041, as described in section VII.F.

In any event, the modeling projections showing that many sources retire instead of installing controls are in line with the trends for these units in the absence of the rule—as the coal-fired fleet ages and lower-cost alternatives become increasingly available, more operators will retire coal-fired units with or without this rule. In 2045, the average age of coal-fired units that have not yet announced retirement dates or coal-to-gas conversion by 2039 will be 61 years old. And, on average, between 2000 and 2022, even in the absence of this rule, coal-fired units generally retired at 53 years old. Thus, taken as a whole, this rule does not dramatically reduce the expected operating horizon of most coal-fired units. Indeed, for units that install CCS, the generous IRC section 45Q tax credit increases the competitiveness of these units, and it allows them to generate more electricity with greater profit than the sources would otherwise generate if they did not install CCS.

The projected effects of the rule do not show the BSER—here, CCS—is akin to generation shifting, or otherwise represents an expansion of EPA authority with vast political or economic significance. As described above at VII.C.1.a.ii, CCS is an affordable emissions control technology. It is also very effective, reducing CO_2 emissions from coal-fired units by 90 percent, as described in section VII.C.1.a.i. Indeed, as noted, the IRA tax credits make CCS so affordable that coal-fired units that install CCS run at higher capacity factors than they would otherwise.

Considered as a whole, and in context with historical retirement trends, the projected impacts of this rule on coal-fired generating units do not raise MQD concerns. The projected impacts are merely incidental to the CCS control itself—the unremarkable consequence of marginally increasing the cost of doing business in a competitive market. Nor is the rule ''transformative.'' The rule does not ''announce what the market share of coal, natural gas, wind, and solar must be, and then requiring plants to reduce operations or subsidize their competitors to get there.'' 597 U.S. at 731 n.4. As noted above, coal-fired units that install CCS are projected to generate substantial amounts of electricity. The retirements that are projected to occur are broadly consistent with market trends over the past two decades, which show that coal-fired electricity production is generally less economic and less competitive than other forms of electricity production. That is, the retirements that the model predicts under this rule, and the structure of the industry that results, diverge little from the prior rate of retirements of coal-fired units over the past two decades. They also diverge little from the rate of retirements from sources that have already announced that they will retire, or from the additional retirements that IPM projects will occur in the base case (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*).

As discussed above, because much of the coal-fired fleet is operating on the edge of viability, many sources would retire instead of installing any meaningful CO_2 emissions control—whether CCS, natural gas co-firing, or otherwise. Under commenters' view that such retirements create a major question, *any* form of meaningful regulation of these sources would create a major question and effect a fundamental revision of the statute. That cannot possibly be so. Section 111(d)(1) plainly mandates regulation of these units, which are the biggest stationary source of dangerous CO_2 emissions.

The legislative history for the CAA further makes clear that Congress intended the EPA to promulgate regulations even where emissions controls had economic costs. At the time of the 1970 CAA Amendments, Congress recognized that the threats of air pollution to public health and welfare had grown urgent and severe. Sen. Edmund Muskie (D–ME), manager of the bill and chair of the Public Works Subcommittee on Air and Water Pollution, which drafted the bill, regularly referred to the air pollution problem as a ''crisis.'' As Sen. Muskie recognized, ''Air pollution control will be cheap only in relation to the costs of lack of control.'' [693] The Senate Committee Report for the 1970 CAA Amendments specifically discussed the precursor provision to section 111(d) and noted, ''there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'' [694] Accordingly, some of the

[692] Under the rule, sources are required to meet their CCS-based standard of performance by January 1, 2032. IPM groups calendar years into 5-year periods, *e.g.*, the 2035 model year and the 2040 model year. January 1, 2032, falls into the 2035 model year.

[693] Sen. Muskie, Sept. 21, 1970, LH 226.

[694] S. Rep. No. 91–1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)). Note that in the 1977 CAA Amendments, the House Committee Report made a similar statement. H.R. Rep. No. 95–294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring EPA to

EPA's prior CAA section 111 rulemakings have imposed stringent requirements, at significant cost, in order to achieve significant emission reductions.[695]

Congress's enactment of the IRA and IIJA further shows its view that reducing air pollution—specifically, in those laws, GHG emissions to address climate change—is a high priority. As discussed in section IV.E.1, that law provided funds for DOE grant and loan programs to support CCS, and extended and increased the IRC section 45Q tax credit for carbon capture. It also adopted the Low Emission Electricity Program (LEEP), which allocates funds to the EPA for the express purpose of using CAA regulatory authority to reduce GHG emissions from domestic electricity generation through use of its existing CAA authorities. CAA section 135, added by IRA section 60107. The EPA is promulgating the present rulemaking with those funds. The congressional sponsor of the LEEP made clear that it authorized the type of rulemaking that the EPA is promulgating today: he stated that the EPA may promulgate rulemaking under CAA section 111, based on CCS, to address CO_2 emissions from fossil fuel-fired power plants, which may be ''impactful'' by having the ''incidental effect'' of leading some ''companies . . . to choose to retire such plants. . . .'' [696]

For these reasons, the rule here is consistent with the Supreme Court's decision in *West Virginia.* The selection of CCS as the BSER for existing coal-fired units is a traditional, add-on control intended to reduce the emissions performance of individual sources. That some sources may retire instead of controlling their emissions does not otherwise show that the rule runs afoul of the MQD. The modeling projections for this rule show that the anticipated retirements are largely consistent with historical trends, and due to many coal-fired units' advanced age and lack of competitiveness with lower cost methods of electricity generation.

2. Redefining the Source

Comment: Some commenters contended that the proposed 40 percent natural gas co-firing performance standard violates legal precedent that bars the EPA from setting technology-based performance standards that would have the effect of ''redefining the source.'' They stated that this prohibition against the redefinition of the source bars the EPA from adopting the proposed performance standard for medium-term coal-fired EGUs, which requires such units to operate in a manner for which the unit was never designed to do, namely operate as a hybrid coal/natural gas co-firing generating unit and combusting 40 percent of its fuel input as natural gas (instead of coal) on an annual basis.

Commenters argued that co-firing would constitute forcing one type of source to become an entirely different kind of source, and that the Supreme Court precluded such a requirement in *West Virginia* v. *EPA* when it stated in footnote 3 of that case that the EPA has ''never ordered anything remotely like'' a rule that would ''simply require coal plants to become natural gas plants'' and the Court ''doubt[ed that EPA] could.'' [697]

Response: The EPA disagrees with these comments.

Standards based on co-firing, as contemplated in this rule, are based on a ''traditional pollution control measure,'' in particular, ''fuel switching,'' as the Supreme Court recognized in *West Virginia.*[698] Rules based on switching to a cleaner fuel are authorized under the CAA, an authorization directly acknowledged by Congress. Specifically, as part of the 1977 CAA Amendments, Congress required that the EPA base its standards regulating certain new sources, including power plants, on ''technological'' controls, rather than simply the ''best system.'' [699] Congress understood this to mean that new sources would be required to implement add-on controls, rather than merely relying on fuel switching, and noted that one of the purposes of this amendment was to allow new sources to burn high sulfur coal while still decreasing emissions, and thus to increase the availability of low sulfur coal for existing sources, which were not subject to the ''technological'' control requirement.[700] In 1990, however, Congress removed the ''technological'' language, allowing the EPA to set fuel-switching based standards for both new and existing power plants.[701]

The EPA has a tradition of promulgating rules based on fuel switching. For example, the 2006 NSPS for stationary compression ignition internal combustion engines required the use of ultra-low sulfur diesel.[702] Similarly, in the 2015 NSPS for EGUs,[703] the EPA determined that the BSER for peaking plants was to burn primarily natural gas, with distillate oil used only as a backup fuel.[704] Nor is this approach unique to CAA section 111; in the 2016 rule setting section 112 standards for hazardous air pollutant emissions from area sources, for example, the EPA finalized an alternative particulate matter (PM) standard that specified that certain oil-fired boilers would meet the applicable

study and then take action to regulate radioactive air pollutants and three other air pollutants).

[695] *See Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding NSPS imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial. EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.'').

[696] 168 Cong. Rec. E868 (August 23, 2022) (statement of Rep. Frank Pallone, Jr.); *id.* E879 (August 26, 2022) (statement of Rep. Frank Pallone, Jr.).

[697] West Virginia v. EPA, 597 U.S, 697, 728 n.3 (2022).

[698] See 597 U.S. at 727.

[699] In 1977, Congress clarified that for purposes of CAA section 111(a)(1)(A), concerning standards of performance for new and modified ''fossil fuel-fired stationary sources'' a standard or performance ''shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best *technological* system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' Clean Air Act 1977 Revisions (emphasis added).

[700] *See* H. Rep. No. 94–1175, 94th Cong., 2d Sess. (May 15, 1976) Part A, at 159 (listing the various purposes of the amendment to Section 111 adding the term 'technological': ''Fourth, by using best control technology on large new fuel-burning stationary sources, these sources could burn higher sulfur fuel than if no technological means of reducing emissions were used. This means an expansion of the energy resources that could be burned in compliance with environmental requirements. Fifth, since large new fuel-burning sources would not rely on naturally low sulfur coal or oil to achieve compliance with new source performance standards, the low sulfur coal or oil that would have been burned in these major new sources could instead be used in older and smaller sources.'')

[701] In 1990, Congress removed this reference to a ''technological system'', and the current text reads simply: ''The term ''standard of performance'' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' 42 U.S.C. 7411(a)(1).

[702] Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 71 FR 39154 (July 11, 2006). In the preamble to the final rule, the EPA noted that for engines which had not previously used this new ultra-low sulfur fuel, additives would likely need to be added to the fuel to maintain appropriate lubricity. *See id.* at 39158.

[703] Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 FR 64510, (October 23, 2015).

[704] *See id.* at 64621.

standard if they combusted only ultra-low-sulfur liquid fuel.[705]

Moreover, the *West Virginia* Court's statements in footnote 3 are irrelevant to the question of the validity of a 40 percent co-firing standard. There, the Court was referring to a complete transformation of the coal-fired unit to a 100 percent gas fired unit—a change that would require entirely repowering the unit. By contrast, increasing co-firing at existing coal-fired units to 40 percent would require only minor changes to the units' boilers. In fact, many coal-fired units are already capable of co-firing some amount of gas without any changes at all, and several have fired at 40 percent and above in recent years. Of the 565 coal-fired EGUs operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source, 162 reported more than one month of consumption of natural gas at their boiler, and 29 co-fired at over 40 percent on an annual heat input basis in at least one year while also operating with annual capacity factors greater than 10 percent. For more on this, see section IV.C.2 of this preamble; see also the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

F. Commitment To Review and, If Appropriate, Revise Emission Guidelines for Coal-Fired Units

The EPA recognizes that the IRC 45Q tax credit is a key component to the cost of CCS, as discussed in section VII.C.1.a.ii(C) of this preamble. The EPA further recognizes that for any affected source, the tax credit is currently available for a 12-year period and not subsequently. The tax credit is generally sufficient to defray the capital costs of CCS and much, if not all, of the operating costs during that 12-year period. Following the 12-year period, affected sources that continue to operate the CCS equipment would have higher costs of generation, due to the CCS operating costs, including parasitic load. Under certain circumstances, these higher costs could push the affected sources lower on the dispatch curve, and thereby lead to reductions in the amount of their generation, *i.e.,* if affected sources are not able to replace the revenue from the tax credit with revenue from other sources, or if the price of electricity does not reflect any additional costs needed to minimize GHG emissions.

However, the costs of CCS and the overall economic viability of operating CO_2 capture at power plants are improving and can be expected to continue to improve in years to come. CO_2 that is captured from fossil-fuel fired sources is currently beneficially used, including, for example, for enhanced oil recovery and in the food and beverage industry. There is much research into developing beneficial uses for many other industries, including construction, chemical manufacturing, graphite manufacturing. The demand for CO_2 is expected to grow considerably over the next several decades. As a result, in the decades to come, affected sources may well be able to replace at least some of the revenues from the tax credit with revenues from the sale of CO_2. We discuss these potential developments in chapter 2 of the Response to Comments document, available in the rulemaking docket.

In addition, numerous states have imposed requirements to decarbonize generation within their borders. Many utilities have also announced plans to decarbonize their fleet, including building small modular (advanced nuclear) reactors. Given the relatively high capital and fixed costs of small modular reactors, plans for their construction represent an expectation of higher future energy prices. This suggests that, in the decades to come, at least in certain areas of the country, affected sources may be able to maintain a place in the dispatch curve that allows them to continue to generate while they continue to operate CCS, even in the absence of additional revenues for CO_2. We discuss these potential developments in the final TSD, *Power Sector Trends,* available in the rulemaking docket.

These developments, which may occur by the 2040s—the expiration of the 12-year period for the IRC 45Q tax credit, the potential development of the CO_2 utilization market, and potential market supports for low-GHG generation—may significantly affect the costs to coal-fired steam EGUs of operating their CCS controls. As a result, the EPA will closely monitor these developments. Our efforts will include consulting with other agencies with expertise and information, including DOE, which currently has a program, the Carbon Conversion Program, in the Office of Carbon Management, that funds research into CO_2 utilization. We regularly consult with stakeholders, including industry stakeholders, and will continue to do so.

In light of these potential significant developments and their impacts, potentially positive or negative, on the economics of continued generation by affected sources that have installed CCS, the EPA is committing to review and, if appropriate, revise this rule by January 1, 2041. This commitment is included in the regulations that the EPA is promulgating with this rule. The EPA will conduct this review based on what we learn from monitoring these developments, as noted above. Completing this review and any appropriate revisions by that date will allow time for the states to revise, if necessary, standards applicable to affected sources, and for the EPA to act on those state revisions, by the early to mid-2040s. That is when the 12-year period for the 45Q tax credit is expected to expire for affected sources that comply with the CCS requirement by January 1, 2032, and when other significant developments noted above may be well underway.

VIII. Requirements for New and Reconstructed Stationary Combustion Turbine EGUs and Rationale for Requirements

A. Overview

This section discusses the requirements for stationary combustion turbine EGUs that commence construction or reconstruction after May 23, 2023. The requirements are codified in 40 CFR part 60, subpart TTTTa. The EPA explains in section VIII.B of this document the two basic turbine technologies that are used in the power sector and are covered by 40 CFR part 60, subpart TTTTa. Those are simple cycle combustion turbines and combined cycle combustion turbines. The EPA also explains how these technologies are used in the three subcategories: low load turbines, intermediate load turbines, and base load turbines. Section VIII.C provides an overview of how stationary combustion turbines have been previously regulated. Section VIII.D discusses the EPA's decision to revisit the standards for new and reconstructed turbines as part of the statutorily required 8-year review of the NSPS. Section VIII.E discusses changes that the EPA is finalizing in both applicability and subcategories in the new 40 CFR part 60, subpart TTTTa, as compared to those codified previously in 40 CFR part 60, subpart TTTT. Most notably, for new and reconstructed natural gas-fired combustion turbines, the EPA is finalizing BSER determinations and standards of performance for the three subcategories mentioned above—low load, intermediate load, and base load.

Sections VIII.F and VIII.G of this document discuss the EPA's

[705] *See* National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 81 FR 63112–01 (September 14, 2016).

determination of the BSER for each of the three subcategories of combustion turbines and the applicable standards of performance, respectively. For low load combustion turbines, the EPA is finalizing a determination that the use of lower-emitting fuels is the appropriate BSER. For intermediate load combustion turbines, the EPA is finalizing a determination that highly efficient simple cycle generation is the appropriate BSER. For base load combustion turbines, the EPA is finalizing a determination that the BSER includes two components that correspond initially to a two-phase standard of performance. The first component of the BSER, with an immediate compliance date (phase 1), is highly efficient generation based on the performance of a highly efficient combined cycle turbine and the second component of the BSER, with a compliance date of January 1, 2032 (phase 2), is based on the use of CCS with a 90 percent capture rate, along with continued use of highly efficient generation. For base load turbines, the standards of performance corresponding to both components of the BSER would apply to all new and reconstructed sources that commence construction or reconstruction after May 23, 2023. The EPA occasionally refers to these standards of performance as the phase 1 or phase 2 standards.

B. Combustion Turbine Technology

For purposes of 40 CFR part 60, subparts TTTT and TTTTa, stationary combustion turbines include both simple cycle and combined cycle EGUs. Simple cycle turbines operate in the Brayton thermodynamic cycle and include three primary components: a multi-stage compressor, a combustion chamber (*i.e.,* combustor), and a turbine. The compressor is used to supply large volumes of high-pressure air to the combustion chamber. The combustion chamber converts fuel to heat and expands the now heated, compressed air through the turbine to create shaft work. The shaft work drives an electric generator to produce electricity. Combustion turbines that recover the energy in the high-temperature exhaust—instead of venting it directly to the atmosphere—are combined cycle EGUs and can obtain additional useful electric output. A combined cycle EGU includes an HRSG operating in the Rankine thermodynamic cycle. The HRSG receives the high-temperature exhaust and converts the heat to mechanical energy by producing steam that is then fed into a steam turbine that, in turn, drives an electric generator. As the thermal efficiency of a stationary combustion turbine EGU is increased, less fuel is burned to produce the same amount of electricity, with a corresponding decrease in fuel costs and lower emissions of CO_2 and, generally, of other air pollutants. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process.

Combustion turbines serve various roles in the power sector. Some combustion turbines operate at low annual capacity factors and are available to provide temporary power during periods of high load demand. These turbines are often referred to as ''peaking units.'' Some combustion turbines operate at intermediate annual capacity factors and are often referred to as cycling or load-following units. Other combustion turbines operate at high annual capacity factors to serve base load demand and are often referred to as base load units. In this rulemaking, the EPA refers to these types of combustion turbines as low load, intermediate load, and base load, respectively.

Low load combustion turbines provide reserve capacity, support grid reliability, and generally provide power during periods of peak electric demand. As such, the units may operate at or near their full capacity, but only for short periods, as needed. Because these units only operate occasionally, capital expenses are a major factor in the overall cost of electricity, and often, the lowest capital cost (and generally less efficient) simple cycle EGUs are intended for use only during periods of peak electric demand. Due to their low efficiency, these units require more fuel per MWh of electricity produced and their operating costs tend to be higher. Because of the higher operating costs, they are generally some of the last units in the dispatch order. Important characteristics for low load combustion turbines include their low capital costs, their ability to start quickly and to rapidly ramp up to full load, and their ability to operate at partial loads while maintaining acceptable emission rates and efficiencies. The ability to start quickly and rapidly attain full load is important to maximize revenue during periods of peak electric prices and to meet sudden shifts in demand. In contrast, under steady-state conditions, more efficient combined cycle EGUs are dispatched ahead of low load turbines and often operate at higher annual capacity factors.

Highly efficient simple cycle turbines and flexible fast-start combined cycle turbines both offer different advantages and disadvantages when operating at intermediate loads. One of the roles of these intermediate or load following EGUs is to provide dispatchable backup power to support variable renewable generating sources (*e.g.,* solar and wind). A developer's decision as to whether to build a simple cycle turbine or a combined cycle turbine to serve intermediate load demand is based on several factors related to the intended operation of the unit. These factors would include how frequently the unit is expected to cycle between starts and stops, the predominant load level at which the unit is expected to operate, and whether this level of operation is expected to remain consistent or is expected to vary over the lifetime of the unit. In areas of the U.S. with vertically integrated electricity markets, utilities determine dispatch orders based generally on economic merit of individual units. Meanwhile, in areas of the U.S. inside organized wholesale electricity markets, owner/operators of individual combustion turbines control whether and how units will operate over time, but they do not necessarily control the precise timing of dispatch for units in any given day or hour. Such short-term dispatch decisions are often made by regional grid operators that determine, on a moment-to-moment basis, which available individual units should operate to balance supply and demand and other requirements in an optimal manner, based on operating costs, price bids, and/or operational characteristics. However, operating permits for simple cycle turbines often contain restrictions on the annual hours of operation that owners/operators incorporate into longer-term operating plans and short-term dispatch decisions.

Intermediate load combustion turbines vary their generation, especially during transition periods between low and high electric demand. Both high-efficiency simple cycle turbines and flexible fast-start combined cycle turbines can fill this cycling role. While the ability to start quickly and quickly ramp up is important, efficiency is also an important characteristic. These combustion turbines generally have higher capital costs than low load combustion turbines but are generally less expensive to operate.

Base load combustion turbines are designed to operate for extended periods at high loads with infrequent starts and stops. Quick-start capability and low capital costs are less important than low operating costs. High-efficiency combined cycle turbines typically fill the role of base load combustion turbines.

The increase in generation from variable renewable energy sources during the past decade has impacted the way in which dispatchable generating resources operate.[706] For example, the electric output from wind and solar generating sources fluctuates daily and seasonally due to increases and decreases in the wind speed or solar intensity. Due to this variable nature of wind and solar, dispatchable EGUs, including combustion turbines as well as other technologies like energy storage, are used to ensure the reliability of the electric grid. This requires dispatchable power plants to have the ability to quickly start and stop and to rapidly and frequently change load—much more often than was previously needed. These are important characteristics of the combustion turbines that provide firm backup capacity. Combustion turbines are much more flexible than coal-fired utility boilers in this regard and have played an important role during the past decade in ensuring that electric supply and demand are balanced.

As discussed in section IV.F.2 of this preamble, in the final TSD, *Power Sector Trends,* and in the accompanying RIA, the EPA's Power Sector Platform 2023 using IPM projects that natural gas-fired combustion turbines will continue to play an important role in meeting electricity demand. However, that role is projected to evolve as additional renewable and non-renewable low-GHG generation and energy storage technologies are added to the grid. Energy storage technologies can store energy during periods when generation from renewable resources is high relative to demand and can provide electricity to the grid during other periods. Energy storage technologies are projected to reduce the need for base load fossil fuel-fired firm dispatchable power plants, and the capacity factors of combined cycle EGUs are forecast to decline by 2040.

C. Overview of Regulation of Stationary Combustion Turbines for GHGs

As explained earlier in this preamble, the EPA originally regulated new and reconstructed stationary combustion turbine EGUs for emissions of GHGs in 2015 under 40 CFR part 60, subpart TTTT. In 40 CFR part 60, subpart TTTT, the EPA created three subcategories: two for natural gas-fired combustion turbines and one for multi-fuel-fired combustion turbines. For natural gas-fired turbines, the EPA created a subcategory for base load turbines and a separate subcategory for non-base load turbines. Base load turbines were defined as combustion turbines with electric sales greater than a site-specific electric sales threshold based on the design efficiency of the combustion turbine. Non-base load turbines were defined as combustion turbines with a capacity factor less than or equal to the site-specific electric sales threshold. For base load turbines, the EPA set a standard of 1,000 lb CO_2/MWh-gross based on efficient combined cycle turbine technology. For non-base load and multi-fuel-fired turbines, the EPA set a standard based on the use of lower-emitting fuels that varied from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending upon whether the turbine burned primarily natural gas or other lower-emitting fuels.

D. Eight-Year Review of NSPS

CAA section 111(b)(1)(B) requires the Administrator to ''at least every 8 years, review and, if appropriate, revise [the NSPS] . . . .'' The provision further provides that ''the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such [NSPS].''

The EPA promulgated the NSPS for GHG emissions for stationary combustion turbines in 2015. Announcements and modeling projections show that project developers are building new fossil fuel-fired combustion turbines and have plans to continue building additional capacity. Because the emissions from this added capacity have the potential to be large and these units are likely to have long operating lives (25 years or more), it is important to limit emissions from these new units. Accordingly, in this final rule, the EPA is updating the NSPS for newly constructed and reconstructed fossil fuel-fired stationary combustion turbines.

E. Applicability Requirements and Subcategorization

This section describes the amendments to the specific applicability criteria for non-fossil fuel-fired EGUs, industrial EGUs, CHP EGUs, and combustion turbine EGUs not connected to a natural gas pipeline. The EPA is also making certain changes to the applicability requirements for stationary combustion turbines affected by this final rule as compared to those for sources affected by the 2015 NSPS. The amendments are described below and include the elimination of the multi-fuel-fired subcategory, further binning non-base load combustion turbines into low load and intermediate load subcategories and establishing a capacity factor threshold for base load combustion turbines.

1. Applicability Requirements

In general, the EPA refers to fossil fuel-fired EGUs that would be subject to a CAA section 111 NSPS as ''affected'' EGUs or units. An EGU is any fossil fuel-fired electric utility steam generating unit (*i.e.,* a utility boiler or IGCC unit) or stationary combustion turbine (in either simple cycle or combined cycle configuration). To be considered an affected EGU under the 2015 NSPS at 40 CFR part 60, subpart TTTT, the unit must meet the following applicability criteria: The unit must: (1) be capable of combusting more than 250 MMBtu/h (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[707] However, 40 CFR part 60, subpart TTTT, includes applicability exemptions for certain EGUs, including: (1) non-fossil fuel-fired units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) CHP units that are subject to a federally enforceable permit limiting annual net electric sales to no more than either the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh, whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* those that are not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (6) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (7) certain projects under development, as discussed in the preamble for the 2015 final NSPS.

[706] Dispatchable generating sources are those that can be turned on and off and adjusted to provide power to the electric grid based on the demand for electricity. Variable (sometimes referred to as intermittent) generating sources are those that supply electricity based on external factors that are not controlled by the owner/operator of the source (*e.g.,* wind and solar sources).

[707] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

a. Revisions to 40 CFR Part 60, Subpart TTTT

The EPA is amending 40 CFR 60.5508 and 60.5509 to reflect that stationary combustion turbines that commenced construction after January 8, 2014, or reconstruction after June 18, 2014, and before May 24, 2023, and that meet the relevant applicability criteria are subject to 40 CFR part 60, subpart TTTT. For steam generating EGUs and IGCC units, 40 CFR part 60, subpart TTTT, remains applicable for units constructed after January 8, 2014, or reconstructed after June 18, 2014. The EPA is finalizing 40 CFR part 60, subpart TTTTa, to be applicable to stationary combustion turbines that commence construction or reconstruction after May 23, 2023, and that meet the relevant applicability criteria.

b. Revisions to 40 CFR Part 60, Subpart TTTT, That Are Also Included in 40 CFR Part 60, Subpart TTTTa

The EPA is finalizing that 40 CFR part 60, subpart TTTT, and 40 CFR part 60, subpart TTTTa, use similar regulatory text except where specifically stated. This section describes amendments included in both subparts.

i. Applicability to Non-Fossil Fuel-Fired EGUs

The current non-fossil applicability exemption in 40 CFR part 60, subpart TTTT, is based strictly on the combustion of non-fossil fuels (*e.g.,* biomass). To be considered a non-fossil fuel-fired EGU, the EGU must be both: (1) Capable of combusting more than 50 percent non-fossil fuel and (2) subject to a federally enforceable permit condition limiting the annual heat input capacity for all fossil fuels combined of 10 percent or less. The current language does not take heat input from non-combustion sources (*e.g.,* solar thermal) into account. Certain solar thermal installations have natural gas backup burners larger than 250 MMBtu/h. As currently treated in 40 CFR part 60, subpart TTTT, these solar thermal installations are not eligible to be considered non-fossil units because they are not capable of deriving more than 50 percent of their heat input from the combustion of non-fossil fuels. Therefore, solar thermal installations that include backup burners could meet the applicability criteria of 40 CFR part 60, subpart TTTT, even if the burners are limited to an annual capacity factor of 10 percent or less. These EGUs would readily comply with the standard of performance, but the reporting and recordkeeping would increase costs for these EGUs.

The EPA proposed and is finalizing several amendments to align the applicability criteria with the original intent to cover only fossil fuel-fired EGUs. These amendments ensure that solar thermal EGUs with natural gas backup burners, like other types of non-fossil fuel-fired units that derive most of their energy from non-fossil fuel sources, are not subject to the requirements of 40 CFR part 60, subpart TTTT or TTTTa. Amending the applicability language to include heat input derived from non-combustion sources allows these facilities to avoid the requirements of 40 CFR part 60, subpart TTTT or TTTTa, by limiting the use of the natural gas burners to less than 10 percent of the capacity factor of the backup burners. Specifically, the EPA is amending the definition of non-fossil fuel-fired EGUs from EGUs capable of ''combusting 50 percent or more non-fossil fuel'' to EGUs capable of ''*deriving* 50 percent or more *of the heat input from* non-fossil fuel *at the base load rating*'' (emphasis added). The definition of base load rating is also being amended to include the heat input from non-combustion sources (*e.g.,* solar thermal).

Revising ''combusting'' to ''deriving'' in the amended non-fossil fuel applicability language ensures that 40 CFR part 60, subparts TTTT and TTTTa, cover the fossil fuel-fired EGUs that the original rule was intended to cover, while minimizing unnecessary costs to EGUs fueled primarily by steam generated without combustion (*e.g.,* thermal energy supplied through the use of solar thermal collectors). The corresponding change in the base load rating to include the heat input from non-combustion sources is necessary to determine the relative heat input from fossil fuel and non-fossil fuel sources.

ii. Industrial EGUs

(A) Applicability to Industrial EGUs

In simple terms, the current applicability provisions in 40 CFR part 60, subpart TTTT, require that an EGU be capable of combusting more than 250 MMBtu/h of fossil fuel and be capable of selling 25 MW to a utility distribution system to be subject to 40 CFR part 60, subpart TTTT. These applicability provisions exclude industrial EGUs. However, the definition of an EGU also includes ''integrated equipment that provides electricity or useful thermal output.'' This language facilitates the integration of non-emitting generation and avoids energy inputs from non-affected facilities being used in the emission calculation without also considering the emissions of those facilities (*e.g.,* an auxiliary boiler providing steam to a primary boiler). This language could result in certain large processes being included as part of the EGU and meeting the applicability criteria. For example, the high-temperature exhaust from an industrial process (*e.g.,* calcining kilns, dryer, metals processing, or carbon black production facilities) that consumes fossil fuel could be sent to a HRSG to produce electricity. If the industrial process uses more than 250 MMBtu/h heat input and the electric sales exceed the applicability criteria, then the unit could be subject to 40 CFR part 60, subpart TTTT or TTTTa. This is potentially problematic for multiple reasons. First, it is difficult to determine the useful output of the EGU (*i.e.,* HRSG) since part of the useful output is included in the industrial process. In addition, the fossil fuel that is combusted could have a relatively high CO_2 emissions rate on a lb/MMBtu basis, making it potentially problematic to meet the standard of performance using efficient generation. This could result in the owner/operator reducing the electric output of the industrial facility to avoid the applicability criteria. Finally, the compliance costs associated with 40 CFR part 60, subpart TTTT or TTTTa, could discourage the development of environmentally beneficial projects.

To avoid these outcomes, the EPA is, as proposed, amending the applicability provision that exempts EGUs where greater than 50 percent of the heat input is derived from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.[708] Reducing the output or not developing industrial electric generating projects where the majority of the heat input is derived from the industrial process itself would not necessarily result in reductions in GHG emissions from the industrial facility. However, the electricity that would have been produced from the industrial project could still be needed. Therefore, projects of this type provide significant environmental benefit by providing additional useful output with little if any additional environmental impact. Including these types of projects would result in regulatory burden without any associated environmental benefit and could discourage project development,

[708] Auxiliary equipment such as boilers or combustion turbines that provide heat or electricity to the primary EGU (including to any control equipment) would still be considered integrated equipment and included as part of the affected facility.

leading to potential overall increases in GHG emissions.

(B) Industrial EGUs Electric Sales Threshold Permit Requirement

The current electric sales applicability exemption in 40 CFR part 60, subpart TTTT, for non-CHP steam generating units includes the provision that EGUs have ''*always been subject to a federally enforceable permit* limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less'' (emphasis added). The justification for this restriction includes that the 40 CFR part 60, subpart Da, applicability language includes ''constructed for the purpose of . . .'' and the Agency concluded that the intent was defined by permit conditions (80 FR 64544; October 23, 2015). This applicability criterion is important both for determining applicability with the new source CAA section 111(b) requirements and for determining whether existing steam generating units are subject to the existing source CAA section 111(d) requirements. For steam generating units that commenced construction after September 18, 1978, the applicability of 40 CFR part 60, subpart Da, would be relatively clear as to what criteria pollutant NSPS is applicable to the facility. However, for steam generating units that commenced construction prior to September 18, 1978, or where the owner/operator determined that criteria pollutant NSPS applicability was not critical to the project (*e.g.,* emission controls were sufficient to comply with either the EGU or industrial boiler criteria pollutant NSPS), owners/operators might not have requested that an electric sales permit restriction be included in the operating permit. Under the current applicability language, some onsite EGUs could be covered by the existing source CAA section 111(d) requirements even if they have never sold electricity to the grid. To avoid covering these industrial EGUs, the EPA proposed and is finalizing amendments to the electric sales exemption in 40 CFR part 60, subparts TTTT and TTTTa, to read, ''annual net electric sales *have never exceeded one-third of its potential electric output or 219,000 MWh, whichever is greater, and is* [the ''*always been*'' would be deleted] subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less'' (emphasis added). EGUs that reduce current generation will continue to be covered as long as they sold more than one-third of their potential electric output at some time in the past. The revisions make it possible for an owner/operator of an existing industrial EGU to provide evidence to the Administrator that the facility has never sold electricity in excess of the electricity sales threshold and to modify their permit to limit sales in the future. Without the amendment, owners/operators of any non-CHP industrial EGU capable of selling 25 MW would be subject to the existing source CAA section 111(d) requirements even if they have never sold any electricity. Therefore, the EPA is eliminating the requirement that existing industrial EGUs must have always been subject to a permit restriction limiting net electric sales.

iii. Determination of the Design Efficiency

The design efficiency (*i.e.,* the efficiency of converting thermal energy to useful energy output) of a combustion turbine is used to determine the electric sales applicability threshold. In 40 CFR part 60, subpart TTTT, the sales criteria are based in part on the individual EGU design efficiency. Three methods for determining the design efficiency are currently provided in 40 CFR part 60, subpart TTTT.[709] Since the 2015 NSPS was finalized, the EPA has become aware that owners/operators of certain existing EGUs do not have records of the original design efficiency. These units would not be able to readily determine whether they meet the applicability criteria (and would therefore be subject to CAA section 111(d) requirements for existing sources) in the same way that 111(b) sources would be able to determine if the facility meets the applicability criteria. Many of these EGUs are CHP units that are unlikely to meet the 111(b) applicability criteria and would therefore not be subject to any future 111(d) requirements. However, the language in the 2015 NSPS would require them to conduct additional testing to demonstrate this. The requirement would result in burden to the regulated community without any environmental benefit. The electricity generating market has changed, in some cases dramatically, during the lifetime of existing EGUs, especially concerning ownership. As a result of acquisitions and mergers, original EGU design efficiency documentation, as well as performance guarantee results that affirmed the design efficiency, may no longer exist. Moreover, such documentation and results may not be relevant for current EGU efficiencies, as changes to original EGU configurations, upon which the original design efficiencies were based, render those original design efficiencies moot, meaning that there would be little reason to maintain former design efficiency documentation since it would not comport with the efficiency associated with current EGU configurations. As the three specified methods would rely on documentation from the original EGU configuration performance guarantee testing, and results from that documentation may no longer exist or be relevant, it is appropriate to allow other means to demonstrate EGU design efficiency. To reduce potential future compliance burden, the EPA proposed and is finalizing in 40 CFR part 60, subparts TTTT and TTTTa, to allow alternative methods as approved by the Administrator on a case-by-case basis. Owners/operators of EGUs can petition the Administrator in writing to use an alternate method to determine the design efficiency. The Administrator's discretion is intentionally left broad and can extend to other American Society of Mechanical Engineers (ASME) or International Organization for Standardization (ISO) methods as well as to operating data to demonstrate the design efficiency of the EGU. The EPA also proposed and is finalizing a change to the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTT, from ''no'' to ''yes'' and that the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTTa, is ''yes.'' This allows the Administrator to approve alternatives to the test methods specified in 40 CFR part 60, subparts TTTT and TTTTa.

c. Applicability for 40 CFR Part 60, Subpart TTTTa

This section describes applicability criteria that are only incorporated into 40 CFR part 60, subpart TTTTa, and that differ from the requirements in 40 CFR part 60, subpart TTTT.

Section 111 of the CAA defines a new or modified source for purposes of a given NSPS as any stationary source that commences construction or modification after the publication of the proposed regulation. Thus, the standards of performance apply to EGUs that commence construction or reconstruction after the date of proposal of this rule—May 23, 2023. EGUs that commenced construction after the date

[709] 40 CFR part 60, subpart TTTT, currently lists ''ASME PTC 22 Gas Turbines,'' ''ASME PTC 46 Overall Plant Performance,'' and ''ISO 2314 Gas turbines—acceptance tests'' as approved methods to determine the design efficiency.

of the proposal for the 2015 NSPS and by May 23, 2023, will remain subject to the standards of performance promulgated in the 2015 NSPS. A modification is any physical change in, or change in the method of operation of, an existing source that increases the amount of any air pollutant emitted to which a standard applies.[710] The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered a new source if it undertakes a reconstruction.[711]

The EPA is finalizing the same applicability requirements in 40 CFR part 60, subpart TTTTa, as the applicability requirements in 40 CFR part 60, subpart TTTT. The stationary combustion turbine must meet the following applicability criteria: The stationary combustion turbine must: (1) be capable of combusting more than 250 MMBtu/h (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[712] In addition, the EPA proposed and is finalizing in 40 CFR part 60, subpart TTTTa, to include applicability exemptions for stationary combustion turbines that are: (1) capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less; (2) combined heat and power units subject to a federally enforceable permit condition limiting annual net electric sales to no more than 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (3) serving a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity is 25 MW or less; (4) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (5) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (6) deriving greater than 50 percent of heat input from an industrial process that does not produce any electrical or mechanical output that is used outside the affected stationary combustion turbine.

The EPA proposed the same requirements to combustion turbines in non-continental areas (*i.e.,* Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA did for comparable units in the contiguous 48 states.[713] However, the Agency solicited comment on whether owners/operators of new and reconstructed combustion turbines in non-continental and non-contiguous areas should be subject to different requirements. Commenters generally commented that due to the difference in non-contiguous areas relative to the lower 48 states, the proposed requirements should not apply to owners/operators of new or reconstructed combustion turbines in non-contiguous areas. The Agency has considered these comments and is finalizing that only the initial BSER component will be applicable to owners/operators of combustion turbines located in non-contiguous areas. Therefore, owners/operators of base load combustions turbines would not be subject to the CCS-based numerical standards in 2032 and would continue to comply with the efficiency-based numeric standard. Based on information reported in the 2022 EIA Form EIA–860, there are no planned new combustion turbines in either Alaska or Hawaii. In addition, since 2015 no new combustion turbines have commenced operation in Hawaii. Two new combustion turbine facilities totaling 190 MW have commenced operation in Alaska since 2015. One facility is a combined cycle CHP facility and the other is at an industrial facility and neither facility would likely meet the applicability of 40 CFR part 60, subpart TTTTa. Therefore, not finalizing phase-2 BSER for non-continental and non-contiguous areas will have limited, if any, impacts on emissions or costs. The EPA notes that the Agency has the authority to amend this decision in future rulemakings.

i. Applicability to CHP Units

For 40 CFR part 60, subpart TTTT, owners/operators of CHP units calculate net electric sales and net energy output using an approach that includes ''at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output.'' It is unlikely that a CHP unit with a relatively low electric output (*i.e.,* less than 20.0 percent) would meet the applicability criteria. However, if a CHP unit with less than 20.0 percent of the total output consisting of electricity were to meet the applicability criteria, the net electric sales and net energy output would be calculated the same as for a traditional non-CHP EGU. Even so, it is not clear that these CHP units would have less environmental benefit per unit of electricity produced than would more traditional CHP units. For 40 CFR part 60, subpart TTTTa, the EPA proposed and is finalizing to eliminate the restriction that CHP units produce at least 20.0 percent electrical or mechanical output to qualify for the CHP-specific method for calculating net electric sales and net energy output.

In the 2015 NSPS, the EPA did not issue standards of performance for certain types of sources—including industrial CHP units and CHPs that are subject to a federally enforceable permit limiting annual net electric sales to no more than the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh or less, whichever is greater. For CHP units, the approach in 40 CFR part 60, subpart TTTT, for determining net electric sales for applicability purposes allows the owner/operator to subtract the purchased power of the thermal host facility. The intent of the approach is to determine applicability similarly for third-party developers and CHP units owned by the thermal host facility.[714] However, as written in 40 CFR part 60, subpart TTTT, each third-party CHP unit would subtract the entire electricity use of the thermal host facility when determining its net electric sales. It is clearly not the intent of the provision to allow multiple third-party developers that serve the same thermal host to all subtract the purchased power of the thermal host facility when determining net electric sales. This would result in counting the purchased power multiple times. In addition, it is not the intent of the provision to allow a CHP developer to provide a trivial amount of useful thermal output to multiple thermal hosts and then subtract all the thermal hosts' purchased power when determining net electric sales for applicability purposes. The EPA

[710] 40 CFR 60.2.

[711] 40 CFR 60.15(a).

[712] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

[713] 40 CFR part 60, subpart TTTT, also includes coverage for owners/operators of combustion turbines in non-contiguous areas. However, owners/operators of combustion turbines not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline) are not subject to the rule. This exemption covers many combustion turbines in non-contiguous areas.

[714] For contractual reasons, many developers of CHP units sell the majority of the generated electricity to the electricity distribution grid. Owners/operators of both the CHP unit and thermal host can subtract the site purchased power when determining net electric sales. Third-party developers that do not own the thermal host can also subtract the purchased power of the thermal host when determining net electric sales for applicability purposes.

proposed and is finalizing in 40 CFR part 60, subpart TTTTa, to limit to the amount of thermal host purchased power that a third-party CHP developer can subtract for electric sales when determining net electric sales equivalent to the percentage of useful thermal output provided to the host facility by the specific CHP unit. This approach eliminates both circumvention of the intended applicability by sales of trivial amounts of useful thermal output and double counting of thermal host-purchased power.

Finally, to avoid potential double counting of electric sales, the EPA proposed and is finalizing that for CHP units determining net electric sales, purchased power of the host facility be determined based on the percentage of thermal power provided to the host facility by the specific CHP facility.

ii. Non-Natural Gas Stationary Combustion Turbines

There is currently an exemption in 40 CFR part 60, subpart TTTT, for stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* those that are not connected to a natural gas pipeline). While combustion turbines not connected to a natural gas pipeline meet the general applicability of 40 CFR part 60, subpart TTTT, these units are not subject to any of the requirements. The EPA is not including in 40 CFR part 60, subpart TTTTa, the exemption for stationary combustion turbines that are not physically capable of combusting natural gas. As described in the standards of performance section, owners/operators of combustion turbines burning fuels with a higher heat input emission rate than natural gas would adjust the natural gas-fired emissions rate by the ratio of the heat input-based emission rates. The overall result is that new stationary combustion turbines combusting fuels with higher GHG emissions rates than natural gas on a lb CO_2/MMBtu basis must maintain the same efficiency compared to a natural gas-fired combustion turbine and comply with a standard of performance based on the identified BSER.

2. Subcategorization

In this final rule, the EPA is continuing to include both simple and combined cycle turbines in the definition of a stationary combustion turbine, and like in prior rules for this source category, the Agency is finalizing three subcategories—low load, intermediate load, and base load combustion turbines. These subcategories are determined based on electric sales (*i.e.,* utilization) relative to the combustion turbines' potential electric output to an electric distribution network on both a 12-operating month and 3-year rolling average basis. The applicable subcategory is determined each operating month and a stationary combustion turbine can switch subcategories if the owner/operator changes the way the facility is operated. Subcategorization based on percent electric sales is a proxy for how a combustion turbine operates and for determining the BSER and corresponding emission standards. For example, low load combustion turbines tend to spend a relatively high percentage of operating hours starting and stopping. However, within each subcategory not all combustion turbines operate the same. Some low load combustion turbines operate with less starting and stopping, but in general, combustion turbines tend to operate with fewer starts and stops (*i.e.,* more steady-state hours of operation) with increasing percentages of electric sales. The BSER for each subcategory is based on representative operation of the combustion turbines in that subcategory and on what is achievable for the subcategory as a whole.

Subcategorization by electric sales is similar, but not identical, to subcategorizing by heat input-based capacity factors or annual hours of operation limits.[715] The EPA has determined that, for NSPS purposes, electric sales is appropriate because it reflects operational limitations inherent in the design of certain units, and also that—given these differences—certain emission reduction technologies are more suitable for some units than for others.[716] This subcategorization approach is also consistent with industry practice. For example, operating permits for simple cycle turbines often include annual operating hour limitations of 1,500 to 4,000 hours annually. When average hourly capacity factors (*i.e.,* duty cycles) are accounted for, these hourly restrictions are similar to annual capacity factor restrictions of approximately 15 percent and 40 percent, respectively. The owners or operators of these combustion turbines never intend for them to provide base load power. In contrast, operating permits do not typically restrict the number of hours of annual operation for combined cycle turbines, reflecting that these types of combustion turbines are intended to have the ability to provide base load power.

The EPA evaluated the operation of the three general combustion turbine technologies—combined cycle turbines, frame-type simple cycle turbines, and aeroderivative simple cycle turbines—when determining the subcategorization approach in this rulemaking.[717] The EPA found that, at the same capacity factor, aeroderivative simple cycle turbines have more starts (including fewer operating hours per start) than either frame simple cycle turbines or combined cycle turbines. The maximum number of starts for aeroderivative simple cycle turbines occurs at capacity factors of approximately 30 percent and the maximum number of starts for frame simple cycle turbines and combined cycle turbines both occur at capacity factors of approximately 25 percent. In terms of the median hours of operation per start, the hours per starts increases exponentially with capacity factor for each type of combustion turbine. The rate of increase is greatest for combined cycle turbines with the run times per start increasing significantly at capacity factors of 40 and greater. This threshold roughly matches the subcategorization threshold for intermediate load and base load turbines in this final rule. As is discussed later in section VIII.F.3 and VIII.F.4, technology options including those related to efficiency and to post combustion capture are impacted by the way units operate and can be more effective for units with fewer stops and starts.

a. Legal Basis for Subcategorization

As noted in section V.C.1 of this preamble, CAA section 111(b)(2) provides that the EPA ''may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing . . . standards [of performance].'' The D.C. Circuit has held that the EPA has broad discretion in determining whether and how to subcategorize under CAA section 111(b)(2). *Lignite Energy Council,* 198 F.3d at 933. As also noted in section V.C.1 of this preamble, in prior CAA section 111 rules, the EPA has subcategorized on numerous bases, including, among other things, fuel type and load, *i.e.,* utilization. In particular, as noted in section V.C.1 of this preamble, the EPA subcategorized on the basis of utilization—for base load

[715] Percent electric sales thresholds, capacity factor thresholds, and annual hours of operation limitations all categorize combustion turbines based on utilization.

[716] While utilization and electric sales are often similar, the EPA uses electric sales because the focus of the applicability is facilities that sell electricity to the grid and not industrial facilities where the electricity is generated primarily for use onsite.

[717] The EPA used manufacturers' designations for frame and aeroderivative combustion turbines.

and non-base load subcategories—in the 2015 NSPS for GHG emissions from combustion turbines, *Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units,* 80 FR 64509 (October 23, 2015), and also in the *NESHAP for Reciprocating Internal Combustion Engines; NSPS for Stationary Internal Combustion Engines,* 79 FR 48072–01 (August 15, 2014).

Subcategorizing combustion turbines based on utilization is appropriate because it recognizes the way differently designed combustion turbines actually operate. Project developers do not construct combined cycle combustion turbine system to start and stop often to serve peak demand. Similarly, project developers do not construct and install simple cycle combustion turbines to operate at higher capacity factors to provide base load demand. And intermediate load demand may be served by higher efficiency simple cycle turbine systems or by ''quick start'' combined cycle units. Thus, there are distinguishing features (*i.e.,* different classes, types, and sizes) of turbines that are predominantly used in each of the utilization-based subcategories. Further, the amount of utilization and the mode of operation are relevant for the systems of emission reduction that the EPA may evaluate to be the BSER and therefore for the resulting standards of performance. See section VII.C.2.a.i for more discussion of the legal basis to subcategorize based upon characteristics relevant to the controls the EPA may determine to be the BSER.

As noted in sections VIII.E.2.b and VIII.F of this preamble, combustion turbines that operate at low load have highly variable operation and therefore highly variable emission rates. This variability made it challenging for the EPA to specify a BSER based on efficient design and operation and limits the BSER for purposes of this rulemaking to lower-emitting fuels. The EPA notes that the subcategorization threshold and the standard of performance are related. For example, the Agency could have finalized a lower electric sales threshold for the low load subcategory (*e.g.,* 15 percent) and evaluated the emission rates at the lower capacity factors. In future rulemaking the Agency could further evaluate the costs and emissions impacts of reducing the threshold for combustion turbines subject to a BSER based on the use of lower emitting fuels.

Intermediate load combustion turbines (*i.e.,* those that operate at loads that are somewhat higher than the low load peaking units) are most often designed to be simple cycle units rather than combined cycle units. This is because combustion turbines operating in the intermediate load range also start and stop and vary their load frequently (though not as often as low load peaking units). Because of the more frequent starts and stops, simple cycle combustion turbines are more economical for project developers when compared to combined cycle combustion turbines. Utilization of CCS technology is not practicable for those simple cycle units due to the lack of a HRSG. Therefore, the EPA has determined that efficient design and operation is the BSER for intermediate load combustion turbines.

While use of CCS is practicable for combined cycle combustion turbines, it is most appropriate for those units that operate at relatively higher loads (*i.e.,* as base load units) that do not frequently start, stop, and change load. Moreover, with current technology, CCS works better on units running at base load levels.

b. Electric Sales Subcategorization (Low, Intermediate, and Base Load Combustion Turbines)

As noted earlier, in the 2015 NSPS, the EPA established separate standards of performance for new and reconstructed natural gas-fired base load and non-base load stationary combustion turbines. The electric sales threshold distinguishing the two subcategories is based on the design efficiency of individual combustion turbines. A combustion turbine qualifies as a non-base load turbine—and is thus subject to a less stringent standard of performance—if it has net electric sales equal to or less than the design efficiency of the turbine (not to exceed 50 percent) multiplied by the potential electric output (80 FR 64601; October 23, 2015). If the net electric sales exceed that level on both a 12-operating month and 3-calendar year basis, then the combustion turbine is in the base load subcategory and is subject to a more stringent standard of performance. Subcategory applicability can change on a month-to-month basis since applicability is determined each operating month. For additional discussion on this approach, see the 2015 NSPS (80 FR 64609–12; October 23, 2015). The 2015 NSPS non-base load subcategory is broad and includes combustion turbines that assure grid reliability by providing electricity during periods of peak electric demand. These peaking turbines tend to have low annual capacity factors and sell a small amount of their potential electric output. The non-base load subcategory in the 2015 NSPS also includes combustion turbines that operate at intermediate annual capacity factors and are not considered base load EGUs. These intermediate load EGUs provide a variety of services, including providing dispatchable power to support variable generation from renewable sources of electricity. The need for this service has been expanding as the amount of electricity from wind and solar continues to grow. In the 2015 NSPS, the EPA determined the BSER for the non-base load subcategory to be the use of lower-emitting fuels (*e.g.,* natural gas and Nos. 1 and 2 fuel oils). In 2015, the EPA explained that efficient generation did not qualify as the BSER due in part to the challenge of determining an achievable output-based CO_2 emissions rate for all combustion turbines in this subcategory.

In this action, the EPA proposed and is finalizing the subcategories in 40 CFR part 60, subpart TTTTa, that will be applicable to sources that commence construction or reconstruction after May 23, 2023. First, the Agency proposed and is finalizing the definition of design efficiency so that the heat input calculation of an EGU is based on the higher heating value (HHV) of the fuel instead of the lower heating value (LHV), as explained immediately below. This has the effect of lowering the calculated potential electric output and the electric sales threshold. In addition, the EPA proposed and is finalizing division of the non-base load subcategory into separate intermediate and low load subcategories.

i. Higher Heating Value as the Basis for Calculation of the Design Efficiency

The *heat rate* is the amount of energy used by an EGU to generate 1 kWh of electricity and is often provided in units of Btu/kWh. As the thermal efficiency of a combustion turbine EGU is increased, less fuel is burned per kWh generated and there is a corresponding decrease in emissions of CO_2 and other air pollutants. The electric energy output as a fraction of the fuel energy input expressed as a percentage is a common practice for reporting the unit's efficiency. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process. Lower heat rates are associated with more efficient power generating plants.

Efficiency can be calculated using the HHV or the LHV of the fuel. The HHV is the heating value directly determined by calorimetric measurement of the fuel in the laboratory. The LHV is calculated using a formula to account for the moisture in the combustion gas (*i.e.,* subtracting the energy required to vaporize the water in the flue gas) and is a lower value than the HHV. Consequently, the HHV efficiency for a given EGU is always lower than the corresponding LHV efficiency because the reported heat input for the HHV is larger. For U.S. pipeline natural gas, the HHV heating value is approximately 10 percent higher than the corresponding LHV heating value and varies slightly based on the actual constituent composition of the natural gas.[718] The EPA default is to reference all technologies on a HHV basis,[719] and the Agency is basing the heat input calculation of an EGU on HHV for purposes of the definition of design efficiency. However, it should be recognized that manufacturers of combustion turbines typically use the LHV to express the efficiency of combustion turbines.[720]

Similarly, the electric energy output for an EGU can be expressed as either of two measured values. One value relates to the amount of total electric power generated by the EGU, or *gross* output. However, a portion of this electricity must be used by the EGU facility to operate the unit, including compressors, pumps, fans, electric motors, and pollution control equipment. This within-facility electrical demand, often referred to as the parasitic load or auxiliary load, reduces the amount of power that can be delivered to the transmission grid for distribution and sale to customers. Consequently, electric energy output may also be expressed in terms of *net* output, which reflects the EGU gross output minus its parasitic load.[721]

When using efficiency to compare the effectiveness of different combustion turbine EGU configurations and the applicable GHG emissions control technologies, it is important to ensure that all efficiencies are calculated using the same type of heating value (*i.e.,* HHV or LHV) and the same basis of electric energy output (*i.e.,* MWh-gross or MWh-net). Most emissions data are available on a gross output basis and the EPA is finalizing output-based standards based on gross output. However, to recognize the superior environmental benefit of minimizing auxiliary/parasitic loads, the Agency is including optional equivalent standards on a net output basis. To convert from gross to net output-based standards, the EPA used a 2 percent auxiliary load for simple and combined cycle turbines and a 7 percent auxiliary load for combined cycle EGUs using 90 percent CCS.[722]

ii. Lowering the Threshold Between the Base Load and Non-Base Load Subcategories

The subpart TTTT distinction between a base load and non-base load combustion turbine is determined by the unit's actual electric sales relative to its potential electric sales, assuming the EGU is operated continuously (*i.e.,* percent electric sales). Specifically, stationary combustion turbines are categorized as non-base load and are subsequently subject to a less stringent standard of performance if they have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). Because the electric sales threshold is based in part on the design efficiency of the EGU, more efficient combustion turbine EGUs can sell a higher percentage of their potential electric output while remaining in the non-base load subcategory. This approach recognizes both the environmental benefit of combustion turbines with higher design efficiencies and provides flexibility to the regulated community. In the 2015 NSPS, it was unclear how often high-efficiency simple cycle EGUs would be called upon to support increased generation from variable renewable generating resources. Therefore, the Agency determined it was appropriate to provide maximum flexibility to the regulated community. To do this, the Agency based the numeric value of the design efficiency, which is used to calculate the electric sales threshold, on the LHV efficiency. This had the impact of allowing combustion turbines to sell a greater share of their potential electric output while remaining in the non-base load subcategory.

The EPA proposed and is finalizing that the design efficiency in 40 CFR part 60, subpart TTTTa be based on the HHV efficiency instead of LHV efficiency and to not include the 50 percent maximum and 33 percent minimum restrictions. When determining the potential electric output used in calculating the electric sales threshold in 40 CFR part 60, subpart TTTT, design efficiencies of greater than 50 percent are reduced to 50 percent and design efficiencies of less than 33 percent are increased to 33 percent for determining electric sales threshold subcategorization criteria. The 50 percent criterion was established to limit non-base load EGUs from selling greater than 55 percent of their potential electric sales.[723] The 33 percent criterion was included to be consistent with applicability thresholds in the electric utility criteria pollutant NSPS (40 CFR part 60, subpart Da).

Neither of those criteria are appropriate for 40 CFR part 60, subpart TTTTa, and the EPA proposed and is finalizing a decision that they are not incorporated when determining the electric sales threshold. Instead, as discussed later in the section, the EPA is finalizing a fixed percent electric sales thresholds and the design efficiency does not impact the subcategorization thresholds. However, the design efficiency is still used when determining the potential electric sales and any restriction on using the actual design efficiency of the combustion turbine would have the impact of changing the threshold. If this restriction were maintained, it would reduce the regulatory incentive for manufacturers to invest in programs to develop higher efficiency combustion turbines.

The EPA also proposed and is finalizing a decision to eliminate the 33 percent minimum design efficiency in the calculation of the potential electric output. The EPA is unaware of any new combustion turbines with design efficiencies meeting the general

[718] The HHV of natural gas is 1.108 times the LHV of natural gas. Therefore, the HHV efficiency is equal to the LHV efficiency divided by 1.108. For example, an EGU with a LHV efficiency of 59.4 percent is equal to a HHV efficiency of 53.6 percent. The HHV/LHV ratio is dependent on the composition of the natural gas (*i.e.,* the percentage of each chemical species (*e.g.,* methane, ethane, propane)) within the pipeline and will slightly move the ratio.

[719] Natural gas is also sold on a HHV basis.

[720] European plants tend to report thermal efficiency based on the LHV of the fuel rather than the HHV for both combustion turbines and steam generating EGUs. In the U.S., boiler efficiency is typically reported on a HHV basis.

[721] It is important to note that net output values reflect the net output delivered to the electric grid and not the net output delivered to the end user. Electricity is lost as it is transmitted from the point of generation to the end user and these ''line losses'' increase the farther the power is transmitted. 40 CFR part 60, subpart TTTT, provides a way to account for the environmental benefit of reduced line losses by crediting CHP EGUs, which are typically located close to large electric load centers. See 40 CFR 60.5540(a)(5)(i) and the definitions of gross energy output and net energy output in 40 CFR 60.5580.

[722] The 7 percent auxiliary load for combined cycle turbines with 90 percent CCS is specific to electric output. Additional auxiliary load includes thermal energy that is diverted to the CCS system instead of being used to generate additional electricity. This additional auxiliary thermal energy is accounted for when converting the phase 1 emissions standard to the phase 2 standard.

[723] While the design efficiency is capped at 50 percent on a LHV basis, the base load rating (maximum heat input of the combustion turbine) is on a HHV basis. This mixture of LHV and HHV results in the electric sales threshold being 11 percent higher than the design efficiency. The design efficiency of all new combined cycle EGUs exceed 50 percent on a LHV basis.

applicability criteria of less than 33 percent; and this will likely have no cost or emissions impact.

The EPA solicited comment on whether the intermediate/base load electric sales threshold should be reduced further to a range that would lower the base load electric sales threshold for simple cycle turbines to between 29 to 35 percent (depending on the design efficiency) and to between 40 to 49 percent for combined cycle turbines (depending on the design efficiency). The specific approach the EPA solicited comment on was reducing the design efficiency by 6 percent (*e.g.,* multiplying by 0.94) when determining the electric sales threshold. Some commenters supported lowering the proposed electric sales threshold while others supported maintaining the proposed standards.

After considering comments, in 40 CFR part 60, subpart TTTTa, the EPA has determined it is appropriate to eliminate the sliding scale electric sales threshold based on the design efficiency and instead base the subcategorization thresholds on fixed electric sales (also referred to sometimes here as capacity factor). In 40 CFR part 60 subpart TTTTa, the EPA is finalizing that the fixed electric sales threshold between intermediate load combustion turbines and base load combustion turbines is 40 percent. The 40 percent electric sales (capacity factor) threshold reflects the maximum capacity factor for intermediate load simple cycle turbines and the minimum prorated efficiency approach for base load combined cycle turbines that the EPA solicited comment on in proposal.[724]

The base load electric sales threshold is appropriate for new combustion turbines because, as will be discussed later, the first component of BSER for base load turbines is based on highly efficient combined cycle generation. Combined cycle units are significantly more efficient than simple cycle turbines; and therefore, in general, the EPA should be focusing its determination of the BSER for base load units on that more efficient technology. The electric sales thresholds and the emission standards are related because, at lower capacity factors, combustion turbines tend to have more variable operation (*e.g.,* more starts and stops and operation at part load conditions) that reduces the efficiency of the combustion turbine. This is particularly the case for combined cycle turbines because while the turbine engine can come to full load relatively quickly, the HRSG and steam turbine cannot, and combined cycle turbines responding to highly variable load will have efficiencies similar to simple cycle turbines.[725] This has implications for the appropriate control technologies and corresponding emission reduction potential. The EPA determined the final standard of performance based on review of emissions data for recently installed combined cycle combustion turbines with 12-operating month capacity factors of 40 percent or greater. The EPA considered a capacity factor threshold lower than 40 percent. However, expanding the subcategory to include combustion turbines with a 12-operating month electric sales of less than 40 percent would require the EPA to consider the emissions performance of combined cycle turbines operating at lower capacity factors and, while it would expand the number of sources in the base load subcategory, it would also result in a higher (*i.e.,* less stringent) numerical emission standard for the sources in the category.

Direct comparison of the costs of combined cycle turbines relative to simple cycle turbines can be challenging because model plant costs are often for combustion turbines of different sizes and do not account for variable operation. For example, combined cycle turbine model plants are generally for an EGU that is several hundred megawatts while simple cycle turbine model plants are generally less than a hundred megawatts. Direct comparison of the LCOE from these model plants is not relevant because the facilities are not comparable. Consider a facility with a block of 10 simple cycle turbines that are each 50 MW (so the overall facility capacity is 500 MW). Each simple cycle turbine operates as an individual unit and provides a different value to the electric grid as compared to a single 500 MW combined cycle turbine. While the minimum load of the combined cycle facility might be 200 MW, the block of 10 simple cycle turbines can provide from approximately 20 MW to 500 MW to the electric grid.

A more accurate cost comparison accounts for economies of scale and estimates the cost of a combined cycle turbine with the same net output as a simple cycle turbine. Comparing the modeled LCOE of these combustion turbines provides a meaningful comparison, at least for base load combustion turbines. Without accounting for economies of scale and variable operation, combined cycle turbines can appear to be more cost effective than simple cycle turbines under almost all conditions. In addition, without accounting for economies of scale, large frame simple cycle turbines can appear to be more cost effective than higher efficiency aeroderivative simple cycle turbines, even if operated at a 100 percent capacity factor. These cost models are not intended to make direct comparisons, and the EPA appropriately accounted for economies of scale when estimating the cost of the BSER. Since base load combustion turbines tend to operate under steady state conditions with few starts and stops, startup and shutdown costs and the efficiency impact of operating at variable loads are not important for determining the compliance costs of base load combustion turbines.

Based on an adjusted model plant comparison, combined cycle EGUs have a lower LCOE at capacity factors above approximately 40 percent compared to simple cycle EGUs operating at the same capacity factors. This supports the final base load fixed electric sales threshold of 40 percent for simple cycle turbines because it would be cost-effective for owners/operators of simple cycle turbines to add heat recovery if they elected to operate at higher capacity factors as a base load unit. Furthermore, based on an analysis of monthly emission rates, recently constructed combined cycle EGUs maintain consistent emission rates at capacity factors of less than 55 percent (which is the base load electric sales threshold in subpart TTTT) relative to operation at higher capacity factors. Therefore, the base load subcategory operating range can be expanded in 40 CFR part 60, subpart TTTTa, without impacting the stringency of the numeric standard. However, at capacity factors of less than approximately 40 percent, emission rates of combined cycle EGUs increase relative to their operation at higher capacity factors. It takes much longer for a HRSG to begin producing steam that can be used to generate additional electricity than it takes a combustion engine to reach full power. Under operating conditions with a significant number of starts and stops, typical of some intermediate and especially low load combustion turbines, there may not be enough time for the HRSG to generate steam that can be used for additional electrical generation. To maximize overall efficiency, combined cycle EGUs often use combustion turbine engines that are less efficient than the most

[724] The EPA solicited comment on basing the electric sales threshold on a value calculated using 0.94 times the design efficiency.

[725] This discussion assumes that the combined cycle turbine incorporates a bypass stack that allows the combustion turbine engine to operate independent of the HRSG/steam turbine. Without a bypass stack the combustion turbine engine could not come to full load as quickly.

efficient simple cycle turbine engines. Under operating conditions with frequent starts and stops where the HRSG does not have sufficient time to begin generating additional electricity, a combined cycle EGU may be no more efficient than a highly efficient simple cycle EGU. These distinctions in operation are thus meaningful for determining which emissions control technologies are most appropriate for types of units. Once a combustion turbine unit exceeds approximately 40 percent annual capacity factor, it is economical to add a HRSG which results in the unit becoming both more efficient and less likely to cycle its operation. Such units are, therefore, better suited for more stringent emission control technologies including CCS.

After the 2015 NSPS was finalized, some stakeholders expressed concerns about the approach for distinguishing between base load and non-base load turbines. They posited a scenario in which increased utilization of wind and solar resources, combined with low natural gas prices, would create the need for certain types of simple cycle turbines to operate for longer time periods than had been contemplated when the 2015 NSPS was being developed. Specifically, stakeholders have claimed that in some regional electricity markets with large amounts of variable renewable generation, some of the most efficient new simple cycle turbines—aeroderivative turbines—could be called upon to operate at capacity factors greater than their design efficiency. However, if those new simple cycle turbines were to operate at those higher capacity factors, they would become subject to the more stringent standard of performance for base load turbines. As a result, according to these stakeholders, the new aeroderivative turbines would have to curtail their generation and instead, less-efficient existing turbines would be called upon to run by the regional grid operators, which would result in overall higher emissions. The EPA evaluated the operation of simple cycle turbines in areas of the country with relatively large amounts of variable renewable generation and did not find a strong correlation between the percentage of generation from the renewable sources and the 12-operating month capacity factors of simple cycle turbines. In addition, most of the simple cycle turbines that commenced operation between 2010 and 2016 (the most recent simple cycle turbines not subject to 40 CFR part 60, subpart TTTT) have operated well below the base load electric sales threshold in 40 CFR part 60, subpart TTTT. Therefore, the Agency does not believe that the concerns expressed by stakeholders necessitates any revisions to the regulatory scheme. In fact, as noted above, the EPA is finalizing that the electric sales threshold can be lowered without impairing the availability of simple cycle turbines where needed, including to support the integration of variable generation. The EPA believes that the final threshold is not overly restrictive since a simple cycle turbine could operate on average for more than 9 hours a day in the intermediate load subcategory.

iii. Low and Intermediate Load Subcategories

This section discusses the EPA's rationale for subcategorizing non-base load combustion turbines into two subcategories—low load and intermediate load.

(A) Low Load Subcategory

The EPA proposed and is finalizing in 40 CFR part 60, subpart TTTTa, a low load subcategory to includes combustion turbines that operate only during periods of peak electric demand (*i.e.,* peaking units), which will be separate from the intermediate load subcategory. Low load combustion turbines also provide ramping capability and other ancillary services to support grid reliability. The EPA evaluated the operation of recently constructed simple cycle turbines to understand how they operate and to determine at what electric sales level or capacity factor their emissions rate is relatively steady. (Note that for purposes of this discussion, the terms ''electric sales'' and ''capacity factor'' are used interchangeably.) Low load combustion turbines generally only operate for short periods of time and potentially at relatively low duty cycles.[726] This type of operation reduces the efficiency and increases the emissions rate, regardless of the design efficiency of the combustion turbine or how it is maintained. For this reason, it is difficult to establish a reasonable output-based standard of performance for low load combustion turbines.

To determine the electric sales threshold—that is, to distinguish between the intermediate load and low load subcategories—the EPA evaluated capacity factor electric sales thresholds of 10 percent, 15 percent, 20 percent, and 25 percent. The EPA proposed to find and is finalizing a conclusion that the 10 percent threshold is problematic for two reasons. First, simple cycle turbines operating at that level or lower have highly variable emission rates, and therefore it is difficult for the EPA to establish a meaningful output-based standard of performance. In addition, only one-third of simple cycle turbines that have commenced operation since 2015 have maintained 12-operating month capacity factors of less than 10 percent. Therefore, setting the threshold at this level would bring most new simple cycle turbines into the intermediate load subcategory, which would subject them to a more stringent emission rate that is only achievable for simple cycle turbines operating at higher capacity factors. This could create a situation where simple cycle turbines might not be able to comply with the intermediate load standard of performance while operating at the low end of the intermediate load capacity factor subcategorization criteria.

Based on the EPA's review of hourly emissions data, at a capacity factor above 15 percent, GHG emission rates for many simple cycle turbines begin to stabilize. At higher capacity factors, more time is typically spent at steady state operation rather than ramping up and down; and emission rates tend to be lower while in steady-state operation. Of recently constructed simple cycle turbines, half have maintained 12-operating month capacity factors of 15 percent or less, two-thirds have maintained capacity factors of 20 percent or less; and approximately 80 percent have maintained maximum capacity factors of 25 percent or less. The emission rates clearly stabilize for most simple cycle turbines operating at capacity factors of greater than 20 percent. Based on this information, the EPA proposed the low load electric sales threshold—again, the dividing line to distinguish between the intermediate and low load subcategories—to be 20 percent and solicited comment on a range of 15 to 25 percent. The EPA also solicited comment on whether the low load electric sales threshold should be determined by a site-specific threshold based on three-fourths of the design efficiency of the combustion turbine.[727]Under this approach, simple

[726] The duty cycle is the average operating capacity factor. For example, if an EGU operates at 75 percent of the fully rated capacity, the duty cycle would be 75 percent regardless of how often the EGU actually operates. The capacity factor is a measure of how much an EGU is operated relative to how much it could potentially have been operated.

[727] The calculation used to determine the electric sales threshold includes both the design efficiency and the base load rating. Since the base load rating stays the same when adjusting the numeric value of the design efficiency for applicability purposes, adjustments to the design efficiency has twice the impact. Specifically, using three-fourths of the

cycle turbines selling less than 18 to 22 percent of their potential electric output (depending on the design efficiency) would still have been considered low load combustion turbines. This ''sliding scale'' electric sales threshold approach is like the approach the EPA used in the 2015 NSPS to recognize the environmental benefit of installing the most efficient combustion turbines for low load applications. Using this approach, combined cycle EGUs would have been able to sell between 26 to 31 percent of their potential electric output while still being considered low load combustion turbines. Some commenters supported a lower electric sales threshold while others supported a higher threshold. Based on these comments, the EPA is finalizing the proposed low load electric sales threshold of 20 percent of the potential electric sales. The fixed 20 percent capacity factor threshold represents a level of utilization at which most simple cycle combustion turbines perform at a consistent level of efficiency and GHG emission performance, enabling the EPA to establish a standard of performance that reflects a BSER of efficient operation. The 20 percent capacity factor threshold is also more environmentally protective than the higher thresholds the EPA considered, since owners and operators of combustion turbines operating above a 20 percent capacity factor would be subject to an output-based emissions standard instead of a heat input-based emissions standard based on the use of lower-emitting fuels. This ensures that owners/operators of intermediate load combined cycle turbines properly maintain and operate their combustion turbines.

(B) Intermediate Load Subcategory

The proposed sliding scale subcategorization approach essentially included two subcategories within the proposed intermediate load subcategory. As proposed, simple cycle turbines would be classified as intermediate load combustion turbines when operated between capacity factors of 20 percent and approximately 40 percent while combined cycle turbines would be classified as intermediate load combustion turbines when operated between capacity factors of 20 percent to approximately 55 percent. Owners/operators of combined cycle turbines operating at the high end of the intermediate load subcategory would only be subject to an emissions standard based on a BSER of high-efficiency simple cycle turbine technology. The proposed approach provided a regulatory incentive for owners/operators to purchase the most efficient technologies in exchange for additional compliance flexibility. The use of a prorated efficiency the EPA solicited comment on would have lowered the simple cycle and combined cycle turbine thresholds to approximately 35 percent and 50 percent, respectively.

In this final rule, the BSER for the intermediate load subcategory is consistent with the proposal—high-efficiency simple cycle turbine technology. While not specifically identified in the proposal, the BSER for the base load subcategory is also consistent with the proposal—the use of combined cycle technology.[728]

The 12-operating month electric sales (*i.e.,* capacity factor) thresholds for the stationary combustion turbine subcategories in this final rule are summarized below in Table 2.

TABLE 2—SALES THRESHOLDS FOR SUBCATEGORIES OF COMBUSTION TURBINE EGUS

Subcategory	12-Operating month electric sales threshold (percent of potential electric sales)
Low Load	≤20
Intermediate Load	>20 and ≤40
Base Load	>40

iv. Integrated Onsite Generation and Energy Storage

Integrated equipment is currently included as part of the affected facility, and the EPA proposed and is finalizing amended regulatory text to clarify that the output from integrated renewables is included as output when determining the NSPS emissions rate. The EPA also proposed that the output from the integrated renewable generation is not included when determining the net electric sales for applicability purposes (*i.e.,* generation from integrated renewables would not be considered when determining if a combustion turbine is subcategorized as a low, intermediate, or base load combustion turbine). In the alternative, the EPA solicited comment on whether instead of exempting the generation from the integrated renewables from counting toward electric sales, the potential output from the integrated renewables would be included when determining the design efficiency of the facility. Since the design efficiency is used when determining the electric sales threshold this would increase the allowable electric sales for subcategorization purposes. Including the integrated renewables when determining the design efficiency of the affected facility has the impact of increasing the operational flexibility of owners/operators of combustion turbines. Commenters generally supported maintaining that integrated renewables are part of the affected facility and including the output of the renewables when determining the emissions rate of the affected facility.[729] Therefore, the Agency is finalizing a decision that the rated output of integrated renewables be included when determining the design efficiency of the affected facility, which is used to determine the potential electric output of the affected facility, and that the output of the integrated renewables be included in determining the emissions rate of the affected facility. However, since the design efficiency is not a factor in determining the subcategory thresholds in 40 CFR part 60, subpart TTTTa, the output of the integrated renewables will not be included for determining the applicable subcategory. If the output from the integrated renewable generation were included for subcategorization purposes, this could discourage the use of integrated renewables (or curtailments) because affected facilities could move to a subcategory with a more stringent emissions standard that could cause the owner/operator to be out of compliance. The impact of this approach is that the electric sales threshold of the combustion turbine island itself, not including the integrated renewables, for an owner/operator of a combustion turbine that includes integrated renewables that increase the potential electric output by 1 percent would be 1 or 2 percent higher for the stationary combustion turbine island not considering the integrated renewables, depending on the design efficiency of the combustion turbine itself, than an identical combustion turbine without integrated renewables. In addition, when the output from the integrated renewables is considered, the output from the integrated renewables

design efficiency reduces the electric sales threshold by half.

[728] Under the proposed subcategorization approach, for a combustion turbine to be subcategorized as an intermediate load combustion turbine while operating at capacity factors of greater than 40 percent required the use of a HRSG (*e.g.,* combined cycle turbine technology).

[729] The EPA did not propose to include, and is not finalizing including, integrated renewables as part of the BSER. Commenters opposed a BSER that would include integrated renewables as part of the BSER. Commenters noted that this could result in renewables being installed in suboptimal locations which could result in lower overall GHG reductions.

lowers the emissions rate of the affected facility by approximately 1 percent.

For integrated energy storage technologies, the EPA solicited comment on and is finalizing a decision to include the rated output of the energy storage when determining the design efficiency of the affected facility. Similar to integrated renewables, this increases the flexibility of owner/operators to sell larger amounts of electricity while remaining in the low, variable, and intermediate load subcategories. While energy storage technologies have high capital costs, operating costs are low and would dispatch prior to the combustion turbine the technology is integrated with. Therefore, simple cycle turbines with integrated energy storage would likely operate at lower capacity factors than an identical simple cycle turbine at the same location. However, while the energy storage might be charged with renewables that would otherwise be curtailed, there is no guarantee that low emitting generation would be used to charge the energy storage. Therefore, the output from the energy storage is not considered in either determining the NSPS emissions rate or as net electric sales for subcategorization applicability purposes. In future rulemaking the Agency could further evaluate the impact of integrated energy storage on the operation of simple cycle turbines to determine if the number of starts and stops are reduced and increases the efficiency of simple cycle turbines relative to simple cycle turbines without integrated energy storage. If this is the case, it could be appropriate to lower the threshold for combustion turbines subject to a lower emitting fuels BSER because emission rates would be stable at lower capacity factors.

v. Definition of System Emergency

In 2015, the EPA included a provision that electricity sold during hours of operation when a unit is called upon due to a system emergency is not counted toward the percentage electric sales subcategorization threshold in 40 CFR part 60, subpart TTTT.[730] The Agency concluded that this exclusion is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector.[731] The intent is that the local grid operator will determine the EGUs essential to maintaining grid reliability. Subsequent to the 2015 NSPS, members of the regulated community informed the EPA that additional clarification of a system emergency is needed to determine and document generation during system emergencies. The EPA proposed to include the system emergency approach in 40 CFR part 60, subpart TTTTa, and solicited comment on amending the definition of system emergency to clarify in implementation in 40 CFR part 60, subparts TTTT and TTTTa. Commenters generally agreed with the proposal to allow owners/operators of EGUs called upon during a system emergency to operate without impacting the EGUs' subcategorization (*i.e.,* electric sales during system emergencies would not be considered when determining net electric sales), and that the Agency should clarify how system emergencies are determined and documented.

In terms of the definition of the system emergency provision, commenters stated that ''abnormal'' be deleted from the definition, and instead of referencing ''the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator,'' the definition should reference ''the balancing authority or reliability coordinator.'' This change would align the regulation's definition with the terms used by NERC. Some commenters also stated that the EPA should specify that electric sales during periods the grid operator declares energy emergency alerts (EEA) levels 1 through 3 be included in the definition of system emergency.[732] In addition, some commenters stated that the definition should be expanded to include the concept of energy emergencies. Specifically, the definition should also exempt generation during periods when a load-serving entity or balancing authority has exhausted all other resource options and can no longer meet its expected load obligations. Finally, commenters stated that the definition should apply to all EGUs, regardless of if they are already operating when the system emergency is declared. This would avoid regulatory incentive to come offline prior to a potential system emergency to be eligible for the electric sales exemption and would treat all EGUs similarly during system emergencies (*i.e.,* not penalize EGUs that are already operating to maintain grid reliability and avoiding the need to declare grid emergencies).

The Agency is including the system emergency concept in 40 CFR part 60, subpart TTTTa, along with a definition that clarifies how to determine generation during periods of system emergencies. The EPA agrees with commenters that the definition of system emergency should be clarified and that it should not be limited to EGUs not operating when the system emergency is declared. Based on information provided by entities with reliability expertise, the EPA has determined that a system emergency should be defined to include EEA levels 2 and 3. These EEA levels generally correspond to time-limited, well-defined, and relatively infrequent situations in which the system is experiencing an energy deficiency. During EEA level 2 and 3 events, all available generation is online and demand-response or other load management procedures are in effect, or firm load interruption is imminent or in progress. The EPA believes it is appropriate to exclude hours of operation during such events in order to ensure that EGUs are not impeded from maintaining or increasing their output as needed to respond to a declared energy emergency. Because these events tend to be short, infrequent, and well-defined, the EPA also believes any incremental GHG emissions associated with operations during these periods would be relatively limited.

The EPA has determined not to include EEA level 1 in the definition of a ''system emergency.'' The EPA's understanding is that EEA level 1 events often include situations in which an energy deficiency does not yet exist, and in which balancing authorities are preparing to pursue various options for either bringing additional resources online or managing load. The EPA also understands that EEA level 1 events tend to be more frequently declared, and longer in duration, than level 2 or 3 events. Based on this information, the EPA believes that including EEA level 1 events in the definition of a ''system emergency'' would carry a greater risk of increasing overall GHG emissions without making a meaningful contribution to supporting reliability. This approach balances the need to have operational flexibility when the grid may be strained to help ensure that all available generating sources are available for grid reliability, while balancing with important considerations about potential GHG emission tradeoffs. The EPA is also amending the definition in 40 CFR part 60, subpart TTTT, to be

[730] In 40 CFR part 60, subpart TTTT, electricity sold by units that are not called upon to operate due to a system emergency (*e.g.,* units already operating when the system emergency is declared) is counted toward the percentage electric sales threshold.

[731] See 80 FR 64612; October 23, 2015.

[732] Commenters noted that grid operators have slightly different terms for grid emergencies, but example descriptions include: EEA 1, all available generation online and non-firm wholesale sales curtailed; EEA 2, load management procedures in effect, all available generation units online, demand-response programs in effect; and EEA 3, firm load interruption is imminent or in progress.

consistent with the definition in 40 CFR part 60, subpart TTTTa.

Commenters also added that operation during system emergencies should be subject to alternate standards of performance (*e.g.,* owners/operators are not required to use the CCS system during system emergencies to increase power output). The EPA agrees with commenters that since system emergencies are defined and historically rare events, an alternate standard of performance should apply during these periods. Carbon capture systems require significant amounts of energy to operate. Allowing owners/operators of EGUs equipped with CCS systems to temporarily reduce the capture rate or cease capture will increase the electricity available to end users during system emergencies. In place of the applicable output-based emissions standard, the owner/operator of an intermediate or base load combustion turbine would be subject to a BSER based on the combustion of lower-emitting fuels during system emergencies.[733] The emissions and output would not be included when calculating the 12-operating month emissions rate. The EPA considered an alternate emissions standard based on efficient generation but rejected that for multiple reasons. First, since system emergencies are limited in nature the emissions calculation would include a limited number of hours and would not necessarily be representative of an achievable longer-term emissions rate. In addition, EGUs that are designed to operate with CCS will not necessarily operate as efficiently without the CCS system operating compared to a similar EGU without a CCS system. Therefore, the Agency is not able to determine a reasonable efficiency-based alternate emissions standard for periods of system emergencies. Due to both the costs and time associated with starting and stopping the CCS system, the Agency has determined it is unlikely that an owner/operator of an affected facility would use it where it is not needed. System emergencies have historically been relatively brief and any hours of operation outside of the system emergencies are included when determining the output-based emissions standard. During short-duration system emergencies, the costs associated with stopping and starting the CCS system could outweigh the increased revenue from the additional electric sales. In addition, the time associated with starting and stopping a CCS system would likely result in an EGU operating without the CCS system in operation during periods of non-system emergencies. This would require the owner/operator to overcontrol during other periods of operation to maintain emissions below the applicable standard of performance. Therefore, it is likely an owner/operator would unnecessarily adjust the operation of the CCS system during EEA levels 2 and 3.

In addition to these measures, DOE has authority pursuant to section 202(c) of the Federal Power Act to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including during events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements. Such orders may be issued for 90 days and may be extended in 90-day increments after consultation with the EPA. DOE has historically issued section 202(c) orders at the request of electric generators and grid operators such as RTOs in order to enable the supply of additional generation in times of expected emergency-related generation shortfalls.

c. Multi-Fuel-Fired Combustion Turbines

In 40 CFR part 60, subpart TTTT, multi-fuel-fired combustion turbines are subcategorized as EGUs that combust 10 percent or more of fuels not meeting the definition of natural gas on a 12-operating month rolling average basis. The BSER for this subcategory is the use of lower-emitting fuels with a corresponding heat input-based standard of performance of 120 to 160 lb CO_2/MMBtu, depending on the fuel, for newly constructed and reconstructed multi-fuel-fired stationary combustion turbines.[734] Lower-emitting fuels for these units include natural gas, ethylene, propane, naphtha, jet fuel kerosene, Nos. 1 and 2 fuel oils, biodiesel, and landfill gas. The definition of natural gas in 40 CFR part 60, subpart TTTT, includes fuel that maintains a gaseous state at ISO conditions, is composed of 70 percent by volume or more methane, and has a heating value of between 35 and 41 megajoules (MJ) per dry standard cubic meter (dscm) (950 and 1,100 Btu per dry standard cubic foot). Natural gas typically contains 95 percent methane and has a heating value of 1,050 Btu/lb.[735] A potential issue with the multi-fuel subcategory is that owners/operators of simple cycle turbines can elect to burn 10 percent non-natural gas fuels, such as Nos. 1 or 2 fuel oil, and thereby remain in that subcategory, regardless of their electric sales. As a result, they would remain subject to the less stringent standard that applies to multi-fuel-fired sources, the lower-emitting fuels standard. This could allow less efficient combustion turbine designs to operate as base load units without having to improve efficiency and could allow EGUs to avoid the need for efficient design or best operating and maintenance practices. These potential circumventions would result in higher GHG emissions.

To avoid these outcomes, the EPA proposed and is finalizing a decision not to include the multi-fuel subcategory for low, intermediate, and base load combustion turbines in 40 CFR part 60, subpart TTTTa. This means that new multi-fuel-fired turbines that commence construction or reconstruction after May 23, 2023, will fall within a particular subcategory depending on their level of electric sales. The EPA also proposed and is finalizing a decision that the performance standards for each subcategory be adjusted appropriately for multi-fuel-fired turbines to reflect the application of the BSER for the subcategories to turbines burning fuels with higher GHG emission rates than natural gas. To be consistent with the definition of lower-emitting fuels in the 2015 NSPS, the maximum allowable heat input-based emissions rate is 160 lb CO_2/MMBtu. For example, a standard of performance based on efficient generation would be 33 percent higher for a fuel oil-fired combustion turbine compared to a natural gas-fired combustion turbine. This assures that the BSER, in this case efficient generation, is applied, while at the same time accounting for the use of multiple fuels.

[733] For owners/operators of combustion turbines the lower emitting fuels requirement is defined to include fuels with an emissions rate of 160 lb CO_2/MMBtu or less. For owners/operators of steam generating units or IGCC facilities the EPA is requiring the use of the maximum amount of non-coal fuels available to the affected facility.

[734] Combustion turbines co-firing natural gas with other fuels must determine fuel-based site-specific standards at the end of each operating month. The site-specific standards depend on the amount of co-fired natural gas. 80 FR 64616 (October 23, 2015).

[735] Note that according to 40 CFR part 60, subpart TTTT, combustion turbines co-firing 25 percent hydrogen by volume could be subcategorized as multi-fuel-fired EGUs because the percent methane by volume could fall below 70 percent, the heating value could fall below 35 MJ/Sm^3, and 10 percent of the heat input could be coming from a fuel not meeting the definition of natural gas.

d. Rural Areas and Small Utility Distribution Systems

As part of the original proposal and during the Small Business Advocacy Review (SBAR) outreach the EPA solicited comment on creating a subcategory for rural electric cooperatives and small utility distribution systems (serving 50,000 customers or less). Commenters expressed concerns that a BSER based on either co-firing hydrogen or CCS may present an additional hardship on economically disadvantaged communities and on small entities, and that the EPA should evaluate potential increased energy costs, transmission upgrade costs, and infrastructure encroachment which may directly affect the disproportionately impacted communities. As described in section VIII.F, the BSER for new stationary combustion turbines does not include hydrogen co-firing and CCS qualifies as the BSER for base load combustion turbines on a nationwide basis. Therefore, the EPA has determined that a subcategory for rural cooperatives and/or small utility distribution systems is not appropriate.

F. Determination of the Best System of Emission Reduction (BSER) for New and Reconstructed Stationary Combustion Turbines

In this section, the EPA describes the technologies it proposed as the BSER for each of the subcategories of new and reconstructed combustion turbines that commence construction after May 23, 2023, as well as topics for which the Agency solicited comment. In the following section, the EPA describes the technologies it is determining are the final BSER for each of the three subcategories of affected combustion turbines and explains its basis for selecting those controls, and not others, as the final BSER. The controls that the EPA evaluated included combusting non-hydrogen lower-emitting fuels (*e.g.,* natural gas and distillate oil), using highly efficient generation, using CCS, and co-firing with low-GHG hydrogen.

For the low load subcategory, the EPA proposed the use of lower-emitting fuels as the BSER. This was consistent with the BSER and performance standards established in the 2015 NSPS for the non-base load subcategory as discussed earlier in section VIII.C.

For the intermediate load subcategory, the EPA proposed an approach under which the BSER was made up of two components: (1) highly efficient generation; and (2) co-firing 30 percent (by volume) low-GHG hydrogen. Each component of the BSER represented a different set of controls, and those controls formed the basis of corresponding standards of performance that applied in two phases. Specifically, the EPA proposed that affected facilities (*i.e.,* facilities that commence construction or reconstruction after May 23, 2023) could apply the first component of the BSER (*i.e.,* highly efficient generation) upon initial startup to meet the first phase of the standard of performance. Then, by 2032, the EPA proposed that affected facilities could apply the second component of the BSER (*i.e.,* co-firing 30 percent (by volume) low-GHG hydrogen) to meet a second and more stringent standard of performance. The EPA also solicited comment on whether the intermediate load subcategory should apply a third component of the BSER: co-firing 96 percent (by volume) low-GHG hydrogen by 2038. In addition, the EPA solicited comment on whether the low load subcategory should also apply the second component of BSER, co-firing 30 percent (by volume) low-GHG hydrogen, by 2032. The Agency proposed that these latter components of the BSER would continue to include the application of highly efficient generation.

For the base load subcategory, the EPA also proposed a multi-component BSER and multi-phase standard of performance. The EPA proposed that each new base load combustion turbine would be required to meet a phase-1 standard of performance based on the application of the first component of the BSER—highly efficient generation—upon initial startup of the affected source. For the second component of the BSER, the EPA proposed two potential technology pathways for base load combustion turbines with corresponding standards of performance. One proposed technology pathway was 90 percent CCS, which base load combustion turbines would install and begin to operate by 2035 to meet the phase-2 standard of performance. A second proposed technology pathway was co-firing low-GHG hydrogen, which base load combustion turbines would implement in two steps: (1) By co-firing 30 percent (by volume) low-GHG hydrogen to meet the phase-2 standard of performance by 2032, and (2) by co-firing 96 percent (by volume) low-GHG hydrogen to meet a phase 3 standard of performance by 2038. Throughout, the Agency proposed base load turbines, like intermediate load turbines, would remain subject to the first component of the BSER based on highly efficient generation.

The proposed approach reflected the EPA's view that the BSER components for the intermediate load and base load subcategories could achieve deeper reductions in GHG emissions by implementing CCS and co-firing low-GHG hydrogen. This proposed approach also recognized that building the infrastructure required to support widespread use of CCS and low-GHG hydrogen technologies in the power sector will take place on a multi-year time scale. Accordingly, new and reconstructed facilities would be aware of their need to ramp toward more stringent phases of the standards, which would reflect application of the more stringent controls in the BSER. This would occur either by co-firing a lower percentage (by volume) of low-GHG hydrogen by 2032 and a higher percentage (by volume) of low-GHG hydrogen by 2038, or with installation and use of CCS by 2035. The EPA also solicited comment on the potential for an earlier compliance date for the second phase.

For the base load subcategory, the EPA proposed two potential BSER pathways because the Agency believed there was more than one viable technology for these combustion turbines to significantly reduce their CO_2 emissions. The Agency also found value in receiving comments on, and potentially finalizing, both BSER pathways to enable project developers to elect how they would reduce their CO_2 emissions on timeframes that make sense for each BSER pathway.[736] The EPA solicited comment on whether the co-firing of low-GHG hydrogen should be considered a compliance pathway for sources to meet a single standard of performance based on the application of CCS rather than a separate BSER pathway. The EPA proposed that there would be earlier opportunities for units to begin co-firing lower amounts of low-GHG hydrogen than to install and begin operating 90 percent CCS systems. However, the Agency proposed that it would likely take longer for those units to increase their co-firing to significant quantities of low-GHG hydrogen. Therefore, in the proposal, the EPA presented the BSER pathways as separate subcategories and solicited comment on the option of finalizing a single standard of performance based on the application of CCS.

For the low load subcategory, the EPA proposed and is finalizing that the BSER is the use of lower-emitting fuels. For the intermediate load subcategory, the EPA proposed and is finalizing that the

[736] The EPA recognizes that standards of performance are technology neutral and that a standard based on application of CCS could be achieved by co-firing hydrogen.

BSER is highly efficient generating technology—simple cycle technology as well as operating and maintaining it efficiently.[737] The EPA is not finalizing a second component of the BSER or a phase-2 standard of performance for intermediate load combustion turbines at this time. For the base load subcategory, the EPA proposed and is finalizing that the first component of the BSER is highly efficient generating technology—combined cycle technology as well as operating and maintaining it efficiently. The EPA proposed and is finalizing a second component of the BSER or a phase-2 standard of performance for base load combustion turbines—efficient generation in combination with 90 percent CCS.

The EPA is not finalizing low-GHG hydrogen co-firing as the second component of the BSER for the intermediate load or base load combustion turbines at this time. (See section VIII.F.5.b for the EPA's explanation of this decision.) With respect to the CCS pathway for base load combustion turbines, the EPA is finalizing a second phase of the standards of performance that includes a single CCS BSER pathway, which includes the use of highly efficient generation and 90 percent CCS. Owners/operators of new and reconstructed base load combustion turbines will be required to meet the second phase standards of performance for 12-operating month rolling averages that begin on or after January 2032, that reflect application of both the phase-1 and phase-2 components of the BSER. Table 3 of this document summarizes the final BSER for combustion turbine EGUs that commence construction or reconstruction after May 23, 2023. The EPA is finalizing standards of performance based on those BSER for each subcategory, as discussed in section VIII.G.

TABLE 3—FINAL BSER FOR COMBUSTION TURBINE EGUS

Subcategory [1]	Fuel	1st Component BSER	2nd Component BSER
Low Load	All Fuels	lower-emitting fuels	N/A.
Intermediate Load	All Fuels	Highly Efficient Simple Cycle Generation.	N/A.
Base Load	All Fuels	Highly Efficient Combined Cycle Generation.	Highly Efficient Combined Cycle Generation Plus 90 Percent CCS Beginning in 2032.

[1] The low load subcategory is applicable to combustion turbines selling 20 percent or less of their potential electric output, the intermediate load subcategory is applicable to combustion turbines selling greater than 20 percent and less than or equal to 40 percent of their potential electric output, and the base load subcategory is applicable to combustion turbines selling greater than 40 percent of their potential electric output.

1. BSER for Low Load Subcategory

This section describes the BSER for the low load (*i.e.,* peaking) subcategory at this time, which is the use of lower-emitting fuels. The Agency proposed and is finalizing a determination that the use of lower-emitting fuels, which the EPA determined to be the BSER for the non-base load subcategory in the 2015 NSPS, is the BSER for this low load subcategory. As explained in section VIII.E.2.b, the EPA is narrowing the definition of the low load subcategory by lowering the electric sales threshold (as compared to the electric sales threshold for non-base load combustion turbines in the 2015 NSPS), so that combustion turbines with higher electric sales would be placed in the intermediate load subcategory and therefore be subject to a more stringent standard based on the more stringent BSER.

a. Background: The Non-Base Load Subcategory in the 2015 NSPS

The 2015 NSPS defined non-base load natural gas-fired EGUs as stationary combustion turbines that (1) burn more than 90 percent natural gas and (2) have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). These are calculated on 12-operating month and 3-calendar year rolling average bases. The EPA also determined in the 2015 NSPS that the BSER for newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines is the use of lower-emitting fuels. Id. at 64515. These lower-emitting fuels are primarily natural gas with a small allowance for distillate oil (*i.e.,* Nos. 1 and 2 fuel oils), which have been widely used in stationary combustion turbine EGUs for decades.

The EPA also determined in the 2015 NSPS that the standard of performance for sources in this subcategory is a heat input-based standard of 120 lb CO_2/MMBtu. The EPA established this clean-fuels BSER for this subcategory because of the variability in the operation in non-base load combustion turbines and the challenges involved in determining a uniform output-based standard that all new and reconstructed non-base load units could achieve.

Specifically, in the 2015 NSPS, the EPA recognized that a BSER for the non-base load subcategory based on the use of lower-emitting fuels results in limited GHG reductions, but further recognized that an output-based standard of performance could not reasonably be applied to the subcategory. The EPA explained that a combustion turbine operating at a low capacity factor could operate with multiple starts and stops, and that its emission rate would be highly dependent on how it was operated and not its design efficiency. Moreover, combustion turbines with low annual capacity factors typically operated differently from each other, and therefore had different emission rates. The EPA recognized that, as a result, at the time it would not be possible to determine a standard of performance that could reasonably apply to all combustion turbines in the subcategory. For that reason, the EPA further recognized, efficient design[738] and operation would not qualify as the BSER; rather, the BSER should be lower-emitting fuels and the associated standard of performance should be based on heat input. Since the 2015 NSPS, all newly constructed simple cycle turbines have been non-base load units and thus have become subject to this standard of performance.

[737] The EPA sometimes refers to highly efficient generating technology in combination with the best operating and maintenance practices as highly efficient generation. The affected sources must meet standards based on this efficient generating technology upon the effective date of the final rule.

[738] Important characteristics for minimizing emissions from low load combustion turbines include the ability to operate efficiently while operating at part load conditions and the ability to rapidly achieve maximum efficiency to minimize periods of operation at lower efficiencies. These characteristics do not necessarily always align with higher design efficiencies that are determined under steady-state full-load conditions.

b. BSER

Consistent with the rationale of the 2015 NSPS, the EPA proposed and is finalizing that the use of fuels with an emissions rate of less than 160 lb CO_2/MMBtu (*i.e.,* lower-emitting fuels) meets the BSER requirements for the low load subcategory at this time. Use of these fuels is technically feasible for combustion turbines. Natural gas comprises the majority of the heat input for simple cycle turbines and is the lowest cost fossil fuel. In the 2015 NSPS, the EPA determined that natural gas comprised 96 percent of the heat input for simple cycle turbines. See 80 FR 64616 (October 23, 2015). Therefore, a BSER based on the use of natural gas and/or distillate oil would have minimal, if any, costs to regulated entities. The use of lower-emitting fuels would not have any significant adverse energy requirements or non-air quality or environmental impacts, as the EPA determined in the 2015 NSPS. *Id.* at 64616. In addition, the use of fuels meeting this criterion would result in some emission reductions by limiting the use of fuels with higher carbon content, such as residual oil, as the EPA also explained in the 2015 NSPS. *Id.* Although the use of fuels meeting this criterion would not advance technology, in light of the other reasons described here, the EPA proposed and is finalizing that the use of natural gas, Nos. 1 and 2 fuel oils, and other fuels [739] currently specified in 40 CFR part 60, subpart TTTT, qualify as the BSER for new and reconstructed combustion turbine EGUs in the low load subcategory at this time. The EPA also proposed including low-GHG hydrogen on the list of fuels meeting the uniform fuels criteria in 40 CFR part 60, subpart TTTTa. The EPA is finalizing the inclusion of hydrogen, regardless of the production pathway, on the list of fuels meeting the uniform fuels criteria in 40 CFR part 60, subpart TTTTa.[740] The addition of hydrogen (and fuels derived from hydrogen) to 40 CFR part 60, subpart TTTTa, simplifies the recordkeeping and reporting requirements for low load combustion turbines that elect to burn hydrogen.

For the reasons discussed in the 2015 NSPS and noted above, the EPA did not propose that efficient design and operation qualify as the BSER for the low load subcategory. The emissions rate of a low load combustion turbine is highly dependent upon the way the specific combustion turbine is operated. For example, a combustion turbine with multiple startups and shutdowns and operation at part loads will have high emissions relative to if it were operated at steady-state high-load conditions. Important characteristics for reducing GHG emissions from low load combustion turbines are the ability to minimize emissions during periods of startup and shutdown and efficient operation at part loads and while changing loads. If the combustion turbine is frequently operated at part-load conditions with frequent starts and stops, a combustion turbine with a high design efficiency, which is determined at full-load steady-state conditions, would not necessarily emit at a lower GHG rate than a combustion turbine with a lower design efficiency. In addition, combustion turbines with higher design efficiencies have higher initial costs compared to combustion turbines with lower design efficiencies. Since the EPA does not have sufficient information at this time to determine emission reduction for the subcategory it is not possible to determine the cost effectiveness of a BSER based on high efficiency simple cycle turbines.[741]

The EPA solicited comment on whether, and the extent to which, high-efficiency designs also operate more efficiently at part loads and can start more quickly and reach the desired load more rapidly than combustion turbines with less efficient design efficiencies. In addition, the EPA solicited comment on the cost premium of high-efficiency simple cycle turbines. To the extent the Agency received additional relevant information, the EPA was considering promulgating design standard requirements pursuant to CAA section 111(h). However, the EPA did not receive comments that changed the proposal conclusions.

The EPA did not propose the use of CCS or hydrogen co-firing as the BSER (or as a component of the BSER) for low load combustion turbines. The EPA did not propose that CCS is the BSER for simple cycle turbines based on the Agency's assessment that currently available post-combustion amine-based carbon capture systems require that the exhaust from a combustion turbine be cooled prior to entering the carbon capture equipment. The most energy efficient way to cool the exhaust gas is to use a HRSG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit. For this reason and due to the high costs of CCS for low load combustion turbines, the Agency did not propose and is not finalizing a determination that CCS qualifies as the BSER for this subcategory of sources.

The EPA did not propose low-GHG hydrogen co-firing as the BSER for low load combustion turbines because not all new combustion turbines can necessarily co-fire higher percentages of hydrogen, there are potential infrastructure issues specific to low load combustion turbines, and at the relatively infrequent levels of utilization that characterize the low load subcategory, a low-GHG hydrogen co-firing BSER would not necessarily result in cost-effective GHG reductions for all low load combustion turbines. As discussed later in this section, the Agency is not determining that low-GHG hydrogen co-firing qualifies as the BSER for combustion turbines. In future rulemaking the Agency could further evaluate the costs and emissions performance of other technologies to reduce emissions from low-load units to determine if other technologies qualify as the BSER.

2. BSER for Intermediate Load Subcategory

This section describes the BSER for new and reconstructed combustion turbines in the intermediate load subcategory. For combustion turbines in the intermediate load subcategory, the BSER is the use of high-efficiency simple cycle turbine technology in combination with the best operating and maintenance practices.

a. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the BSER for intermediate load combustion turbines because, as described earlier in this section, it would achieve few GHG emission reductions compared to highly efficient generation.

b. Highly Efficient Generation

This section includes a discussion of the various highly efficient generation technologies used by owners/operators of combustion turbines. The appropriate technology depends on how the combustion turbine is operated, and the EPA has determined it does not have sufficient information to determine an appropriate output-based emissions standard for low load combustion turbines. At higher capacity factors, emission rates for simple cycle combustion turbines are more consistent, and the EPA has sufficient

[739] The BSER for multi-fuel-fired combustion turbines subject to 40 CFR part 60, subpart TTTT, is also the use of fuels with an emissions rate of 160 lb CO_2/MMBtu or less. The use of these fuels will demonstrate compliance with the low load subcategory.

[740] The EPA is not finalizing a definition of low-GHG hydrogen.

[741] The cost effectiveness calculation is highly dependent upon assumptions concerning the increase in capital costs, the decrease in heat rate, and the price of natural gas.

information to determine a BSER other than lower-emitting fuels.

The use of highly efficient generating technology in combination with the best operating and maintenance practices has been demonstrated by multiple facilities for decades. Notably, over time, as technologies have improved, what is considered highly efficient has changed as well. Highly efficient generating technology is available and offered by multiple vendors for both simple cycle and combined cycle turbines. Both types of combustion turbines can also employ best operating and maintenance practices, which include routine operating and maintenance practices that minimize fuel use.

For simple cycle turbines, manufacturers continue to improve the efficiency by increasing firing temperature, increasing pressure ratios, using intercooling on the air compressor, and adopting other measures. These improved designs allow for improved operating efficiencies and reduced emission rates. Design efficiencies of simple cycle turbines range from 33 to 40 percent. Best operating practices for simple cycle turbines include proper maintenance of the combustion turbine flow path components and the use of inlet air cooling to reduce efficiency losses during periods of high ambient temperatures.

For combined cycle turbines, high-efficiency technology uses a highly efficient combustion turbine engine matched with a high-efficiency HRSG. The most efficient combined cycle EGUs use HRSG with three different steam pressures and incorporate a steam reheat cycle to maximize the efficiency of the Rankine cycle. It is not necessarily practical for owners/operators of combined cycle facilities using a turbine engine with an exhaust temperature below 593 °C or a steam turbine engine smaller than 60 MW to incorporate a steam reheat cycle. Smaller combustion turbine engines, less than those rated at approximately 2,000 MMBtu/h, tend to have lower exhaust temperatures and are paired with steam turbines of 60 MW or less. These smaller combined cycle units are limited to using a HRSG with three different steam pressures, but without a reheat cycle. This increases the heat rate of the combined cycle unit by approximately 2 percent. High efficiency also includes, but is not limited to, the use of the most efficient steam turbine and minimizing energy losses using insulation and blowdown heat recovery. Best operating and maintenance practices include, but are not limited to, minimizing steam leaks, minimizing air infiltration, and cleaning and maintaining heat transfer surfaces.

A potential drawback of combined cycle turbines with the highest design efficiencies is that the facility is relatively complicated and startup times can be relatively long. Combustion turbine manufacturers have invested in fast-start technologies that reduce startup times and improve overall efficiencies. According to the NETL Baseline Flexible Operation Report, while the design efficiencies are the same, the capital costs of fast-start combined cycle turbines are 1.6 percent higher than a comparable conventional start combined cycle facility.[742] The additional costs include design parameters that significantly reduce start times. However, fast-start combined cycle turbines are still significantly less flexible than simple cycle turbines and generally do not serve the same role. The startup time to full load from a hot start takes a simple cycle turbine 5 to 8 minutes, while a combined cycle turbines ranges from 30 minutes for a fast-start combined cycle turbine to 90 minutes for a conventional start combined cycle turbine. The startup time to full load from a cold start takes a simple cycle turbine 10 minutes, while a combined cycle turbines ranges from 120 minutes for a fast-start combined cycle turbine to 250 minutes for a conventional start combined cycle turbine. In addition, fast-start combined cycle turbines require the use of an auxiliary boiler during warm and cold starts.[743] In addition, minimum run times for simple cycle aeroderivative engines and combined cycle EGUs equal one minute and 120 minutes, respectively. Minimum downtime for the same group is five minutes and 60 minutes, respectively. Finally, simple cycle aeroderivative turbines have no limit to the number of starts per year. Combined cycle EGUs are limited in the number of starts, and additional maintenance costs will occur if the hours/start ratio drops below 25. The model combined cycle turbines in the NETL Baseline Flexible Operation Report use a HRSG with three different steam pressures and a reheat cycle. While the use of this type of HRSG increases design efficiencies at steady state conditions, it increases the capital costs and decreases the flexibility (*e.g.,* longer start times) of the combined cycle turbine. While less common, combined cycle turbines can be designed with a relatively simple HRSG that produces either a single or two pressures of steam without a reheat cycle. While design efficiencies are lower, the combined cycle turbines are more flexible and have the potential to operate similar to at least a portion of the simple cycle turbines in the intermediate load subcategory and provide the same value to the grid.

The EPA solicited comment on whether additional technologies for new simple and combined cycle EGUs that could reduce emissions beyond what is currently being achieved by the best performing EGUs should be included in the BSER. Specifically, the EPA sought comment on whether pressure gain combustion should be incorporated into a standard of performance based on an efficient generation BSER for both simple and combined cycle turbines. In addition, the EPA sought comment on whether the HRSG for combined cycle turbines should be designed to utilize supercritical steam conditions or to utilize supercritical CO_2 as the working fluid instead of water; whether useful thermal output could be recovered from a compressor intercooler and boiler blowdown; and whether fuel preheating should be implemented. Commenters generally noted that these technologies are promising, but that because the EPA did not sufficiently evaluate the BSER criteria in the proposal and none of these technologies should be incorporated as part of the BSER. The EPA continues to believe these technologies are promising, but the Agency is not including them as part of the BSER at this time.

The EPA also solicited comment on whether the use of steam injection is applicable to intermediate load combustion turbines. Steam injection is the use of a relatively simple and low-cost HRSG to produce steam, but instead of recovering the energy by expanding the steam through a steam turbine, the steam is injected into the compressor and/or through the fuel nozzles directly into the combustion chamber and the energy is extracted by the combustion turbine engine.[744] Advantages of steam injection include improved efficiency and increased output of the combustion turbine as well as reduced NO_X emissions. Combustion turbines using steam

[742] "Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation." DOE/NETL–2023/3855. May 5, 2023.

[743] Fast start combined cycle turbine do not use an auxiliary boiler during hot starts and conventional start combined cycle turbine do not have auxiliary boilers.

[744] A steam injected combustion turbine would be considered a combined cycle combustion turbine (for NSPS purposes) because energy from the turbine engine exhaust is recovered in a HRSG and that energy is used to generate additional electricity.

injection have characteristics in-between simple cycle and combined cycle combustion turbines. They are more efficient, but more complex and have higher capital costs than simple cycle combustion turbines without steam injection. Conversely, compared to combined cycle EGUs, simple cycle combustion turbines using steam injection are simpler, have shorter construction times, and have lower capital costs, but have lower efficiencies.[745] [746] Combustion turbines using steam injection can start quickly, have good part-load performance, and can respond to rapid changes in demand, making the technology a potential solution for reducing GHG emissions from intermediate load combustion turbines. A potential drawback of steam injection is that the additional pressure drop across the HRSG can reduce the efficiency of the combustion turbine when the facility is running without the steam injection operating.

The EPA is aware of a limited number of combustion turbines that are using steam injection that have maintained 12-operating month emission rates of less than 1,000 lb CO_2/MWh-gross. Commenters stated that steam injection does not qualify as the BSER because it has not been adequately demonstrated and the EPA did not include sufficient analysis of the technology in the proposal to determine it as the BSER for intermediate load combustion turbines. The EPA continues to believe the technology is promising and it may be used to comply with the standard of performance, but the Agency is not determining that it is the BSER for intermediate load combustion turbines at this time. In a potential future rulemaking, the Agency could further evaluate the costs and emissions performance of steam injection to determine if the technology qualifies as the BSER.

i. Adequately Demonstrated

The EPA proposed and is finalizing that highly efficient simple cycle designs are adequately demonstrated because highly efficient simple cycle turbines have been demonstrated by multiple facilities for decades, the efficiency improvements of the most efficient designs are incremental in nature and do not change in any significant way how the combustion turbine is operated or maintained, and the levels of efficiency that the EPA is proposing have been achieved by many recently constructed combustion turbines. Therefore, efficient generation technology described in this BSER is commercially available and the standards of performance are achievable.

ii. Costs

In general, advanced generation technologies enhance operational efficiency compared to lower efficiency designs. Such technologies present little incremental capital cost compared to other types of technologies that may be considered for new and reconstructed sources. In addition, more efficient designs have lower fuel costs, which offsets at least a portion of the increase in capital costs.

For the intermediate load subcategory, the EPA considers that the costs of high-efficiency simple cycle combustion turbines are reasonable. As described in the subcategory section, the cost of combustion turbine engines is dependent upon many factors, but the EPA estimates that that the capital cost of a high-efficiency simple cycle turbine is 10 percent more than a comparable lower efficiency simple cycle turbine. Assuming all other costs are the same and that the high-efficiency simple cycle turbine uses 8 percent less fuel, high-efficiency simple cycle combustion turbines have a lower LCOE compared to standard efficiency simple cycle combustion turbines at a 12-operating month capacity factor of approximately 31 percent. At a 20 percent and 15 percent capacity factors, the compliance costs are $1.5/MWh and $35/metric ton and $3.0/MWh and $69/metric ton, respectively. The EPA has determined that the incremental costs the use of high efficiency simple cycle turbines as the BSER for intermediate load combustion turbines is reasonable. The EPA notes that the approach the Agency used to estimate these costs have a relatively high degree of uncertainty and are likely high given the common use of high efficiency simple cycle turbines without a regulatory driver.

The EPA considered but is not finalizing combined cycle unit design for combustion turbines as the BSER for the intermediate load subcategory because it is unclear if combined cycle turbines could serve the same role as intermediate load simple cycle turbines as a whole. Specifically, the EPA does not have sufficient information to determine that an intermediate load combined cycle turbine can start and stop with enough flexibility to provide the same level of grid support as intermediate load simple cycle turbines as a whole. In addition, the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Intermediate load combustion turbines start and stop so frequently that there would often not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

Some commenters agreed with the proposed rationale of the EPA, and other commenters disagreed and said that combined cycle turbine technology is cost effective and lower-emitting than simple cycle turbine technology and therefore qualifies as the BSER for intermediate load combustion turbines. Commenters supporting combined cycle technology as the BSER submitted cost information that indicated that combined cycle EGUs have lower capital costs and LCOE than simple cycle turbines. However, the commenters compared capital costs of larger combined cycle turbines to smaller simple cycle turbines and did not account for economies of scale. The EPA has concluded that the appropriate cost comparison is for combustion turbines with the same rated net output.[747] Comparing the costs of different size EGUs is not appropriate because these EGUs provide different grid services. In addition, the commenters did not account for startup costs and the time required for a steam turbine to begin operating when determining the LCOE.

The EPA considered the operation of simple cycle turbine to determine the potential for simple cycle turbine to add a HRSG while continuing to operate in the same manner, providing the same grid services, as current simple cycle turbines. As noted previously, aeroderivative simple cycle turbines have shorter run times per start than frame type simple cycle turbines at the same capacity factor. At an annual capacity factor of 20 percent, the median run time per start for aeroderivative and frame simple cycle turbines is 12 and 16 hours respectively. At an annual capacity factor of 30 percent, the average run times per start increase to 17 and 26 hours for aeroderivative and frame turbines respectively. The higher operating times of frame type simple cycle turbines,

[745] Bahrami, S., *et al.* (2015). *Performance Comparison between Steam Injected Gas Turbine and Combined Cycle during Frequency Drops.* Energies 2015, Volume 8. *https://doi.org/10.3390/en8087582.*

[746] Mitsubishi Power. *Smart-AHAT (Advanced Humid Air Turbine). https://power.mhi.com/products/gasturbines/technology/smart-ahat.*

[747] The costing approach used by the EPA compares a combined cycle turbine using a smaller turbine engine plus a steam turbine to match the output from a simple cycle turbine.

along with the larger size of frame type turbines, indicate that combined cycle technology could be applicable to at least a portion of intermediate load combustion turbines. In future rulemakings addressing GHGs from new as well as existing combustion turbines, the EPA intends to further evaluate the costs and potential emission reductions of the use of faster starting and lower cost HRSG technology for intermediate load combustion turbines to determine if the technology does in fact qualify as the BSER.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Use of highly efficient generation reduces all non-air quality health and environmental impacts and energy requirements assuming it displaces less efficient or higher-emitting generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output; and, as a result, emissions are reduced for all pollutants. The use of highly efficient combustion turbines, compared to the use of less efficient combustion turbines, reduces all pollutants.[748] By the same token, because improved efficiency allows for more electricity generation from the same amount of fuel, it will not have any adverse effects on energy requirements.

Designating highly efficient generation as part of the BSER for new and reconstructed intermediate load combustion turbines will not have significant impacts on the nationwide supply of electricity, electricity prices, or the structure of the electric power sector. On a nationwide basis, the additional costs of the use of highly efficient generation will be small because the technology does not add significant costs and at least some of those costs are offset by reduced fuel costs. In addition, at least some of these new combustion turbines would be expected to incorporate highly efficient generation technology in any event.

iv. Extent of Reductions in CO_2 Emissions

The EPA estimated the potential emission reductions associated with a standard that reflects the application of highly efficient generation as BSER for the intermediate load subcategory. As discussed in section VIII.G.1, the EPA determined that the standards of performance reflecting this BSER are 1,170 lb CO_2/MWh-gross for intermediate load combustion turbines.

Between 2015 and 2022, 113 simple cycle turbines, an average of 16 per year, commenced operation. Of these, 112 reported 12-operating month capacity factors. The EPA estimates that 23 simple cycle turbines operated at 12-operating month capacity factors greater than 20 percent and potentially would be considered intermediate combustion turbines. To estimate reductions, the EPA assumed that the number of simple cycle turbines constructed between 2015 and 2022 and the operation of those combustion turbines would continue on an annual basis.[749] For each simple cycle turbine that operated at a capacity greater than 20 percent, the EPA determined the percent reduction in emissions, based on the maximum 12-operating months intermediate load emission rate, that would be required to comply with the final NSPS for intermediate load turbines. The EPA then applied that same percent reduction in emissions to the average operating capacity factor to determine the emission reductions from the NSPS. Using this approach, the EPA estimates that the intermediate load standard will impact approximately a quarter of new simple cycle turbines. The EPA divided the total amount of calculated reductions for intermediate load simple cycle turbines built between 2015 and 2022 and divided that value by 7 (the number of years evaluated) to get estimated annual reductions. This approach results in annual reductions of 31,000 tons of CO_2 as well as 8 tons of NO_X. The emission reductions are projected to result primarily from building additional higher efficiency aeroderivative simple cycle turbines instead of less efficient frame simple cycle turbines. The reduced emissions come from relatively small reductions in the emission rates of the intermediate load aeroderivative simple cycle turbines. This is a snapshot of projected emission reductions from applying the NSPS retroactively to 2022. If more intermediate load simple cycle turbines are built in the future, the emission reductions would be higher than this estimate. Conversely, if fewer intermediate load simple cycles are built, the emission reductions would be lower than the EPA's estimate.

Importantly, the ''highly efficient generation'' which the EPA has determined to be the BSER for new and reconstructed intermediate load combustion turbines and to be the first component BSER for base load stationary combustions, is not the same as the ''heat rate improvements'' (HRI, or ''efficiency improvements'') that the EPA determined to be the BSER for existing coal-fired steam generating EGUs in the ACE Rule. As noted earlier in this document, the EPA has concluded that the suite of HRI in the ACE Rule is not an appropriate BSER for existing coal-fired EGUs. In the EPA's technical judgment, the suite of HRI set forth in the ACE Rule would provide negligible CO_2 reductions at best and, in many cases, may increase CO_2 emissions because of the ''rebound effect,'' which is explained and discussed in section VII.D.4.a.iii of this preamble. Increased CO_2 emissions from the ''rebound effect'' can occur when a coal-fired EGU improves its efficiency (heat rate), which can move the unit up on the dispatch order—resulting in an EGU operating for more hours during the year than it would have without having done the efficiency improvements. There is also the possibility that a more efficient coal-fired EGU could displace a lower emitting generating source, further exacerbating the problem.

Conversely, including ''highly efficient generation'' as a component of the BSER for new and reconstructed does not create this risk of displacing a lower-emitting generating source. A new highly efficient stationary combustion turbine may be dispatched more than it would have been if it were not built as a highly efficient turbine, but it is more likely to displace an existing coal-fired EGU or a less efficient existing stationary combustion turbine. It would be unlikely to displace a renewable generating source.

For base load stationary combustion turbines, ''highly efficient generation'' is the first component of the BSER—with 90 percent capture CCS being the second component of the BSER. This is very similar to the Agency's BSER determination for the NSPS for new fossil fuel-fired steam generating units. In that final rule, the EPA established standards of performance for newly constructed fossil fuel-fired steam generating units based on the performance of a new highly efficient supercritical pulverized coal (SCPC) EGU implementing post-combustion partial CCS technology, which the EPA determined to be the BSER for these sources.[750]

[748] The emission reduction comparison is done assuming the same level of operation. Overall emission impacts would be different if the more efficient combustion turbine operates more then the baseline.

[749] This is a simplified assumption that does not take into account changing market conditions that could change the makeup and operation of new combustion turbines.

[750] See 80 FR 64510 (October 23, 2015).

v. Promotion of the Development and Implementation of Technology

The EPA also considered the potential impact of selecting highly efficient simple cycle generation technology as the BSER for the intermediate load subcategory in promoting the development and implementation of improved control technology. New highly efficient simple cycle turbines are more efficient than the average new simple cycle turbine and a standard based on the performance of the most efficient, best performing simple cycle turbine will promote penetration of the most efficient units throughout the industry. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the BSER.

c. Low-GHG Hydrogen and CCS

The EPA did not propose and is not finalizing either CCS or co-firing low-GHG hydrogen as the first component of the BSER for intermediate load combustion turbines, for the reasons given in sections VIII.F.4.c.iii (CCS) and VIII.F.5 (low-GHG hydrogen).

d. Summary of BSER Determinations

The EPA is finalizing that highly efficient generating technology in combination with the best operating and maintenance practices is the BSER for intermediate load combustion turbines. Specifically, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices is the BSER for intermediate load combustion turbines.

Highly efficient generation qualifies the BSER because it is adequately demonstrated, it can be implemented at reasonable cost, it achieves emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements. The fact that it promotes greater use of advanced technology provides additional support; however, the EPA considers highly efficient generation to the BSER for intermediate load combustion turbines even without taking this factor into account.

3. BSER for Base Load Subcategory—First Component

This section describes the first component of the BSER for newly constructed and reconstructed combustion turbines in the base load subcategory. For combustion turbines in the base load subcategory, the first component of the BSER is the use of high-efficiency combined cycle technology in combination with the best operating and maintenance practices.

a. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the BSER for base load combustion turbines because, as described earlier in this section, it would achieve few GHG emission reductions compared to highly efficient generation.

b. Highly Efficient Generation

i. Adequately Demonstrated

The EPA proposed and is finalizing that highly efficient combined cycle designs are adequately demonstrated because highly efficient combined cycle EGUs have been demonstrated by multiple facilities for decades, and the efficiency improvements of the most efficient designs are incremental in nature and do not change in any significant way how the combustion turbine is operated or maintained. Due to the differences in HRSG efficiencies for smaller combined cycle turbines, the EPA proposed and is finalizing less stringent standards of performance for smaller base load turbines with base load ratings of less than 2,000 MMBtu/h relative to those for larger base load turbines. The levels of efficiency that the EPA is proposing have been achieved by many recently constructed combustion turbines. Therefore, efficient generation technology described in this BSER is commercially available and the standards of performance are achievable.

ii. Costs

For the base load subcategory, the EPA considers the cost of high-efficiency combined cycle EGUs to be reasonable. While the capital costs of a higher efficiency combined cycle EGUs are 1.9 percent higher than standard efficiency combined cycle EGUs, fuel use is 2.6 percent lower.[751] The reduction in fuel costs fully offset the capital costs at capacity factors of 40 percent or greater over the expected 30-year life of the facility. Therefore, a BSER based on the use of high-efficiency combined cycle combustion turbines for base load combustion turbines would have minimal, if any, overall compliance costs since the capital costs would be recovered through reduced fuel costs over the expected 30-year life of the facility.

[751] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022), *https://www.osti.gov/servlets/purl/1893822.*

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Use of highly efficient generation reduces all non-air quality health and environmental impacts and energy requirements as compared to use of less efficient generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output; and, as a result, emissions are reduced for all pollutants. The use of highly efficient combustion turbines, compared to the use of less efficient combustion turbines, reduces all pollutants. By the same token, because improved efficiency allows for more electricity generation from the same amount of fuel, it will not have any adverse effects on energy requirements.

Designating highly efficient generation as part of the BSER for new and reconstructed base load combustion turbines will not have significant impacts on the nationwide supply of electricity, electricity prices, or the structure of the electric power sector. On a nationwide basis, the additional costs of the use of highly efficient generation will be small because the technology does not add significant costs and at least some of those costs are offset by reduced fuel costs. In addition, at least some of these new combustion turbines would be expected to incorporate highly efficient generation technology in any event.

iv. Extent of Reductions in CO_2 Emissions

The EPA used a similar approach to estimating emission reductions for base load combustion turbines as intermediate load combustion turbines, except the Agency reviewed recently constructed combined cycle EGUs. As discussed in section VIII.G.1, the EPA determined that the standard of performance reflecting this BSER is 800 lb CO_2/MWh-gross for base load combustion turbines. The Agency assumed all new combined cycle turbines would be impacted by the base load emissions standard. Between the beginning of 2015 and the beginning of 2022, 129 combined cycle turbines, an average of 18 per year, commenced operation. Of those combined cycle turbines, 107 had 12-operating month emissions data. For each of these 107 combined cycle turbines that had a maximum 12-operating month emissions rate greater than 800 lb CO_2/MWh-gross, the EPA determined the reductions that would occur assuming the combined cycle turbine reduced its emissions rate to 800 lb CO_2/MWh-gross and continued to operate at its average capacity factor. The EPA summed the results and divided by 8 (the number of years evaluated) to estimate the annual GHG reductions that will result from this final rule. The EPA estimates that the base load standard will result in annual reductions of 313,000 tons of CO_2 as well as 23 tons of NO_X. The reductions increase each year and in year 3 the annual reductions would be 939,000 tons of CO_2 and 69 tons of NO_X.

v. Promotion of the Development and Implementation of Technology

The EPA also considered the potential impact of selecting highly efficient generation technology as the BSER in promoting the development and implementation of improved control technology. The highly efficient combustion turbines are more efficient and lower emitting than the average new combustion turbine generation technology. Determining that highly efficient turbines are a component of the BSER will advance penetration of the best performing combustion turbines throughout the industry—and will incentivize manufacturers to offer improved turbines that meet the final standard of performance associated with application of the BSER. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the BSER.

c. Low-GHG Hydrogen and CCS

The EPA did not propose and is not finalizing either CCS or co-firing low-GHG hydrogen as the first component of the BSER for base load combustion turbines, for the reasons given in sections VIII.F.4.c.iii (CCS) and VIII.F.5 (low-GHG hydrogen).

d. Summary of BSER Determinations

The EPA is finalizing that highly efficient generating technology in combination with the best operating and maintenance practices is the BSER for first component of the BSER for base load combustion turbines. The phase-1 standards of performance are based on the application of that technology. Specifically, the use of highly efficient combined cycle technology in combination with best operating and maintenance practices is the first component of the BSER for base load combustion turbines.

Highly efficient generation qualifies as the BSER because it is adequately demonstrated, it can be implemented at reasonable cost, it achieves emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements. The fact that it promotes greater use of advanced technology provides additional support; however, the EPA considers highly efficient generation to be a component of the BSER for base load combustion turbines even without taking this factor into account.

4. BSER for Base Load Subcategory—Second Component

a. Authority To Promulgate a Multi-Part BSER and Standard of Performance

The EPA's approach of promulgating standards of performance that apply in multiple phases, based on determining the BSER to be a set of controls with multiple components, is consistent with CAA section 111(b). That provision authorizes the EPA to promulgate "standards of performance," CAA section 111(b)(1)(B), defined, in the singular, as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER]." CAA section 111(a)(1). CAA section 111(b)(1)(B) further provides, "[s]tandards of performance . . . shall become effective upon promulgation." In this rulemaking, the EPA is determining that the BSER is a set of controls that, depending on the subcategory, include highly efficient generation plus use of CCS. The EPA is determining that affected sources can apply the first component of the BSER—highly efficient generation—by the effective date of the final rule and can apply both the first and second components of the BSER—highly efficient generation in combination with 90 percent CCS—in 2032.

Accordingly, the EPA is finalizing standards of performance that reflect the application of this multi-component BSER and that take the form of standards of performance that affected sources must comply with in two phases. This multi-phase standard of performance "become[s] effective upon promulgation." CAA section 111(b)(1)(B). That is, upon promulgation, affected sources become legally subject to the multi-phase standard of performance and must comply with it by its terms. Specifically, affected sources must comply with the first phase standards, which are based on the application of the first component of the BSER, upon initial startup of the facility. They must comply with the second phase standards, which are based on the application of both the first and second components of the BSER, beginning January 2032.

D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the "adequately demonstrated" criterion—even if the controls require some amount of "lead time," which the court has defined as "the time in which the technology will have to be available." [752] The caselaw's interpretation of "adequately demonstrated" to accommodate lead time accords with common sense and the practical experience of certain types of controls, discussed below. Consistent with this caselaw, the phased implementation of the standards of performance in this rule ensures that facilities have sufficient lead time for planning and implementation of the use of CCS-based controls necessary to comply with the second phase of the standards, and thereby ensures that the standards are achievable. For further discussion of this point, see section V.C.2.b.iii.

The EPA has promulgated several prior rulemakings under CAA section 111(b) that have similarly provided the regulated sector with lead time to accommodate the availability of technology, which also serve as precedent for the two-phase implementation approach proposed in this rule. See 81 FR 59332 (August 29, 2016) (establishing standards for municipal solid waste landfills with 30-month compliance timeframe for installation of control device, with interim milestones); 80 FR 13672, 13676 (March 16, 2015) (establishing stepped compliance approach to wood heaters standards to permit manufacturers lead time to develop, test, field evaluate and certify current technologies to meet Step 2 emission limits); 78 FR 58416, 58420 (September 23, 2013) (establishing multi-phased compliance deadlines for revised storage vessel standards to permit sufficient time for production of necessary supply of control devices and for trained personnel to perform installation); 77 FR 56422, 56450 (September 12, 2012) (establishing standards for petroleum refineries, with 3-year compliance timeframe for installation of control devices); 71 FR 39154, 39158 (July 11, 2006) (establishing standards for stationary compression ignition internal combustion engines, with 2- to 3-year compliance timeframe and up to 6 years for certain emergency fire pump engines); 70 FR 28606, 28617 (March 18, 2005) (establishing two-phase caps for

[752] See *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

mercury standards of performance from new and existing coal-fired electric utility steam generating units based on timeframe when additional control technologies were projected to be adequately demonstrated).[753] *Cf.* 80 FR 64662, 64743 (October 23, 2015) (establishing interim compliance period to phase in final power sector GHG standards to allow time for planning and investment necessary for implementation activities).[754] In each action, the standards and compliance timelines were effective upon the final rule, with affected facilities required to comply consistent with the phased compliance deadline specified in each action.

It should be noted that the multi-phased implementation of the standards of performance that the EPA is finalizing in this rule, like the delayed or multi-phased standards in prior rules just described, is distinct from the promulgation of revised standards of performance under the 8-year review provision of CAA section 111(b)(1)(B). As discussed in section VIII.F, the EPA has determined that the proposed BSER—highly efficient generation and use of CCS—meet all of the statutory criteria and are adequately demonstrated for the compliance timeframes being finalized. Thus, the second phase of the standard of performance applies to affected facilities that commence construction after May 23, 2023 (the date of the proposal). In contrast, when the EPA later reviews and (if appropriate) revises a standard of performance under the 8-year review provision, then affected sources that commence construction after the date of that proposal of the revised standard of performance will be subject to that standard, but not sources that commenced construction earlier.

Similarly, the multi-phased implementation of the standard of performance that the EPA is including in this rule is also distinct from the promulgation of emission guidelines for existing sources under CAA section 111(d). Emission guidelines only apply to existing sources, which are defined in CAA section 111(a)(6) as ''any stationary source other than a new source.'' Because new sources are defined relative to the proposal of standards pursuant to CAA section 111(b)(1)(B), standards of performance adopted pursuant to emission guidelines will only apply to sources constructed before May 23, 2023, the date of the proposed standards of performance for new sources.

b. BSER for the Intermediate Load Subcategory—Second Component

The EPA proposed that the second component of the BSER for intermediate load combustion turbines was co-firing 30 percent low-GHG hydrogen in 2032. As discussed in section VIII.F.5.b, the EPA is not determining that low-GHG hydrogen qualifies as the BSER at this time. Therefore, the Agency is not finalizing a second component of the BSER for intermediate load combustion turbines.

c. BSER for Base Load Subcategory—Second Component

i. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the second component of the BSER for intermediate or base load combustion turbines because it would achieve few emission reductions, compared to highly efficient generation without or in combination with the use of CCS.

ii. Highly Efficient Generation

For the reasons described above, the EPA is determining that highly efficient generation in combination with best operating and maintenance practices continues to be a component of the BSER that is reflected in the second phase of the standards of performance for base load combustion turbine EGUs. Highly efficient generation reduces fuel use and, therefore, the amount of CO_2 that must be captured by a CCS system. Since a highly efficient turbine system would produce less flue gas that would need to be treated (compared to a less efficient turbine system), physically smaller carbon capture equipment may be used—potentially reducing capital, fixed, and operating costs.

iii. Hydrogen Co-Firing

The EPA proposed a pathway for the second component of the BSER for base load combustion turbines of co-firing 30 percent low-GHG hydrogen in 2032 increasing to 96 percent low-GHG hydrogen co-firing in 2038. As discussed in section VIII.F.5.b of this preamble, the EPA is not finalizing a determination that low-GHG hydrogen co-firing qualifies as the BSER. Therefore, the Agency is not finalizing a second component low-GHG hydrogen co-firing pathway of the BSER for base load combustion turbines. As the EPA's standard of performance is technology neutral, however, affected sources may comply with it by co-firing hydrogen.

iv. CCS

(A) Overview

In this section of the preamble, the EPA explains its rationale for finalizing that CCS with 90 percent capture is a component of the BSER for new base load combustion turbines. CCS is a control technology that can be applied at the stack of a combustion turbine EGU, achieves substantial reductions in emissions and can capture and permanently sequester at least 90 percent of the CO_2 emitted by combustion turbines. The technology is adequately demonstrated, given that it has been operated on a large scale and is widely applicable to these sources, and there are vast sequestration opportunities across the continental U.S. Additionally, the costs for CCS are reasonable in light of recent technology cost declines and policies including the tax credit under IRC section 45Q. Moreover, the non-air quality health and environmental impacts of CCS can be mitigated, and the energy requirements of CCS are not unreasonably adverse. The EPA's weighing of these factors together provides the basis for finalizing 90 percent capture CCS as a component of BSER for these sources. In addition, this BSER determination aligns with the caselaw, discussed in section V.C.2.h of the preamble, stating that CAA section 111 encourages continued advancement in pollution control technology.

This section incorporates by reference the parts of section VII.C.1.a. of this preamble that discuss the many aspects of CCS that are common to both steam generating units and to new combustion turbines. This includes the discussion of simultaneous demonstration of CO_2 capture, transport, and sequestration discussed at VII.C.1.a.i(A); the discussion of CO_2 capture technology used at coal-fired steam generating units at VII.C.1.a.i(B) (the Agency explains below why that record is also relevant to our BSER analysis for new combustion turbines); the discussion of CO_2 transport at VII.C.1.a.i(C); and the discussion of geologic storage of CO_2 at VII.C.1.a.i(D). And the record supporting that transport and sequestration of CO_2 from coal-fired units is adequately demonstrated and meets the other requirements for BSER applies as well to transport and sequestration of CO_2 from combustion turbines.

The primary differences between using post-combustion capture from a coal combustion flue gas and a natural gas combustion flue gas are associated with the level of CO_2 in the flue gas stream and the levels of other pollutants that must be removed. In coal

[753] *Cf. New Jersey* v. *EPA,* 517 F.3d 574, 583–584 (D.C. Cir. 2008) (vacating rule on other grounds).

[754] *Cf. West Virginia* v. *EPA,* 597 U.S. 697 (2022) (vacating rule on other grounds).

combustion flue gas, the concentration of CO_2 is typically approximately 13 to 15 volume percent, while the concentration of CO_2 from natural gas-fired combined cycle combustion flue gas is approximately 3 to 4 volume percent.[755] Capture of CO_2 at dilute concentrations is more challenging but there are commercially available amine-based solvents that can be used with dilute CO_2 streams to achieve 90 percent capture. In addition, flue gas from a coal-fired steam EGU contains a variety of non-carbonaceous components that must be removed to meet environmental limits (*e.g.,* mercury and other metals, particulate matter (fly ash), and acid gases (including sulfur dioxide (SO_2) and hydrogen chloride and hydrogen fluoride). When amine-based post-combustion carbon capture is used with a coal-fired EGU, the flue gas stream must be further cleaned, sometimes beyond required environmental standards, to avoid the fouling of downstream process equipment and to prevent degradation of the amine solvent. Absent pretreatment of the coal combustion flue gas, the amines can absorb SO_2 and other acid gases to form heat stable salts, thereby degrading the performance of the solvent. Amine solvents can also experience catalytic oxidative degradation in the presence of some metal contaminants. Thermal oxidation of the solvent can also occur but can be mitigated by interstage cooling of the absorber column. Natural gas combustion flue gas typically contains very low (if any) levels of SO_2, acid gases, fly ash, and metals. Therefore, fouling and solvent degradation are less of a concern for carbon capture from natural gas-fired EGUs.

New natural gas-fired combustion turbine EGUs also have the option of using oxy-combustion technology—such as that currently being demonstrated and developed by NET Power. As discussed earlier, the NET Power system uses oxy-combustion (combustion in pure oxygen) of natural gas and a high-pressure supercritical CO_2 working fluid (instead of steam) to produce electricity in a combined cycle turbine configuration. The combustion products are water and high-purity, pipeline-ready CO_2 which is available for sequestration or sale to another industry. The NET Power technology does not involve solvent-based CO_2 separation and capture since pure CO_2 is a product of the process. The NET Power technology is not currently applicable to coal-fired steam generating utility boilers—though it could be utilized with combustion of gasified coal or other solid fossil fuels (*e.g.,* petroleum coke).

For new base load combustion turbines, the EPA proposed that CCS with a 90 percent capture rate, beginning in 2035, meets the BSER criteria. Some commenters agreed with the EPA that CCS for base load combustion turbines satisfies the BSER criteria. Other commenters claimed that CCS is not a suitable BSER for new base load combustion turbines. The EPA disagrees with these commenters.

As with existing coal-fired steam generating units, CCS applied to new combined cycle combustion turbines has three major components: CO_2 capture, transportation, and sequestration/storage. CCS with 90 percent capture has been adequately demonstrated for combined cycle combustion turbines for many of the same reasons described in section VII.C.1.a.i. The Bellingham Energy Center, a natural gas-fired combined cycle combustion turbine in south central Massachusetts, successfully applied post-combustion carbon capture using the Fluor Econamine FG Plus^{SM} amine-based solvent from 1991–2005 with 85–95 percent CO_2 capture.[756] The plant captured approximately 365 tons of CO_2 per day from a 40 MW slip stream [757] and was ultimately shut down and decommissioned primarily due to rising gas prices.

As discussed in further detail below, additional natural gas-fired combined cycle combustion turbine CCS projects are in the planning stage, which confirms that CCS is becoming accepted across the industry. As discussed above, CCS with 90 percent capture has been demonstrated for coal-fired steam generating units, and that information forms part of the basis for the EPA's determination that CCS with 90 percent capture has been have adequately demonstrated for these combustion turbines. Statements from vendors and the experience of industrial applications of CCS provide further support that post-combustion CCS with 90 percent capture is adequately demonstrated for these combustion turbines.

The EPA's analysis of the transportation and sequestration components of CCS for new base load combustion turbines is similar to its analysis of those components for existing coal-fired steam generating units and, therefore, for much the same reasons, the EPA is determining that each of those components is adequately demonstrated, and that CCS as a whole—including those components when combined with the 90 percent CO_2 capture component—is adequately demonstrated. In addition, new sources may consider access to CO_2 transport and storage sites in determining where to build, and the EPA expects that since this rule was proposed, companies siting new base load combustion turbines have taken into consideration the likelihood of a regulatory regime requiring significant emissions reductions.

The use of CCS at 90 percent capture can be implemented at reasonable cost because it allows affected sources to maximize the benefits of the IRC section 45Q tax credit. Finally, any adverse health and environmental impacts and energy requirements are limited and, in many cases, can be mitigated or avoided. It should also be noted that a determination that CCS is the BSER for these units will promote further use and development of this advanced technology. After balancing these factors, the EPA is determining that utilization of CCS with 90 percent capture for new base load combustion turbine EGUs satisfies the criteria for BSER.

(B) Adequately Demonstrated

The legal test for an adequately demonstrated system, and an achievable standard, has been discussed at length above. (See sections V.C.2.b and VII.C.a.i of this preamble). As previously noted, concepts of adequate demonstration and achievability are closely related: ''[i]t is the *system* which must be adequately demonstrated and the *standard* which must be achievable,'' [758] based on application of the system. An achievable standard means a standard based on the EPA's finding that sufficient evidence exists to reasonably determine that the affected sources in the source category can adopt a specific system of emission reduction to achieve the specified degree of emission limitation. The foregoing sections have shown that CCS, specifically using amine post-combustion CO_2 capture, is adequately demonstrated for existing coal units,

[755] NETL Carbon Dioxide Capture Approaches. *https://netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/capture-approaches.*

[756] Fluor Econamine FG Plus^{SM} brochure. *https://a.fluor.com/f/1014770/x/a744f915e1/econamine-fg-plus-brochure.pdf.*

[757] ''Commercially Available CO_2 Capture Technology'' Power, (Aug 2009). *https://www.powermag.com/commercially-available-co2-capture-technology/.*

[758] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (1973).

and that a 90 percent capture standard is achievable.[759]

Pursuant to *Lignite Energy Council* v. *EPA,* the EPA may extrapolate based on data from a particular kind of source to conclude that the technology at issue will also be effective at a similar source.[760] This standard is satisfied in our case, because of the essential ways in which CO_2 capture at coal-fired steam generating units is identical to CO_2 capture at natural gas-fired combined cycle turbines. As detailed in section VII.C.1.a.i(B), amine-based CO_2 capture removes CO_2 from post-combustion flue gas by reaction of the CO_2 with amine solvent. The same technology (*i.e.,* the same solvents and processes) that is employed on coal-fired steam generating units—and that is employed to capture CO_2 from fossil fuel combustion in other industrial processes—can be applied to remove CO_2 from the post-combustion flue gas of natural gas-fired combined cycle EGUs. In fact, the only differences in application of amine-based CO_2 capture on a natural gas-fired combined cycle unit relative to a coal-fired steam generating unit are related to the differences in composition of the respective post-combustion flue gases, and as explained below, these differences do not preclude achieving 90 percent capture from a gas-fired turbine.

First, while coal flue gas contains impurities including SO_2, PM, and trace minerals that can affect the downstream CO_2 process, and thus coal flue gas requires substantial pre-treatment, the post-combustion flue gas of natural gas-fired combustion turbines has few, if any, impurities that would impact the downstream CO_2 capture plant. Where impurities are present, SO_2 in particular can cause solvent degradation, and coal-fired sources without an FGD would likely need to install one. Filterable PM (fly ash) from coal, if not properly managed, can cause fouling and scale to accumulate on downstream blower fans, heat exchangers, and absorber packing material. Further, additional care in the solvent reclamation is necessary to mitigate solvent degradation that could otherwise occur due to the trace elements that can be present in coal. Because the flue gas from natural gas-fired combustion turbines contains few, if any, impurities that would impact downstream CO_2 capture, the flue gas from natural gas-fired combined cycle EGUs is easier to work with for CO_2 capture, and many of the challenges that were faced by earlier commercial scale demonstrations on coal-fired units can be avoided in the application of CCS at natural gas-fired combustion turbines.

Second, the CO_2 concentration of natural gas-fired combined cycle flue gas is lower than that of coal flue gas (approximately 3-to-4 volume percent for natural gas combined cycle EGUs; 13-to-15 volume percent for coal). For solvent-based CO_2 capture, CO_2 concentration is the driving force for mass transfer and the reaction of CO_2 with the solvent. However, flue gases with lower CO_2 concentrations can be readily addressed by the correct sizing and design of the capture equipment—and such considerations have been made in evaluating the BSER here and are reflected in the cost analysis in VII.C.1.a.ii(A) of this preamble. Moreover, as is detailed in the following sections of the preamble, amine-based CO_2 capture has been shown to be effective at removal of CO_2 from the flue gas of natural gas-fired combined cycle EGUs. In fact, there is not a technical limit to removal of CO_2 from flue gases with low CO_2 concentrations—the EPA notes that amine solvents have been shown to be able to remove CO_2 to concentrations that are less than the concentration of CO_2 in the atmosphere.

Considering these factors, the evidence that underlies the EPA's determination that amine post-combustion CO_2 capture is adequately demonstrated, and that a 90 percent capture standard is achievable, at coal-fired steam generating units, also applies to natural gas-fired combined cycle EGUs. Where differences exist, due to differences in flue gas composition, CCS at natural gas-fired combined cycle combustion turbines will in general face fewer challenges than CCS at coal-fired steam generators.[761] Moreover, in addition to the evidence outlined above, the following sections provide additional information specific to, including examples of, anime-based capture at natural gas-fired combined cycle EGUs. For these reasons, the EPA has determined that CCS at 90 percent capture is adequately demonstrated for natural gas fired combined cycle EGUs.

(1) CO_2 Capture for Combined Cycle Combustion Turbines

As discussed in the preceding, new stationary combustion turbines can use amine-based post-combustion capture. Additionally, new stationary combustion turbines may also utilize oxy-combustion, which uses a purified oxygen stream from an air separation unit (often diluted with recycled CO_2 to control the flame temperature) to combust the fuel and produce a nearly pure stream of CO_2 in the flue gas, as opposed to combustion with oxygen in air which contains 80 percent nitrogen. Currently available post-combustion amine-based CO_2 capture systems require that the flue gas be cooled prior to entering the capture equipment. This holds true for the exhaust from either a coal-fired utility boiler or from a combustion turbine. The most energy efficient way to cool the flue gas stream is to use a HRSG—which, as explained above, is an integral component of a combined cycle turbine system—to generate additional useful output.[762]

CO_2 capture has been successfully applied to an existing combined cycle turbine and several other projects are in development, as discussed immediately below.

(a) CCS on Combined Cycle EGUs

The most prominent example of the use of carbon capture technology on a natural gas-fired combined cycle turbine EGU was at the 386 MW Bellingham Cogeneration Facility in Bellingham, Massachusetts. The plant used Fluor's Econamine FG Plus℠ amine-based CO_2 capture system with a capture capacity of 360 tons of CO_2 per day. The system was used to produce food-grade CO_2 and was in continuous commercial operation from 1991 to 2005 (14 years). The capture system was able to continuously capture 85–95 percent of the CO_2 that would have otherwise been emitted from the flue gas of a 40 MW slip stream.[763] The natural gas combustion flue gas at the facility contained 3.5 volume percent CO_2 and 13–14 volume percent oxygen. As mentioned earlier, the flue gas from a coal combustion flue gas stream has a typical CO_2 concentration of approximately 15 volume percent and more dilute CO_2 stream are more challenging to separate and capture. Just before the CO_2 capture system was shut

[759] The EPA uses the two phrases (i) BSER is CCS with 90 percent capture and (ii) CCS with 90 percent capture is achievable, or similar phrases, interchangeably.

[760] *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[761] Many of the challenges faced by Boundary Dam Unit 3—which proved to be solvable—were caused by the impurities, including fly ash, SO_2, and trace contaminants in coal-fired post-combustion flue gas—which do not occur in the natural gas post-combustion flue gas. As a result, for CO_2 capture for natural gas combustion, flue gas handling is simpler, solvent degradation is easier to prevent, and fewer redundancies may be necessary for various components (*e.g.,* heat exchangers).

[762] The EPA proposed that because the BSER for non-base load combustion turbines was simple cycle technology, CCS was not applicable.

[763] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. *https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.*

down in 2005 (due to high natural gas price), the system had logged more than 120,000 hours of CO_2 capture[764] and had a 98.5 percent on-stream (availability) factor.[765]

The Fluor Econamine FG Plus℠ is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation. This technology uses a proprietary solvent to capture CO_2 from post-combustion sources. The process is well suited to capture CO_2 from large, single-point emission sources such as power plants or refineries, including large facilities with CO_2 capture capacities greater than 10,000 tons per day.[766] On February 6, 2024, Fluor Corporation announced that Chevron New Energies plans to use the Econamine FG Plus℠ carbon capture technology to reduce CO_2 emissions at Chevron's Eastridge Cogeneration combustion turbine facility in Kern County, California. When installed, Fluor's carbon capture solution is expected to reduce the Eastridge Cogeneration facility's carbon emissions by approximately 95 percent.[767]

Moreover, recently, CO_2 capture technology has been operated on NGCC post-combustion flue gas at the Technology Centre Mongstad (TCM) in Norway.[768] TCM can treat a 12 MWe flue gas stream from a natural gas combined cycle cogeneration plant at Mongstad power station. Many different solvents have been operated at TCM including MHI's KS–21™ solvent,[769] achieving capture rates of over 98 percent.

Additionally, in Scotland, the proposed 900 MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. MHI is developing a FEED for the power plant and capture facility.[770] It is anticipated that the power plant will be operational by the end of the 2020s and will have the potential to capture 90 percent of the CO_2 emitting from the combined cycle facility and sequester up to 1.5 million metric tons of CO_2 annually. A storage site being developed 62 miles off the Scottish North Sea coast will serve as a destination for the captured CO_2.[771][772]

Furthermore, the Global CCS Centre is tracking other international CCS on combustion turbine projects that are in on-going stages of development.[773]

(b) NET Power Cycle

In addition, there are several planned projects using NET Power's Allam-Fetvedt Cycle.[774] The Allam-Fetvedt Cycle is a proprietary process for producing electricity that combusts a fuel with purified oxygen (diluted with recycled CO_2 to control flame temperature) and uses supercritical CO_2 as the working fluid instead of water/steam. This cycle is designed to achieve thermal efficiencies of up to 59 percent.[775] Potential advantages of this cycle are that it emits no NO_X and produces a stream of high-purity CO_2[776] that can be delivered by pipeline to a storage or sequestration site without extensive processing. A 50 MW (thermal) test facility in La Porte, Texas was completed in 2018 and has since accumulated over 1,500 hours of runtime. There are several announced NET Power commercial projects proposing to use the Allam-Fetvedt Cycle. These include the 280 MW Broadwing Clean Energy Complex in Illinois, and several international projects.

In Scotland, the proposed 900 MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. MHI is developing a FEED for the power plant and capture facility.[777] It is anticipated that the power plant will be operational by the end of the 2020s and will have the potential to capture 90 percent of the CO_2 emitting from the combined cycle facility and sequester up to 1.5 million metric tons of CO_2 annually. A storage site being developed 62 miles off the Scottish North Sea coast will serve as a destination for the captured CO_2.[778][779]

(c) Coal-Fired Steam Generating Units

As detailed in section VII.C.1.a, CCS has been demonstrated on coal-fired power plants, which provides further support that CCS on base load combined cycle units is adequately demonstrated. Further, 90 percent capture is expected to be, in some ways, more straightforward to achieve for natural gas-fired combined cycle combustion turbines than for coal-fired steam generators. Many of the challenges faced by Boundary Dam Unit 3—which proved to be solvable—were caused by the impurities, including fly ash, SO_2, and trace contaminants in coal-fired post-combustion flue gas. Such impurities naturally occur in coal (sulfur and trace contaminants) or are a natural result of combusting coal (fly ash), but not in natural gas, and thus they do not appear in the natural gas post-combustion flue gas. As a result, for CO_2 capture for natural gas combustion, flue gas handling is simpler, solvent degradation is easier to prevent, and fewer redundancies may be necessary for various components (*e.g.,* heat exchangers).

(d) Other Industry

As discussed in section VII.C.1.a.i.(A)(1) of this preamble, CCS installations in other industries support that capture equipment can achieve 90 percent capture of CO_2 from natural gas-fired base load combined cycle combustion turbines.

(e) EPAct05-Assisted CO_2 Capture Projects at Stationary Combustion Turbines

As for steam generating units, EPAct05-assisted CO_2 capture projects on stationary combustion turbines corroborate that CO_2 capture on gas combustion turbines is adequately demonstrated. Several CCS projects with at least 90 percent capture at commercial-scale combined cycle turbines are in the planning stages. These projects support that CCS with at least 90 percent capture for these units is the industry standard and support the EPA's determination that CCS is adequately demonstrated.

CCS is planned for the existing 550 MW natural gas-fired combined cycle (two combustion turbines) at the Sutter Energy Center in Yuba City, California.[780] The Sutter

[764] *https://boereport.com/2022/08/16/fluor/.*

[765] ''Technologies for CCS on Natural Gas Power Systems'' Dr. Satish Reddy presentation to USEA, April 2014, *https://usea.org/sites/default/files/event-/Reddy%20USEA%20Presentation%202014.pptx.*

[766] *https://www.fluor.com/market-reach/industries/energy-transition/carbon-capture.*

[767] *https://newsroom.fluor.com/news-releases/news-details/2024/Fluors-Econamine-FG-PlusSM-Carbon-Capture-Technology-Selected-to-Reduce-CO2-Emissions-at-Chevron-Facility/default.aspx.*

[768] *https://netl.doe.gov/carbon-capture/power-generation.*

[769] Mitsubishi Heavy Industries, ''Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New KS–21™ Solvent for CO_2 Capture,'' *https://www.mhi.com/news/211019.html.*

[770] MHI and MHIENG Awarded FEED Contract. *https://www.mhi.com/news/22083001.html.*

[771] Buli, N. (2021, May 10). SSE, Equinor plan new gas power plant with carbon capture in Scotland. *Reuters. https://www.reuters.com/business/sustainable-business/sse-equinor-plan-new-gas-power-plant-with-carbon-capture-scotland-2021-05-11/.*

[772] Acorn CCS granted North Sea storage licenses. September 18, 2023. *https://www.ogj.com/energy-transition/article/14299094/acorn-granted-licenses-for-co2-storage.*

[773] *https://status23.globalccsinstitute.com/.*

[774] The NET Power Cycle was formerly referred to as the Allam-Fetvedt cycle. *https://netpower.com/technology/.*

[775] Yellen, D. (2020, May 25). Allam Cycle carbon capture gas plants: 11 percent more efficient, all CO_2 captured. *Energy Post. https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/.*

[776] This allows for capture of over 97 percent of the CO_2 emissions. *www.netpower.com.*

[780] Calpine Sutter Decarbonization Project, May 17, 2023. *https://www.smud.org/en/Corporate/*

Continued

Decarbonization project will use ION Clean Energy's amine-based solvent technology at a capture rate of 95 percent or more. The project expects to complete a FEED study in 2024 and, prior to being selected by DOE for funding award negotiation, planned commercial operation in 2027. Sutter Decarbonization is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program.[781]

The CO_2 capture project at the Deer Park Energy Center in Deer Park, Texas will be designed to capture 95 percent or more of the flue gas from the five combustion turbines at the 1,200 MW natural gas-fired combined cycle power plant, using technology from Shell CANSOLV.[782] The CO_2 capture project already has an air permit issued for the project, which includes a reduction in the allowable emission limits for NO_X from four of the combustion turbines.[783] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column.

The Baytown Energy Center in Baytown, Texas is an existing natural gas-fired combined cycle cogeneration facility providing heat and power to a nearby industrial facility, while distributing additional electricity to the grid. CCS using Shell's CANSOLV solvent is planned for the equivalent of two of the three combustion turbines at the 896 MW natural gas-fired combined cycle power plant, with a capture rate of 95 percent. The CO_2 capture facility at Baytown Energy Center also has an air permit in place, and the permit application provides some details on the process design.[784] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column. To mitigate NO_X emissions, the operation of the SCR systems for the combustion turbines will be adjusted to meet lower NO_X allowable limits—adjustments may include increasing ammonia flow, more frequent SCR repacking and head cleaning, and, possibly, optimization of the ammonia distribution system. The Baytown CO_2 capture project is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program.[785] Captured CO_2 will be transported and stored at sites along the U.S. Gulf Coast.

An 1,800 MW natural gas-fired combustion turbine that will be constructed in West Virginia and will utilize CCS has been announced. The project is planned to begin operation later this decade.[786]

There are numerous other EPAct05-assisted projects related to natural gas-fired combined cycle turbines including the following.[787] [788] [789] [790] [791] These projects provide corroborating evidence that capture of at least 90 percent is accepted within the industry.

• General Electric (GE) (Bucks, Alabama) was awarded $5,771,670 to retrofit a combined cycle turbine with CCS technology to capture 95 percent of CO_2 and is targeting commercial deployment by 2030.

• Wood Environmental & Infrastructure Solutions (Blue Bell, Pennsylvania) was awarded $4,000,000 to complete an engineering design study for CO_2 capture at the Shell Chemicals Complex. The aim is to reduce CO_2 emissions by 95 percent using post-combustion technology to capture CO_2 from several plants, including an onsite natural gas CHP plant.

• General Electric Company, GE Research (Niskayuna, New York) was awarded $1,499,992 to develop a design to capture 95 percent of CO_2 from combined cycle turbine flue gas with the potential to reduce electricity costs by at least 15 percent.

• SRI International (Menlo Park, California) was awarded $1,499,759 to design, build, and test a technology that can capture at least 95 percent of CO_2 while demonstrating a 20 percent cost reduction compared to existing combined cycle turbine carbon capture.

• CORMETECH, Inc. (Charlotte, North Carolina) was awarded $2,500,000 to further develop, optimize, and test a new, lower-cost technology to capture CO_2 from combined cycle turbine flue gas and improve scalability to large, combined cycle turbines.

• TDA Research, Inc. (Wheat Ridge, Colorado) was awarded $2,500,000 to build and test a post-combustion capture process to improve the performance of combined cycle turbine flue gas CO_2 capture.

• GE Gas Power (Schenectady, New York) was awarded $5,771,670 to perform an engineering design study to incorporate a 95 percent CO_2 capture solution for an existing combined cycle turbine site while providing lower costs and scalability to other sites.

• Electric Power Research Institute (EPRI) (Palo Alto, California) was awarded $5,842,517 to complete a study to retrofit a 700 MWe combined cycle turbine with a carbon capture system to capture 95 percent of CO_2.

• Gas Technology Institute (Des Plaines, Illinois) was awarded $1,000,000 to develop membrane technology capable of capturing more than 97 percent of combined cycle turbine CO_2 flue gas and demonstrate upwards of 40 percent reduction in costs.

• RTI International (Research Triangle Park, North Carolina) was awarded $1,000,000 to test a novel non-aqueous solvent technology aimed at demonstrating 97 percent capture efficiency from simulated combined cycle turbine flue gas.

• Tampa Electric Company (Tampa, Florida) was awarded $5,588,173 to conduct a study retrofitting Polk Power Station with post-combustion CO_2 capture technology aiming to achieve a 95 percent capture rate.

There are also several announced NET Power Allam-Fetvedt Cycle based CO_2 capture projects that are EPAct05-assisted. These include the 280 MW Coyote Clean Power Project on the Southern Ute Indian Reservation in

Environmental-Leadership/2030-Clean-Energy-Vision/CEV-Landing-Pages/Calpine-presentation.

[781] Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[782] Calpine Carbon Capture. *https://calpinecarboncapture.com/wp-content/uploads/2023/05/Calpine-Deer-Park-English.pdf.*

[783] Deer Park Energy Center TCEQ Records Online Primary ID 171713.

[784] Baytown Energy Center Air Permit TCEQ Records Online Primary ID 172517.

[785] Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[786] Competitive Power Ventures (2022). *Multi-Billion Dollar Combined Cycle Natural Gas Power Station with Carbon Capture Announced in West Virginia.* Press Release. September 16, 2022. *https://www.cpv.com/2022/09/16/multi-billion-dollar-combined-cycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.*

[787] General Electric (GE) (2022). *U.S. Department of Energy Awards $5.7 Million for GE-Led Carbon Capture Technology Integration Project Targeting to Achieve 95% Reduction of Carbon Emissions.* Press Release. February 15, 2022. *https://www.ge.com/news/press-releases/us-department-of-energy-awards-57-million-for-ge-led-carbon-capture-technology.*

[788] Larson, A. (2022). *GE-Led Carbon Capture Project at Southern Company Site Gets DOE Funding.* Power. *https://www.powermag.com/ge-led-carbon-capture-project-at-southern-company-site-gets-doe-funding/.*

[789] U.S. Department of Energy (DOE) (2021). *DOE Invests $45 Million to Decarbonize the Natural Gas Power and Industrial Sectors Using Carbon Capture and Storage.* October 6, 2021. *https://www.energy.gov/articles/doe-invests-45-million-decarbonize-natural-gas-power-and-industrial-sectors-using-carbon.*

[790] DOE (2022). *Additional Selections for Funding Opportunity Announcement 2515.* Office of Fossil Energy and Carbon Management. *https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515.*

[791] DOE (2019). *FOA 2058: Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants.* Office of Fossil Energy and Carbon Management. *https://www.energy.gov/fecm/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas.*

Colorado and a 300 MW project located near Occidental's Permian Basin operations close to Odessa, Texas. Commercial operation of the facility near Odessa, Texas is expected in 2028.

(f) Range of Conditions

The composition of natural gas combined cycle post-combustion flue gas is relatively uniform as the level of impurities is, in general, low. There may be some difference in NO_X emissions, but considering the sources are new, it is likely that they will be installed with SCR, resulting in uniform NO_X concentrations in the flue gas. The EPA notes that some natural gas combined cycle units applying CO_2 capture may use exhaust gas recirculation to increase the concentration of CO_2 in the flue gas—this produces a higher concentration of CO_2 in the flue gas. For those sources that apply that approach, the CO_2 capture system can be scaled smaller, reducing overall costs. Considering these factors, the EPA concludes that there are not substantial differences in flue gas conditions for natural gas combined cycle units, and the small differences that could exist would not adversely impact the operation of the CO_2 capture equipment.

As detailed in section VII.C.1.a.i(B)(7), single trains of CO_2 capture facilities have turndown capabilities of 50 percent. Effective turndown to 25 percent of throughputs can be achieved by using 2 trains of capture equipment. CO_2 capture rates have also been shown to be higher at lower throughputs. Moreover, during off-peak hours when electricity prices are lower, additional lean solvent can be produced and held in reserve, so that during high-demand hours, the auxiliary demands to the capture plant stripping column reboiler be reduced. Considering these factors, the capture rate would not be affected by load following operation, and the operation of the combustion turbine would not be limited by turndown capabilities of the capture equipment. As detailed in preceding sections, simple cycle combustion turbines cycle frequently, and have a number of startups and shutdowns per year. However, combined cycle units cycle less frequently and have fewer startups and shutdowns per year. Startups of combined cycle units are faster than coal-fired steam generating units described in section VII.C.1.a.i(B)(7) of the preamble. Cold startups of combined cycle units typically take not more than 3 hours (hot startups are faster), and shutdown takes less than 1 hour. During startup, heat input to the unit is lower to slowly raise the temperature of the HRSG.

Importantly, natural gas post-combustion flue gas does not require the same pretreatment as coal post-combustion flue gas. Therefore, amine solvents are able to capture CO_2 as soon as the flue gas contacts the lean solvent, and startup does not have to wait for operation of other emission controls. Furthermore, there are several different process strategies that can be employed to enable capture during cold startup.[792] [793] These include using an additional reserve of lean solvent (solvent without absorbed CO_2), dedicated heat storage for reboiler preheating, and fast starting steam cycle technologies or high-pressure bypass extraction. Each of these three options has been modeled to show that 95 percent capture rates can be achieved during startup. The first option simply uses a reserve of lean solvent during startup so that capture can occur without needing to wait for the stripping column reboiler to heat up. For hot starts, the startup time of the NGCC is faster, and since the reboiler is already warm, the capture plant can begin operating faster. Shutdowns are short, and high capture efficiencies can be maintained.

Considering that startup and shutdown for natural gas combined cycle units is fast, startups are relatively few, and simple process strategies can be employed so that high capture efficiencies can be achieved during startup, the EPA has concluded that startup and shutdown do not adversely impact the achievable CO_2 capture rate.

Considering the preceding information, the EPA has determined that 90 percent capture is achievable over long periods (*i.e.,* 12-month rolling averages) for base load combustion turbines for all relevant flue gas conditions, variable load, and startup and shutdown.

(g) Summary of Evidence Supporting BSER Determination Without EPAct05-Aassisted Projects

As noted above, under the EPA's interpretation of the EPAct05 provisions, the EPA may not rely on capture projects that received assistance under EPAct05 as the sole basis for a determination of adequate demonstration, but the EPA may rely on those projects to support or corroborate other information that supports such a determination. The information described above that supports the EPA's determination that 90 percent CO_2 capture from natural gas-fired combustion turbines is adequately demonstrated, without consideration of the EPAct05-assisted projects, includes (i) the information concerning coal-fired steam generating units listed in VII.C.1.a.i.(B)(9)[794] (other than the information concerning EPAct05-assisted coal-fired unit projects and the information concerning natural gas-fired combustion turbines); (ii) the information that a 90 percent capture standard is achievable at coal-fired steam generating units, also applies to natural gas-fired combined cycle EGUs (*i.e.,* all the information in VIII.F.4.c.iv.(B) (before (1)) and (1) (before (a)); (iii) the information concerning CCS on combined cycle EGUs (*i.e.,* all the information in VIII.F.4.c.iv.(B)(1)(a)); and (iv) the information concerning Net Power (*i.e.,* all the information in VIII.F.4.c.iv.(B)(1)(b)). All this information by itself is sufficient to support the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated. Substantial additional information from EPAct05-assisted projects, as described in section VIII.F.4.c.iv.(B)(1)(e), provides additional support and confirms that 90 percent CO_2 capture from natural gas-fired combustion turbines is adequately demonstrated.

(2) Transport of CO_2

In section VII.C.1.a.i.(C) of this document, the EPA described its rationale for finalizing a determination that CO_2 transport by pipelines as a component of CCS is adequately demonstrated for use of CCS with existing steam generating EGUs. The Agency's rationale for finalizing the same determination—that CO_2 transport by pipelines as a component of CCS is adequately demonstrated for CCS use with new combustion turbine EGUs—is much the same as that described in section VII.C.1.a.i.(C). As discussed in

[792] *https://ieaghg.org/ccs-resources/blog/new-ieaghg-report-2022-08-start-up-and-shutdown-protocol-for-power-stations-with-co2-capture.*

[793] *https://assets.publishing.service.gov.uk/media/5f95432ad3bf7f35f26127d2/start-up-shut-down-times-power-ccus-main-report.pdf.*

[794] Specifically, this includes the information concerning Boundary Dam, coupled with engineering analysis concerning key improvements that can be implemented in future CCS deployments during initial design and construction (*i.e.,* all the information in section VII.C.1.a.i.(B)(1)(a) and the information concerning Boundary Dam in section VII.C.1.a.i.(B)(1)(b)); (ii) the information concerning other coal-fired demonstrations, including the Argus Cogeneration Plant and AES's Warrior Run (*i.e.,* all the information concerning those sources in section VII.C.1.a.i.(B)(1)(a)); (iii) the information concerning industrial applications of CCS (*i.e.,* all the information in section VII.C.1.a.i.(A)(1); and (iv) the information concerning CO_2 capture technology vendor statements (*i.e.,* all the information in VII.C.1.a.i.(B)(3)).

section VII.C.1.a.i.(C) of this preamble, CO_2 pipelines are available and their network is expanding in the U.S., and the safety of existing and new supercritical CO_2 pipelines is comprehensively regulated by PHMSA.[795] A new combustion turbine may also be co-located with a storage site, so that minimal transport of the CO_2 is required.

Pipeline transport of CO_2 captured from newly constructed or reconstructed natural gas-fired combustion turbine EGUs meets the BSER requirements based on the same evidence, and for the same reasons, as does pipeline transport of CO_2 captured from existing coal-fired steam generating EGUs, as described in section VII.C.1.a.i.(C) of this preamble. This is because the CO_2 that is captured from a natural gas-fired turbine, compressed, and delivered into a pipeline is indistinguishable from the CO_2 that is captured from an existing coal-fired steam generating unit. Accordingly, all the evidence and explanation in section VII.C.1.a.i.(C) of this preamble that it is adequately demonstrated, cost-effective, and consistent with the other BSER factors for an existing coal-fired steam generating unit to construct a lateral pipeline from its facility to a sequestration site applies to new natural gas-fired turbines. This includes the history of CO_2 pipeline build-out (VII.C.1.a.i.(C)(1)), the recent examples of new pipelines (VII.C.1.a.i.(C)(1)(b)), EPAct05-assisted CO_2 pipelines for CCS (VII.C.1.a.i.(C)(1)(c)), the network of existing and planned CO_2 trunklines (VII.C.1.a.i.(C)(1)(d)), permitting and rights of way considerations (VII.C.1.a.i.(C)(2)), and considerations of the security of CO_2 transport, including PHMSA requirements (VII.C.1.a.i.(C)(3)).

The only difference between pipeline transport for the coal-fired steam generation and the gas-fired turbines is that the coal-fired units are already in existence and, as a result, the location and length of their pipelines, as needed to transport their CO_2 to nearby sequestration, is already known, whereas new gas-fired turbines are not yet sited. We discuss the implications for new gas-fired turbines in the next section.

[795] PHMSA additionally initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020. For more information, see: *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

(3) Geologic Sequestration of CO_2

In section VII.C.1.a.i.(D) of this document, the EPA described its rationale for finalizing a determination that geologic sequestration (*i.e.,* the long-term containment of a CO_2 stream in subsurface geologic formations) is adequately demonstrated as a component of the use of CCS with existing coal-fired steam generating EGUs. Similar to the previous discussion regarding CO_2 transport, the Agency's rationale for finalizing a determination that geologic sequestration is adequately demonstrated as a component of the use of CCS with new combustion turbine EGUs is the same as described in VII.C.1.a.i.(D) for existing coal-fired steam generating EGUs. The storage/sequestration sites used to store captured CO_2 from existing coal-fired EGUs could also be used to store captured CO_2 from newly constructed or reconstructed combustion turbine EGUs. All of the considerations and challenges associated with developing geologic storage sites for existing sources are also considerations and challenges associated with developing such sites for newly constructed or reconstructed sources.

(a) In General

Geologic sequestration (*i.e.,* the long-term containment of a CO_2 stream in subsurface geologic formations) is well proven. Deep saline formations, which may be evaluated and developed for CO_2 sequestration are broadly available throughout the U.S. Geologic sequestration requires a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. As discussed in section VII.C.1.a.i.(D) of this preamble, there have been numerous instances of geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. This regulatory framework includes the UIC well regulations, which are under the authority of the SDWA, and the GHGRP, under the authority of the CAA.

Geologic settings which may be suitable for geologic sequestration of CO_2 are widespread and available throughout the U.S. Through an availability analysis of sequestration potential in the U.S. based on resources from the DOE, the USGS, and the EPA, the EPA found that there are 43 states with access to, or are within 100 km from, onshore or offshore storage in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs.

All of the evidence and explanation that geological sequestration of CO_2 is adequately demonstrated and meets the other BSER factors that the EPA described with respect to sequestration of CO_2 from existing coal-fired steam generating units in section VII.C.1.a.i.(D) of this preamble apply with respect to CO_2 from new natural gas-fired combustion turbines. Sequestration is broadly available (VII.C.1.a.i.(D)(1)(a)). It is adequately demonstrated, with many examples of projects successfully injecting and containing CO_2 in the subsurface (VII.C.1.a.i.(D)(2)). It provides secure storage, with a detailed set of regulatory requirements to ensure the security of sequestered CO_2, including the UIC well regulations pursuant to SDWA authority, and the GHGRP pursuant to CAA authority (VII.C.1.a.i.(D)(4)). The EPA has the experience to properly regulate and review permits for UIC Class VI injection wells, has made considerable improvements to its permitting process to expedite permitting decisions, and has granted several states primacy to issue permits, and is supporting that state permitting (VII.C.1.a.i.(D)(5)).

(b) New Natural Gas-Fired Combustion Turbines

As discussed in section VII.C.1.a.i.(D)(1), deep saline formations that may be considered for use in geologic sequestration (or storage) are common in the continental United States. In addition, there are numerous unmineable coal seams and depleted oil and gas reserves throughout the country that could potentially be utilized as sequestration sites. The DOE estimates that areas of the U.S. with appropriate geology have a sequestration potential of at least 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, unmineable coal seams, and oil and gas reservoirs. The EPA's scoping assessment found that at least 37 states have geologic characteristics that are amenable to deep saline sequestration and identified an additional 6 states are within 100 kilometers of potentially amenable deep saline formations in either onshore or offshore locations. In terms of land area, 80 percent of the continental U.S. is within 100 km of deep saline formations.[796] While the EPA's geographic availability analyses focus on deep saline formations, other geologic formations such as unmineable coal seams or depleted oil and gas

[796] For additional information on CO_2 transportation and geologic sequestration availability, please see EPA's final TSD, *GHG Mitigation Measures for Steam Generating Units.*

reservoirs represent potential additional CO_2 storage options. Therefore, we expect that the vast majority of new base load combustion turbine EGUs could be sited within 100 km of a sequestration site.

While the potential for some type of sequestration exists in large swaths of the continental U.S., we recognize that there are a few states that do not have geologic conditions suitable for geologic sequestration within or near their borders. If an area does not have a suitable geologic sequestration site, then a utility or project developer seeking to build a new combustion turbine EGU for base load generation has two options—either (1) the new EGU may be located near the electricity demand and the CO_2 transported via a CO_2 pipeline to a geologic sequestration site, or (2) the new EGU may be located closer to a geologic sequestration site and the electricity delivered to customers through transmission lines. Regarding option 1, as discussed in VII.C.1.a.i(C), the EPA believes that both new and existing EGUs are capable of constructing CO_2 pipelines as needed. With regard to option 2, we expect that this option may be preferred for projects where a CO_2 pipeline of substantial length would be required to reach the sequestration site. However, we note that for new base load combustion turbine EGUs, project developers have flexibility with regard to siting such that they can balance whether to site a new unit closer to a potential geologic sequestration site or closer to a load area depending on their specific needs.

Electricity demand in areas that may not have geologic sequestration sites may be served by gas-fired EGUs that are built in areas with geologic sequestration, and the generated electricity can be delivered through transmission lines to the load areas through ''gas-by-wire.'' An analogous approach, known as ''coal-by-wire'' has long been used in the electricity sector for coal-fired EGUs because siting a coal-fired EGU near a coal mine and transmitting the generated electricity long distances to the load area is sometimes less expensive than siting the coal EGU near the load area and shipping the coal long distances. The same principle may apply to new base load combustion turbine EGUs such that it may be more practicable for an project developer to site a new base load combustion turbine EGU in a location in close proximity to a geologic sequestration site and to deliver the electricity generated through transmission lines to the load area rather than siting the new gas-fired combustion turbine EGU near the load area and building a lengthy pipeline to the geologic sequestration site.

Gas-by-wire and coal-by-wire are possible due to the electricity grid's extensive high voltage transmission networks that enable electricity to be transmitted over long distances. See the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units,* which is available in the rulemaking docket for this action. In many of the areas without reasonable access to geologic sequestration, utilities, electric cooperatives, and municipalities have a history of joint ownership of electricity generation outside the region or contracting with electricity generation in outside areas to meet demand. Some of the areas are in Regional Transmission Organizations (RTOs),[797] which engage in planning as well as balancing supply and demand in real time throughout the RTO's territory. Accordingly, generating resources in one part of the RTO can serve load in other parts of the RTO, as well as load outside of the RTO.

In the coal context, there are many examples of where coal-fired power generation in one state has been used to supply electricity in other states. For example, the Prairie State Generating Plant, a 2-unit 1,600 MW coal-fired power plant in Illinois that is currently considering retrofitting with CCS, serves load in eight different states from the Midwest to the mid-Atlantic.[798] The Intermountain Power Project, a coal-fired plant located in Delta, Utah, that is converting to co-fire hydrogen and natural gas, serves customers in both Utah and California.[799] Additionally, historically nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah. Further, Idaho Power, which serves customers in Idaho and eastern Oregon has met demand in part from power generating at coal-fired power plants located in Wyoming and Nevada. This same concept of siting generation in one location to serve demand in another area and using existing transmission infrastructure to do so could similarly be applied to gas-fired combustion turbine power plants, and, in fact, there are examples of gas-fired combustion turbine EGUs serving demand more than 100 km away from where they are sited. For example, Portland General Electric's Carty Generating Station, a 436–MW NGCC unit located in Boardman, Oregon[800] serves demand in Portland, Oregon,[801] which is approximately 270 km away from the source.

In the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units,* we explore in detail the potential for gas-by-wire and the ability of demand in areas without geologic sequestration potential to be served by gas generation located in areas that have access to geologic sequestration. As discussed in the memorandum, the vast majority of the United States is within 100 km of an area with geologic sequestration potential. A review of our scoping assessment indicates that there are limited areas of the country that are not within 100 km of a potential deep saline sequestration formation (although some of these areas may be within 100 km of an unmineable coal seam or depleted oil and gas reservoir that could potentially serve as a sequestration site). In many instances, these areas include areas with low population density, areas that are already served by transmission lines that could deliver gas-by-wire, and/or include areas that have made policy or other decisions not to pursue a resource mix that includes new NGCC due to state renewable portfolio standards or for other reasons.

In many of these areas, utilities, electric cooperatives, and municipalities have a history of obtaining electricity from generation in outside areas to meet demand. Some of the relevant areas are in an RTO or ISO, which operate the transmission system and dispatch generation to balance supply and demand regionwide, as well as engage in regionwide planning and cost allocation to facilitate needed transmission development. Accordingly, generating resources in one part of an RTO/ISO, such as through an NGCC plant, can serve loads in other parts of the RTO/ISO, as well as serving load areas outside of the RTO/ISO. As we consider each of these geographic areas in the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units,* we make key points as to why this final rule does not negatively impact the ability of these regions to access new NGCC generation to the extent that NGCC generation is needed to supply demand and/or those regions

[797] In this discussion, the term RTO indicates both ISOs and RTOs.

[798] *https://prairiestateenergycampus.com/about/ownership/.*

[799] *https://www.ipautah.com/participants-services-area/.*

[800] Portland General Electric, ''Our Power Plants,'' *https://portlandgeneral.com/about/who-we-are/how-we-generate-energy/our-power-plants.*

[801] See George Plaven, ''PGE power plant rising in E. Oregon,'' The Columbian (October 10, 2015, 5:55 a.m.), *https://www.columbian.com/news/2015/oct/10/pge-power-plant-rising-in-e-oregon/.* See also Portland General Electric, ''PGE Service Area,'' *https://portlandgeneral.com/about/info/service-area.*

want to include new NGCC generation in their resource mixes.

(C) Costs

The EPA has evaluated the costs of CCS for new combined cycle units, including the cost of installing and operating CO_2 capture equipment as well as the costs of transport and storage. The EPA has also compared the costs of CCS for new combined cycle units to other control costs, in part derived from other rulemakings that the EPA has determined to be cost-reasonable, and the costs are comparable. Based on these analyses, the EPA considers the costs of CCS for new combined cycle units to be reasonable. Certain elements of the transport and storage costs are similar for new combustion turbines and existing steam generating units. In this section, the EPA outlines these costs and identifies the considerations specific to new combustion turbines. These costs are significantly reduced by the IRC section 45Q tax credit.

(1) Capture Costs

According to the NETL Fossil Energy Baseline Report (October 2022 revision), before accounting for the IRC section 45Q tax credit for sequestered CO_2, using a 90 percent capture amine-based post-combustion CO_2 capture system increases the capital costs of a new combined cycle EGU by 115 percent on a $/kW basis, increases the heat rate by 13 percent, increases incremental operating costs by 35 percent, and derates the unit (*i.e.,* decreases the capacity available to generate useful output) by 11 percent.[802] For a base load combustion turbine, carbon capture increases the LCOE by 62 percent (an increase of 27 $/MWh) and has an estimated cost of $81/ton ($89/metric ton) of onsite CO_2 reduction.[803] The NETL costs are based on the use of a second-generation amine-based capture system without exhaust gas recirculation (EGR) and, as discussed below, do not take into account further cost reductions that can be expected to occur from efficiency improvements as post-combustion capture systems are more widely deployed, as well as potential technological developments.[804]

The flue gas from natural gas-fired combined cycle turbine differs from that of coal-fired EGUs in several ways that impact the cost of CO_2 capture. These include that the CO_2 concentration in the flue gas is approximately one-third of that observed at coal-fired EGUs, the volumetric flow rate on a per MW basis is larger, and the oxygen concentration is approximately 3 times that of a coal-fired EGU. While the higher amount of excess oxygen has the potential to reduce the efficiency of amine-based solvents that are susceptible to oxidation, natural gas post-combustion flue gas does not have other impurities (SO_2, PM, trace metals) that are present and must be managed in coal flue gas. Other important factors include that the lower concentrations of CO_2 reduce the efficiency of the capture process and that the larger volumetric flow rates require a larger CO_2 absorber, which increases the capital cost of the capture process. Exhaust gas recirculation (EGR), also referred to as flue gas recirculation (FGR), is a process that addresses all these issues. EGR diverts some of the combustion turbine exhaust gas back into the inlet stream for the combustion turbine. Doing so increases the CO_2 concentration and decreases the O_2 concentration in the exhaust stream and decreases the flow rate, producing more favorable conditions for CCS. One study found that EGR can decrease the capital costs of a combined cycle EGU with CCS by 6.4 percent, decrease the heat rate by 2.5 percent, decrease the LCOE by 3.4 percent, and decrease the overall CO_2 capture costs by 11 percent relative to a combined cycle EGU without EGR.[805] The EPA notes that the NETL costs on which the EPA bases its cost calculations for combined cycle CCS do not assume the use of EGR, but as discussed below, EGR use is plausible and would reduce those costs.

While the costs considered in the preceding are based on the current costs of CCS, the EPA notes that the costs of capture systems can be expected to decrease over the rest of this decade and continue to decrease afterwards.[806] As part of the plan to reduce the costs of CO_2 capture, the DOE is funding multiple projects to further advance CCS technology from various point sources, including combined cycle turbines, cement manufacturing plants, and iron and steel plants.[807] It should be noted that some of these projects may be EPAct05-assisted. The general aim is to lower the costs of the technologies, and to increase investor confidence in the commercial scale applications, particularly for newer technologies or proven technologies applied under unique circumstances. In particular, OCED's Carbon Capture Demonstration Projects are targeted to accelerate continued power sector carbon capture commercialization through reducing costs and reducing uncertainties to project development. These cost and uncertainty reductions arise from reductions in cost of capital, increases in system scale, standardization and reduction in non-recurring engineering costs, maturation of supply chain ecosystem, and improvements in engineering design and materials over time.[808]

Although current post-combustion CO_2 capture projects have primarily been based on amine capture systems, there are multiple alternate capture technologies in development—many of which are funded through industry research programs—that could yield reductions in capital, operating, and auxiliary power requirements and could reduce the cost of capture significantly or improve performance. More specifically, post combustion carbon capture systems generally fall into one of several categories: solvents, sorbents, membranes, cryogenic, and molten carbonate fuel cells[809] systems. It is

[802] CCS reduced the net output of the NETL F class combined cycle EGU from 726 MW to 645 MW.

[803] Although not our primary approach to assessing costs in this final rule, for consistency with the proposal's assumption capacity factor, these calculations use a service life of 30 years, an interest rate of 7.0 percent, a natural gas price of $3.61/MMBtu, and a capacity factor of 65 percent. These costs do not include CO_2 transport, storage, or monitoring costs.

[804] Recent DOE analysis has compared the NETL costs with more recent FEED study costs and expert interviews and determined they are consistent after accounting for differences in inflation, economic assumptions, and other technology details. *Portfolio Insights: Carbon Capture in the Power Sector,* DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[805] Energy Procedia. (2014). *Impact of exhaust gas recirculation on combustion turbines. Energy and economic analysis of the CO_2 capture from flue gas of combined cycle power plants. https://www.sciencedirect.com/science/article/pii/S1876610214001234.*

[806] For example, see the article *CCUS Market Outlook 2023: Announced Capacity Soars by 50%,* which states, ''New gas power plants with carbon capture, for example, could be cheaper than unabated power in Germany as early as next year when coupled with the carbon price.'' *https://about.bnef.com/blog/ccus-market-outlook-2023-announced-capacity-soars-by-50/.*

[807] The DOE has also previously funded FEED studies for natural gas-fired combined cycle turbine facilities. These include FEED studies at existing combined cycle turbine facilities at Panda Energy Fund in Texas, Elk Hills Power Plant in Kern County, California, Deer Park Energy Center in Texas, Delta Energy Center in Pittsburg, California, and utilization of a Piperazine Advanced Stripper (PZAS) process for CO_2 capture conducted by The University of Texas at Austin.

[808] *Portfolio Insights: Carbon Capture in the Power Sector* report. DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[809] Molten carbonate fuel cells are configured for emissions capture through a process where the flue gas from an EGU is routed through the molten carbonate fuel cell that concentrates the CO_2 as a side reaction during the electric generation process

expected that as CCS infrastructure increases, technologies from each of these categories will become more economically competitive. For example, advancements in solvents that are potentially direct substitutes for current amine-solvents will reduce auxiliary energy requirements and reduce both operating and capital costs, and thereby, increase the economic competitiveness of CCS.[810] Planned large-scale projects, pilot plants, and research initiatives will also decrease the capital and operating costs of future CCS technologies.

In general, CCS costs have been declining as carbon capture technology advances.[811] While the cost of capture has been largely dependent on the concentration of CO_2 in the gas stream, advancements in varying individual CCS technologies tend to drive down the cost of capture for other CCS technologies. The increase in CCS investment is already driving down the costs of near-future CCS technologies. The Global CCS Institute has tracked publicly available information on previously studied, executed, and proposed CO_2 capture projects.[812] The cost of CO_2 capture from low-to-medium partial pressure sources such as coal-fired power generation has been trending downward over the past decade, and is projected to fall by 50 percent by 2025 compared to 2010. This is driven by the familiar learning-processes that accompany the deployment of any industrial technology. A review of learning rates (the reduction in cost for a doubling of production or capacity) for various energy related technologies similar to carbon capture (flue gas desulfurization, selective catalytic reduction, combined cycle turbines, pulverized coal boilers, LNG production, oxygen production, and hydrogen production via steam methane reforming) demonstrated learning rates of 5 percent to 27 percent for both capital expenditures and operations and maintenance costs.[813] [814] Studies of the cost of capture and compression of CO_2 from power stations completed 10 years ago averaged around \$95/metric ton (\$2020). Comparable studies completed in 2018/2019 estimated capture and compression costs could fall to approximately \$50/metric ton CO_2 by 2025. Current target pricing for announced projects at coal-fired steam generating units is approximately \$40/metric ton on average, compared to Boundary Dam whose actual costs were reported to be \$105/metric ton, noting that these estimates do not include the impact of the 45Q tax credit as enhanced by the IRA. Additionally, IEA suggests this trend will continue in the future as technology advancements ''spill over'' into other projects to reduce costs.[815] Similarly, EIA incorporates a minimum 20 percent reduction in carbon capture and sequestration costs by 2035 in their Annual Energy Outlook 2023 modeling in part to account for the impact of spillover and international learning.[816] The Annual Technology Baseline published by NREL with input from NETL projects a 10 percent reduction in capital expenditures from 2021 through 2032 in the ''Conservative Technology Innovation Scenario'' for natural gas carbon capture retrofit projects, under the assumption that only learning processes lead to future cost reductions and that there are no additional improvements from investments in targeted technology research and development.[817] In a recent case study of the cost and performance of carbon capture retrofits on existing natural gas combined cycle units, based on discussions with external technology providers, engineering consultants, asset developers, and applicants for DOE awards, DOE used a 25 percent capital cost reduction estimate to illustrate the potential future capital costs of an Nth-of-a-Kind facility, as well as ''conservatively model[ing]'' operating expense reductions at 1 percent, for a combined overall decrease in the levelized cost of energy of about 10 percent for the Nth-of-a-Kind facility compared to a First-of-a-Kind facility.[818] DOE further found this illustrative cost reduction estimate from learning through doing to be consistent with other studies that use hybrid engineering-economic and experience-curve approaches to estimate potential decreases in the levelized cost of energy of 10–11 percent for Nth-of-a-Kind plants compared with First-of-a-Kind plants.[819] [820] Policies in the IIJA and IRA are further increasing investment in CCS technology that can accelerate the pace of innovation and deployment.

(2) CO_2 Transport and Sequestration Costs

NETL's ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies'' provides an estimation of transport costs based on the CO_2 Transport Cost Model.[821] The CO_2 Transport Cost Model estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.

NETL's Quality Guidelines also provide an estimate of sequestration costs. These costs reflect the cost of site screening and evaluation, permitting and construction costs, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Permitting and construction costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. NETL calculates these sequestration costs on the basis of generic plant locations in the Midwest, Texas, North Dakota, and Montana, as described in the NETL energy system studies.[822]

in the fuel cell. FuelCell Energy, Inc. (2018). *SureSource Capture. https://www.fuelcellenergy.com/recovery-2/suresource-capture/*.

[810] DOE. *Carbon Capture, Transport, & Storage. Supply Chain Deep Dive Assessment.* February 24, 2022. *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf*.

[811] International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions—A new era for CCUS. https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus*. The same is true for CCS on coal-fired EGUs.

[812] Technology Readiness and Costs of CCS (2021). Global CCS Institute. *https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf*.

[813] *https://www.sciencedirect.com/science/article/pii/S1750583607000163*.

[814] As an additional example for cost reductions from learning processes via deployment achieved in other complex power generation projects, the most recent sustained deployment of 19 nuclear reactors in South Korea from 1989 through 2008 resulted in a 13 percent reduction in capital costs. *https://www.sciencedirect.com/science/article/pii/S0301421516300106*.

[815] International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions—CCUS technology innovation. https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus*.

[816] Energy Information Administration (EIA) (2023). *Assumptions to the Annual Energy Outlook 2023: Electricity Market Module. https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf*.

[817] National Renewable Energy Laboratory (NREL) (2023). *Annual Technology Baseline 2023. https://atb.nrel.gov/electricity/2023/fossil_energy_technologies*.

[818] *Portfolio Insights: Carbon Capture in the Power Sector.* DOE. 2024. *https://www.energy.gov/oced/portfolio-strategy*.

[819] *https://www.frontiersin.org/articles/10.3389/fenrg.2022.987166/full*.

[820] *https://www.sciencedirect.com/science/article/pii/S1750583607000163*.

[821] Grant, T., *et al.* ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies.'' National Energy Technology Laboratory. 2019. *https://www.netl.doe.gov/energy-analysis/details?id=3743*.

[822] National Energy Technology Laboratory (NETL), ''FE/NETL CO2 Saline Storage Cost Model (2017),'' U.S. Department of Energy, DOE/NETL–2018–1871, 30 September 2017. *https://netl.doe.gov/energy-analysis/details?id=2403*.

There are two primary cost drivers for a CO_2 sequestration project: the rate of injection of the CO_2 into the reservoir and the areal extent of the CO_2 plume in the reservoir. The rate of injection depends, in part, on the thickness of the reservoir and its permeability. Thick, permeable reservoirs provide for better injection and fewer injection wells. The areal extent of the CO_2 plume depends on the sequestration capacity of the reservoir. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have lower testing and monitoring costs. NETL's Quality Guidelines model costs for a given cumulative storage potential.[823]

In addition, provisions in the IIJA and IRA are expected to significantly increase the CO_2 pipeline infrastructure and development of sequestration sites, which, in turn, are expected to result in further cost reductions for the application of CCS at a new combined cycle EGUs. The IIJA establishes a new Carbon Dioxide Transportation Infrastructure Finance and Innovation program to provide direct loans, loan guarantees, and grants to CO_2 infrastructure projects, such as pipelines, rail transport, ships and barges.[824] The IIJA also establishes a new Regional Direct Air Capture Hubs program which includes funds to support four large-scale, regional direct air capture hubs and more broadly support projects that could be developed into a regional or inter-regional network to facilitate sequestration or utilization.[825] DOE is additionally implementing IIJA section 40305 (Carbon Storage Validation and Testing) through its CarbonSAFE initiative, which aims to further development of geographically widespread, commercial-scale, safe storage.[826] The IRA increases and extends the IRC section 45Q tax credit, discussed next.

(3) IRC Section 45Q Tax Credit

For the reasons explained in section VII.C.1.a.ii of this preamble, in determining the cost of CCS, the EPA is taking into account the tax credit provided under IRC section 45Q, as revised by the IRA. The tax credit is available at $85/metric ton ($77/ton) and offsets a significant portion of the capture, transport, and sequestration costs noted above.

(4) Total Costs of CCS

In a typical NSPS analysis, the EPA amortizes costs over the expected operating life of the affected facility and assumes constant revenue and expenses over that period of time. For a new combustion turbine, the expected operating life is 30 years. The EPA has adjusted that analysis in this rule to account for the fact that the IRC section 45Q tax credit is available for only the 12 years after operation is commenced. Since the duration of the tax credit is less than the expected life of a new base load combustion turbine, the EPA conducted the costing analysis by recognizing that the substantial revenue available for sequestering CO_2 during the first 12 years of operation is expected to result in higher capacity factors for that period, and the potential higher operating costs during the subsequent 18 years when the 45Q tax credit is not available is likely to result in lower capacity factors (see final TSD, *Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines* for more discussion).[827] [828]

Specifically, the EPA's cost analysis assumes that the combined cycle turbine operates at a capacity of 80 percent over the initial 12-year period. This capacity level is generally consistent with the IPM model projections of 87 percent (and, in fact, somewhat more conservative). The 80 percent capacity factor assumption is also less than the 85 percent capacity factor assumption in the NETL analysis.[829] But notably, the higher capacity factors in the IPM analysis and in the NETL analysis suggest that higher capacity factors may be reasonable and as figure 8 in the final TSD, *Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines* demonstrates, would result in even lower costs. The analysis further assumes that the turbine operates at a capacity of 31 percent during the remaining 18-year period. As explained in the final TSD, *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines,* to avoid impacting the compliance costs due to changes in the overall capacity factors with the base case, the EPA kept the overall 30-year capacity factor at the historical average of 51 percent. The EPA evaluated several operational scenarios (as described in the TSD). The scenario with an initial 12-year capacity factor of 80 percent and a subsequent 18-year capacity factor of 31 percent (for a 30-year capacity factor of 51 percent) represents the primary policy case. It should be noted that at a 31 percent capacity factor, the combustion turbine would be subcategorized as an intermediate load combustion turbine, and therefore would be subject to a less stringent standard of performance that is based on efficient operation, not on the use of CCS.

This costing approach results in lower compliance costs than assuming a constant capacity factor for the 30-year useful life of the turbine because of increased revenue from generation during the initial 12-year period, increased revenue from the IRC section 45Q tax credits during that period, and lower costs during the last 18 years when the tax credit is not available. As noted, this is a reasonable approach because the economic incentive provided by the tax credit is so significant on a $/ton basis that the EPA expects sources to dispatch at higher levels while the tax credit is in effect.

The EPA calculated two sets of CCS costs: the first assumes that the turbine continues to operate the capture system during the last 18 years, and the second assumes that the turbine does not operate the capture system during the last 18 years.[830] Assuming continued operation of the capture equipment, the compliance costs are $15/MWh and $46/ton ($51/metric ton) for a 6,100 MMBtu/h H-Class turbine, which has a net output of approximately 990 MW; and $19/MWh and $57/ton ($63/metric ton) for a 4,600 MMBtu/h F-Class turbine, which has a net output of

[823] Department of Energy. Regional Direct Air Capture Hubs. (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[824] DOE. Carbon Dioxide Transportation Infrastructure. *https://www.energy.gov/lpo/carbon-dioxide-transportation-infrastructure.*

[825] Department of Energy. "Regional Direct Air Capture Hubs." (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[826] For more information, see the NETL announcement. *https://www.netl.doe.gov/node/12405.*

[827] In the proposal, the EPA used a constant 65 percent capacity factor, representative of the initial capacity factor of recently constructed combined cycle turbines, and effective 30-year 45Q tax credit of $41/ton. For this final rule, the EPA considers the approach of using a higher capacity factor for the first 12 years and a lower one for the last 18 years to reflect more accurately actual operating conditions, and therefore to be a more realistic basis for calculating CCS costs.

[828] The EPA's cost approach for CCS for existing coal-fired units also assumed that those units would increase their capacity during the 12-year period when the 45Q tax credit was available. See preamble section VII.C.1.a.ii, and *Greenhouse Gas Mitigation Measures for Steam Generating Units* TSD section 4.7.5. Because coal-fired power plants are existing plants, the EPA calculated CCS costs by assuming a 12-year amortization period for the CCS equipment, and the EPA did not need to make any assumptions about the operation of the coal-fired unit after the 12-year period.

[829] Compliance costs would be lower if higher capacity factors were used during the first 12 years of operation.

[830] The CCS and CO_2 TS&M costs are amortized over the period the equipment is operated—30 years or 12 years.

approximately 700 MW.[831] [832] If the capture system is not operated while the combustion turbine is subcategorized as an intermediate load combustion turbine, the compliance costs are reduced to $8/MWh and $43/ton ($47/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $12/MWh and $60/ton ($66/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. All of these costs are comparable to the cost metrics that, based on prior rules, the EPA finds to be reasonable in this rulemaking.[833] For a more detailed discussion of costs, see the TSD—*GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* section 2.3, Figure 12a.

The EPA considers these CCS cost estimates to be conservatively high because they do not take into account cost improvements from the potential use of exhaust gas recirculation, which, according to one study, could lower LCOE by 3.4 percent, as described in preamble section VIII.F.4.c.iv.(C)(1). Nor do they consider the potential for additional efficiency improvements for combined cycle units [834] or CCS technological advances, as discussed in preamble section VIII.F.4.c.iv.(B)(1)(b), VIII.F.4.c.iv.(C)(1), and RTC section 3.1. The EPA considers that at least some of these cost improvements are likely. Accordingly, the EPA also calculated the CCS costs based on an assumed 5 percent reduction in costs, in order to approximate these likely improvements, as follows: Assuming continued operation of the capture equipment, the compliance costs are $13/MWh and $40/ton ($44/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $18/MWh and $54/ton ($59/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. If the capture system is not operated while the combustion turbine is subcategorized as in intermediate load combustion turbine, the compliance costs are reduced to $8/MWh and $39/ton ($43/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $11/MWh and $56/ton ($61/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine.

In addition, the EPA considers all those costs to be conservative (in favor of higher costs) because they assume that the combustion turbine operator will not receive any revenues from captured CO_2 after the 12-year period for the tax credit. In fact, it is plausible that there will be sources of revenue, potentially including from the sale of the CO_2 for utilization and credits to meet state or corporate clean energy goals, as discussed in RTC section 2.2.4.3.

It should be noted that natural gas-fired combustion turbines with CCS may well generate at higher capacity factors after the expiration of the 45Q tax credit than the EPA's above-described BSER cost analysis assumes. In fact, the EPA's IPM model projects that the natural gas combined cycle generation that is projected to install CCS in the illustrative final rule scenario operates at an average 73 percent capacity factor, due to existing state regulatory requirements, during the 2045 model year, which is after the expiration of the 45Q tax credit. In addition, as discussed in RTC section 2.2.4.3, it is plausible that following the 12-year period of the tax credit, by the 2040s, cost improvements in CCS operations, more widespread adoption of CO_2 emission limitation requirements in the electricity sector, and greater demand for CO_2 for beneficial uses will support continued operation of fossil fuel-fired generation with CCS. Accordingly, the EPA also calculated CCS costs assuming that new F-Class and H-Class combustion turbines with CCS generate at a constant capacity factor of at least 60 percent, and up to 80 percent, during their 30-year useful life. In this calculation, the EPA amortized the costs of CCS over the 30-year useful life of the turbine. The EPA includes these costs in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* section 2.3, Figure 8.[835] At the lower levels of capacity, costs are higher than described above (which assumed 80 percent capacity during the first 12 years), but even at those lower levels, the costs are broadly consistent with the cost-reasonable metrics based on prior rules, particularly when those costs are reduced by an additional 5 percent to account for improved efficiency and other factors, as noted above. Nonetheless, consistent with the EPA's commitment to review, and if appropriate, revise the emission guidelines for coal-fired steam generating units as discussed in section VII.F, the EPA also intends to evaluate, by 2041, the continued cost-reasonableness of CCS for natural gas-fired combustion turbines in light of these potential significant developments, and will consider at that time whether a future regulatory action may be appropriate.

(5) Comparison to Other Costs of Controls

The costs for CCS applied to a representative new base load stationary combustion turbine EGU are generally lower than the costs of other controls in EPA rules for fossil fuel-fired electric generating units, as well as the costs of other controls for greenhouse gases, as described in section VII.C.1.a.ii(D), which supports the EPA's view that the CCS costs are reasonable.

(D) Non-Air Quality Health and Environmental Impact and Energy Requirements

In this section of the preamble, the EPA considers the non-air quality health and environmental impacts of CCS for new combined cycle turbines and concludes there are limited consequences related to non-air quality health and environmental impact and energy requirements. The EPA first discusses energy requirements, and then considers non-GHG emissions impacts and water use impacts, resulting from the capture, transport, and sequestration of CO_2.

With respect to energy requirements, including a 90 percent or greater carbon capture system in the design of a new combined cycle turbine will increase the unit's parasitic/auxiliary energy demand and reduce its net power output. A utility that wants to construct a combined cycle turbine to provide 500 MWe-net of power could build a

[831] The output of the H-Class model combined cycle EGU without CCS is 992 MW. The auxiliary load of CCS reduces the net out to 883 MW. The output of the F-Class model combined cycle EGU without CCS is 726 MW. The auxiliary load of CCS reduces the net out to 645 MW.

[832] As we explain in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* sections 2.3–2.5, the 6,100 MMBtu/h H-Class combustion turbine is the median size of recently constructed combined cycle facilities and the 4,600 MMBtu/h F-Class combustion turbine approximates the size of a number of recently constructed combined cycle facilities as well. CCS costs for smaller sources are higher but are not prohibitive. *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines* TSD, section 2.3, Figures 12a and 13. As noted in RTC section 3.1, we expect costs to decrease due to learning by doing and technological development. In addition, since the incremental generating costs of larger more efficient combined cycle turbines are lower relative to smaller combined cycle turbines, it is more likely that larger more efficient combined cycle turbine will operate as base load combustion turbines.

[833] A DOE analysis of a representative NGCC plant using CCS in the ERCOT market indicates that operating at high operating capacity could be profitable today with the IRC 45Q tax credits. *Portfolio Insights: Carbon Capture in the Power Sector.* DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[834] These additional efficiency improvements are noted in the final TSD, *Efficient Generation: Combustion Turbine Electric Generating Units.*

[835] The compliance costs assume the same capacity factors in the base and policy case, that is, without CCS and with CCS. If combined cycle turbine with CCS were to operate at higher capacity factors in the policy case, compliance costs would be reduced.

500 MWe-net plant knowing that it will be de-rated by 11 percent (to a 444 MWe-net plant) with the installation and operation of CCS. In the alternative, the project developer could build a larger 563 MWe-net combined cycle turbine knowing that, with the installation of the carbon capture system, the unit will still be able to provide 500 MWe-net of power to the grid. Although the use of CCS imposes additional energy demands on the affected units, those units are able to accommodate those demands by scaling larger, as needed.

Regardless of whether a unit is scaled larger, the installation and operation of CCS itself does not impact the unit's potential-to-emit any criteria air pollutants. In other words, a new base load stationary combustion turbine EGU constructed using highly efficient generation (the first component of the BSER) would not see an increase in emissions of criteria air pollutants as a direct result of installing and using 90 percent or greater CO_2 capture CCS to meet the second phase standard of performance.[836]

Scaling a unit larger to provide heat and power to the CO_2 capture equipment would have the potential to increase non-GHG air emissions. However, most pollutants would be mitigated or controlled by equipment needed to meet other CAA requirements. In general, the emission rates and flue gas concentrations of most non-GHG pollutants from the combustion of natural gas in stationary combustion turbines are relatively low compared to the combustion of oil or coal in boilers. As such, it is not necessary to use an FGD to pretreat the flue gas prior to CO_2 removal in the CO_2 scrubber column. The sulfur content of natural gas is low relative to oil or coal and resulting SO_2 emissions are therefore also relatively low. Similarly, PM emissions from combustion of natural gas in a combustion turbine are relatively low. Furthermore, the high combustion efficiency of combustion turbines results in relatively low HAP emissions. Additionally, combustion turbines at major sources of HAP are subject to the stationary combustion turbine NESHAP, which includes limits for formaldehyde emissions for new sources that may require installation of an oxidation catalyst (87 FR 13183; March 9, 2022). Regarding NO_X emissions, in most cases, the combustion turbines in new combined cycle units will be equipped with low-NO_X burners to control flame temperature and reduce NO_X formation. Additionally, new combined cycle units are typically subject to major NSR requirements for NO_X emissions, which may require the installation of SCR to comply with a control technology determination by the permitting authority. See section XI.A of this preamble for additional details regarding the NSR program. Although NO_X concentrations may be controlled by SCR, for some amine solvents NO_X in the post-combustion flue gas can react in the CO_2 absorber to form nitrosamines. A conventional multistage water wash or acid wash and a mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.,* nitrosamine) emissions.[837] [838] Acetaldehyde and formaldehyde can form through oxidation of the solvent, however, this can be mitigated by selecting compatible materials to limit catalytic oxidation and interstage cooling in the absorber to limit thermal oxidation.

The use of water for cooling presents an additional issue. Due to their relatively high efficiency, combined cycle EGUs have relatively small cooling requirements compared to other base load EGUs. According to NETL, a combined cycle EGU without CCS requires 190 gallons of cooling water per MWh of electricity. CCS increases the cooling water requirements due both to the decreased efficiency and the cooling requirements for the CCS process to 290 gallons per MWh, an increase of about 50 percent. However, because combined cycle turbines require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS is relatively small compared to the amount of water used by a coal-fired EGU. A coal-fired EGU without CCS requires 450 gallons or more per MWh and the industry has demonstrated an ability to secure these quantities of water and the EPA has determined that the increased water requirements for CCS can be addressed. In addition, many combined cycle EGUs currently use dry cooling technologies and the use of dry or hybrid cooling technologies for the CO_2 capture process would reduce the need for additional cooling water. Therefore, the EPA is finalizing a determination that the challenges of additional cooling requirements from CCS are limited and do not disqualify CCS from being the BSER.

Stakeholders have shared with the EPA concerns about the safety of CCS projects and that historically disadvantaged and overburdened communities may bear a disproportionate environmental burden associated with CCS projects.[839] The EPA takes these concerns seriously, agrees that any impacts to historically disadvantaged and overburdened communities are important to consider, and has done so as part of its analysis discussed at section XII.E. For the reasons noted above, the EPA does not expect CCS projects to result in uncontrolled or substantial increases in emissions of non-GHG air pollutants from new combustion turbines. Additionally, a robust regulatory framework exists to reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. These projects will likely be subject to major NSR requirements for their emissions of criteria pollutants, and therefore the sources would be required to (1) control their emissions of attainment pollutants by applying BACT and demonstrate the emissions will not cause or contribute to a NAAQS violation, and (2) control their emissions of nonattainment pollutants by applying LAER and fully offset the emissions by securing emission reductions from other sources in the area. Also, as mentioned in section VII.C.1, carbon capture systems that are themselves a major source of HAP should evaluate the applicability of CAA section 112(g) and conduct a case-by-case MACT analysis if required, to establish MACT for any listed HAP, including listed nitrosamines, formaldehyde, and acetaldehyde. But, as also discussed in section VII.C.1, a conventional multistage water or acid wash and mist eliminator (demister) at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.,* nitrosamine) emissions. Additionally, as noted in

[836] While the absolute onsite mass emissions would not increase from the second component of the BSER, the emissions rate on a lb/MWh-net basis would increase by 13 percent.

[837] Sharma, S., Azzi, M., ''A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies,'' *Fuel,* 121, 178 (2014).

[838] Mertens, J., *et al.,* ''Understanding ethanolamine (MEA) and ammonia emissions from amine-based post combustion carbon capture: Lessons learned from field tests,'' *Int'l J. of GHG Control,* 13, 72 (2013).

[839] In outreach with potentially vulnerable communities, residents have voiced two primary concerns. First, there is the concern that their communities have experienced historically disproportionate burdens from the environmental impacts of energy production, and second, that as the sector evolves to use new technologies such as CCS, they may continue to face disproportionate burden. This is discussed further in section XII.E of this preamble.

section VII.C.1.a.i.(C) of this preamble, PHMSA oversight of supercritical CO_2 pipeline safety protects against environmental release during transport and UIC Class VI regulations under the SDWA, in tandem with GHGRP requirements, ensure the protection of USDWs and the security of geologic sequestration.

The EPA is committed to working with its fellow agencies to foster meaningful engagement with communities and protect communities from pollution. This can be facilitated through the existing detailed regulatory framework for CCS projects and further supported through robust and meaningful public engagement early in the technological deployment process.

The EPA also expects that the meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders, including community members who might be adversely impacted by non-GHG pollutants, will have an opportunity to raise this concern with states and permitting authorities. Additionally, state permitting authorities, and project developers are, in general, required to provide public notice and comment on permits for such projects. This provides additional opportunities for affected stakeholders to engage in that process, and it is the EPA's expectation that the responsible entities consider these concerns and take full advantage of existing protections. Moreover, the EPA through its regional offices is committed to thoroughly review permits associated with CO_2 capture.

(E) Impacts on the Energy Sector

The EPA does not believe that determining CCS to be BSER for base load combustion turbines will cause reliability concerns, for several independent reasons. First, the EPA is finalizing a determination that the costs of CCS are reasonable and comparable to other control requirements the EPA has required the electric power industry to adopt without significant effects on reliability. Second, base load combined cycle turbines are only one of many options that companies have to build new generation. The EPA expects there to be considerable interest in building intermediate load and low load combustion turbines to meet demand for dispatchable generation. Indeed, the portion of the combustion turbine fleet that is operating at base load is declining as shown in the EPA's reference case modeling (Power Sector Platform 2023 using IPM reference case, see section IV.F of the preamble). In 2023, combined cycle turbines are only expected to represent 14 percent of all new generating capacity built in the U.S. and only a portion of that is natural gas combined cycle capacity.[840] Several companies have recently announced plans to move away from new combined cycle turbine projects in favor of more non-base load combustion turbines, renewables, and battery storage. For example, Xcel recently announced plans to build new renewable power generation instead of the combined cycle turbine it had initially proposed to replace the retiring Sherco coal-fired plant.[841] Finally, while CCS is adequately demonstrated and cost-reasonable, this final rulemaking allows companies that want to build a base load combined cycle turbine another compliance option to meet its requirements: building a unit that co-fires low-GHG hydrogen in the appropriate amount to meet the standard of performance. In fact, companies are currently pursuing both of these options—units with CCS as well as units that will co-fire low-GHG hydrogen are both in various stages of development. For these reasons, determining CCS to be the BSER for base load units will not cause reliability concerns.

(F) Extent of Reductions in CO_2 Emissions

Designating CCS as a component of the BSER for certain base load combustion turbine EGUs prevents large amounts of CO_2 emissions. For example, a new base load combined cycle EGU without CCS could be expected to emit 45 million tons of CO_2 over its 30-year operating life, or 1.5 million tons of CO_2 per year. Use of CCS would avoid the release of nearly 41 million tons of CO_2 over the operating life of the combined cycle EGU, or 1.37 million tons per year. However, due to the auxiliary/parasitic energy requirements of the carbon capture system, capturing 90 percent of the CO_2 does not result in a corresponding 90 percent reduction in CO_2 emissions. According to the NETL baseline report, adding a 90 percent CO_2 capture system increases the EGU's gross heat rate by 7 percent and the unit's net heat rate by 13 percent. Since more fuel would be consumed in the CCS case, the gross and net emissions rates are reduced by 89.3 percent and 88.7 percent respectively. These amounts of CO_2 emissions and reductions are larger than for any other industrial source, except for coal-fired steam generating units.

(G) Promotion of the Development and Implementation of Technology

The EPA also considered whether determining CCS to be a component of the BSER for new base load combustion turbines will advance the technological development of CCS and concluded that this factor further corroborates our BSER determination. A standard of performance based on highly efficient generation in combination with the use of CCS—combined with the availability of IRC section 45Q tax credits and investments in supporting CCS infrastructure from the IIJA—should result in more widespread adoption of CCS. In addition, while solvent-based CO_2 capture has been adequately demonstrated at the commercial scale, a CCS-based standard of performance may incentivize the development and use of better-performing solvents or other components of the capture equipment.

Furthermore, the experience gained by utilizing CCS with stationary combustion turbine EGUs, with their lower CO_2 flue gas concentration relative to other industrial sources such as coal-fired EGUs, will advance capture technology with other lower CO_2 concentration sources. The EIA 2023 Annual Energy Outlook projects that almost 862 billion kWh of electricity will be generated from natural gas-fired sources in 2040.[842] Much of that generation is projected to come from existing combined cycle EGUs and further development of carbon capture technologies could facilitate increased retrofitting of those EGUs.

(H) Summary of BSER Determination

As discussed, the EPA is finalizing a determination that the second component of the BSER for base load stationary combustion turbines is the utilization of CCS at 90 percent capture. The EPA has determined that 90 percent CCS meets the criteria for BSER for new base load combustion turbines. It is an adequately demonstrated technology that can be implemented a reasonable cost. Importantly, use of CCS at 90 percent capture results in significant reductions of CO_2 as compared to a base load combustion turbine without CCS. In addition, the EPA has considered non-air quality and energy impacts. Considering all these factors together, with particular emphasis on the importance of significantly reducing carbon pollution from these heavily utilized sources, the EPA concludes that

[840] *https://www.eia.gov/todayinenergy/detail.php?id=55419.*

[841] *https://cubminnesota.org/xcel-is-no-longer-pursuing-gas-power-plant-proposes-more-renewable-power/.*

[842] Does not include 114 billion kilowatt hours from natural gas-fired CHP projected in AEO 2023.

CCS at 90 percent capture is BSER for new base load combustion turbines. In addition, selecting CCS at 90 percent capture further promotes the development and implementation of this critical carbon pollution reduction technology, which confirms the appropriateness of determining it to be the BSER.

The BSER for base load combustion turbines contains two components and the EPA is promulgating standards of performance to be implemented in two phases with each phase reflecting the degree of emission reduction achievable through the application of each component of the BSER. The first component of the BSER is most efficient generation—an affected new base load combustion turbine must be constructed (or reconstructed) to meet a phase 1 emission standard that reflects the emission rate of the best performing combustion turbine systems. The phase 1 standard of performance for base load combustion turbines is in effect immediately once the source begins operation. The second component of the BSER, as just discussed, is use of CCS at a 90 percent capture rate. The phase 2 standard of performance for base load combustion turbines reflects the implementation of 90 capture CCS on a highly efficient combined cycle combustion turbine system. The compliance date begins January 1, 2032.

(I) January 2032 Compliance Date

The EPA proposed a compliance date beginning January 1, 2035, for new and reconstructed base load stationary combustion turbines subject to the phase 2 standard of performance based on CCS as the BSER. Some commenters were supportive of the proposed compliance date and some urged the EPA to set an earlier compliance date; the EPA also received comments on the proposed rule that stated that the proposed compliance date was not achievable and referenced longer project timelines for CO_2 capture. The EPA has considered the comments and information available and is finalizing a compliance date of January 1, 2032, for the phase 2 standard of performance for base-load stationary combustion turbines. The EPA is also finalizing a mechanism for a compliance date extension of up to 1 year in cases where a source faces a delay in the installation and startup of controls that are beyond the control of the EGU owner or operator, as detailed in section VIII.N of this preamble.

In total, the January 1, 2032, compliance date allows for more than 7 years for installation of CCS after issuance of this rule for sources that have recently commenced construction. This is consistent with the extended project schedule in the Sargent & Lundy report. This is also greater than the approximately 6 years from start to finish for Boundary Dam Unit 3 and Petra Nova.

As discussed in section VII.C.1.a.i(E), the timing for installation of CCS on existing coal-fired steam generating units is based on the baseline project schedule for the capture plant developed by Sargent and Lundy (S&L) [843] and a review of the available information for installation of CO_2 pipelines and sequestration sites.[844] The representative timeline for CCS for coal-fired steam generating units is detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket, and the anticipated timeline for development of a CCS project for application at a new or reconstructed base load stationary combustion turbine would be similar. The explanations the EPA provided in section VII.C.1.a.i(E) regarding the timeline for long-term coal-fired steam generating units generally apply to new combustion turbines as well. The EPA expects that the owners or operators of affected combustion turbines will be able to complete the design, planning, permitting, engineering, and construction steps for the carbon capture and transport and storage systems in a similar amount of time as projects for coal-fired EGUs.

While those considerations apply in general, the EPA notes that the timeline for the installation of CCS on coal-fired steam generating units accounted for the state plan development process. Because there are not state plans required for new combustion turbines, new sources can commit to beginning substantial work earlier (*e.g.,* FEED studies, right-of-way acquisition), immediately after the completion of feasibility work. However, the EPA also recognizes that other elements of a state plan (*e.g.,* RULOF), by which a source under specific circumstances could have a later compliance date, are not available to new sources. Therefore, while the timeline for CCS on coal-fired steam generating units is based on the baseline S&L capture plant schedule (about 6.25 years), the EPA bases the timeline for CCS on new combustion turbines on the extended S&L capture plant schedule (7 years).

As discussed, base load stationary combustion turbines that commence construction or reconstruction on or after May 23, 2023, are subject to standards of performance that are implemented initially in two phases. New stationary combustion turbines that are designed and constructed for the purpose of operating in the base load subcategory (*i.e.,* at a 12-operating month capacity factor of greater than 40 percent) that hypothetically commenced construction on May 23, 2023, could, according to the schedule allowing, conservatively, up to 7 years to develop a CCS project, have a system constructed and on-line by May 23, 2030. However, the EPA is finalizing a compliance date of January 1, 2032, because some base load combined cycle stationary combustion projects that commenced construction between May 23, 2023, and the date of this final rule, may not have included CCS in the original design and planning for the new EGU and, therefore, would be unlikely to be able to have an operational CCS system available by May 23, 2030.

Further, the EPA notes that a delayed compliance date (of January 1, 2035) was proposed for the phase 2 standards of performance due to overlapping demands on the capacity to design, construct, and operate carbon capture systems as well as pipeline systems that would potentially be needed to support CCS projects for existing steam generating units and other industrial sources. As discussed in section VII.C.1.a.i(E), in this action the EPA is finalizing a compliance date of January 1, 2032 for long term coal-fired steam generating EGUs to meet a standard of performance based on 90 percent capture CCS. This compliance date for long-term coal-fired steam generating EGUs places fewer demands on the capacity to design, construct, and operate carbon capture systems and the associated infrastructure for those sources. Therefore, the EPA does not believe that there is a need to extend the compliance date for phase 2 standards for base load combustion turbine EGUs by 5 years beyond that for existing coal-fired steam generating EGUs, as proposed.

Considering these factors, the EPA is therefore finalizing the compliance date of January 1, 2032 for base load combustion turbine EGUs to meet the phase 2 standard of performance. This is the same compliance date applicable to existing long term coal-fired steam generating EGUs that are subject to a standard of performance based on 90 percent capture CCS. The EPA assumes the timelines for development of the various components of CCS for an existing coal-fired steam generating

[843] CO_2 Capture Project Schedule and Operations Memo, Sargent & Lundy (2024).

[844] Transport and Storage Timeline Summary, ICF (2024).

EGU, as discussed in section VII.C.1.a.i(E), are very similar for those components for a CCS system serving a new or reconstructed base load combustion turbine EGU.

Some commenters argued that because the power sector will require some amount of time before CCS and associated infrastructure may be installed on a widespread basis, CCS cannot be considered adequately demonstrated. This argument is similar to the argument, discussed in section V.C.2.b, that in order to be adequately demonstrated, a technology must be in widespread commercial use. Both arguments are incorrect. Under CAA section 111, for a control technology to qualify as the BSER, the EPA must demonstrate that it is adequately demonstrated for affected sources. The EPA must also show that the industry can deploy the technology at scale in the compliance timeframe. That the EPA has provided lead time in order to ensure adequate time for industry to deploy the technology at scale shows that the EPA is meeting its statutory obligation, not the inverse. Indeed, it is not at all unusual for the EPA to provide lead time for industry to deploy new technology. The EPA's approach is in line with the statutory text and caselaw encouraging technology-forcing standard-setting cabined by the EPA's obligation to ensure that its standards are reasonable and achievable.

CCS is clearly adequately demonstrated, and ripe for wider implementation. Nevertheless, the EPA acknowledged in the proposed rule, and reaffirms now, that the power sector will require some amount of lead time before individual plants can install CCS as necessary. Deploying CCS requires the building of capture facilities, pipelines to transport captured CO_2 to sequestration sites, and the development of sequestration sites. This is true for both existing coal-fired steam generating EGUs, some of which would be required to retrofit with CCS under the emission guidelines included in this final rulemaking, and new gas-fired combustion turbine EGUs, which must incorporate CCS into their construction planning.

In this final rulemaking, the EPA is setting a compliance deadline of January 1, 2032 for the CCS-based standard for new base load combustion turbines. The EPA determined, examining the evidence and exercising its appropriate discretion to do so, that this is a reasonable amount of time to allow for CCS buildout at the plant level. As the EPA explained at proposal, D.C. Circuit caselaw supports this approach. There, the EPA cited *Portland Cement* v. *Ruckelshaus,* for the proposition that ''D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the 'adequately demonstrated' criterion—even if the controls require some amount of 'lead time,' which the court has defined as 'the time in which the technology will have to be available.' '' (footnote omitted). Nothing in the comments alters the EPA's view of the relevant legal requirements related to adequate demonstration or lead time.

d. BSER for Base Load Subcategory—Third Component

The EPA proposed a third component of the BSER of 96 percent (by volume) hydrogen co-firing in 2038 for owners/operators of base load combustion turbines that elected to comply with the low-GHG hydrogen co-firing pathway. As discussed in the next section, the EPA is not finalizing the proposed BSER pathway of low-GHG hydrogen co-firing at this time. Therefore, the Agency is not finalizing a third component of the BSER for base load combustion turbines.

5. Technologies Proposed by the EPA But Ultimately Not Determined To Be the BSER

The EPA is not finalizing its proposed BSER pathway of low-GHG hydrogen co-firing for new and reconstructed base load and intermediate load combustion turbines as part of this action. In light of public comments and additional analysis, uncertainties regarding projected costs prevent the EPA from determining that low-GHG hydrogen is a component of the BSER at this time.

The next section provides a summary of the proposed requirements for low-GHG hydrogen followed by, in section VIII.F.5.b, an explanation for why the Agency is not finalizing its proposed determination that low-GHG hydrogen co-firing is BSER. In section VIII.F.6, the EPA discusses considerations for the potential use of hydrogen. In section VIII.F.6.a, the Agency explains why it is not limiting the hydrogen that may be co-fired in a new or reconstructed combustion turbine to only low-GHG hydrogen. In section VIII.F.6.b, the Agency discusses its decision to not include a definition of low-GHG hydrogen.

a. Proposed Low-GHG Hydrogen Co-Firing BSER

The EPA proposed that new and reconstructed intermediate load combustion turbines were subject to a second component of the BSER that consisted of co-firing 30 percent (by volume) low-GHG hydrogen by 2032. The EPA also proposed that new and reconstructed base load combustion turbines could elect either (i) a second component of BSER that consisted of installing CCS by 2035, or (ii) a second and third component of BSER that consisted of co-firing 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent (by volume) low-GHG hydrogen by 2038.

The EPA solicited comment on whether the Agency should finalize both the CCS and low-GHG hydrogen co-firing pathways as separate subcategories with separate standards of performance and on whether the EPA should finalize one pathway with the option of meeting the standard of performance using either system of emission reduction (88 FR 33277, May 23, 2023). The EPA also solicited comment on the option of finalizing a single standard of performance based on the application of CCS for the base load subcategory (88 FR 33283, May 23, 2023).

b. Explanation for Not Finalizing Low-GHG Hydrogen Co-Firing as a BSER

The EPA is not finalizing a low-GHG hydrogen co-firing component of the BSER at this time. The EPA proposed that co-firing low-GHG hydrogen qualified as a BSER pathway because the components of the system met specific criteria, namely that the capability of combustion turbines to co-fire hydrogen was adequately demonstrated and there was a reasonable expectation that the necessary quantities of low-GHG hydrogen would be nationally available by 2032 and 2038 at reasonable cost. Due to concerns raised by commenters, the EPA conducted additional analysis of key components of the low-GHG hydrogen best system and the Agency's proposed determination that low-GHG hydrogen co-firing qualified as the BSER. This additional analysis, discussed further below, indicated that the currently estimated cost of low-GHG hydrogen in 2030 is higher than anticipated at proposal. These higher cost estimates were key factors in the EPA's decision to revise its 2030 cost estimate for delivered low-GHG hydrogen.

While the EPA is not finalizing a BSER determination with regard to co-firing with low-GHG hydrogen as part of this rulemaking and is therefore not making any determination about whether such a practice is adequately demonstrated, the Agency notes that there are multiple models of combustion turbines available from major manufacturers that have successfully demonstrated the ability to combust hydrogen. Manufacturers have stated that they expect to have additional models of combustion turbines available that will be capable of firing 100 percent hydrogen while limiting emissions of other pollutants (*e.g.,* NO_X). The EPA further discusses considerations around the technical feasibility of hydrogen co-firing in new and reconstructed combustion turbines, and what they mean for the potential use of hydrogen co-firing as a compliance strategy, in section VIII.F.6 of this preamble.

While the EPA believes that hydrogen co-firing is technically feasible based on combustion turbine technology, information about how the low-GHG hydrogen production industry will develop in the future is not sufficiently certain for the EPA to be able to determine that adequate quantities will be available. That is, there remain, at the time of this final rulemaking, uncertainties pertaining to how the future nationwide availability of low-GHG hydrogen will develop. Relatedly, estimates of its future costs are more uncertain than anticipated at proposal. For low-GHG hydrogen to meet the BSER criteria as proposed, the EPA would have to be able to determine that significant quantities of low-GHG hydrogen will be available at reasonable costs such that affected sources in the power sector nationwide could rely on it for use by 2032 and 2038. While some analyses [845] show that this will likely be the case, the full set of information necessary to support such a determination is not available at this time. However, the EPA believes this may change as the low-GHG hydrogen industry continues to develop. The Agency plans to monitor the development of the industry; if appropriate, the EPA will reevaluate its findings and establish standards of performance that achieve additional emission reductions. Furthermore, as noted above, the EPA considers the co-firing of hydrogen to be technically feasible in multiple models of available combustion turbines.

As noted above, the EPA has revised its cost analysis of low-GHG hydrogen and determined that, due to the present uncertainty, estimated future hydrogen costs are higher than at proposal. The higher estimated cost of low-GHG hydrogen relative to proposal is the key factor in the EPA's decision to not finalize low-GHG hydrogen co-firing as a BSER pathway for new and reconstructed base load and intermediate load combustion turbines at this time.

In the proposal, the EPA modeled low-GHG hydrogen as a fuel available at a fixed delivered [846] price of $1/kg (or $7.40/MMBtu) in the baseline. This cost decreased to $0.50/kg (or $3.70/MMBtu) in the Integrated Proposal case when the second phase of the new combustion turbine standard began in 2032. This fuel was assumed to be ''clean'' and eligible for the highest subsidy under the IRC section 45V hydrogen production tax credit and would comply with the proposed requirement to use low-GHG hydrogen (88 FR 33314, May 23, 2023). The EPA's revised modeling of the power sector for the final rule used a price of $1.15/kg for delivered low-GHG hydrogen in both the final baseline and policy cases. For additional discussion of the EPA's revised modeling of the power sector and increased cost estimate for low-GHG hydrogen, see the final RIA included in the docket for this rulemaking.

The U.S. Department of Energy's 2022 report, *Pathways to Commercial Liftoff: Clean Hydrogen,* informed the EPA's revised low-GHG hydrogen cost analysis. According to the DOE report, the cost to produce, transport, store, and deliver low-GHG or ''clean'' hydrogen is expected to be between $0.70/kg and $1.15/kg by 2030 with the IRA's $3/kg maximum IRC section 45V production tax credit included.[847] The report also points out that the power sector is competing with other industrial sectors—such as transportation, ammonia and chemical production, oil refining, and steel manufacturing—in terms of potential downstream applications of clean hydrogen for the purpose of reducing GHG emissions. The DOE report also estimates that $0.40/kg to $0.50/kg is the price the power sector would be willing to pay for clean hydrogen.

Some analyses of future hydrogen costs provide estimates that are higher than those of the DOE. For example, public commenters estimated the cost of delivered ''clean'' hydrogen to be less than $3/kg by 2030 before declining to $2/kg by 2035. These estimates of delivered hydrogen costs include the IRC section 45V hydrogen production tax credits contained in the IRA, but they do not reflect regulations proposed by the U.S. Department of the Treasury pertaining to clean hydrogen production tax and energy credits, which proposed certain eligibility parameters (88 FR 89220, December 26, 2023). Until Treasury's regulations on the IRC section 45V hydrogen production tax credit are final, some analysts only estimate future production costs of hydrogen, not delivered costs, and do not include any projected potential impacts of the IRA incentives. For example, both McKinsey and BloombergNEF project the unsubsidized production cost of clean hydrogen to be approximately $2/kg by 2030, which could lead to negative to zero prices for some subsidized hydrogen after considering transportation and storage.[848] [849] One of the highest estimates for the unsubsidized production cost of clean hydrogen is from the Rhodium Group, which estimates the price to be from $3.39/kg to $4.92/kg in 2030.[850] Again, it should be noted these estimates do not include additional costs for transportation and storage. The increased cost projections for low-GHG hydrogen production are partly due to higher costs for capital equipment, such as electrolyzers. The DOE published a Program Record [851] detailing higher costs than previously estimated by levering data from the regional clean hydrogen hubs and other literature. Costs increases are predominantly driven by inflation, supply chain cost increases, and higher estimated installation costs. However, there is a significant range in electrolyzer costs; some companies cite costs that are significantly lower ($750-$900/kW installed cost) [852] than that published in the Program Record.

[845] Electric Power Research Institute (EPRI). (November 3, 2023). Impact of IRA's 45V Clean Hydrogen Production Tax Credit. White paper. *https://www.epri.com/research/products/000000003002028407.*

[846] The delivered price includes the cost to produce, transport, and store hydrogen.

[847] U.S. Department of Energy (DOE) (March 2023). *Pathways to Commercial Liftoff: Clean Hydrogen. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.*

[848] Heid, B.; Sator, A.; Waardenburg, M.; and Wilthaner, M. (25 Oct 2022). Five charts on hydrogen's role in a net-zero future. McKinsey & Company. *https://www.mckinsey.com/capabilities/sustainability/our-insights/five-charts-on-hydrogens-role-in-a-net-zero-future.*

[849] Schelling, K. (9 Aug 2023). Green Hydrogen to Undercut Gray Sibling by End of Decade. BloombergNEF. *https://about.bnef.com/blog/green-hydrogen-to-undercut-gray-sibling-by-end-of-decade/.*

[850] Larsen, J.; King, B.; Kolus, H.; Dasari, N.; Bower, G.; and Jones, W. (12 Aug 2022). A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act. Rhodium Group. *https://rhg.com/research/climate-clean-energy-inflation-reduction-act/.*

[851] U.S. Department of Energy (DOE). (February 22, 2024). *Summary of Electrolyzer Cost Data Synthesized from Applications to the DOE Clean Hydrogen Hubs Program.* DOE Hydrogen Program, Office of Clean Energy Demonstrations Program Record. *https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/24002-summary-electrolyzer-cost-data.pdf.*

[852] Martin, P. (December 18, 2023). What gives Bill Gates-backed start-up Electric Hydrogen the edge over other electrolyzer makers? Hydrogen

6. Considerations for the Potential Use of Hydrogen

The ability of combustion turbines to co-fire hydrogen can effectively reduce stack GHG emissions. Hydrogen also offers unique solutions for decarbonization because of its potential to provide dispatchable, clean energy with long-term storage and seasonal capabilities. For example, hydrogen is an energy carrier that can provide long-term storage of low-GHG energy that can be co-fired in combustion turbines and used to balance load with the increasing volumes of variable generation. These services support the reliability of the power system while facilitating the integration of variable zero-emitting energy resources and supporting decarbonization of the electric grid. One technology with the potential to reduce curtailment is energy storage, and some power producers envision a role for hydrogen to supplement natural gas as a fuel to support the balancing and reliability of an increasingly decarbonized electric grid.

Hydrogen is a zero-GHG emitting fuel when combusted, so that co-firing it in a combustion turbine in place of natural gas reduces GHG emissions at the stack. For this reason, certain owners/operators of combustion turbines in the power sector may elect to co-fire hydrogen in the coming years to reduce onsite GHG emissions.[853] Co-firing low-emitting fuels—sometimes referred to as clean fuels—is a traditional type of emissions control. However, the EPA recognizes that even though the *combustion* of hydrogen is zero-GHG emitting, its *production* can entail a range of GHG emissions, from low to high, depending on the method. These differences in GHG emissions from the different methods of hydrogen production are well-recognized in the energy sector (88 FR 33306, May 23, 2023), and, in fact, hydrogen is generally characterized by its production method and the attendant level of GHG emissions.

While the focus of this rule is the reduction of stack GHG emissions from combustion turbines, the EPA also recognizes that, to ensure overall GHG benefits, it is important any hydrogen used in the power sector be low-GHG hydrogen. Thus, even though the EPA is not finalizing the use of low-GHG hydrogen as a component of the BSER for base load or intermediate load combustion turbines, it maintains that the type of hydrogen used (*i.e.,* the method by which the hydrogen was produced) should be a primary consideration for any source that decides to co-fire hydrogen. Again, the Agency reiterates its concern that sources in the power sector that choose to co-fire hydrogen to reduce their GHG emission rate should co-fire only low-GHG hydrogen to achieve overall GHG reductions and important climate benefits.

In the proposal, the EPA solicited comment on whether it is necessary to require low-GHG hydrogen. Similarly, the EPA also solicited comment as to whether the low-GHG hydrogen requirement could be treated as severable from the remainder of the standard such that the standard could function without this requirement. The EPA also solicited comment on a host of recordkeeping and reporting topics. These pertained to the complexities of tracking the sources of quantities of produced low-GHG hydrogen and the public interest in such data.

a. Explanation for Not Requiring Hydrogen Used for Compliance To Be Low-GHG Hydrogen

The EPA proposed that the type of hydrogen co-fired must be limited to low-GHG hydrogen, and not include other types of hydrogen.[854] This requirement was proposed to prevent the anomalous outcome of a GHG control strategy contributing to an increase in overall GHG emissions; the provision that only low-GHG hydrogen could be used for compliance mirrored the EPA's proposal that low-GHG hydrogen, in particular, could qualify as a component of the BSER. For the reasons explained below, the EPA is not finalizing a requirement that any hydrogen that sources choose to co-fire must be low-GHG hydrogen. However, the Agency continues to stress, notwithstanding the lack of requirement under this rule, the importance of ensuring that any hydrogen used in combustion turbines is low-GHG hydrogen. The EPA's choice to not finalize a low-GHG requirement at this time is based in large part on knowledge of current and future efforts that will reinforce the availability and role of low-GHG hydrogen in the national economy and, more specifically, in the power sector. As discussed further below, this decision is against the backdrop of ongoing developments in the public and private sectors, Treasury's regulations implementing a tax credit for the production of clean hydrogen, multiple Federal government grant and assistance programs, and the EPA's investigation into methods to control emissions of air pollutants from hydrogen production.

The EPA's decision to not require that any hydrogen used for compliance be low-GHG hydrogen was based primarily on the current market and policy developments regarding hydrogen production at this particular point in time, including the clean hydrogen production tax credits. There are currently multiple private and public efforts to develop, *inter alia,* greenhouse gas accounting practices, verification protocols, reporting conventions, and other elements that will help determine how low-GHG hydrogen is measured, tracked, and verified over the next several years. For example, Treasury is expected to finalize parameters for evaluating overall emissions associated with hydrogen production pathways as it prepares to implement IRC section 45V.[855] The overall objective of Treasury's parameters is to recognize that different methods of hydrogen production generate different amounts of GHG emissions while encouraging lower-emitting production methods through the multi-tier hydrogen production tax credit (IRC section 45V) (see 88 FR 89220, December 26, 2023). In light of these nascent but fast-moving efforts, the EPA does not believe it is reasonable or helpful to prescribe its own definitions, protocols, and requirements for low-GHG hydrogen at this point in time.

Furthermore, the Agency anticipates that combustion turbines will, despite not being required to do so, use low-GHG hydrogen (to the extent they are co-firing hydrogen as a compliance strategy). Depending on market development in the coming decade, it is reasonable to expect that any hydrogen used in the power sector would generally be low-GHG hydrogen, even without a specific BSER pathway or low-GHG-only requirement included in this final NSPS. For example, several utilities with dedicated access to affordable low-GHG hydrogen are actively developing co-firing projects with the goal of reducing their GHG

Insight. *https://www.hydrogeninsight.com/electrolysers/what-gives-bill-gates-backed-start-up-electric-hydrogen-the-edge-over-other-electrolyser-makers-/2-1-1572694.*

[853] In June 2022, the U.S. Department of Energy (DOE) Loans Program Office issued a $504.4 million loan guarantee to finance the Advanced Clean Energy Storage (ACES) project in Delta, Utah. ACES expects to utilize a 220 MW bank of electrolyzers and curtailed renewable energy to produce clean hydrogen that will be stored in salt caverns. The hydrogen will fuel an 840 MW combined cycle combustion turbine at the Intermountain Power Project facility. *https://www.energy.gov/lpo/advanced-clean-energy-storage.*

[854] 88 FR 33240, 33315 (May 23, 2023).

[855] U.S. Department of the Treasury. (October 5, 2022). Treasury Seeks Public Input on Implementing the Inflation Reduction Act's Clean Energy Tax Incentives. Press release. *https://home.treasury.gov/news/press-releases/jy0993.*

emissions. The infrastructure funding and tax incentives included in the IIJA and the IRA are also driving the development of the low-GHG hydrogen supply chain. These rapid changes in the hydrogen marketplace not only counsel against the EPA's locking in its own requirements at this time; they also provide confidence that greater quantities of low-GHG hydrogen will be available moving forward, even if the precise timing and quantity cannot currently be accurately forecast. The EPA also provides information further below about its intentions to open a non-regulatory docket to engage stakeholders on potential future rulemakings for thermochemical-based hydrogen production facilities to address issues pertaining to GHG, criteria, and HAP emissions.

i. Hydrogen Production and Associated GHGs

Hydrogen is used in industrial processes; in recent years, applications of hydrogen co-firing have also expanded to include stationary combustion turbines used to generate electricity. Several commenters responded to the proposal by stating that to fully evaluate the potential GHG emission reductions from co-firing low-GHG hydrogen in a combustion turbine EGU, it is important to consider the different processes for producing hydrogen and the GHG emissions associated with each process. The EPA agrees that the method of hydrogen production is critical to consider when assessing whether hydrogen co-firing actually reduces overall GHG emissions. As stated previously, the varying levels of CO_2 emissions associated with different hydrogen production processes are well-recognized, and stakeholders routinely refer to hydrogen on the basis of the different production processes and their different GHG profiles.

ii. Technological and Market Transformation of Low-GHG Hydrogen Resources

In the proposal, the EPA highlighted ongoing efforts—independent of any BSER pathway, requirement, or performance standard—of combustion turbine manufacturers and industry stakeholders to research, develop, and deploy hydrogen co-firing technologies (88 FR 33307, May 23, 2023). Their co-firing demonstrations are producing results, such as increasing the percentages (by volume) of hydrogen that a turbine can combust while answering questions regarding safety, performance, reliability, durability, and the emission of other pollutants (*e.g.,* NO_X). Such efforts by industry to invest in the development of hydrogen co-firing, and specifically in projects designed to co-fire low-GHG hydrogen, in particular, give the EPA confidence that any hydrogen that sources do choose to co-fire for compliance under this rule will be low-GHG hydrogen. As these efforts progress, a sharper understanding of costs will come into focus while significant Federal funding—through grants, financial assistance programs, and tax incentives included in the IIJA and the IRA discussed below—is intended to support the continued development of a nationwide clean hydrogen supply chain.

For the most part, companies that have announced that they are exploring the use of hydrogen co-firing have stated that they intend to use low-GHG hydrogen in the future as greater quantities of the fuel become available at lower, stabilized prices. Many utilities and merchant generators own and are developing low-GHG electricity generating sources as well as combustion turbines, with the intent to produce low-GHG hydrogen for sale and to use a portion of it to fuel their stationary combustion turbines.[856] [857] This emerging trend lends support to the view that, while acknowledging the uncertainty of the ultimate timing of implementation, there is growing interest in hydrogen co-firing in the power sector and stakeholders are developing these resources with the intent to increase access to low-GHG hydrogen as they increase hydrogen utilization in their co-firing applications. Additional information provided by commenters and analysis by the EPA identified several new combustion turbine projects planning to co-fire low-GHG hydrogen, even though these low-GHG methods of hydrogen production are not currently readily available on a nationwide basis.[858] [859] [860]

iii. Infrastructure Funding and Tax Incentives Included in the IIJA and IRA

In both the IIJA and the IRA, Congress provided extensive support for the development of hydrogen produced through low-GHG methods. This support includes investment in infrastructure through the IIJA, and the provision of tax credits in the IRA to incentivize the manufacture of hydrogen through low GHG-emitting methods over the coming decades. For example, the IIJA included the H2Hubs program, the Clean Hydrogen Manufacturing and Recycling Program, the Clean Hydrogen Electrolysis Program, and a non-regulatory Clean Hydrogen Production Standard (CHPS).[861] In the IRA, Congress enacted or expanded tax credits to encourage the production and use of low-GHG hydrogen.[862] In addition, as discussed in the proposal, IRA section 60107 added new CAA section 135, or the Low Emission Electricity Program (LEEP). This provision provides $1 million for the EPA to assess the GHG emissions reductions from changes in domestic electricity generation and use anticipated to occur annually through fiscal year 2031; and further provides $18 million for the EPA to promulgate additional CAA rules to ensure GHG emissions reductions that go beyond the reductions expected in that assessment. CAA section 135(a)(5)–(6).

Given the incentives provided in both the IRA and IIJA for low-GHG hydrogen production and the current trajectory of hydrogen use in the power sector, by 2032, the start date for compliance with the proposed second phase of the NSPS, low-GHG hydrogen may be more widely available and possibly the most common source of hydrogen available for electricity production. It is also possible that the cost of delivered low-GHG hydrogen will continue to decline toward the DOE's Hydrogen Shot target. These expectations are based on a combination of economies of scale as low-GHG production methods expand, the increasing availability of low-cost input electricity—largely powered by zero- or low-emitting energy sources—

[856] Mitsubishi Power. (2020). *Intermountain Power Agency Orders MHPS JAC Gas Turbine Technology for Renewable-Hydrogen Energy Hub. https://power.mhi.com/regions/amer/news/200310.html.*

[857] Intermountain Power Agency (2022). *https://www.ipautah.com/ipp-renewed/.*

[858] Los Angeles Department of Water & Power (2023*). Initial Study: Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project. https://ceqanet.opr.ca.gov/2023050366.*

[859] *https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf.*

[860] Hering, G. (2021). First major US hydrogen-burning power plant nears completion in Ohio. *S&P Global Market Intelligence. https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-first-major-us-hydrogen-burning-power-plant-nears-completion-in-ohio.*

[861] U.S. Department of Energy (DOE). (September 22, 2022). Clean Hydrogen Production Standard. Hydrogen and Fuel Cell Technologies Office. *https://www.energy.gov/eere/fuelcells/articles/clean-hydrogen-production-standard.*

[862] These tax credits include IRC section 45V (tax credit for production of hydrogen through low- or zero-emitting processes), IRC section 48 (tax credit for investment in energy storage property, including hydrogen production), IRC section 45Q (tax credit for CO_2 sequestration from industrial processes, including hydrogen production); and the use of hydrogen in transportation applications, IRC section 45Z (clean fuel production tax credit), IRC section 40B (sustainable aviation fuel credit).

and learning by doing as more combustion turbine projects are developed. The EPA recognizes that the pace and scale of government programs and private research suggest that the Agency will gain significant experience and knowledge on this topic in the future.

iv. EPA Non-Regulatory Docket and Stakeholder Engagement on Potential Regulatory Approaches for Emissions From Thermochemical Hydrogen Production

In addition to the ongoing industry development of and Congressional support for low-GHG hydrogen, the EPA is also taking steps consistent with the importance of mitigating GHG emissions associated with hydrogen production. On September 15, 2023, the EPA received a petition from the Environmental Defense Fund (EDF) along with 13 other health, environmental, and community groups, to regulate fossil and other thermochemical methods of hydrogen production given the current emissions from these facilities and the anticipated growth in the sector spurred by IRA incentives. The petition notes that facilities producing hydrogen for sale produced about 10 MMT of hydrogen and emitted more than 40 MMT of CO_2e in 2020.[863] Regulatory safeguards are advocated by petitioners to help ensure that the anticipated growth in this sector does not result in an unbounded increase in emissions of GHGs, criteria, and hazardous air pollutants (HAP). The petition requests that the EPA list hydrogen production facilities as significant sources of pollution under CAA sections 111 and 112, and that the EPA develop both standards of performance for new and modified hydrogen production facilities as well as emission guidelines for existing facilities. The development of emission standards for HAP, including but not limited to methanol, was also requested by petitioners. Petitioners assert that emissions of CO_2, NO_X, and PM should be addressed under the EPA's section 111 authorities, and HAP should be addressed by EPA regulations under section 112.[864] The EPA is reviewing the petition. As a predicate to potential future rulemakings, the Agency is developing a set of framing questions and opening a non-regulatory docket to solicit public comment on potential approaches for regulation of GHGs and criteria pollutants under CAA section 111 and an exploration of the appropriateness of regulating HAP emissions under CAA section 112 and on potential section 114 reporting requirements to address this growing industry.

b. Definition of Low-GHG Hydrogen

The EPA proposed to define low-GHG hydrogen as hydrogen produced with emissions of less than 0.45 kg CO_2e/kg H_2, from well-to-gate, which aligned with the highest of the four tiers of tax credits available for hydrogen production, IRC section 45V(b)(2)(D). At that GHG emission rate or less, hydrogen producers are eligible for a tax credit of $3/kg. With these provisions, Congress indicated its judgement as to what GHG levels could be attained by the lowest-GHG hydrogen production, and its intention to incentivize production of that type of hydrogen. Congress's views informed the EPA's proposal to define low-GHG hydrogen for purposes of making the BSER for this CAA section 111 rulemaking consistent with IRC section 45V(b)(2)(D).

The EPA solicited comment broadly on its proposed definition for low-GHG hydrogen, and on alternative approaches, to help develop reporting and recordkeeping requirements that would have ensured that co-firing low-GHG hydrogen minimized GHG emissions, and that combustion turbines subject to this standard utilized only low-GHG hydrogen. The EPA also solicited comment on whether it was necessary to provide a definition of low-GHG hydrogen in this final rule.

The EPA is not finalizing a definition of low-GHG hydrogen in this action. Because the Agency is not finalizing co-firing with low-GHG hydrogen as a component of the BSER for certain combustion turbines and is not finalizing a requirement that any hydrogen co-fired for compliance by low-GHG hydrogen, there is no reason to finalize a definition of low-GHG hydrogen at this time.

7. Other Options for BSER

The EPA considered several other systems of emission reduction as candidates for the BSER for combustion turbines but is not determining them to be the BSER. They include partial capture CCS, CHP and the hybrid power plant, as discussed below.

a. Partial Capture CCS

Partial capture for CCS was not determined to be BSER because the emission reductions are lower and the costs would, in general, be higher. As discussed in section IV, individual natural gas-fired combined cycle combustion turbines are the second highest-emitting individual plants in the nation, and the natural gas-fired power plant sector is higher-emitting than all other sectors. CCS at 90 percent capture removes very high absolute amounts of emissions. Partial capture CCS would fail to capture large quantities of emissions. With respect to costs, designs for 90 percent capture in general take greater advantage of economy of scale. Eligibility for the IRC section 45Q tax credit for existing EGUs requires design capture rates equivalent to 75 percent of a baseline emission rate by mass. Sources with partial capture rates that do not meet that requirement would not be eligible for the tax credit and as a result, for them, the CCS requirement would be too expensive to qualify for as the BSER. Even assuming partial capture rates meet that definition, lower capture rates would receive fewer returns from the IRC section 45Q tax credit (since these are tied to the amount of carbon sequestered, and all else equal lower capture rates would result in lower amounts of sequestered carbon) and costs would thereby be higher.

b. Combined Heat and Power (CHP)

CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP has lower-emission rates and can be more economic than separate electric and thermal generation. However, a critical requirement for a CHP facility is that it primarily generates thermal output and generates electricity as a byproduct and must therefore be physically close to a thermal host that can consistently accept the useful thermal output. It can be particularly difficult to locate a thermal host with sufficiently large thermal demands such that the useful thermal output would impact the emissions rate. The refining, chemical manufacturing, pulp and paper, food processing, and district energy systems tend to have large thermal demands. However, the thermal demand at these facilities is generally only sufficient to support a smaller EGU, approximately a maximum of several hundred MW. This

[863] Petition for Rulemaking to List and Establish National Emission Standards for Hydrogen Production Facilities under the Clean Air Act Sections 111 and 112. The petition can be accessed at *https://www.edf.org/sites/default/files/2023-09/Petition%20for%20Rulemaking%20-%20Hydrogen%20Production%20Facilities%20-%20CAA%20111%20and%20112%20-%20EDF%20et%20al.pdf.*

[864] *Id.*

would limit the geographically available locations where new generation could be constructed in addition to limiting its size. Furthermore, even if a sufficiently large thermal host were in close proximity, the owner/operator of the EGU would be required to rely on the continued operation of the thermal host for the life of the EGU. If the thermal host were to shut down, the EGU could be unable to comply with the standard of performance. This reality would likely result in difficulty in securing funding for the construction of the EGU and could also lead the thermal host to demand discount pricing for the delivered useful thermal output. For these reasons, the EPA did not propose CHP as the BSER.

c. Hybrid Power Plant

Hybrid power plants combine two or more forms of energy input into a single facility with an integrated mix of complementary generation methods. While there are multiple types of hybrid power plants, the most relevant type for this proposal is the integration of solar energy (*e.g.,* concentrating solar thermal) with a fossil fuel-fired EGU. Both coal-fired and combined cycle turbine EGUs have operated using the integration of concentrating solar thermal energy for use in boiler feed water heating, preheating makeup water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps.

One of the benefits of integrating solar thermal with a fossil fuel-fired EGU is the lower capital and operation and maintenance (O&M) costs of the solar thermal technology. This is due to the ability to use equipment (*e.g.,* HRSG, steam turbine, condenser, *etc.*) already included at the fossil fuel-fired EGU. Another advantage is the improved electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces steam at relatively low temperatures and pressures, and the conversion of the thermal energy in the steam to electricity is relatively low efficiency. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HRSG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low-grade steam produced by the solar thermal facility in the boiler improves the relative conversion efficiencies of the solar thermal to electricity process. The primary incremental costs of the non-emitting generation in a hybrid power plant are the costs of the mirrors, additional piping, and a steam turbine that is 10 to 20 percent larger than that in a comparable fossil-only EGU to accommodate the additional steam load during sunny hours. A drawback of integrating solar thermal is that the larger steam turbine will operate at part loads and reduced efficiency when no steam is provided from the solar thermal panels (*i.e.,* the night and cloudy weather). This limits the amount of solar thermal that can be integrated into the steam cycle at a fossil fuel-fired EGU.

In the 2018 Annual Energy Outlook,[865] the levelized cost of concentrated solar power (CSP) without transmission costs or tax credits is $161/MWh. Integrating solar thermal into a fossil fuel-fired EGU reduces the capital cost and O&M expenses of the CSP portion by 25 and 67 percent compared to a stand-alone CSP EGU respectively.[866] This results in an effective LCOE for the integrated CSP of $104/MWh. Assuming the integrated CSP is sized to provide 10 percent of the maximum steam turbine output and the relative capacity factors of a combined cycle turbine and the CSP (those capacity factors are 65 and 25 percent, respectively) the overall annual generation due to the concentrating solar thermal would be 3 percent of the hybrid EGU output. This would result in a 3 percent reduction in the overall CO_2 emissions and a 1 percent increase in the LCOE, without accounting for any reduction in the steam turbine efficiency. However, these costs do not account for potential reductions in the steam turbine efficiency due to being oversized relative to a non-hybrid EGU. A 2011 technical report by the National Renewable Energy Laboratory (NREL) cited analyses indicating that solar augmentation of fossil power stations is not cost-effective, although likely less expensive and containing less project risk than a stand-alone solar thermal plant. Similarly, while commenters stated that solar augmentation has been successfully integrated at coal-fired plants to improve overall unit efficiency, commenters did not provide any new information on costs or indicate that such augmentation is cost-effective.

In addition, solar thermal facilities require locations with abundant sunshine and significant land area in order to collect the thermal energy. Existing concentrated solar power projects in the U.S. are primarily located in California, Arizona, and Nevada with smaller projects in Florida, Hawaii, Utah, and Colorado. NREL's 2011 technical report on the solar-augment potential of fossil-fired power plants examined regions of the U.S. with ''good solar resource as defined by their direct normal insolation (DNI)'' and identified sixteen states as meeting that criterion: Alabama, Arizona, California, Colorado, Florida, Georgia, Louisiana, Mississippi, Nevada, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, and Utah. The technical report explained that annual average DNI has a significant effect on the performance of a solar-augmented fossil plant, with higher average DNI translating into the ability of a hybrid power plant to produce more steam for augmenting the plant. The technical report used a points-based system and assigned the most points for high solar resource values. An examination of a NREL-generated DNI map of the U.S. reveals that states with the highest DNI values are located in the southwestern U.S., with only portions of Arizona, California, Nevada, New Mexico, and Texas (plus Hawaii) having solar resources that would have been assigned the highest points by the NREL technical report (7 kWh/m2/day or greater).

Commenters supported not incorporating hybrid power plants as part of the BSER, and the EPA is not including hybrid power plants as part of the BSER because of gaps in the EPA's knowledge about costs, and concerns about the cost-effectiveness of the technology, as noted above.

G. Standards of Performance

Once the EPA has determined that a particular system or technology represents BSER, the CAA authorizes the Administrator to establish standards of performance for new units that reflect the degree of emission limitation achievable through the application of that BSER. As noted above, the EPA is finalizing a two-phase set of standards of performance, which reflect a two-component BSER, for base load combustion turbines. Under this approach, for the first phase of the standards, which applies as of the effective date the final rule, the BSER is highly efficient generation and best operating and maintenance practices. During this phase, owners/operators of EGUs will be subject to a numeric standard of performance that is representative of the performance of the best performing EGUs in the subcategory. For the second phase of the standards, beginning in 2035, the BSER for base load turbines includes 90

[865] EIA, Annual Energy Outlook 2018, February 6, 2018. *https://www.eia.gov/outlooks/aeo/.*

[866] B. Alqahtani and D. Patiño-Echeverri, Duke University, Nicholas School of the Environment, ''Integrated Solar Combined Cycle Power Plants: Paving the Way for Thermal Solar,'' Applied Energy 169:927–936 (2016).

percent capture CCS. The affected EGUs will be subject to an emissions rate that reflects continued use of highly efficient generation and best operating and maintenance practices, coupled with CCS. In addition, the EPA is finalizing a single component BSER, applicable from May 23, 2023, for low and intermediate load combustion turbines.

1. Phase-1 Standards

The first component of the BSER is the use of highly efficient combined cycle technology for base load EGUs in combination with the best operating and maintenance practices, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices for intermediate load EGUs, and the use of lower-emitting fuels for low load EGUs.

The EPA proposed that for base load combustion turbines, the first-component BSER supports a standard of 770 lb CO_2/MWh-gross for large natural gas-fired EGUs, *i.e.,* those with a base load rating heat input greater than 2,000 MMBtu/h; 900 lb CO_2/MWh-gross for small natural gas-fired EGUs, *i.e.,* those with a base load rating of 250 MMBtu/h; and between 900 and 770 lb CO_2/MWh-gross, based on the base load rating of the EGU, for natural gas-fired EGUs with base load ratings between 250 MMBtu/h and 2,000 MMBtu/h.[867] The EPA proposed that the most efficient available simple cycle technology—which qualifies as the BSER for intermediate load combustion turbines—supports a standard of 1,150 lb CO_2/MWh-gross for natural gas-fired EGUs. For new and reconstructed low load combustion turbines, the EPA proposed to find that the use of lower-emitting fuels—which qualifies as the BSER—supports a standard that ranges from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending on the fuel burned. The EPA proposed these standards to apply at all times and compliance to be determined on a 12-operating month rolling average basis.

The EPA proposed that these standards of performance are achievable specifically for natural gas-fired base load and intermediate load combustion turbine EGUs. However, combustion turbine EGUs burn a variety of fuels, including fuel oil during natural gas curtailments. Owners/operators of combustion turbines burning fuels other than natural gas would not necessarily be able to comply with the proposed standards for base load and intermediate load natural gas-fired combustion turbines using highly efficient generation. Therefore, the Agency proposed that owners/operators of combustion turbines burning fuels other than natural gas may elect to use the ratio of the heat input-based emissions rate of the specific fuel(s) burned to the heat input-based emissions rate of natural gas to determine a source-specific standard of performance for the operating period. For example, the NSPS emissions rate for a large base load combustion turbine burning 100 percent distillate oil during the 12-operating month period would be 1,070 lb CO_2/MWh-gross.[868]

Some commenters stated that the proposed base load emissions standard based on highly efficient generation is not adequately demonstrated, and that site conditions and certain operating parameters are outside of the control of the owner/operator. These commenters explained that the emissions rate of a combustion turbine is dependent on external and site-specific factors, rather than the design efficiency. Factors such as warmer climates, elevation, water conservation measures (*e.g.,* the use of dry cooling), and automatic generation control negatively impacted efficiency. They emphasized that operating units at partial loads would be necessary for maintaining grid reliability, especially as more renewables are incorporated, and the proposed limit is only achievable under ideal operating conditions. Commenters noted that the emission standards should account for start and stop cycles, back-up fuel use, degradation, and compliance tolerance. Commenters stated that the lack of flexibility would force units to operate at nameplate capacity, even when it was unnecessary and could result in increased emissions. In addition, some commenters stated that duct burners could be an alternative to simple cycle turbines for peaking generation, even though they were less efficient than combined cycle turbines without duct burners. They recommended the Agency consider excluding emissions and heat input from duct burners from the emissions standard. Furthermore, commenters noted multiple units that the EPA used in the analysis to support the proposed base load standards were permitted near or above 800 lb CO_2/MWh. Commenters stated that the original equipment manufacturer would not be able to provide a warranty that the proposed 12-month rolling emissions rate is achievable due to the varying operating conditions. Commenters recommended the EPA raise the emissions standard to 850 or 900 lb CO_2/MWh-gross for large base load combustion turbines. In addition, commenters suggested that the EPA incorporate scaling for smaller units to 1,100 lb CO_2/MWh-gross, and the beginning of the sliding scale should be at least 2,500 MMBtu/h.

a. Base Load Phase-1 Emission Standards

Considering the public comments, the EPA re-evaluated the phase-1 standard of performance for base load combustion turbines. To determine the impact of duty cycle and temperature, the EPA binned hourly data by load and season. This allowed the Agency to isolate the impact of ambient temperature and duty cycle separately. The EPA evaluated the impact of ambient temperature by comparing the average emissions for all hours between 70 to 80 percent load during different seasons. For the combined cycle turbines evaluated, the difference between the summer and winter average emission rates was minimal, typically in the single digits and less than a 1 percent difference in emission rates. Since the seasonal temperature differences are much larger than regional variations, the EPA determined that regional ambient temperature has minimal impact on the emissions rate of combined cycle EGUs. Owners/operators of combined cycle EGUs are either using inlet cooling effectively to manage the efficiency losses of the combustion turbine engine or increased generation from the Rankine cycle portion (*i.e.,* HRSG and steam turbine) of the combined cycle turbine is offsetting efficiency losses in the combustion turbine engine.[869] In addition, the variation in emissions rate by load (described below) is much larger than temperature and therefore the operating load is a more important factor than ambient temperature impacting CO_2 emission rates.

Based on the emissions data submitted to the EPA, combined cycle

[867] As proposed, a new small natural gas-fired base load EGU would determine the facility emissions rate by taking the difference in the base load rating and 250 MMBtu/h, multiplying that number by 0.0743 lb CO_2/(MW * MMBtu), and subtracting that number from 900 lb CO_2/MWh-gross. The emissions rate for a natural gas-fired base load combustion turbine with a base load rating of 1,000 MMBtu/h is 900 lb CO_2/MWh-gross minus 750 MMBtu/h (1,000 MMBtu/h–250 MMBtu/h) times 0.0743 lb CO_2/(MW * MMBtu), which results in an emissions rate of 844 lb CO_2/MWh-gross.

[868] The heat input-based emission rates of natural gas and distillate oil are 117 and 163 lb CO_2/MMBtu, respectively. The ratio of the heat input-based emission rates (1.39) is multiplied by the natural gas-fired standard of performance (770 lb CO_2/MWh) to get the applicable emissions rate (1,070 lb CO_2/MWh).

[869] As the efficiency of the combustion turbine engine is reduced at higher ambient temperatures relatively more heat is in the exhaust entering the HRSG. This can increase the output from the steam turbine.

CO_2 emission are lowest at between approximately 80 to 90 percent load. Emission rates are relatively stable at higher loads and down to approximately 70 percent load—typically 1 or 2 percent higher than the lowest emissions rate. Emissions can increase dramatically at lower loads and could impact the ability of an owner/operator to comply with the base load standard. The EPA considered two approaches to address potential compliance issues for owners/operators of base load combustion turbines operating at lower duty cycles. The first approach was to calculate emission rates using only hourly data when the combined cycle turbine was operating at an hourly load of 70 percent or higher. However, this has minimal impact on the calculated base load emissions rate. This is because of 2 reasons. First, the majority of operating hours for base load combustion turbines are at 70 percent load or higher. In addition, the 12-operating month averages are determined by the overall sum of the CO_2 emissions divided by the overall output during the 12-operating month period and not the average of the individual hourly rates. The impact of this approach is that low load hours have smaller impacts on the 12-operating month average relative to high load hours. Therefore, the EPA determined that using only higher load hours to determine the base load emission rates would not address potential issues for owners/operators of base load combustion turbines operating at relative low duty cycles (*i.e.,* low hourly capacity factors).

The second approach the EPA considered, and is finalizing, is estimating the emissions rate of combined cycle turbines at the lower end of the base load threshold—where more hours of low load operation could potentially be included in the 12-operating month average—and establishing a standard of performance that is achievable at lower percent of potential electric sales for the base load subcategory. To determine what emission rates are currently achieved by existing high-efficiency combined cycle EGUs, the EPA reviewed 12-operating month generation and CO_2 emissions data from 2015 through 2023 for all combined cycle turbines that submitted continuous emissions monitoring system (CEMS) data to the EPA's emissions collection and monitoring plan system (ECMPS). The data were sorted by the lowest maximum 12-operating month emissions rate for each unit to identify long-term emission rates on a lb CO_2/MWh-gross basis that have been demonstrated by the existing combined cycle EGU fleets. Since an NSPS is a never-to-exceed standard, the EPA proposed and is finalizing a conclusion that use of long-term data are more appropriate than shorter term data in determining an achievable standard. These long-term averages account for degradation and variable operating conditions, and the EGUs should be able to maintain their current emission rates, as long as the units are properly maintained. While annual emission rates indicate a particular standard is achievable for certain EGUs in the short term, they are not necessarily representative of emission rates that can be maintained over an extended period using highly efficient generating technology in combination with best operating and maintenance practices.

To determine the 12-operating month average emissions rate that is achievable by application of the BSER, the EPA proposed and is finalizing an approach to calculating 12-month CO_2 emission rates by dividing the sum of the CO_2 emissions by the sum of the gross electrical energy output over the same period. The EPA did this separately for combined cycle EGUs and simple cycle EGUs to determine the emissions rate for the base load and intermediate load subcategories, respectively. Commenters generally supported the 12-month rolling average for emission standard compliance.

The average maximum 12-operating month base load emissions rate for large combined cycle turbines that began operation since 2015 is 810 lb CO_2/MWh-gross. The range of the maximum 12-operating month emissions rate for individual units is 720 to 920 lb CO_2/MWh-gross. The lowest emissions rate was achieved by an individual unit at the Okeechobee Clean Energy Center. This facility is a large 3-on-1 combined cycle EGU that commenced operation in 2019 and uses a recirculating cooling tower for the steam cycle. Each turbine is rated at 380 MW and the three HRSGs feed a single steam turbine of 550 MW. The EPA did not propose to use the emissions rate of this EGU to determine the standard of performance for multiple reasons. The Okeechobee Clean Energy Center uses a 3-on-1 multi-shaft configuration but, many combined cycle EGUs use a 1-on-1 configuration. Combined cycle EGUs using a 1-on-1 configuration can be designed such that both the combustion turbine and steam turbine are arranged on one shaft and drive the same generator. This configuration has potential capital cost and maintenance costs savings and a smaller plant footprint that can be particularly important for combustion turbines enclosed in a building. In addition, a single shaft configuration has higher net efficiencies when operated at part load than a multi-shaft configuration. Basing the standard of performance strictly on the performance of multi-shaft combined cycle EGUs could limit the ability of owners/operators to construct new combined cycle EGUs in space-constrained areas (typically urban areas [870]) and combined cycle EGUs with the best performance when operated as intermediate load EGUs.[871] Either of these outcomes could result in greater overall emissions from the power sector. An advantage of multi-shaft configurations is that the turbine engine can be installed initially and run as a simple cycle EGU, with the HRSG and steam turbines added at a later date, all of which allows for more flexibility for the regulated community. In addition, a single large steam turbine in a 2–1 or 3–1 configuration can generate electricity more efficiently than multiple smaller steam turbines, increasing the overall efficiency of comparably sized combined cycle EGUs. According to Gas Turbine World 2021, multi-shaft combined cycle EGUs have design efficiencies that are 0.7 percent higher than single shaft combined cycle EGUs using the same turbine engine.[872]

The efficiency of the Rankine cycle (*i.e.,* HRSG plus the steam turbine) is determined in part by the ability to cool the working fluid (*e.g.,* steam) after it has been expanded through the turbine. All else equal, the lower the temperature that can be achieved, the more efficient the Rankine cycle. The Okeechobee Clean Energy Center used a recirculating cooling system, which can achieve lower temperatures than EGUs using dry cooling systems and therefore would be more efficient and have a lower emissions rate. However dry cooling systems have lower water requirements and therefore could be the preferred technology in arid regions or

[870] Generating electricity closer to electricity demand can reduce stress on the electric grid, reducing line losses and freeing up transmission capacity to support additional generation from variable renewable sources. Further, combined cycle EGUs located in urban areas could be designed as CHP EGUs, which have potential environmental and economic benefits.

[871] Power sector modeling projects that combined cycle EGUs will operate at lower capacity factors in the future. Combined cycle EGUs with lower base load efficiencies but higher part load efficiencies could have lower overall emission rates.

[872] According to the data in Gas Turbine World 2021, while there is a design efficiency advantage of going from a 1-on-1 configuration to a 2-on-1 configuration (assuming the same turbine engine), there is no efficiency advantage of 3-on-1 configurations compared to 2-on-1 configurations.

in areas where water requirements could have significant ecological impacts. Therefore, the EPA proposed and is finalizing that the efficient generation standard for base load EGUs should account for the use of cooling technologies with reduced water requirements.

Finally, the Okeechobee Clean Energy Center operates primarily at high duty cycles where efficiency is the highest and since it is a relatively new facility efficiency degradation might not be accounted for in the emissions analysis. Therefore, the EPA is not determining that the performance of the Okeechobee Clean Energy Facility is appropriate for a nationwide standard.

The proposed emissions rate of 770 lb CO_2/MWh-gross has been demonstrated by approximately 15 percent of recently constructed large combined cycle EGUs. As noted in the proposal, these combustion turbines include combined cycle EGUs using 1-on-1 configurations, dry cooling, and combustion turbines on the lower end of the large base load subcategory. In addition, this emissions rate has been demonstrated by using combustion turbines from multiple manufacturers and from one facility that commenced operation in 2011—demonstrating the long-term achievability of the proposed emissions standard. However, as noted by commenters the majority of recently constructed combined cycle turbines are not achieving an emissions rate of 770 lb CO_2/MWh-gross and combustion turbine manufacturers might not be willing to guarantee this emissions level in operating making it challenging to build a new combined cycle EGU.

To account for differences in the performance of the best performing combustion turbines and design options that result in less efficient operation, the EPA normalized the reported emission rates for combined cycle EGUs.[873] Specifically, for the reported emissions rates of combined cycle turbines with cooling towers was increased by 1.0 percent to account for potential new units using dry cooling. Similarly, the emissions rate of 2–1 and 3–1 combined cycle turbines were increased by 1.4 percent to account for potential new units using a 1–1 configuration. In addition, for the best performing combined cycle turbines, the EPA plotted the 12-operating month emissions rate against the 12-operating month heat input-based capacity factor. Based on this data, the EPA used the trend in increasing emission rates at lower 12-operating month capacity factors to estimate the emissions rate at capacity factors at which an individual facility has never operated. This approach allowed the EPA to estimate the emissions rate at a 40 percent 12-operating month capacity factor for the best performing combined cycle turbines. This allows the estimation of the emissions rate at the lower end of the base load subcategory using higher capacity factor data.[874] The EPA did not correct the achievable emissions rate for combined cycle turbines where the relationship indicated emission rates declined at lower 12-operating month capacity factors.

As noted in the proposal, one of the best performing large combined cycle EGUs that has maintained a 12-operating-month base load emissions rate of 770 lb CO_2/MWh-gross is the Dresden plant, located in Ohio.[875] This 2-on-1 combined cycle facility uses a recirculating cooling tower. The turbine engines are rated at 2,250 MMBtu/h, which demonstrates that the standard of performance for large base load combustion turbines is achievable at a heat input rating of 2,000 MMBtu/h. As noted, a 2-on-1 configuration and a cooling tower are more efficient than a 1-on-1 configuration and dry cooling. Normalizing for these factors and accounting for operation at a 12-operating month capacity factor of 40 percent increases the achievable demonstrated emissions rate to 800 lb CO_2/MWh-gross. However, the Dresden Energy Facility does not use the most efficient combined cycle design currently available. Multiple more efficient designs have been developed since the Dresden Energy Facility commenced operation a decade ago that more than offset these efficiency losses. Therefore, the EPA has determined that the Dresden combined cycle EGU demonstrates that an emissions rate of 800 lb CO_2/MWh-gross is achievable for all new large combined cycle EGUs with an acceptable compliance margin. Therefore, the EPA is finalizing a phase 1 standard of performance of 800 lb CO_2/MWh-gross for large base load combustion turbines (*i.e.,* those with a base load rating heat input greater than 2,000 MMBtu/h) based on the BSER of highly efficient combined cycle technology.

With respect to small combined cycle combustion turbines, the best performing unit identified by the EPA is the Holland Energy Park facility in Holland, Michigan, which commenced operation in 2017 and uses a 2-on-1 configuration and a cooling tower.[876] The 50 MW turbine engines have individual heat input ratings of 590 MMBtu/h and serve a single 45 MW steam turbine. The facility has maintained a 12-operating month, 99 percent confidence emissions rate of 870 lb CO_2/MWh-gross. The emissions standard for a base load combustion turbine of this size is 880 lb CO_2/MWh-gross. The normalized emissions rate accounting for the use of recirculating cooling towers, a 2–1 configuration, and operation at a 40 percent capacity factor is 900 lb CO_2/MWh-gross. While this is higher than the final emissions standard in this rule, there are efficient generation technologies that are not being used at the Holland Energy Park. For example, a commercially available HRSG that uses supercritical CO_2 instead of steam as the working fluid is available. This HRSG would be significantly more efficient than the HRSG that uses dual pressure steam, which is common for small combined cycle EGUs.[877] When these efficiency improvements are accounted for, a similar combined cycle EGU would be able to maintain an emissions rate of 880 lb CO_2/MWh-gross. In addition, the normalization approach assumes a worst-case scenario. Hybrid cooling technologies are available and offer performance similar to that of wet cooling towers. This long-term data accounts for degradation and variable operating conditions and demonstrates that a base load combustion turbine EGU with a turbine rated at 590 MMBtu/h should be able to maintain an emissions rate of 880 lb CO_2/MWh-gross.[878] Therefore, estimating that

[873] A similar normalization approach was used by the EPA in previous EGU GHG NSPS rulemakings to benchmark the performance of coal-fired EGUs when determining an achievable efficiency-based standard of performance.

[874] The most efficient combined cycle turbines tend to operate strictly as base load combustion turbines, well above the base load subcategorization threshold.

[875] The Dresden Energy Facility is listed as being located in Muskingum County, Ohio, as being owned by the Appalachian Power Company, as having commenced commercial operation in late 2011. The facility ID (ORISPL) is 55350 1A and 1B.

[876] The Holland Park Energy Center is a CHP system that uses hot water in the cooling system for a snow melt system that uses a warm water piping system to heat the downtown sidewalks to clear the snow during the winter. Since this useful thermal output is low temperature, it likely only results in a small reduction of the electrical efficiency of the EGU. If the useful thermal output were accounted for, the emissions rate of the Holland Energy Park would be lower. The facility ID (ORISPL) is 59093 10 and 11.

[877] If the combustion turbine engine exhaust temperature is 500 °C or greater, a HRSG using 3 pressure steam without a reheat cycle could potentially provide an even greater increase in efficiency (relative to a HRSG using 2 pressure steam without a reheat cycle).

[878] To estimate an achievable emissions rate for an efficient combined cycle EGU at 250 MMBtu/h

Continued

emission rates will be slightly higher for smaller combustion turbines, the EPA is finalizing a phase 1 standard of performance of 900 lb CO_2/MWh-gross for small base load combustion turbines (*i.e.,* those with a base load rating of 250 MMBtu/h) based on the BSER of highly efficient combined cycle technology.

b. Intermediate Load Emission Standards

For the intermediate load standards of performance, some commenters stated that an emissions standard of 1,150 lb CO_2/MWh-gross is only achievable for simple cycle except under ideal operating conditions. Since the emissions standard is not achievable in practice, these commenters stated that the majority of new simple cycle turbines would be prevented from operating as variable or intermediate load units. Similar to comments on the base load emissions standard, commenters stated the standard of performance should account for ambient conditions, operation at part load, automatic generation control, and variable loads. If the intermediate load standard is not achievable in practice, it could result in the operation of less efficient generation in other operating modes and an increase in overall GHG emissions. They also explained this could force simple cycle turbines to always operate at nameplate capacity, even when it was not necessary, which would also lead to increased emissions. These commenters requested that the EPA raise the variable and intermediate load emissions standard to 1,250 to 1,300 lb CO_2/MWh-gross.

Considering the public comments, the EPA re-evaluated the standard of performance for intermediate load combustion turbines using the same approach as for combined cycle turbines, except using the performance of simple cycle EGUs. The average maximum 12-operating operating month intermediate load emissions rate for simple cycle turbines that began operation since 2015 is 1,210 lb CO_2/MWh-gross. The range of the maximum 12-operating month emissions rate for individual units is 1,080 to 1,470 lb CO_2/MWh-gross. The lowest emissions rate was achieved by an individual unit at the Scattergood Generating Station. This facility includes 2 large aeroderivative simple cycle turbines (General Electric LMS 100) that commenced operation in 2015. Each turbine is rated at approximately 100 MW and use water injection to reduce NO_X emissions. The EPA did not propose and is not finalizing to use the emissions rate of this EGU to determine the standard of performance for multiple reasons. Simple cycle turbine efficiency tends to increase with size and the simple cycle turbines at the Scattergood Facility are the largest aeroderivative turbines available. Establishing a standard of performance based on emission rates that only large aeroderivative turbines could achieve would limit the ability to develop new firm combustion turbine based generating capacity in smaller than 100 MW increments. This could result in the local electric grid operating in a less overall efficient manner, increasing overall GHG emissions. In addition, the largest available aeroderivative simple cycle turbines can use either water injection or dry low NO_X combustion to reduce emissions of NO_X. For this particular design, the use of water injection has higher design efficiencies than the dry low NO_X option. Water injection has similar ecological impacts as water used for cooling towers, the EPA has determined in this case it is important to preserve the option for new intermediate load combustion turbines to use dry low NO_X combustion.

The proposed emissions rate of 1,150 lb CO_2/MWh-gross was achieved by 20 percent of recently constructed intermediate load simple cycle turbines. However, only two-thirds of LMS 100 simple cycle turbines installed to date have maintained an intermediate load emissions rate of 1,150 lb CO_2/MWh-gross. In addition, only one-third of the Siemens STG–A65 simple cycle turbines and only 10 percent of General Electric LM6000 simple cycle combustion turbine have maintained this emissions rate. Both of these are common aeroderivative turbines and since they do require an intercooler have potential space consideration advantages compared to the LMS100. Finalizing the proposed emissions standard could restrict new intermediate load simple cycle turbine to the use of intercooling, limiting application to locations that can support a cooling tower. An intermediate load emissions rate of 1,170 lb CO_2/MWh-gross has been achieved by three-quarters of both the LMS100 and STG–A65 installations and 20 percent of LM6000 installations. In addition, this emissions rate has been demonstrated by a frame simple turbine. The EPA notes that the more efficient versions of the combustion turbines—water injection in the case of the LMS 100 and DLN in the case of the STG–A65—have higher design efficiencies and higher compliance levels than the version with the alternate NO_X control technology. This standard of performance has been demonstrated by 40 percent of recently installed intermediate load simple cycle turbines and the Agency has determined that with proper maintenance is achievable with combustion turbines from multiple manufacturers, with and without intercooling, and is finalizing a standard of 1,170 lb CO_2/MWh-gross for intermediate load combustion turbines. The EPA considered, but rejected, finalizing an emissions standard of 1,190 lb CO_2/MWh-gross. This standard of performance has been achieved by essentially all LMS 100 and SGT–A65 intermediate load simple cycle turbines and 70 percent of recently installed intermediate load simple cycle turbines but would not require the most efficient available versions of new intermediate load simple cycle turbines and does not represent the BSER.

2. Phase-2 Standards

The EPA proposed that 90 percent CCS (as part of the CCS pathway) qualifies as the second component of the BSER for base load combustion turbines. For the base load combustion turbines, the EPA reduced the emissions rate by 89 percent to determine the CCS based phase-2 standards.[879] The CCS percent reduction is based on a CCS system capturing 90 percent of the emitting CO_2 being operational anytime the combustion turbine is operating. Similar to the phase-1 emission standards, the EPA proposed and is finalizing a decision that standard of performance for base load combustion turbines be adjusted based on the uncontrolled emission rates of the fuels relative to natural gas. For 100 percent distillate oil-fired combustion turbines, the emission rates would be 120 lb CO_2/MWh-gross.

The EPA solicited comment on the range of reduction in emission rate of 75 to 90 percent. In addition, the EPA solicited comment on whether carbon capture equipment has lower availability/reliability than the combustion turbine or the CCS equipment takes longer to startup than the combustion turbine itself there would be periods of operation where the CO_2 emissions would not be controlled by the carbon capture equipment. For the same reasons as for coal-fired EGUs, the EPA has determined 90 percent CCS

the EPA assumed a linear relationship for combined cycle efficiency with turbine engines with base load ratings of less than 2,000 MMBtu/h.

[879] The 89 percent reduction from CCS accounts for the increased auxiliary load of a 90 percent post combustion amine-based capture system. Due to rounding, the proposed numeric standards of performance do not necessarily match the standards that would be determined by applying the percent reduction to the phase-1 standards.

has been demonstrated and appropriate for base load combustion turbines, see section VII.C.

H. Reconstructed Stationary Combustion Turbines

All the major manufacturers of combustion turbines sell upgrade packages that increase both the output and efficiency of existing combustion turbines. An owner/operator of a reconstructed combustion turbine would be able to use one of these upgrade packages to comply with the intermediate load emission standards in this final rule. Some examples of these upgrades include GE's Advanced Gas Path, Siemens' Hot Start on the Fly, and Solar Turbines' Gas Compressor Restaging. The Advanced Gas Path option includes retrofitting existing turbine components with improved materials to increase durability, air sealing, and overall efficiency.[880] Hot Start on the Fly upgrades include implementing new software to allow for the gas and steam turbine to start-up simultaneously, which greatly improves start times, and in some cases could do so by up to 20 minutes.[881] Compressor restaging involves analyzing the current operation of an existing combustion turbine and adjusting its gas compressor characteristics including transmission, injection, and gathering, to operate in the most efficient manner given the other operating conditions of the turbine.[882] In addition, steam injection is a retrofittable technology that is estimated to be available for a total cost of all the equipment needed for steam injection of $250/kW.[883] Due to the differences in materials used and necessary additional infrastructure, a steam injection system can be up to 60 percent smaller than a similar HRSG, which is valuable for retrofit purposes.[884]

For owners/operators of base load combustion turbines, however, HRSG have been added to multiple existing simple cycle turbines to convert to combined cycle technology. There have been multiple examples of this kind of conversion from simple cycle to combined cycle. One such example is Unit 12 at Riverton Power Plant in Riverton, Kansas, which was originally built in 2007 as a 143 MW simple cycle combustion turbine. In 2013, an HRSG and additional equipment was added to convert Unit 12 to a combined cycle combustion turbine.[885] Another is Energy Center Dover, located in Dover, Delaware, which in addition to a coal-fired steam turbine, originally had two 44 MW simple cycle combustion turbines. Also in 2013, the unit added an HRSG to one of the existing simple cycle combustion turbines, connected the existing steam generator to it, and retired the remaining coal-related equipment to convert that combustion turbine to a combined cycle one.[886] Some other examples include the Los Esteros Critical Energy Facility in San Jose, California, which converted from a four-turbine simple cycle peaking facility to a combined-cycle one in 2013, and the Tracy Combined Cycle Power Plant.[887] The Tracy facility, located in Tracy, California, was built in 2003 with two simple cycle combustion turbines and in 2012 was converted to combined cycle with the addition of a steam turbine.[888]

In the previous sections, the EPA explained the background of and requirements for new and reconstructed stationary combustion turbines and evaluated various control technology configurations to determine the BSER. Because the BSER is the same for new and reconstructed stationary combustion turbines, the Agency used the same emissions analysis for both new and reconstructed stationary combustion turbines. For each of the subcategories, the EPA proposed and is finalizing a conclusion that the BSER results in the same standard of performance for new stationary combustion turbines and reconstructed stationary combustion turbines. For CCS, consistent with the NETL Combined Cycle CCS Retrofit Report, the EPA approximated the cost to add CCS to a reconstructed combustion turbine by increasing the capital costs of the carbon capture equipment by 9 percent relative to the costs of adding CCS to a newly constructed combustion turbine and decreasing the net efficiency by 0.3 percent.[889] Using the same costing assumptions for newly constructed combined cycle turbines, the compliance costs for reconstructed combined cycle turbines are approximately 10 percent higher than for comparable newly constructed combined cycle turbine. Assuming continued operation of the capture equipment, the compliance costs are $17/MWh and $51/ton ($56/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $21/MWh and $63/ton ($69/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. If the capture system is not operated while the combustion turbine is subcategorized as in intermediate load combustion turbine, the compliance costs are reduced to $10/MWh and $50/ton ($55/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $13/MWh and $67/ton ($73/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine.

A reconstructed stationary combustion turbine is not required to meet the standards if doing so is deemed to be ''technologically and economically'' infeasible.[890] This provision requires a case-by-case reconstruction determination in the light of considerations of economic and technological feasibility. However, this case-by-case determination considers the identified BSER, as well as technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and of reasonable cost, depending on site-specific considerations and if so, would likely result in sufficient GHG reductions to comply with the applicable reconstructed standards. Finally, in some cases, equipment upgrades, and best operating practices would result in sufficient reductions to achieve the reconstructed standards.

I. Modified Stationary Combustion Turbines

CAA section 111(a)(4) defines a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' Certain types of physical or operational changes are exempt from consideration as a modification. Those are described in 40 CFR 60.2, 60.14(e).

In the 2015 NSPS, the EPA did not finalize standards of performance for stationary combustion turbines that conduct modifications; instead, the EPA concluded that it was prudent to delay

[880] *https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/advanced-gas-path-brochure.pdf.*

[881] *https://www.siemens-energy.com/global/en/home/stories/trianel-power-plant-upgrades.html.*

[882] *https://s7d2.scene7.com/is/content/Caterpillar/CM20191213-93d46-8e41d.*

[883] ''GTI'' (2019). Innovative Steam Technologies. *https://otsg.com/industries/powergen/gti/.*

[884] Ibid.

[885] *https://www.nsenergybusiness.com/news/newsempire-district-starts-riverton-plants-combined-cycle-expansion-231013/.*

[886] *https://news.delaware.gov/2013/07/26/repowered-nrg-energy-center-dover-unveiled-gov-markell-congressional-delegation-dnrec-sec-omara-other-officials-join-with-nrg-to-announce-cleaner-natural-gas-facility/.*

[887] *https://www.calpine.com/los-esteros-critical-energy-facility.*

[888] *https://www.middleriverpower.com/#portfolio.*

[889] ''Cost and Performance of Retrofitting NGCC Units for Caron Capture—Revision 3.'' DOE/NETL–2023/3845. March 17, 2023.

[890] 40 CFR 60.15(b)(2).

issuing standards until the Agency could gather more information (80 FR 64515; October 23, 2015). There were several reasons for this determination: few sources had undertaken NSPS modifications in the past, the EPA had little information concerning them, and available information indicated that few owners/operators of existing combustion turbines would undertake NSPS modifications in the future; and since the Agency eliminated proposed subcategories for small EGUs in the 2015 NSPS, questions were raised as to whether smaller existing combustion turbines that undertake a modification could meet the final performance standard of 1,000 lb CO_2/MWh-gross.

It continues to be the case that the EPA is aware of no evidence indicating that owners/operators of combustion turbines intend to undertake actions that could qualify as NSPS modifications in the future. The EPA did not propose or solicit comment on standards of performance for modifications of combustion turbines and is not establishing any in this final rule.

J. Startup, Shutdown, and Malfunction

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the D.C. Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that the SSM exemption violates the requirement under section 302(k) of the CAA that some CAA section 112 standard apply continuously. The EPA has determined the reasoning in the court's decision in *Sierra Club* v. *EPA* applies equally to CAA section 111 because the definition of emission or standard in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS. Consistent with *Sierra Club* v. *EPA,* the EPA is finalizing standards in this rule that apply at all times. The NSPS general provisions in 40 CFR 60.11(c) currently exclude opacity requirements during periods of startup, shutdown, and malfunction and the provision in 40 CFR 60.8(c) contains an exemption from non-opacity standards. These general provision requirements would automatically apply to the standards set in an NSPS, unless the regulation specifically overrides these general provisions. The NSPS subpart TTTT (40 CFR part 60, subpart TTTT) does not contain an opacity standard, thus, the requirements at 40 CFR 60.11(c) are not applicable. The NSPS subpart TTTT also overrides 40 CFR 60.8(c) in table 3 and requires that sources comply with the standard(s) at all times. In reviewing NSPS subpart TTTT and proposing the new NSPS subpart TTTTa, the EPA proposed to retain in subpart TTTTa the requirements that sources comply with the standard(s) at all times in table 3 of the new subpart TTTTa to override the general provisions for SSM exemption related provisions. The EPA proposed and is finalizing that all standards in subpart TTTTa apply at all times.

In developing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained in this section of the preamble, is not establishing alternate standards for those periods. The EPA analysis of achievable standards of performance used CEMS data that includes all period of operation. Since periods of startup, shutdown, and malfunction were not excluded from the analysis, the EPA is not establishing alternate standard for those periods of operation.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment. (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in caselaw requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting standards of performance, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting ''achievable'' standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

K. Testing and Monitoring Requirements

Because the NSPS reflects the application of the best system of emission reduction under conditions of proper operation and maintenance, in doing the NSPS review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the NSPS. This section includes a discussion on the current testing and monitoring requirements of the NSPS and any additions the EPA is including in 40 CFR part 60, subpart TTTTa.

1. General Requirements

The EPA proposed to allow three approaches for determining CO_2 emissions: a CO_2 CEMS and stack gas flow monitor; hourly heat input, fuel characteristics, and F factors [891] for EGUs firing oil or gas; or Tier 3 calculations using fuel use and carbon content. The first two approaches are in use for measuring CO_2 by units affected by the Acid Rain program (40 CFR part 75), to which most, if not all, of the EGUs affected by NSPS subpart TTTT are already subject, while the last approach is in use for stationary fuel combustion sources reporting to the GHGRP (40 CFR part 98, subpart C).

The EPA believes continuing the use of approaches already in use by other programs represents a cost-effective means of obtaining quality assured data requisite for determining carbon dioxide mass emissions. MPS reporting software required by this subpart for reporting emissions to the EPA expects hourly or daily CO_2 emission values and has thousands of electronic checks to validate data using the Acid Rain program requirements (40 CFR part 75). ECMPS does not currently accommodate or validate data under GHGRP's Tier 3 approach. Because most, if not all, of the EGUs that will be affected by this final rule are already affected by Acid Rain program monitoring requirements, the cost and burden for EGU owners or operators are already accounted for by other rulemakings. Therefore, this aspect of the final rule is designed to have minimal, if any, cost or burden associated with CO_2 testing and monitoring. In addition, there are no changes to measurement and testing requirements for determining electrical output, both gross and net, as well as

[891] An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel.

thermal output, to existing requirements.

However, the EPA requested comment on whether continuous CO_2 CEMS and stack gas flow measurements should be the sole means of compliance for this rule. Such a switch would increase costs for those EGU owners or operators who are currently relying on the oil- or gas-fired calculation-based approaches. By way of reference, the annualized cost associated with adoption and use of continuous CO_2 and flow measurements where none now exist is estimated to be about $52,000. To the extent that the rule were to mandate continuous CO_2 and stack gas flow measurements in accordance with what is currently allowed as one option and that an EGU lacked this instrumentation, its owner or operator would need to incur this annual cost to obtain such information and to keep the instrumentation calibrated. Commenters encouraged the EPA to maintain the flexibility for EGUs to use hourly heat input measurements, fuel characteristics, and F factors as is allowed under the Acid Rain program. Commenters argued that in addition to the incremental costs, some facilities have space constraints that could make the addition of stack gas flow monitors difficult or impractical. In this final rule, the EPA allows the use of hourly heat input, fuel characteristics, and F factors as an alternative to CO_2 CEMS and stack gas flow monitors for EGUs that burn oil or gas.

One commenter argued that the part 75 data requirements, which are required for several emission trading programs including the Acid Rain program, are punitive and that the data are biased high. Other commenters argued that the part 75 CO_2 data are biased low. EPA disagrees that the data requirements are punitive. Most, if not all, of the EGUs subject to this subpart are already reporting the data under the Acid Rain program. Oil- and gas-fired EGUs that are not subject to the Acid Rain program but are subject to a Cross-State Air Pollution Rule program are already reporting most of the necessary data elements (*e.g.,* hourly heat input and F factors) for SO_2 and/or NO_X emissions. The additional data and effort necessary to calculate CO_2 emissions is minor. The EPA also disagrees that the data are biased significantly high or low. Each CO_2 CEMS and stack gas flow monitor must undergo regular quality assurance and quality control activities including periodic relative accuracy test audits where the EGU's monitoring system is compared to an independent monitoring system. In a May 2022 study conducted by the EPA, the average difference between the EGU's monitoring system and the independent monitoring system was approximately 2 percent for CO_2 concentration and slightly greater than 2 percent for stack gas flow.

2. Requirements for Sources Implementing CCS

The CCS process is also subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The ''suppliers of carbon dioxide'' source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the ''geologic sequestration of carbon dioxide'' source category of the GHGRP (GHGRP subpart RR). In April 2024, to complement GHGRP subpart RR, the EPA finalized the ''geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916'' source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[892 893 894]

CCS as the BSER, as detailed in section VIII.F.4.c.iv of this preamble, is determined to be adequately demonstrated based solely on geologic sequestration that is not associated with EOR. However, EGUs also have the compliance option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. The EPA is requiring that any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility that reports in accordance with GHGRP subpart RR or GHGRP subpart VV. This does not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation, though the EPA anticipates that the quantity of CO_2 sequestered will be substantially similar to the quantity captured. However, to verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, the Agency is leveraging regulatory reporting requirements under the GHGRP. The EPA also emphasizes that this final rule does not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU transfer the captured CO_2 to an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. This avoids duplicative monitoring, reporting, and verification requirements between this rule and the GHGRP, while also ensuring that the facility injecting and sequestering the CO_2 (which may not necessarily be the EGU) maintains responsibility for these requirements. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of this final rule.

L. Recordkeeping and Reporting Requirements

The current rule (subpart TTTT of 40 CFR part 60) requires EGU owners or operators to prepare reports in accordance with the Acid Rain Program's ECMPS. Such reports are to be submitted quarterly. The EPA believes all EGU owners and operators have extensive experience in using the ECMPS and use of a familiar system ensures quick and effective rollout of the program in this final rule. Because all EGUs are expected to be covered by and included in the ECMPS, minimal, if any, costs for reporting are expected for

[892] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[893] International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as ''CSA/ANSI ISO 27916:2019'').

[894] As described in 87 FR 36920 (June 21, 2022), both subpart RR and subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

this final rule. In the unlikely event that a specific EGU is not already covered by and included in the ECMPS, the estimated annual per unit cost would be about $8,500.

The current rule's recordkeeping requirements at 40 CFR part 60.5560 rely on a combination of general provision requirements (see 40 CFR 60.7(b) and (f)), requirements at subpart F of 40 CFR part 75, and an explicit list of items, including data and calculations; the EPA is retaining those existing subpart TTTT of 40 CFR part 60 requirements in the new NSPS subpart TTTTa of 40 CFR part 60. The annual cost of those recordkeeping requirements will be the same amount as is required for subpart TTTT of 40 CFR part 60 recordkeeping. As the recordkeeping in subpart TTTT of 40 CFR part 60 will be replaced by similar recordkeeping in subpart TTTTa of 40 CFR part 60, this annual cost for recordkeeping will be maintained.

M. Compliance Dates

Owners/operators of affected sources that commenced construction or reconstruction after May 23, 2023, must meet the requirements of 40 CFR part 60, subpart TTTTa, upon startup of the new or reconstructed affected facility or the effective date of the final rule, whichever is later. This compliance schedule is consistent with the requirements in section 111 of the CAA.

N. Compliance Date Extension

Several industry commenters noted the potential for delay in installation and utilization of emission controls—especially CCS—due to supply chain constraints, permitting challenges, environmental assessments, or delays in development of necessary infrastructure, among other reasons. Commenters requested that the EPA include a mechanism to extend the compliance date for affected EGUs that are installing emission controls. These commenters explained that an extension mechanism could provide greater regulatory certainty for owners and operators.

After considering these comments, the EPA believes that it is reasonable to provide a consistent and transparent means of allowing a limited extension of the Phase 2 compliance deadline where an affected new or reconstructed base load stationary combustion EGU has demonstrated such an extension is needed for installation and utilization of controls. This mechanism is intended to address unavoidable delays in implementation—not to provide more time to assess the NSPS compliance strategy for the affected EGU.

As indicated, the EPA is finalizing a provision that will allow the owner/operators of new or reconstructed base load stationary combustion turbine EGUs to request a limited Phase 2 compliance extension based on a case-by-case demonstration of necessity. Under these provisions, the owner or operator of an affected source may apply for a Phase 2 compliance date extension of up to 1 year to comply with the applicable emissions control requirements, which if approved by the EPA, would require compliance with Phase 2 standards of performance no later than January 1, 2033. This mechanism is only available for situations in which an affected source encounters a delay in installation or startup of a control technology that makes it impossible to commence compliance with Phase 2 standards of performance by January 1, 2032 (*i.e.,* the Phase 2 compliance date specified in section VIII.F.4 of this preamble).

The EPA will grant a request for a Phase 2 compliance extension of up to 1 year only where a source demonstrates that it has taken all steps possible to install and start up the necessary controls and still cannot comply with the Phase 2 standards of performance by the January 1, 2032 compliance date due to circumstances entirely beyond its control. Any request for a Phase 2 compliance extension must be received by the EPA at least 180 days before the January 1, 2032 Phase 2 compliance date. The owner/operator of the requesting source must provide documentation of the circumstances that precipitated the delay (or an anticipated delay) and demonstrate that those circumstances are entirely beyond the control of the owner/operator and that the owner/operator has no ability to remedy the delay. These circumstances may include, but are not limited to, delays related to permitting, delays in delivery or construction of parts necessary for installation or implementation of the control technology, or development of necessary infrastructure (*e.g.,* CO_2 pipelines).

The request must include documentation that demonstrates that the necessary controls cannot be installed or started up by the January 1, 2032 Phase 2 compliance date. This may include information and documentation obtained from a control technology vendor or engineering firm demonstrating that the necessary controls cannot be installed or started up by the applicable Phase 2 compliance date, documentation of any permit delays, or documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology. The owner/operator of an affected new stationary combustion turbine EGU remains subject to the January 1, 2032 Phase 2 compliance date unless and until the Administrator grants a compliance extension.

As discussed in sections VII.C.1.a.i.(E) and VII.C.2.b.i(C), the EPA has determined compliance timelines for these new sources that are consistent with achieving emission reductions as expeditiously as practicable given the time it takes to install and startup the BSER technologies for compliance with the Phase 2 standards of performance. The Phase 2 compliance dates are designed to accommodate the process steps and timeframes that the EPA reasonably anticipates will apply to affected EGUs. This extension mechanism acknowledges that circumstances entirely outside the control of the owners or operators of affected EGUs may extend the timeframe for installation or startup of control technologies beyond the timeframe that the EPA has determined is reasonable as a general matter. Thus, so long as this extension mechanism is limited to circumstances that cannot be reasonably controlled or remedied by the owners or operators of the affected EGUs and that make it impossible to achieve compliance with Phase 2 standards of performance by the January 1, 2032 compliance date, its use is consistent with achieving compliance as expeditiously as practicable.

The EPA believes that a 1-year extension on top of the lead time already provided by the 2032 compliance date should be sufficient to address any compliance delays and to allow all base load units to timely install CSS. New or reconstructed base load stationary combustion turbines that are granted a 1-year Phase 2 compliance date extension and still are not able to install or startup the control technologies necessary to meet the Phase 2 standard of performance by the extended Phase 2 compliance date of January 1, 2033 may adjust their operation to the intermediate load subcategory (*i.e.,* 12-operating-month capacity factor between 20–40 percent). Such sources must then comply with applicable standards of performance for the intermediate load stationary combustion turbine subcategory until the necessary controls are installed and operational such that the source can comply with the Phase 2 standard of performance.

IX. Requirements for New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units

A. 2018 NSPS Proposal Withdrawal

1. Background

As discussed in section V.B, the EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015 (''2015 NSPS'').[895] The 2015 NSPS finalized partial CCS as the BSER and finalized standards of performance to limit emissions of GHG manifested as CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired EGUs (*i.e.,* utility boilers and integrated gasification combined cycle (IGCC) units). In the same document, the Agency also finalized CO_2 emission standards for newly constructed and reconstructed stationary combustion turbine EGUs. 80 FR 64510 (October 23, 2015). These final standards were codified in 40 CFR part 60, subpart TTTT.

On December 20, 2018, the EPA published a proposal to revise certain parts of the 2015 Rule, titled ''Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.'' 83 FR 65424 (December 20, 2018) (''2018 Proposal''). In Fall 2020, after reviewing comments on the 2018 Proposal, the EPA developed a draft final rule and sent that package to the Office of Management and Budget (OMB) for interagency review under Executive Order 12866 (''2020 OMB Review Package''). The 2020 OMB Review Package, if finalized, would have amended the BSER for new coal-fired EGUs and required a pollutant-specific significant contribution finding (SCF) prior to regulating a source category. The review of the BSER portion of the package was delayed[896] and the pollutant-specific SCF portion of the 2020 OMB Review Package was finalized on January 13, 2021 in a final rule, titled ''Pollutant-Specific Contribution Finding for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories.'' 86 FR 2542 (January 13, 2021) (''SCF Rule''). However, the D.C. Circuit vacated the SCF Rule on April 5, 2021.[897] The BSER analysis and that portion of the 2018 Proposal have not been finalized and are being withdrawn in this final action. The 2018 Proposal stated that the Agency was proposing to find that partial CCS is not the BSER on grounds that it is too costly and that the 2015 Rule did not show that the technology had sufficient geographic scope to qualify as the BSER for newly constructed coal-fired EGUs. The EPA instead proposed that the BSER for newly constructed coal-fired EGUs would be the most efficient available steam cycle (*i.e.,* supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with the best operating practices instead of partial CCS. In addition, for newly constructed coal-fired EGUs firing moisture-rich fuels (*i.e.,* lignite), the BSER would also include pre-combustion fuel drying using waste heat from the process. The 2018 Proposal also would have revised the standards of performance for reconstructed EGUs, the maximally stringent standards for coal-fired EGUs undergoing large modifications (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent), and for base load and non-base load operating conditions that reflected the Agency's revised BSER determination. The 2018 Proposal did not revise the BSER for any other sources as determined in the 2015 Rule. It also included minor amendments to the applicability criteria for combined heat and power (CHP) and non-fossil EGUs and other miscellaneous technical changes in the regulatory requirements.

2. Withdrawal of the 2018 Proposal

In this action, under CAA section 111(b), the Agency is withdrawing the 2018 Proposal and the proposed determination that the BSER for coal-fired steam generating units should be highly efficient generation technology combined with best operating practices. The EPA no longer believes there is a basis for finding that highly efficient generation technology combined with best operating practices are the BSER for coal-fired steam generating units. As described at length in this preamble, CCS technology is adequately demonstrated for coal-fired steam generating units and so it is not appropriate to impose the less effective emission control of highly efficient generation combined with best operating practices for new sources in this source category. Moreover, the EPA is presently considering whether to revise the 2015 Rule to take into account improvements in CCS technology and the existing tax credits under the IRA. For a more in-depth, technical discussion of the rationale underlying this action, please refer to the technical memorandum in the docket titled, *2018 Proposal Withdrawal.*

B. Additional Amendments

The EPA proposed and is finalizing multiple less significant amendments. These amendments are either strictly editorial and will not change any of the requirements of 40 CFR part 60, subpart TTTT, or will add additional compliance flexibility. The amendments are also incorporated into the final subpart TTTTa. For additional information on these amendments, see the redline strikeout version of the rule showing the amendments in the docket for this action.

First, the EPA proposed and is finalizing editorial amendments to define acronyms the first time they are used in the regulatory text. Second, the EPA proposed and is finalizing adding International System of Units (SI) equivalent for owners/operators of stationary combustion turbines complying with a heat input-based standard. Third, the EPA proposed and is finalizing correcting errors in the current 40 CFR part 60, subpart TTTT, regulatory text referring to part 63 instead of part 60. Fourth, as a practical matter owners/operators of stationary combustion turbines subject to the heat input-based standard of performance need to maintain records of electric sales to demonstrate that they are not subject to the output-based standard of performance. Therefore, the EPA proposed and is finalizing adding a specific requirement that owner/operators maintain records of electric sales to demonstrate they did not sell electricity above the threshold that would trigger the output-based standard. Next, the EPA proposed and is finalizing updating the ANSI, ASME, and ASTM International (ASTM) test methods to include more recent versions of the test methods. Finally, the EPA proposed and is finalizing adding additional compliance flexibilities for EGUs either serving a common electric generator or using a common stack.

C. Eight-year Review of NSPS for Fossil Fuel-Fired Steam Generating Units

1. Modifications

In the 2015 NSPS, the EPA issued final standards for a steam generating

[895] 80 FR 64510 (October 23, 2015).

[896] As part of the interagency review process, an error in the partial CCS costing report that the EPA used to update the costs of partial CCS between the 2018 Proposal and 2020 OMB Review Package was identified. The error included in the original 2020 OMB Review Package had the impact of increasing the cost of partial CCS. The corrected report resulted in partial CCS costs that were similar to those included in the 2018 Proposal.

[897] *State of California* v. *EPA* (D.C. Cir. 21–1035), Document No. 1893155 (April 5, 2021).

unit that implements a "large modification," defined as a physical change, or change in the method of operation, that results in an increase in hourly CO_2 emissions of more than 10 percent when compared to the source's highest hourly emissions in the previous 5 years. Such a modified steam generating unit is required to meet a unit-specific CO_2 emission limit determined by that unit's best demonstrated historical performance (in the years from 2002 to the time of the modification). The 2015 NSPS did not include standards for a steam generating unit that implements a "small modification," defined as a change that results in an increase in hourly CO_2 emissions of less than or equal to 10 percent when compared to the source's highest hourly emissions in the previous 5 years.[898]

In the 2015 NSPS, the EPA explained its basis for promulgating this rule as follows. The EPA has historically been notified of only a limited number of NSPS modifications involving fossil fuel-fired steam generating units and therefore predicted that very few of these units would trigger the modification provisions and be subject to the proposed standards. Given the limited information that we have about past modifications, the Agency has concluded that it lacks sufficient information to establish standards of performance for all types of modifications at steam generating units at this time. Instead, the EPA has determined that it is appropriate to establish standards of performance at this time for larger modifications, such as major facility upgrades involving, for example, the refurbishing or replacement of steam turbines and other equipment upgrades that result in substantial increases in a unit's hourly CO_2 emissions rate. The Agency has determined, based on its review of public comments and other publicly available information, that it has adequate information regarding the types of modifications that could result in large increases in hourly CO_2 emissions, as well as on the types of measures available to control emissions from sources that undergo such modifications, and on the costs and effectiveness of such control measures, upon which to establish standards of performance for modifications with large emissions increases at this time.[899] The EPA did not reopen any aspect of these determinations concerning modifications in the 2015 NSPS, except, as noted below, for the BSER and associated requirements for large modifications.

Because the EPA has not promulgated a NSPS for small modifications, any existing steam generating unit that undertakes a change that increases its hourly CO_2 emissions rate by 10 percent or less will continue to be treated as an existing source that is subject to the CAA section 111(d) requirements being finalized today.

With respect to large modifications, the EPA explained in the 2015 NSPS that they are rare, but there is record evidence indicating that they may occur.[900] Because the EPA is finalizing requirements for existing coal-fired steam generating units that are, on their face, more stringent than the requirements for large modifications, the EPA believes it is appropriate to review and revise the latter requirements to minimize the anomalous incentive that an existing source could have to undertake a large modification for the purpose of avoiding the more stringent requirements that it would be subject to if it remained an existing source. Accordingly, the EPA proposed and is finalizing amending the BSER for large modifications for coal-fired steam generating units to mirror the BSER for the subcategory of long-term coal-fired steam generating units that is, the use of CCS with 90 percent capture of CO_2. The EPA believes that it is reasonable to assume that any existing source that invests in a physical change or change in the method of operation that would qualify as a large modification expects to continue to operate past 2039. Accordingly, the EPA has determined that CCS with 90 percent capture qualifies as the BSER for such a source for the same reasons that it qualifies as the BSER for existing sources that plan to operate past December 31, 2039. The EPA discusses these reasons in section VII.C.1.a of this preamble. The EPA has determined that CCS with 90 percent capture qualifies as the BSER for large modifications, and not the controls determined to be the BSER in the 2015 NSPS, due to the recent reductions in the cost of CCS.

By the same token, the EPA is finalizing that the degree of emission limitation associated with CCS with 90 percent capture is an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis), the same as finalized for existing sources with CCS with 90 percent capture. See section VII.C.3.a of this preamble. Based on this degree of emission limitation, the EPA proposed and is finalizing that the standard of performance for steam generating units that undertake large modifications after May 23, 2023, is a unit-specific emission limit determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification). The EPA proposed and is finalizing that an owner/operator of a modified steam generating unit comply with the emissions rate upon startup of the modified affected facility or the effective date of the final rule, whichever is later. The EPA proposed and is finalizing the same testing, monitoring, and reporting requirements as are currently in 40 CFR part 60, subpart TTTT.

The EPA did not propose, and is not finalizing, any review or revision of the 2015 standard for large modifications of oil- or gas-fired steam generating units because the we are not aware of any existing oil- or gas-fired steam generating EGUs that have undertaken such modifications or have plans to do so, and, unlike an existing coal-fired steam generating EGUs, existing oil- or gas-fired steam units have no incentive to undertake such a modification to avoid the requirements we are including in this final rule for existing oil- or gas-fired steam generating units.

2. New Construction and Reconstruction

The EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015. In the proposal, the EPA proposed that it did not need to review the 2015 NSPS because at that time, the EPA did not have information indicating that any such units will be constructed or reconstructed. However, the EPA has recently become aware that a new coal-fired power plant is under consideration in Alaska. In November 2023, DOE announced a $9 million cooperative agreement for the Alaska Railbelt Carbon Capture and Storage (ARCCS) project, to be led by researchers at the University of Alaska Fairbanks. The ARCCS project would study the viability of a carbon storage complex in Southcentral Alaska, likely at the mostly-depleted Beluga River gas field west of Anchorage" in the Cook Inlet Basin, which could store captured CO_2. According to reports, the privately owned Flatlands Energy Corp. is considering constructing a 400 MW coal- and biomass-fired power plant in the Susitna River valley region, which, if built, would be one of the sources of captured CO_2.[901]

[898] 80 FR 64514 (October 23, 2015).

[899] *Id.* at 64597–98.

[900] *Id.* at 64598.

[901] DOE Funding Opportunity Announcement, "DOE Invests More Than $444 Million for CarbonSAFE Project," (November 15, 2023), *https://netl.doe.gov/node/13090*; University of Alaska

In light of this development, the EPA is not finalizing its proposal not to review the 2015 NSPS. Instead, the EPA will continue to consider whether to review the 2015 NSPS and will monitor the development of this potential new construction project in Alaska as well as any other potential projects to newly construct or reconstruct a coal-fired power plant. If the EPA does decide to review the 2015 NSPS, it would propose to revise them for coal-fired steam generating units.

D. Projects Under Development

During the 2015 NSPS rulemaking, the EPA identified the Plant Washington project in Georgia and the Holcomb 2 project in Kansas as EGU ''projects under development'' based on representations by developers that the projects had commenced construction prior to the proposal of the 2015 NSPS and, thus, would not be new sources subject to the final NSPS (80 FR 64542–43; October 23, 2015). The EPA did not set a performance standard at the time but committed to doing so if new information about the projects became available. These projects were never constructed and are no longer expected to be constructed.

The Plant Washington project was to be an 850 MW supercritical coal-fired EGU. The Environmental Protection Division (EPD) of the Georgia Department of Natural Resources issued air and water permits for the project in 2010 and issued amended permits in 2014.[902 903 904] In 2016, developers filed a request with the EPD to extend the construction commencement deadline specified in the amended permit, but the director of the EPD denied the request, effectively canceling the approval of the construction permit and revoking the plant's amended air quality permit.[905]

The Holcomb 2 project was intended to be a single 895 MW coal-fired EGU and received permits in 2009 (after earlier proposals sought approval for development of more than one unit). In 2020, after developers announced they would no longer pursue the Holcomb 2 expansion project, the air permits were allowed to expire, effectively canceling the project.

For these reasons, the EPA proposed and is finalizing a decision to remove these projects under the applicability exclusions in subpart TTTT.

X. State Plans for Emission Guidelines for Existing Fossil Fuel-Fired EGUs

A. Overview

This section provides information related to state plan development, including methodologies for establishing presumptively approvable standards of performance for affected EGUs, flexibilities for complying with standards of performance, and components that must be included in state plans as well as the process for submission. This section also addresses significant comments on and any changes to the proposed emission guidelines regarding state plans that the EPA is finalizing in this action.

State plan submissions under these emission guidelines are governed by the requirements of 40 CFR part 60, subpart Ba (subpart Ba).[906] The EPA finalized revisions to certain aspects of 40 CFR part 60, subpart Ba, in November 2023, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* (final subpart Ba).[907] Unless expressly amended or superseded in these emission guidelines, the provisions of subpart Ba apply. This section explicitly addresses any instances where the EPA is adding to, superseding, or otherwise varying the requirements of subpart Ba for the purposes of these particular emission guidelines.

As noted in the preamble of the proposed action, under the Tribal Authority Rule (TAR) adopted by the EPA, Tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to that of a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to that of a state for purposes of developing a Tribal Implementation Plan (TIP) implementing the emission guidelines. If a Tribe obtains approval and submits a TIP, the EPA will generally use similar criteria and follow similar procedures as those described for state plans when evaluating the TIP submission and will approve the TIP if appropriate. The EPA is committed to working with eligible Tribes to help them seek authorization and develop plans if they choose. Tribes that choose to develop plans will generally have the same flexibilities available to states in this process.

In section X.B of this document, the EPA describes the foundational requirement that state plans achieve an equivalent level of emission reduction to the degree of emission limitation achievable through application of the BSER as determined by the EPA. Section X.C describes the presumptive methodology for calculating the standards of performance for affected EGUs based on subcategory assignment, as well as requirements related to invoking RULOF to apply a less stringent standard of performance than results from the EPA's presumptive methodology. Section X.C also describes requirements for increments of progress for affected EGUs in certain subcategories and for establishing milestones and reporting obligations for affected EGUs that plan to permanently cease operations, as well as testing and monitoring requirements. In section X.D, the EPA describes how states are permitted to include flexibilities such as emission trading and averaging as compliance measures for affected EGUs in their state plans. Finally, section X.E describes what must be included in state plans, including plan components specific to these emission guidelines and requirements for conducting meaningful engagement, as well as the timing of state plan submission and EPA review of state plans and plan revisions.

In this section of the preamble, the term ''affected EGU'' means any existing fossil fuel-fired steam generating unit that meets the applicability criteria described in section VII.B of this preamble. Affected EGUs are covered by the emission guidelines being finalized in this action under 40 CFR part 60 subpart UUUUb.

Fairbanks, Institute of Northern Engineering, ''Cook Inlet Region Low Carbon Power Generation With Carbon Capture, Transport, and Storage Feasibility Study,'' *https://ine.uaf.edu/media/391133/cook-inlet-low-carbon-power-feasibility-study-uaf-pcorfinal.pdf*; Herz, Nathaniel, ''Could a new Alaska coal power plant be climate friendly? An $11 million study aims to find out,'' Northern Journal (December 29, 2923), republished in Anchorage Daily News, *https://www.adn.com/business-economy/energy/2023/12/29/could-a-new-alaska-coal-power-plant-be-climate-friendly-an-11-million-study-aims-to-find-out/*.

[902] *https://www.gpb.org/news/2010/07/26/judge-rejects-coal-plant-permits*.

[903] *https://www.southernenvironment.org/press-release/court-rules-ga-failed-to-set-safe-limits-on-pollutants-from-coal-plant/*.

[904] *https://permitsearch.gaepd.org/permit.aspx?id=PDF-OP-22139*.

[905] *https://www.southernenvironment.org/wp-content/uploads/legacy/words_docs/EPD_Plant_Washington_Denial_Letter.pdf*.

[906] 40 CFR 60.20a–60.29a.

[907] 88 FR 80480 (November 17, 2023). At the time of promulgation of these emission guidelines, the November 2023 updates to the CAA section 111(d) implementing regulations are subject to litigation in the D.C. Circuit Court of Appeals. *West Virginia* v. *EPA,* D.C. Circuit No. 24–1009. The outcome of that litigation will not affect any of the distinct requirements being finalized in these emission guidelines, which are not directly dependent on those procedural requirements. Moreover, regardless of the outcome of that litigation, the necessary regulatory framework will exist for states to develop and submit state plans that include standards of performance for affected EGUs pursuant to these emission guidelines and prior implementing regulations.

B. Requirement for State Plans To Maintain Stringency of the EPA's BSER Determination

As explained in section V.C of this preamble, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include standards of performance for existing sources. Under CAA section 111(a)(1), a standard of performance is ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated.'' That is, the EPA has the responsibility to determine the BSER for a given category or subcategory of sources and to determine the degree of emission limitation achievable through application of the BSER to affected sources.[908] The level of emission reductions required of existing sources under CAA section 111 is reflected in the EPA's presumptive standards of performance,[909] which achieve emission reductions under these emission guidelines through requiring cleaner performance by affected sources.

States use the EPA's presumptive standards of performance to establish requirements for affected sources in their state plans. In general, the standards of performance that states establish for affected sources must be no less stringent than the presumptive standards of performance in the applicable emission guidelines.[910] Thus, in order for the EPA to find a state plan ''satisfactory,'' that plan must address each affected EGU within the state and must achieve at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance, after accounting for any application of RULOF.[911] That is, while states have the discretion to establish the applicable standards of performance for affected EGUs in their state plans, the structure and purpose of CAA section 111 and the EPA's regulations require that those plans achieve an equivalent level of emission reductions as applying the EPA's presumptive standards of performance to each of those sources (again, after accounting for any application of RULOF). Section X.C of this preamble addresses how states maintain the level of emission reduction when establishing standards of performance, and section X.D of this preamble addresses how states maintain the level of emission reduction when incorporating compliance flexibilities.

Additionally, consistent with the understanding that the purpose of CAA section 111 is for affected sources to reduce their emissions through cleaner operation, the Agency is also clarifying that emissions reductions from sources *not* affected by the final emission guidelines may not be counted towards compliance with either a source-specific or aggregate standard of performance. In other words, state plans may not account for emission reductions at non-affected fossil fuel-fired EGUs, emission reductions due to the operation or installation of other electricity-generating resources not subject to these emission guidelines for the purposes of demonstrating compliance with affected EGUs' standards of performance.

C. Establishing Standards of Performance

This section addresses several topics related to standards of performance in state plans. First, this section describes affected EGUs' eligibility for the subcategories in the final emission guidelines and how to calculate presumptive standards of performance, including calculating unit-specific baseline emission performance. Second, it summarizes compliance date information as well as how states can provide for a compliance date extension mechanism in their state plans. Third, this section describes how states may consider RULOF to apply a less stringent standard of performance or a longer compliance schedule to a particular affected EGU. Fourth, it explains how states must establish certain increments of progress for affected EGUs installing control technology to comply with standards of performance, as well as milestones and reporting obligations for affected EGUs demonstrating that they plan to permanently cease operations. And, finally, this section describes emission testing and monitoring requirements.

Affected EGUs that meet the applicability requirements discussed in section VII.B must be addressed in the state plan. For each affected EGU within the state, the state plan must include a standard of performance and compliance schedule. That is, each individual unit must have its own, source-specific standard of performance and compliance schedule. Coal-fired affected EGUs must have increments of progress in the state plan and, if they plan to permanently cease operation and to rely on such cessation of operation for purposes of these emission guidelines, an enforceable commitment and reporting obligations and milestones. State plans must also specify the test methods and procedure for determining compliance with the standards of performance.

While a presumptive methodology for standards of performance and other requirements were proposed for existing combustion turbine EGUs, the EPA is not finalizing emission guidelines for such EGUs at this time; therefore, the following discussion will not address the proposed combustion turbine EGU requirements or comments pertaining to these proposed requirements. In addition, the EPA is not finalizing the imminent- and near-term coal-fired subcategories for coal-fired steam generating units; therefore, the following discussion will not address these proposed subcategories or comments pertaining to these proposed subcategories. Similarly, the EPA is not finalizing emission guidelines for states and territories in non-contiguous areas, and is therefore not finalizing the proposed subcategories for non-continental oil-fired steam generating units or associated requirements nor addressing comments pertaining to these subcategories in this section.

1. Application of Presumptive Standards

This section of the preamble describes the EPA's approach to providing presumptive standards of performance for each of the subcategories of affected EGUs under these emission guidelines, including establishing baseline emission performance. As explained in section X.B of this preamble, CAA section 111(a)(1) requires that standards of performance reflect the degree of emission limitation achievable through application of the BSER, as determined by the EPA. For each subcategory of affected EGUs, the EPA has determined a BSER and degree of emission limitation and is providing, in these emission guidelines, a methodology for

[908] *See, e.g., West Virginia* v. *EPA,* 597 U.S. 697, 720 (2022) (''In devising emissions limits for power plants, EPA first 'determines' the 'best system of emission reduction' that—taking into account cost, health, and other factors—it finds 'has been adequately demonstrated.' The Agency then quantifies 'the degree of emission limitation achievable' if that best system were applied to the covered source.'') (internal citations omitted).

[909] See 40 CFR 60.22a(b)(5).

[910] 40 CFR 60.24a(c).

[911] As explained in section X.C.2 of this preamble, states may invoke RULOF to apply a less stringent standard of performance to a particular affected EGU when the state demonstrates that the EGU cannot reasonably achieve the degree of emission limitation determined by the EPA. In this case, the state plan may not necessarily achieve the same stringency as each source achieving the EPA's presumptive standards of performance because affected EGUs for which RULOF has been invoked would have standards of performance less stringent than the EPA's presumptive standards.

establishing presumptively approvable standards of performance (also referred to as ''presumptive standards of performance'' or ''presumptive standards''). Appropriate use of these methodologies will result in standards of performance that achieve the requisite degree of emission limitation and therefore meet the statutory requirements of section 111(a)(1) and the corresponding regulatory requirement that standards of performance must generally be no less stringent that the corresponding emission guidelines.[912] 40 CFR 60.24a(c).

Thus, a state, when establishing standards of performance for affected EGUs in its plan, must identify each affected EGU in the state and specify into which subcategory each affected EGU falls. The state would then use the corresponding methodology for the given subcategory to establish the presumptively approvable standard of performance for each affected EGU.

As discussed in section X.C.2 of this preamble, states may apply less stringent standards of performance to particular affected EGUs in certain circumstances based on consideration of RULOF. States also have the authority to deviate from the methodology provided in these emission guidelines for presumptively approvable standards in order to apply a more stringent standard of performance (*e.g.,* a state decides that an affected EGU in the medium-term coal-fired subcategory should comply with a standard of performance corresponding to co-firing 50 percent natural gas instead of 40 percent). Application of a standard of performance that is more stringent than provided by the EPA's presumptive methodology does not require application of the RULOF provisions.[913]

a. Establishing Baseline Emission Performance for Presumptive Standards

For each subcategory, the methodology to calculate a standard of performance entails establishing a baseline of CO_2 emissions and corresponding electricity generation or heat input for an affected EGU and then applying the degree of emission limitation achievable through the application of the BSER (as established in section VII.C of this preamble). The methodology for establishing baseline emission performance for an affected EGU will result in a value that is unique to each affected EGU. To establish baseline emission performance for an affected EGU in all the subcategories except the low load natural gas- and oil-fired subcategories, the EPA is finalizing a determination that a state will use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**. For affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, the EPA is finalizing a determination that a state will use the CO_2 mass emissions and corresponding heat input for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**. This period is based on the NSR program's definition of ''baseline actual emissions'' for existing electric steam generating units. See 40 CFR 52.21(b)(48)(i). Eight quarters of 40 CFR part 75 data corresponds to a 2-year period, but the EPA is finalizing this continuous 8-quarter period as it corresponds to quarterly reporting according to 40 CFR part 75. Functionally, the EPA expects states to utilize the most representative continuous 8-quarter period of data from the 5-year period immediately preceding the date the final rule is published in the **Federal Register**. For the 8 quarters of data, a state would divide the total CO_2 emissions (in the form of pounds) over that continuous time period by either the total gross electricity generation (in the form of MWh) or, for affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, the total heat input (in the form of MMBtu) over that same time period to calculate baseline CO_2 emission performance in either lb of CO_2 per MWh or lb of CO_2 per MMBtu. As an example, a state establishing baseline emission performance for an affected EGU in the medium-term coal-fired subcategory in the year 2023 would start by evaluating the CO_2 emissions and electricity generation data for the affected EGU for 2018 through 2022 and choose a continuous 8-quarter period that it deems to be the most appropriate representation of the operation of that affected EGU. While the EPA will evaluate the choice of baseline periods chosen by states when reviewing state plan submissions, the EPA intends to defer to a state's reasonable exercise of discretion as to which 8-quarter period is representative.

The EPA is finalizing the use of 8 quarters during the 5-year period prior to the date the final rule is published in the **Federal Register** as the relevant period for the baseline methodology for several reasons. First, each affected EGU has unique operational characteristics that affect the emission performance of the EGU (load, geographic location, hours of operation, coal rank, unit size, *etc.*), and the EPA believes each affected EGU's emission performance baseline should be representative of the source-specific conditions of the affected EGU and how it has typically operated. Additionally, allowing a state to choose (likely in consultation with the owners or operators of affected EGUs) the 8-quarter period for assessing baseline performance can avoid situations in which a prolonged period of atypical operating conditions would otherwise skew the emissions baseline. Relatedly, the EPA believes that, by using total mass CO_2 emissions and total electric generation or heat input for an affected EGU over an 8-quarter period, any relatively short-term variability of data due to seasonal operations or periods of startup and shutdown, or other anomalous conditions, will be averaged into the calculated level of baseline emission performance. The baseline-setting approach also aligns with the reporting and compliance requirements in the final emission guidelines. Using total mass CO_2 emissions and total electric generation or heat input provides a simple and streamlined approach for calculating baseline emission performance without the need to sort and filter non-representative data; any minor amount of non-representative data will be subsumed and accounted for through implicit averaging over the course of the 8-quarter period. Moreover, by not sorting or filtering the data, this approach reduces the need for discretion in assessing whether the data is appropriate to use. Commenters generally supported the proposed methodology for setting a baseline, particularly saying that they prefer not to have to sort or filter any data.

The EPA believes that using this baseline-setting approach as the basis for establishing presumptively approvable standards of performance will provide certainty for states, as well as transparency and a streamlined process for state plan development. While this approach is specifically designed to be flexible enough to

[912] Should a state decide to establish a standard of performance for an affected EGU using a methodology other than that provided by the EPA in these emission guidelines, the state would have to demonstrate that the resulting standard of performance achieves equivalent emission reductions as application of the EPA's presumptive standard of performance.

[913] 88 FR 80529–31 (November 17, 2023).

accommodate unit-specific circumstances, states retain the ability to deviate from this methodology. The EPA believes that the instances in which a state may need to use an alternate baseline-setting methodology will be limited to anticipated changes in operation, (*i.e.,* circumstances in which historical emission performance is not representative of future emission performance). States that wish to vary the baseline calculation for an affected EGU based on anticipated changes in operation of that EGU, when those changes result in a less stringent standard of performance, must use the RULOF mechanism, which is designed to address such contingencies.

Comment: Commenters sought clarification as to whether the methodology referred to the previous 5 calendar years or the 5-year period ending on the most recent quarter reported under 40 CFR part 75 prior to publication of the final emission guidelines.

Response: The EPA clarifies that the methodology refers to the 5-year period ending on the most recent quarter reported under 40 CFR part 75 prior to publication of the final emission guidelines in the **Federal Register**.

b. Presumptive Standards for Fossil Fuel-Fired Steam Generating Units

As described in section VII of this preamble, the EPA is finalizing separate subcategories of existing fossil fuel-fired steam generating units based on fuel type (*i.e.,* coal-fired, natural gas-fired, or oil-fired). Fuel type is based on the status of the source on January 1, 2030, and annual fuel use reporting is required after that date as a part of compliance. The EPA is further creating a subcategory for coal-fired steam generating units operating in the medium term, and further subcategorizing natural gas- and oil-fired steam generating units by load level.

Consistent with CAA section 111(d)(1)'s requirement that state plans provide for the implementation and enforcement of standards of performance, for affected EGUs in the medium-term subcategory, states must include sources' enforceable commitments to cease operating before January 1, 2039, in their plans. The state plan must specify the calendar date by which the affected EGU plans to cease operation; to be included in a state plan, a commitment to cease operations by such a date must be enforceable by the state, whether through state rule, agreed order, permit, or other legal instrument.[914] Upon EPA approval of the state plan, that commitment will become federally- and citizen-enforceable.

For affected oil- and natural gas-fired steam generating units, subcategories are defined by load level and the type of fuel fired. There are three subcategories for natural gas- and oil-fired steam generating units (base load, intermediate load, and low load). Because subcategory applicability is determined retrospectively, as opposed to prospectively, and because the standards of performance for oil- and natural gas-fired affected EGUs are based on BSERs that do not require add-on controls, it is not necessary to require these sources to take enforceable utilization commitments limiting them to just one subcategory in order to implement and enforce their standards. For steam generating units that meet the definition of natural gas- or oil-fired, and that either retain the capability to fire coal after the date this final rule is published in the **Federal Register**, that fired any coal during the 5-year period prior to that date, or that will fire any coal after that date and before January 1, 2030, the plan must include a requirement to remove the capability to fire coal before January 1, 2030.

The EPA is finalizing a requirement that compliance be demonstrated annually. For affected EGUs in all subcategories except the low load natural gas- and oil-fired subcategory, an affected EGU must demonstrate compliance based on the lb CO_2/MWh emission rate derived by dividing the total reported CO_2 mass emissions by the total reported electric generation during the compliance period (corresponding to 1 calendar year), which is consistent with the expression of the degree of emission limitation for each subcategory in sections VII.C.3 and VII.D.3. For affected EGUs in the low load natural gas- and oil-fired subcategory, an affected EGU must demonstrate compliance based on the lb CO_2/MMBtu emission rate derived by dividing the total reported CO_2 mass emissions by the total reported heat input during the compliance period (again, corresponding to 1 calendar year), consistent with the expression of the degree of emission limitation for the subcategory in section VII.D.3.[915] In other words, for units with a compliance date of January 1, 2030, the first compliance period will be January 1, 2030, through December 31, 2030. For units with a compliance date of January 1, 2032, the first compliance period will be January 1, 2032, through December 31, 2032. The compliance demonstration must occur by March 1 of the following year (*i.e.,* for the 2030 compliance period, by March 1, 2031).

In addition, the EPA is finalizing a requirement that standards of performance must be established as either a rate or, for affected EGUs in certain subcategories, a mass of emissions. If a state chooses to allow mass-based compliance for certain affected EGUs it must first calculate the rate-based emission limitation that corresponds to the presumptive standard of performance, and then explain how it translated that rate-based emission limitation into the mass that constitutes an affected EGU's standard of performance. See section X.D of this preamble for more information on demonstrating compliance where states are incorporating compliance flexibilities.

i. Long-Term Coal-Fired Steam Generating Units

This section describes the EPA's methodology for establishing presumptively approvable standards of performance for long-term coal-fired steam generating units. Affected coal-fired steam generating units that do not meet the specifications of the medium-term coal-fired EGU subcategory are necessarily long-term units, and have a BSER of CCS with 90 percent capture and a degree of emission limitation of 90 percent capture of the mass of CO_2 in the flue gas (*i.e.,* the mass of CO_2 after the boiler but before the capture equipment) over an extended period of time and an 88.4 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*i.e.,* an annual calendar-year basis). The EPA is finalizing a determination that where states use the methodology described here to establish standards of performance for affected EGUs in this subcategory, those established standards will be presumptively approvable when included in a state plan submission.

Establishing a standard of performance for an affected coal-fired EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described in section X.C.1.a of this preamble); and applying the degree of emission limitation, based on the application of the BSER, to that level of baseline emission performance. Implementation of CCS with a capture rate of 90 precent translates to a degree

[914] 40 CFR 60.26a.

[915] If the state plan incorporates compliance flexibilities like emission averaging and trading, an affected EGU must demonstrate compliance consistent with the expression of the respective flexibility. See section X.D of this preamble for more information.

of emission limitation comprising of an 88.4 percent reduction in CO_2 emission rate compared to the baseline level of emission performance. Using the complement of 88.4 percent (*i.e.,* 11.6 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance. For example, if a long-term coal-fired EGU's level of baseline emission performance is 2,000 lbs CO_2 per MWh, it will have a presumptively approvable standard of performance of 232 lbs CO_2 per MWh (2,000 lbs CO_2 per MWh multiplied by 0.116).

The EPA is also finalizing a requirement that affected coal-fired EGUs in the long-term subcategory comply with federally enforceable increments of progress, which are described in section X.C.3 of this preamble.

ii. Medium-Term Coal-Fired Steam Generating Units

This section describes the EPA's methodology for establishing presumptively approvable standards of performance for medium-term coal-fired steam generating units. Affected coal-fired steam generating units that plan to commit to permanently cease operations before January 1, 2039, have a BSER of 40 percent natural gas co-firing on a heat input basis. The EPA is finalizing a determination that where states use the methodology described here to establish standards of performance for an affected EGU in this subcategory, those established standards of performance would be presumptively approvable when included in a state plan submission.

Establishing a standard of performance for an affected EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described in section X.C.1.a); and applying the degree of emission limitation, based on the application of the BSER, to that level of baseline emission performance. Implementation of natural gas co-firing at a level of 40 percent of total annual heat input translates to a level of stringency of a 16 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*i.e.,* an annual calendar-year basis) compared to the baseline level of emission performance. Using the complement of 16 percent (*i.e.,* 84 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance for the affected EGU. For example, if a medium-term coal-fired EGU's level of baseline emission performance is 2,000 lbs CO_2 per MWh, it will have a presumptively approvable standard of performance of 1,680 CO_2 lbs per MWh (2,000 lbs CO_2 per MWh multiplied by 0.84).

For medium-term coal-fired steam generating units that have an amount of co-firing that is reflected in the baseline operation, the EPA is finalizing a requirement that states account for such preexisting co-firing in adjusting the degree of emission limitation. If, for example, an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to a 12 percent reduction in CO_2 emission rate on a lb CO_2/MWh-gross basis compared to the baseline level of emission performance (*i.e.,* an additional 30 percent of natural gas by heat input) to reflect the preexisting level of natural gas co-firing. This results in a standard of performance based on the degree of emission limitation achieving an additional 30 percent co-firing beyond the 10 percent that is accounted for in the baseline. The EPA believes this approach is a more straightforward mathematical adjustment than adjusting the baseline to appropriately reflect a preexisting level of co-firing.

The standard of performance for the medium-term coal-fired subcategory is based on the degree of emission limitation that is achievable through application of the BSER to the affected EGUs in the subcategory and consists exclusively of the rate-based emission limitation. However, the BSER determination for this subcategory is predicated on the assumption that affected EGUs within it will permanently cease operations prior to January 1, 2039. If a state decides to place an affected EGU in the medium-term coal-fired subcategory, the state plan must include that EGU's commitment to permanently cease operating as an enforceable requirement. The state plan must also include provisions that provide for the implementation and enforcement of this commitment, including requirements for monitoring, reporting, and recordkeeping.

Affected coal-fired EGUs that are relying on commitments to cease operating must comply with the milestones and reporting requirements as specified under these emission guidelines. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with their state plan requirements and to help ensure that any issues with implementation are identified in a timely and efficient manner. These milestones are described in detail in section X.C.4 of this preamble. Affected EGUs in this subcategory would also be required to comply with the federally enforceable increments of progress described in section X.C.3 of this preamble.

iii. Natural Gas-Fired Steam Generating Units and Oil-Fired Steam Generating Units

This section describes the EPA's final methodology for presumptively approvable standards of performance for the following subcategories of affected natural gas-fired and oil-fired steam generating units: low load natural gas-fired steam generating units, intermediate load natural gas-fired steam generating units, base load natural gas-fired steam generating units, low load oil-fired steam generating units, intermediate load oil-fired steam generating units, and base load oil-fired steam generating units. The final definitions of these subcategories are discussed in section VII.D.1 of this preamble. The final presumptive standards of performance are based on degrees of emission limitation that units are currently achieving, consistent with the proposed BSER of routine methods of operation and maintenance, which amounts to a proposed degree of emission limitation of no increase in emission rate.

For natural gas-fired steam generating units, the EPA proposed fixed presumptive standards of 1,500 lb CO_2/MWh-gross for intermediate load units (solicited comment on values between 1,400 and 1,600 lb/MWh-gross) and 1,300 lb CO_2/MWh-gross for base load units (solicited comment on values between 1,250 and 1,400 lb CO_2/MWh-gross). For oil-fired steam generating units, the EPA proposed fixed presumptive standards of 1,500 lb CO_2/MWh-gross for intermediate load units (solicited comment on values between 1,400 and 2,000 lb/MWh-gross) and 1,300 lb CO_2/MWh-gross for base load units (solicited comment on values between 1,250 and 1,800 lb CO_2/MWh-gross).

The EPA is finalizing presumptive standards of performance for affected natural gas-fired and oil-fired steam generating units in lieu of methodologies that states would use to establish presumptive standards of performance. This is largely because of the low variability in emissions data at intermediate and base load for these units and relatively consistent performance between these units at those load levels, as discussed in section VII.D of this preamble and detailed in the final TSD, *Natural Gas- and Oil-fired Steam Generating Units,* which supports the establishment of a generally applicable standard of performance.

For intermediate load natural gas-fired units (annual capacity factors greater than or equal to 8 percent and less than 45 percent), annual emission rates are less than 1,600 lb CO_2/MWh-gross for more than 95 percent of units. Therefore, the EPA is finalizing the presumptive standard of performance of an annual calendar-year emission rate of 1,600 lb CO_2/MWh-gross for these units.

For base load natural gas-fired units (annual capacity factors greater than or equal to 45 percent), annual emission rates are less than 1,400 lb CO_2/MWh-gross for more than 95 percent of units. Therefore, the EPA is finalizing the presumptive standard of performance of an annual calendar-year emission rate of 1,400 lb CO_2/MWh-gross for these units.

In the continental U.S., there are few if any oil-fired steam generating units that operate with intermediate or high utilization. Liquid-oil-fired steam generating units with 24-month capacity factors less than 8 percent do qualify for a work practice standard in lieu of emission requirements under the MATS (40 CFR part 63, subpart UUUUU). If oil-fired units operated at higher annual capacity factors, it is likely they would do so with substantial amounts of natural gas-firing and have emission rates that are similar to steam generating units that fire only natural gas at those levels of utilization. There are a few natural gas-fired steam generating units that are near the threshold for qualifying as oil-fired units (*i.e.,* firing more than 15 percent oil in a given year) but that on average fire more than 90 percent of their heat input from natural gas. Therefore, the EPA is finalizing the same presumptive standards of performance for oil-fired steam generating units as for natural gas-fired units (1,400 lb CO_2/MWh-gross for base load units and 1,600 lb CO_2/MWh-gross for intermediate load units).

Lastly, the EPA is finalizing uniform fuels as the BSER for low load natural gas and oil-fired steam generating units. The EPA is finalizing degrees of emission limitation defined by 130 lb CO_2/MMBtu for low load natural gas-fired steam generating units and 170 lb CO_2/MMBtu for low load oil-fired steam generating units, and presumptively approvable standards consistent with those values.

Comment: One commenter stated that the EPA should instead allow states to define standards using a source's baseline emission rate, with some additional flexibilities to account for changes in load.[916] The commenter also requested that, if the EPA were to finalize presumptive standards, then the higher values that the EPA solicited comment on for natural gas-fired units should be finalized. The commenter similarly requested that, if the EPA were to finalize presumptive standards, then the higher values that the EPA solicited comment on for oil-fired units should be finalized—however, the commenter also noted that its two sources that are currently oil-firing operate below an 8 percent annual capacity factor and would therefore not be subject to the intermediate load or base load presumptive standard.

Response: The EPA is finalizing presumptive standards for natural gas-fired steam generating units of 1,400 lb CO_2/MWh-gross for base load units and 1,600 lb CO_2/MWh-gross for intermediate load units. The EPA is finalizing the same standards for oil-fired steam generating units for the reasons discussed in the preceding text. Few, if any, oil-fired units operate as intermediate load or base load units, as acknowledged by the commenter. Those oil-fired units that have operated near the threshold for intermediate load have typically fired a large proportion of natural gas and operated at emission rates consistent with the final presumptive standards.

c. Compliance Dates

This section summarizes information on the compliance dates, or the first date on which the standard of performance applies, that the EPA is finalizing for each subcategory. As discussed in section X.C.1.b, compliance is required to be demonstrated on an annual (*i.e.,* calendar year) basis.

The EPA proposed a compliance date of January 1, 2030, for all affected steam generating units. As discussed in section VII.C.1.a.i(E) of this preamble, the EPA received comments that this compliance date was not achievable for sources in the long-term coal-fired EGU subcategory that would be installing CCS. In response to those comments, the EPA reevaluated the information and timeline for CCS installation and is finalizing a compliance date of January 1, 2032, for the long-term coal-fired subcategory. The Agency is finalizing a compliance date of January 1, 2030, for units in the medium-term coal-fired subcategory as well as for natural gas- and oil-fired steaming generating units.

The EPA refers to January 1, 2030, and January 1, 2032, as ''compliance dates,'' ''final compliance dates,'' and ''initial compliance dates'' in various parts of this preamble. In each case, the EPA means that this is the date on which affected EGUs must start monitoring and reporting their emissions and other relevant data for purposes of demonstrating compliance with their standards of performance under these emission guidelines. Affected EGUs demonstrate compliance on a calendar year basis, *i.e.,* the compliance period for affected EGUs is 1 calendar year. Therefore, affected EGUs will not have to demonstrate that they are achieving their standards of performance on January 1, 2030, or January 1, 2032, as that demonstration is made only at the end of the compliance period, *i.e.,* at the end of the calendar year. But, again, these are the dates on which affected EGUs in the relevant subcategories must start monitoring and reporting for purposes of their future compliance demonstrations with their standards of performance.

d. Compliance Date Extension Mechanism

The EPA is finalizing provisions that allow states to include a mechanism to extend the compliance date for certain affected EGUs in their state plans. This mechanism is only available for situations in which an affected EGU encounters a delay in installation of a control technology that makes it impossible to commence compliance by the date specified in section X.C.1.c of this preamble. The owner or operator must provide documentation of the circumstances that precipitated the delay (or the anticipated delay) and demonstrate that those circumstances were or are entirely beyond the owner or operator's control and that the owner or operator has no ability to remedy the delay. These circumstances may include, but are not limited to, permitting-related delays or delays in delivery or construction of parts necessary for installation or implementation of the control technology.

The EPA received extensive comment requesting a mechanism to extend the compliance date for affected EGUs installing a control technology to address situations in which the owner or operator of the affected EGU encounters a delay outside of their control. Several industry commenters noted the potential for such delays due to, among other reasons, supply chain constraints, permitting processes, and/or environmental assessments as well as

[916] See Document ID No. EPA–HQ–OAR–2023–0072–0806.

delays in deployment of supporting infrastructure like pipelines. These commenters explained that an extension mechanism could provide greater regulatory certainty for owners and operators. In light of this feedback and acknowledgment that there may be circumstances outside of owners/operators' control that impact their ability to meet the compliance dates in these emission guidelines, the EPA believes that it is reasonable to provide a consistent and transparent means of allowing a limited extension of the compliance deadline where an affected EGU has demonstrated such an extension is needed for installation of controls. This mechanism is intended to address delays in implementation—not to provide more time to assess the compliance strategy (*i.e.,* the type of technology or subcategory assignment) for the affected EGU, as some commenters suggested; those decisions are to be made at the time of state plan approval.

The compliance date extension mechanism is consistent with both CAA section 111 and these emission guidelines. Consistent with the statutory purpose of remedying dangerous air pollution, state plans must generally provide for compliance with standards of performance as expeditiously as practicable but no later than specified in the emission guidelines. 40 CFR 60.24a(c). As discussed in sections VII.C.1.a.i.(E) and VII.C.2.b.i(C), the EPA has determined compliance timelines in these emission guidelines consistent with achieving emission reductions as expeditiously as practicable given the time it takes to install the BSER technologies for the respective subcategories. The compliance dates are designed to accommodate the process steps and timeframes that the EPA reasonably anticipates will apply to affected EGUs. This extension mechanism acknowledges that circumstances entirely outside the control of the owners or operators of affected EGUs may extend the timeframe for installation of control technologies beyond what the EPA reasonably expects for the subcategories as a general matter. Thus, so long as this extension mechanism is limited to circumstances that cannot be reasonably controlled or remedied by states or affected EGUs and that make it impossible to achieve compliance by the dates specified in these emission guidelines, its use is consistent with achieving compliance as expeditiously as practicable.

The EPA is establishing parameters, described in this subsection, for the features of this mechanism (*e.g.,* documentation, time limitation). Within these parameters, states should consider state-specific circumstances related to the implementation and enforcement of this mechanism in their state plans. Importantly, in order to provide compliance date extensions that do not require a state plan revision available to affected EGUs, states must include the mechanism in their proposed state plans that are provided for public comment and meaningful engagement (as well as in the final state plan submitted to the EPA), and the circumstances for and consequences of using this mechanism must be clearly spelled out and bounded. States are not required to include this mechanism in their state plans; absent its inclusion, states must submit a state plan revision in order to extend a compliance schedule that has been approved into a plan.

First, state plans must provide that a compliance date extension through this mechanism is available only for affected EGUs that are installing add-on controls. Affected EGUs that intend to comply without installing additional control technologies—including, but not limited to, oil and gas-fired steam generating EGUs—should not experience the types of installation or implementation delays that this mechanism is intended to address. Second, state plan mechanisms must provide that to receive a compliance date extension, the owner or operator of an affected EGU is required to demonstrate to the state air pollution control agency, and provide supporting documentation to establish, the basis for and plans to address the delay. For each affected EGU, this demonstration must include (1) confirmation that the affected EGU has met the relevant increments of progress up to the point of the delay, including any permits obtained and/or contracts entered into for the installation of control technology, (2) documentation, such as invoices or correspondence with permitting authorities, vendors, etc., of the circumstances of the delay and that the delay is due to the action, or lack thereof, of a third party (*e.g.,* supplier or permitting authority), and that the owner or operator of the affected EGU has itself acted consistent with achieving timely compliance (*e.g.,* in applying for permits with all necessary information or contracting in sufficient time to perform in accordance with required schedules), and (3) plans for addressing the circumstances and remedying the delay as expeditiously as practicable, including updated dates for the final increment of progress corresponding to the compliance date as well as any other increments that are outstanding at the time of the demonstration. These requirements for documentation are intended to ensure, *inter alia,* that the owner or operator has made all reasonable efforts to achieve timely compliance and that the circumstances for granting an extension are not speculative but are rather based on delays the affected EGU is currently experiencing or is reasonably certain to experience.

The extended compliance date must be as expeditiously as practicable and the maximum time allowed for this extension is 1 year beyond the compliance date specified for the affected EGU by the state plan. Several commenters suggested that a 1-year extension was appropriate. If the delay is anticipated to be longer than 1 year, states can provide for the use of this mechanism for up to 1 year but should also initiate a state plan revision if necessary to provide an updated compliance date through consideration of RULOF, subject to EPA approval of the plan revision.

The state air pollution control agency is charged with approving or disapproving a compliance date extension request based on its written determination that the affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation. All documentation for the extension request must be submitted by the owner or operator of the affected EGU to the state air pollution control agency no later than 6 months prior to the compliance date provided in these emission guidelines. The owner or operator of the affected EGU must also notify the relevant EPA Regional Administrator of their compliance date extension request at the time of the submission of the request. The owner or operator of the affected EGU must also post their application for the compliance date extension request to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, when they submit the request to the state air pollution control agency. The state air pollution control agency must notify the relevant EPA Regional Administrator of any determination on an extension request and the new compliance date for any affected EGU(s) with an approved extension at the time of the determination on the extension request. The owner or operator of the affected EGU must also post the state's determination on the compliance extension request to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, upon receipt of the determination, and, if the request is approved, update information on the website related to the compliance date and increments of progress dates within 30 days of the receipt of the state's approval.

2. Remaining Useful Life and Other Factors

Under CAA section 111(d), the EPA is required to promulgate regulations under which states submit plans that ''establish[] standards of performance for any existing source'' and ''provide for the implementation and enforcement of such standards of performance.'' While states establish the standards of performance, there is a fundamental obligation under CAA section 111(d) that such standards reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA.[917] The EPA identifies this degree of emission limitation as part of its emission guideline. 40 CFR 60.22a(b)(5). Thus, as described in section X.C.2 of this preamble, the EPA is providing methodologies for states to follow in determining and applying presumptively approvable standards of performance to affected EGUs in each of the subcategories covered by these emission guidelines. In general, the standards of performance that states establish for designated facilities must be no less stringent than the presumptively approvable standards of performance specified in these emission guidelines. 40 CFR 60.24a(c).

However, CAA section 111(d)(1) also requires that the EPA's regulations permit the states, in applying a standard of performance to any particular designated facility, to ''take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies.'' The EPA's implementing regulations under 40 CFR 60.24a allow a state to consider a particular designated facility's remaining useful life and other factors (''RULOF'') in applying to that facility a standard of performance that is less stringent than the presumptive level of stringency in the applicable emission guideline, or a compliance schedule that is longer than prescribed by that emission guideline.

In the proposal, the EPA indicated that it had recently proposed, in a separate rulemaking, to clarify the general implementing regulations governing the application of RULOF. The Agency further explained that the revised RULOF regulations, as finalized in that separate rulemaking, would apply to these emission guidelines. The revisions to the implementing regulations' RULOF provisions were finalized in November 2023, with some changes in response to public comments relative to proposal. As provided by 40 CFR 60.20a(a) and (a)(1) and indicated in the proposal, the RULOF provisions in 40 CFR 60.24a, as revised in the November 2023 final rule, will govern the use of RULOF to provide less stringent standards of performance or longer compliance schedules under these emission guidelines. The EPA is not superseding any provision of the RULOF regulations at 40 CFR 60.24a in these emission guidelines.

As explained in the preamble to the final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clear Air Act Section 111(d),* the EPA has interpreted the RULOF provision of CAA section 111(d)(1) as allowing states to apply a standard of performance that is less stringent than the degree of emission limitation in the applicable emission guideline, or a longer compliance schedule, to a particular facility based on that facility's remaining useful life and other factors. The use of RULOF to deviate from an emission guideline is available only when there are fundamental differences between the circumstances of a particular facility and the information the EPA considered in determining the degree of emission limitation or the compliance schedule, and those fundamental differences make it unreasonable for the facility to achieve the degree of emission limitation or meet the compliance schedule in the emission guideline. This ''fundamentally different'' standard is consistent with the statutory purpose of reducing dangerous air pollution under CAA section 111; the statutory framework under which, to achieve that purpose, the EPA is directed to determine the degree of emission under CAA section 111(a)(1); and the understanding that RULOF is intended as a limited variance from the EPA's determination to address unusual circumstances at particular facilities.[918]

The relevant consideration for states contemplating the use of RULOF to apply a less stringent standard of performance is whether a designated facility can reasonably achieve the degree of emission limitation in the applicable emission guideline, not whether it can implement the system of emission reduction the EPA determined is the BSER. That is, if a designated facility cannot implement the BSER but can reasonably achieve the specified degree of emission limitation using a different system of emission reduction, the state cannot use RULOF to apply a less stringent standard of performance to that facility.

If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular facility cannot reasonably achieve the degree of emission limitation or compliance schedule determined by the EPA in these emission guidelines, the state may then apply a less stringent standard of performance or longer compliance schedule. The process for doing so is laid out in 40 CFR 60.24a(f). Critically, standards of performance and compliance schedules pursuant to RULOF must be no less stringent, or no longer, than is necessary to address the fundamental difference between the information the EPA considered and the particular facility that was the basis for invoking RULOF under 40 CFR 60.24a(e). In determining a less stringent standard of performance, the state must, to the extent necessary, evaluate the systems of emission reduction identified in the emission guidelines using the factors and evaluation metrics the EPA considered in assessing those systems, including technical feasibility, the amount of emission reductions, the cost of achieving such reductions, any non-air quality health and environmental impacts, and energy requirements. States may also consider, as justified, other factors specific to the facility that were the basis for invoking RULOF under 40 CFR 60.24a(e), as well as additional systems of emission reduction.

The RULOF provision at 40 CFR 60.24a(g) states that, where the basis of a less stringent standard of performance is an operating condition within the control of a designated facility, the state plan must include such operating condition as an enforceable requirement. The state plan must also include requirements, such as for monitoring, reporting, and recordkeeping, for the implementation and enforcement of the condition. This is relevant in the case of, for example, less stringent standards of performance that are based on a particular designated facility's remaining useful life or utilization.

Finally, the general implementing regulations provide that states may always adopt and enforce, as part of their state plans, standards of

[917] *West Virginia* v. *EPA,* 597 U.S. 697, 720 (2022) (''In devising emissions limits for power plants, EPA first 'determines' the 'best system of emission reduction' that—taking into account cost, health, and other factors—it finds 'has been adequately demonstrated.' The Agency then quantifies 'the degree of emission limitation achievable' if that best system were applied to the covered source.'') (internal citations omitted).

[918] See, *e.g.,* 88 FR 80512 (November 17, 2023).

performance that are more stringent than the degree of emission limitation determined by the EPA and compliance schedules that require final compliance more quickly than specified in the applicable emission guidelines. 40 CFR 60.24a(i). States do not have to use the RULOF provisions in 40 CFR 60.24a(e)–(h) to apply a more stringent standard of performance or faster compliance schedule.

The EPA notes that there were a number of RULOF provisions proposed as additions to the general implementation regulations in subpart Ba and discussed in the proposed emission guidances that the EPA did not finalize as part of that separate rulemaking. Any proposed RULOF requirements that were not finalized in 40 CFR 60.24a are likewise not being finalized in this action and do not apply as requirements under these emission guidelines. However, two considerations in particular remain relevant to states' development of plans despite not being finalized as requirements: consideration of communities most impacted by and vulnerable to the health and environmental impacts of an affected EGU that is invoking RULOF, and the need to engage in reasoned decision making that is supported by information and a rationale that is included in the state plan.[919]

As explained in the preamble to the November 2023 final rule revising subpart Ba, consideration of health and environmental impacts is inherent in consideration of two factors, the non-air quality health and environmental impacts and amount of emission reduction, that the EPA considers under CAA section 111(a)(1). Therefore, a state considering whether a variance from the EPA's degree of emission limitation is appropriate will necessarily consider the potential impacts and benefits of control to communities impacted by an affected EGU that is potentially receiving a less stringent standard of performance.[920] Additionally, as discussed in section X.E.1.b.i of this preamble, the general implementing regulations for CAA section 111(d) in subpart Ba require states to submit, with their state plans or plan revisions, documentation that they have conducted meaningful engagement with pertinent stakeholders and/or their representative in the plan (or plan revision) development process. 40 CFR 60.23a(i). The application of a less stringent standard of performance or longer compliance schedule pursuant to RULOF can impact the effects a state plan has on pertinent stakeholders, which include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of a state plan or plan revision. See 40 CFR 60.21a(l). Therefore, the potential application of less stringent standards of performance or longer compliance schedule should be part of a state's meaningful engagement on a state plan or plan revision.

Similarly, the EPA emphasized in the preamble to the November 2023 final rule revising subpart Ba that states carry the burden of making any demonstrations in support of less-stringent standards of performance pursuant to RULOF in developing their plans. As a general matter, states always bear the responsibility of reasonably documenting and justifying the standards of performance in their plans. In order to find a standard of performance satisfactory, the EPA must be able to ascertain, based on the information and analysis included in the state plan submission, that the standard meets the statutory and regulatory requirements.[921]

Comment: Multiple commenters expressed support for the EPA's proposed approach to RULOF, including its framework for ensuring that less stringent standards of performance and longer compliance schedules are limited to unique circumstances that reflect fundamental differences from the circumstances that the EPA considered, and that such standards do not undermine the overall effectiveness of the emission guidelines. These commenters also noted that the proposed RULOF approach is consistent with CAA section 111(d). However, other commenters argued that the EPA lacks authority to put restrictions on how states consider RULOF to apply less stringent standards of performance or longer compliance schedules. Some commenters stated that the EPA's framework for the consideration of RULOF runs counter to section 111's framework of cooperative federalism and that the EPA has a limited role of determining BSER for the source category while the statute reserves significant authority for the states to establish and implement standards of performance. One commenter elaborated that the broad discretion given to states to establish standards of performance gives the EPA only a limited role in reviewing states' RULOF demonstrations.

Response: The provisions that will govern states' use of RULOF under these emission guidelines are contained in the part 40, subpart Ba CAA section 111(d) implementing regulations. Following proposal of these emission guidelines, the EPA finalized revisions to the subpart Ba RULOF provisions in a separate rulemaking. Any comments on these generally applicable provisions, including the EPA's authority to promulgate and implement them and consistency with the cooperative federalism framework of CAA section 111(d), are outside the scope of this action. The EPA has, however, considered and responded to comments that concern the application of these generally applicable RULOF provisions under these particular emission guidelines.

Comment: Several commenters spoke to the role of RULOF given the structure of the proposed subcategories for coal-fired steam generating affected EGUs. Some commenters supported the EPA's statement that, given the four proposed subcategories based on affected EGUs' intended operating horizons, the Agency did not anticipate that states would be likely to need to invoke RULOF based on a particular affected EGU's remaining useful life. In contrast, other commenters stated that the EPA was attempting to unlawfully preempt state consideration of RULOF. Some noted that, regardless of the approach to subcategorization, a particular source may still present source-specific considerations that a state may consider relevant when applying a standard of performance. One commenter referred to RULOF as a way for states to "modify" subcategories to address the circumstances of particular affected EGUs.

Response: As explained in section VII.C of this preamble, the structure of the subcategories for coal-fired steam generating affected EGUs under these final emission guidelines differs from the four subcategories that the EPA proposed. The EPA is finalizing just two subcategories for coal-fired EGUs: the long-term subcategory and the medium-term subcategory. Under these circumstances, the justification for the EPA's statement at proposal that it is unlikely that states would need to invoke RULOF based on a coal-fired steam generating affected EGU's remaining useful life no longer applies. Consistent with 40 CFR 60.24a(e) and the Agency's explanation in the proposal, states have the ability to

[919] The other RULOF provisions that the EPA proposed as additions to 40 CFR 60.24a but did not finalize are related to setting imminent and outermost dates for the consideration of remaining useful life and consideration of RULOF to apply more stringent standards of performance. See 88 FR 80480, 80525, 80529 (November 17, 2023).

[920] 88 FR 80528 (November 17, 2023).

[921] See *id.* at 80527.

consider, *inter alia,* a particular source's remaining useful life when applying a standard of performance to that source.[922]

Moreover, the EPA is clarifying that RULOF may be used to particularize the compliance obligations for an affected EGU when a state demonstrates that it is unreasonable for that EGU to achieve the applicable degree of emission limitation or compliance schedule determined by the EPA. Invocation of RULOF does not have the effect of modifying the subcategory structure or creating a new subcategory for a particular affected EGU. That EGU remains in the applicable subcategory. As explained elsewhere in this section of the preamble, the particularized compliance obligations must differ as little as possible from the presumptive standard of performance and compliance schedule for the subcategory into which the affected EGU falls under these emission guidelines.

Comment: One commenter requested that the EPA identify situations in which it is reasonable to deviate from the presumptive standards of performance in the emission guidelines and include presumptively approvable approaches for states to use when invoking RULOF. The commenter noted that this would reduce the regulatory burden on states developing and submitting plans. Another commenter, however, stated that the EPA should not provide any presumptively approvable standard, criteria, or analytic approach for states seeking to use RULOF. This commenter explained that the premise of source-specific variances under RULOF is that they reflect circumstances that are unique to a particular unit and fundamental differences from the general case, and that it would be inappropriate to offer a generic rubric for approving variances separate from the particularized facts of each case.

Response: The EPA is not identifying circumstances in which it would be reasonable to deviate from its determinations or providing presumptively approvable approaches to invoking RULOF in these emission guidelines. For this source category—fossil-fuel fired steam generating EGUs—in particular, the circumstances and characteristics of affected EGUs and the control strategies the EPA has identified as BSER are extremely context- and source-specific. In order to invoke RULOF for a particular affected EGU, a state must demonstrate that it is unreasonable for that EGU to reasonably achieve the applicable degree of emission limitation or compliance schedule. Given the diversity of sizes, ages, locations, process designs, operating conditions, *etc.,* of affected EGUs, it is highly unlikely that the circumstances that result in one affected EGU being unable to reasonably achieve the applicable presumptive standard or compliance schedule would apply to any other affected EGU. Further, the RULOF provisions of subpart Ba provide clarity for and guidance to states as to what constitutes a satisfactory less-stringent standard of performance under these emission guidelines.

While the EPA is not providing presumptively approvable circumstances or analyses for RULOF in these emission guidelines, it is providing information and analysis that states can leverage in making any determinations pursuant to the RULOF provisions. As explained elsewhere in this section of the preamble, the EPA expects that states will be able to particularize the information it is providing in section VII of this preamble and the final Technical Support Documents for the circumstances of any affected EGUs for which they are considering RULOF, thereby decreasing the analytical burdens.

Comment: Several commenters stated that the proposed emission guidelines did not provide adequate time for RULOF analyses.

Response: As noted above, the EPA expects states to leverage the information it is providing in section VII of this preamble and the final Technical Support Documents in conducting any RULOF analyses under these emission guidelines. In particular, the Agency believes states will be able to use the information it is providing on available control technologies for affected EGUs, technical considerations, and costs given different amortization periods and particularize it for the purpose of conducting any analyses pursuant to 40 CFR 60.24a(e) and (f). Additionally, as discussed in section X.C.2.b of this preamble, the regulatory provisions for RULOF under subpart Ba provide a framework for determining less stringent standards of performance that have the practical effect of minimizing states' analytical burdens. Given the EPA's consideration of affected EGU's circumstances and operational characteristics in designing these emission guidelines, the Agency does not anticipate that states will be in the position of conducting numerous RULOF analyses as part of their state planning processes. The EPA therefore believes that states will have sufficient time to consider RULOF and conduct any RULOF analyses under these emission guidelines.

a. Threshold Requirements for Considering RULOF

The general implementing regulations of 40 CFR part 60, subpart Ba, provide that a state may apply a less stringent standard of performance or longer compliance schedule than otherwise required under the applicable emission guidelines based on consideration of a particular source's remaining useful life and other factors. To do so, the state must demonstrate for each designated facility (or class of such facilities) that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA (*i.e.,* the presumptively approvable standard of performance) based on: (1) Unreasonable cost resulting from plant age, location, or basic process design, (2) physical impossibility or technical infeasibility of installing the necessary control equipment, or (3) other factors specific to the facility. In order to determine that one or more of these circumstances has been met, the state must demonstrate that there are fundamental differences between the information specific to a facility (or class of such facilities) and the information the EPA considered in the applicable emission guidelines that make achieving the degree of emission limitation or compliance schedule in those guidelines unreasonable for the facility.

For each subcategory of affected EGUs in these emission guidelines, the EPA determined the degree of emission limitation achievable through application of the BSER by considering information relevant to each of the factors in CAA section 111(a)(1): whether a system of emission reduction is adequately demonstrated for the subcategory, the costs of a system of emission reduction, the non-air quality health and environmental impacts and energy requirements associated with a system of emission reduction, and the extent of emission reductions from a system.[923] As noted above, the relevant consideration for invoking RULOF is whether an affected EGU can reasonably achieve the presumptive standard of

[922] See 88 FR 33383 (invoking RULOF based on a particular coal-fired EGU's remaining useful life "is not prohibited under these emission guidelines").

[923] The EPA also considered expanded use and development of technology in determining the BSER for each subcategory. However, as this consideration is not necessarily relevant at the scale of a particular source for which a less stringent standard of performance is being considered, it is not addressed here.

performance for the applicable subcategory, as opposed to whether it can implement the BSER. In determining the BSER the EPA found that certain costs, impacts, and energy requirements were, on balance, reasonable for affected EGUs; it is therefore reasonable to assume that the same costs, impacts, and energy requirements would be equally reasonable in the context of other systems of reduction, as well. Therefore, the information the EPA considered in relation to each of these factors is the baseline for consideration of RULOF regardless of the system of emission reduction being considered.

The EPA is providing presumptive standards of performance in these emission guidelines in the form of rate-based emission limitations. Thus, the focus for states considering whether a particular affected EGU has met the threshold for a less stringent standard of performance pursuant to RULOF is whether that affected EGU can reasonably achieve the applicable rate-based presumptive standard of performance in these emission guidelines.

Within each of the statutory factors it considered in determining the BSER, the Agency considered information using one or more evaluation metrics. For example, for both the long-term and medium-term coal-fired steam generating EGUs the EPA considered cost in terms of dollars/ton CO_2 reduced and increases in levelized costs expressed as dollars per MWh electricity generation. Under the non-air quality health and environmental impacts and energy requirements factor, the EPA considered non-greenhouse gas emissions and energy requirements in terms of parasitic load and boiler efficiency, in addition to evaluation metrics specific to the systems being evaluated for each subcategory. For the full range of factors, evaluation metrics, and information the EPA considered with regard to the long-term and medium-term coal-fired steam generating EGU subcategories, see section VII.D.1 and VII.D.2 of this preamble.

Although the considerations for invoking RULOF described in 40 CFR 60.24a(e) are broader than just unreasonable cost of control, much of the information the EPA considered in determining the BSER, and therefore many of the circumstances states might consider in determining whether to invoke RULOF, are reflected in the cost consideration. Where possible, states should reflect source-specific considerations in terms of cost, as it is an objective and replicable metric for comparison to both the EPA's information and across affected EGUs and states.[924] For example, consideration of pipeline length needed for a particular affected EGU is best reflected through consideration of the cost of that pipeline. In particular, consideration of the remaining useful life of a particular affected EGU should be considered with regard to its impact on costs. In determining the BSER, the EPA considers costs and specifically annualized costs associated with payment of the total capital investment associated with the BSER. An affected EGU's remaining useful life and associated length of the capital recovery period can have a significant impact on annualized costs. States invoking RULOF based on an affected EGU's remaining useful life should demonstrate that the annualized costs of applying the degree of emission limitation achievable through application of the BSER for a source with a short remaining useful life are fundamentally different from the costs that the EPA found were reasonable. For purposes of determining the annualized costs for an affected EGU with a shorter remaining useful life, the EPA considers the amortization period to begin at the compliance date for the applicable subcategory.

States considering the use of RULOF to provide a less stringent standard of performance for a particular EGU must demonstrate that the information relevant to that EGU is fundamentally different from the information the EPA considered. For example, in determining the degree of emission limitation achievable through the application of co-firing for medium-term coal-fired steam generating EGUs, the EPA found that costs of \$71/ton CO_2 reduced and \$13/MWh are reasonable. A state seeking to invoke RULOF for an affected coal-fired steam generating EGU based on unreasonable cost of control resulting from plant age, location, or basic process design would therefore, pursuant to 40 CFR 60.24a(e), demonstrate that the costs of achieving the applicable degree of emission limitation for that particular affected EGU are fundamentally different from \$71/ton CO_2 reduced and/or \$13/MWh.

Any costs that the EPA has determined are reasonable for any BSER for affected EGUs under these emission guidelines would not be an appropriate basis for invoking RULOF. Additionally, costs that are not fundamentally different from costs that the EPA has determined are or could be reasonable for sources would also not be an appropriate basis for invoking RULOF. Thus, costs that are not fundamentally different from, *e.g.,* \$18.50/MWh (the cost for installation of wet-FGD on a 300 MW coal-fired steam generating unit, used for cost comparison in section VIII.D.1.a.ii of this preamble) would not be an appropriate basis for invoking RULOF under these emission guidelines. On the other hand, costs that constitute outliers, *e.g.,* that are greater than the 95th percentile of costs on a fleetwide basis (assuming a normal distribution) would likely represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF.

Importantly, the costs evaluated in BSER determinations are, in general, based on average values across the fleet of steam generating units. Those BSER cost analysis values represent the average of a distribution of costs including costs that are above or below the average representative value. On that basis, implicit in the determination that those average representative values are reasonable is the determination that a significant portion of the unit-specific costs around those average representative values are also reasonable, including some portion of those unit-specific costs that are above but not significantly different than the average representative values. That is, the cost values the EPA considered in determining the BSER should not be considered bright-line upper thresholds between reasonable and unreasonable costs. Moreover, the examples in this discussion are provided merely for illustrative purposes; because each RULOF demonstration must be evaluated based on the facts and circumstances relevant to a particular affected EGU, the EPA is not setting any generally applicable thresholds or providing presumptively approvable approaches for determining what constitutes a fundamental difference in cost or any other consideration under these emission guidelines. The Agency will assess each use of RULOF in a state plan against the applicable regulatory requirements; however, the EPA is providing examples in this preamble in response to comments requesting that it provide further clarity and guidance on what constitutes a satisfactory use of RULOF.

Under 40 CFR 60.24a(e)(1)(iii), states may also consider ''other factors specific to the facility.'' Such ''other factors'' may include both factors (categories of information) that the EPA did not consider in determining the degree of emission limitation achievable through

[924] The EPA reiterates that states are not precluded from considering information and factors other than costs under 40 CFR 60.24a(e)(ii) and (iii).

application of the BSER and additional evaluation metrics (ways of considering a category of information) that the EPA did not consider in its analysis. To invoke RULOF based on consideration of ''other factors,'' a state must demonstrate that a factor makes it unreasonable for the affected EGU to achieve the applicable degree of emission limitation in these emission guidelines.

The general implementing regulations of subpart Ba provide that states may invoke RULOF for a class of facilities. In the preamble to the subpart Ba final rule, the EPA explained that ''invoking RULOF and providing a less-stringent standard [of] performance or longer compliance schedule for a class of facilities is only appropriate where all the facilities in that class are similarly situated in all meaningful ways. That is, they must not only share the circumstance that is the basis for invoking RULOF, they must also share all other characteristics that are relevant to determining whether they can reasonably achieve the degree of emission limitation determined by the EPA in the applicable EG. For example, it would not be reasonable to create a class of facilities for the purpose of RULOF on the basis that the facilities do not have space to install the EPA's BSER control technology if some of them are able to install a different control technology to achieve the degree of emission limitation in the EG.'' [925] Given that individual fossil fuel-fired steam generating EGUs are very unlikely to be similarly situated with regard to all of the characteristics relevant to determining the reasonableness of meeting a degree of emission limitation, the EPA believes it would not likely be reasonable for a state to invoke RULOF for a class of facilities under these emission guidelines. That is, because there are relatively few affected EGUs in each subcategory and because each EGU is likely to have a distinct combination of size, operating process, footprint, geographic location, *etc.,* it is highly unlikely that the same threshold analysis would apply to two or more units.

i. Invoking RULOF for Long-Term Coal-Fired Steam Generating EGUs

In determining the BSER for the long-term coal-fired steam generating EGUs, the EPA considered several evaluation metrics specific to CCS. However, affected EGUs are not required to implement CCS to comply with their standards of performance. To the extent a state is considering whether it is reasonable for a particular affected EGU in this subcategory to achieve the degree of emission limitation using CCS as the control strategy, the state would consider whether that affected EGU's circumstances are fundamentally different from the evaluation metrics and information the EPA considered in these emission guidelines. If a state is considering whether it is reasonable for an affected EGU to achieve the degree of emission limitation for long-term coal-fired steam generating EGUs through some other control strategy, certain of the evaluation metrics and information the EPA considered, such as overall costs and energy requirements, would be relevant while other metrics or information may or may not be.

As discussed above, the EPA considered costs in terms of \$/ton CO_2 reduced and \$/MWh. The Agency broke down its cost consideration for CCS into capture costs and CO_2 transport and sequestration costs, as discussed in sections VIII.D.1.a.ii.(A) and (B) of this preamble. The EPA also considered the availability of the IRC section 45Q tax credit in evaluating the cost of CCS for affected EGUs, and finally, evaluated the impacts of two different capacity factor assumptions on costs. Similarly, the Agency considered a number of evaluation metrics specific to CCS under the non-air quality health and environmental impacts and energy requirements factors, in addition to considering non-greenhouse gas emissions and parasitic/auxiliary energy demand increases and the net power output decreases. In particular, the EPA considered water use, CO_2 capture plant siting, transport and geologic sequestration, and impacts on the energy sector in terms of long-term structure and reliability of the power sector. A state may also consider other factors and circumstances that the EPA did not consider in its evaluation of CCS, to the extent such factors or circumstances are relevant to the reasonableness of achieving the associated degree of emission limitation.

As detailed in section VII.D.1.a.i of this preamble, the EPA has determined that CCS is adequately demonstrated for long-term coal-fired steam generating EGUs. The Agency evaluated the components of CCS both individually and in concurrent, simultaneous operation. If a state believes a particular affected EGU cannot reasonably implement CCS based on physical impossibility or technical infeasibility, the state must demonstrate that the circumstances of that individual EGU are fundamentally different from the information on CCS that the EPA considered in these emission guidelines.

ii. Invoking RULOF for Medium-Term Coal-Fired Steam Generating EGUs

As for the long-term coal-fired steam generating EGU subcategory, the EPA also considered evaluation metrics and information specific to the BSER, natural gas co-firing, for the medium-term subcategory. Again, similar to the long-term subcategory, certain generally applicable metrics and information that the EPA considered, *e.g.,* overall costs and energy requirements, will be relevant regardless of the control strategy a state is considering for an affected EGU in the medium-term subcategory. To the extent a state is considering whether it is reasonable for a particular affected EGU to reasonably achieve the presumptive standard of performance using natural gas co-firing as a control, the state should evaluate whether there is a fundamental difference between the circumstances of that EGU and the information the EPA considered. In considering costs for natural gas co-firing, the Agency took into account costs associated with adding new gas burners and other boiler modifications, fuel cost, and new natural gas pipelines. In considering non-air quality health and environmental impacts and energy requirements, the EPA addressed losses in boiler efficiency due to co-firing, as well as non-greenhouse gas emissions and impact on the structure of the energy sector. States may also consider other factors and circumstances that are relevant to determining the reasonableness of achieving the applicable degree of emission limitation.

iii. Invoking RULOF To Apply a Longer Compliance Schedule

Under 40 CFR 60.24a(c), ''final compliance,'' *i.e.,* compliance with the applicable standard of performance, ''shall be required as expeditiously as practicable but no later than the compliance times specified'' in the applicable emission guidelines, unless a state has demonstrated that a particular designated facility cannot reasonably comply with the specific compliance time per the RULOF provision at 40 CFR 60.24a(e). The EPA, in these emission guidelines, has detailed the amount of time needed for states and affected EGUs in the long-term and medium-term coal-fired steam generating EGU subcategories to comply with standards of performance using CCS and natural gas co-firing, respectively, in sections VII.C.1 and VII.C.2 of this preamble. These compliance times are based on information available for and applicable to the subcategories as a whole. The

[925] 88 FR 80517 (November 17, 2023).

Agency anticipates that some affected EGUs will be able to comply more expeditiously than on these generally applicable timelines. Similarly, there may be circumstances in which a particular EGU cannot reasonably comply with its standard of performance by the compliance date specified in these emission guidelines. In order to provide a longer compliance schedule, the state must demonstrate that there is a fundamental difference between the information the EPA considered for the subcategory as a whole and the circumstances of a particular EGU. These circumstances should not be speculative; the state must substantiate the need for a longer compliance schedule with documentation supporting that need and justifying why a certain component or components of implementation will take longer than the EPA considered in these emission guidelines. If a state anticipates that a process or activity will take longer than is typical for similarly situated EGUs within and outside the state or longer than it has historically, the state should provide an explanation of why it expects this to be the case as well as evidence corroborating the reasons and need for additional time. Consistent with 40 CFR 60.24a(c) and (e), states should not use the RULOF provision to provide a longer compliance schedule unless there is a demonstrated, documented reason at the time of state plan submission that a particular source will not be able to achieve compliance by the date specified in these emission guidelines. The EPA notes that it is providing a number of flexibilities in these final emission guidelines for states and sources if they find, subsequent to state plan submission, that additional time is necessary for compliance; states should consider these flexibilities in conjunction with the potential use of RULOF to provide a longer compliance schedule. A source-specific compliance date pursuant to RULOF must be no later than necessary to address the fundamental difference; that is, it must be as close to the compliance schedule provided in these emission guidelines as reasonably possible. Considerations specific to providing a longer compliance schedule to address reliability are addressed in section X.C.2.e.i of this preamble.

Comment: Several commenters stated that the EPA must respect the broad authority granted to states under the CAA and that while the EPA's information on various factors is helpful to states, states may readily deviate from the emission guidelines in order to account for source- and state-specific characteristics. The commenters argued that the EPA's general implementing regulations at 40 CFR 60.24a(c) recognize that states may consider factors that make application of a less stringent standard of performance or longer compliance time significantly more reasonable, and commenters stated that those factors should include, *inter alia,* cost, feasibility, infrastructure development, NSR implications, fluctuations in performance depending on load, state energy policy, and potential reliability issues. The commenters stated that states have the authority to account for consideration of other factors in various ways and that the EPA must defer to state choices, provided those choices are reasonable and consistent with the statute.

Response: Comments on states' use of RULOF vis-à-vis the EPA's determinations pursuant to CAA section 111(a)(1) in the applicable emission guidelines are outside the scope of this rulemaking.[926] Similarly, comments on the EPA's authority to review states' use of RULOF in state plans and the scope of that review are outside the scope of this rulemaking.[927] The EPA is also clarifying that, while the commenters are correct that the general implementing regulations at 40 CFR 60.24a(c) recognize that states may invoke RULOF to provide a less stringent standard of performance or longer compliance schedule, they also provide that, unless the threshold for the use of RULOF in 40 CFR 60.24a(e) has been met, ''standards of performance shall be no less stringent than the corresponding emission guideline(s) . . . and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified'' in the emission guidelines. The threshold for invoking RULOF is when a state demonstrates that a particular affected EGU cannot reasonably achieve the degree of emission limitation determined by the EPA, based on one or more of the circumstances at 40 CFR 60.24a(e)(i)–(iii), because there are fundamental differences between the information the EPA considered in the emission guidelines and the information specific to the affected EGU. The ''significantly more reasonable'' standard does not apply to RULOF determinations under these emission guidelines.[928]

The EPA agrees that states have authority to consider ''other circumstances specific to the facility.'' States are uniquely situated to have knowledge about unit-specific considerations. If a unit-specific factor or circumstance is fundamentally different from the information the EPA considered and that difference makes it unreasonable for the affected EGU to achieve that degree of emission limitation or compliance schedule,[929] it is grounds for applying a less stringent standard of performance or longer compliance schedule. The EPA will review states' RULOF analyses and determinations for consistency with the applicable regulatory requirements at 40 CFR 60.24a(e)–(h).

Comment: Multiple commenters weighed in on the subject of cost metrics. Two commenters stated that the EPA should not require states to consider costs using the same metrics that it considered in the emission guidelines. These commenters explained that the unique circumstances of each unit mean that different metrics may be appropriate and should be allowed as long as the state plan provides a justification. Other commenters, however, supported the proposed requirement for states to consider costs using the same metrics as the EPA. Similarly, commenters differed on the example in the proposed rule preamble that costs that are greater than the 95th percentile of costs on a fleetwide basis would likely be fundamentally different from the fleetwide costs that the EPA considered in these emission guidelines. While one commenter believed that the 95th percentile may not be an appropriate threshold in all circumstances and should not be treated as an absolute, another commenter argued that the EPA should formalize the 95th percentile threshold as a requirement for states seeking to invoke RULOF based on unreasonable cost.

Response: The EPA believes that, in order to evaluate whether there is a fundamental difference between the cost information the EPA considered in these emission guidelines and the cost information for a particular affected EGU, it is necessary for states to evaluate costs using the same metrics that the EPA considered. However, states are not precluded from considering additional cost metrics alongside the two metrics used in these emission guidelines: \$/ton of CO_2 reduced and \$/MWh of electricity

[926] See 88 FR 80509–17 (November 17, 2023).

[927] See *id.* at 80526–27.

[928] 40 CFR 60.20a(a).

[929] ''Other factors'' may include facility-specific circumstances and factors that the EPA did not anticipate and consider in the applicable emission guideline that make achieving the EPA's degree of emission limitation unreasonable for that facility. 88 FR 80480, 80521 (November 17, 2023).

generated. States should justify why any additional cost metrics are relevant to determining whether a particular affected EGU can reasonably achieve the applicable degree of emission limitation.

The EPA did not state that a cost that is greater than the 95th percentile of fleetwide costs would necessarily justify invocation of RULOF. Nor did the EPA intend to suggest that such costs are the only way states can demonstrate that the costs for a particular affected EGU are fundamentally different. While it may be an appropriate benchmark in some cases, there are other ways for states to demonstrate that the cost for a particular affected EGU is an outlier. That is, the EPA is not requiring that the unit-specific costs be above the 95th percentile in order to demonstrate that they are fundamentally different from the costs the Agency considered in these emission guidelines. As discussed elsewhere in this section of the preamble, the diversity in circumstances of individual affected EGUs under these emission guidelines makes it infeasible for the EPA to *a priori* define a bright line for what constitutes reasonable versus unreasonable costs for individual units in these emission guidelines.

Comment: One commenter noted that the EPA should only approve the use of RULOF to provide a longer compliance schedule where there is clearly documented evidence (*e.g.,* receipts, invoices, actual site work) that a source is making best endeavors to achieve compliance as expeditiously as possible.

Response: The EPA believes this kind of evidence is strong support for providing a longer compliance schedule. The Agency further believes that states should show that the need to provide a longer compliance schedule is notwithstanding best efforts on the parts of all relevant parties to achieve timely compliance. The EPA is not, however, precluding the possibility that states could reasonably justify a longer compliance schedule based on other types of information or evidence.

b. Calculation of a Standard of Performance That Accounts for RULOF

If a state has demonstrated that a particular affected EGU is unable to reasonably achieve the applicable degree of emission limitation or compliance schedule under these emission guidelines per 40 CFR 60.24a(e), it may then apply a less stringent standard of performance or longer compliance schedule according to the process laid out in 40 CFR 60.24a(f). Pursuant to that process, the state must determine the standard of performance or compliance schedule that, respectively, is no less stringent or no longer than necessary to address the fundamental difference that was the basis for invoking RULOF. That is, the standard of performance or compliance schedule must be as close to the EPA's degree of emission limitation or compliance schedule as reasonably possible for that particular EGU.

The EPA notes that the proposed emission guidelines would have included requirements for how states determine less stringent standards of performance, including what systems of emission reduction states must evaluate and the order in which they must be evaluated. These proposed requirements were intended to ensure that states reasonably consider the controls that may qualify as a source-specific BSER.[930] However, the final RULOF provisions in subpart Ba for determining less stringent standards of performance differ from the proposed subpart Ba provisions in a way that obviates the need for the separate requirements proposed in these emission guidelines. First, as opposed to determining a source-specific BSER for sources that have met the threshold requirements for RULOF, states determine the standard of performance that is no less stringent than the EPA's degree of emission limitation than necessary to address the fundamental difference. Second, the process for determining such a standard of performance that the EPA finalized at 40 CFR 60.24a(f)(1) involves evaluating, to the extent necessary, the systems of emission reduction that the EPA identified in the applicable emission guidelines using the factors and evaluation metrics that the Agency considered in assessing those systems. Because the final RULOF provisions of subpart Ba create essentially the same process as the provisions the EPA proposed for determining a less stringent standard of performance under these emission guidelines, the EPA has determined it is not necessary to finalize those provisions here.

The EPA anticipates that states invoking RULOF for affected EGUs will do so because an EGU is in one of two circumstances: it is implementing the control strategy the EPA determined is the BSER but cannot achieve the degree of emission limitation in the emission guideline using that control (or any other system of emission reduction); or it is not implementing the BSER and cannot reasonably achieve the degree of emission limitation using any system of emission reduction.

If an affected EGU will be implementing the BSER but cannot meet the degree of emission limitation due to fundamental differences between the circumstances of that particular EGU and the circumstances the EPA considered in the emission guidelines, it may not be necessary for the state to evaluate other systems of emission reduction to determine the less stringent standard of performance. In this instance, the state and affected EGU would determine the degree of emission limitation the EGU can reasonably achieve, consistent with the requirement that it be no less stringent than necessary. That degree of emission limitation would be the basis for the less stringent standard of performance. For example, assume an affected EGU in the long-term coal-fired steam generating EGU subcategory is intending to install CCS and the state has demonstrated that it is not reasonably possible for the capture equipment at that particular EGU to achieve 90 percent capture of the mass of CO_2 in the flue gas (corresponding to an 88.4 percent reduction in emission rate), but it can reasonably achieve 85 percent capture. If the source cannot reasonably achieve an 88.4 percent reduction in emission rate using any other system of emission reduction, the state may apply a less stringent standard of performance that corresponds to 85 percent capture without needing to evaluate further systems of emission reduction.

In other cases, however, an affected EGU may not be implementing the BSER and may not be able to reasonably achieve the applicable degree of emission limitation (*i.e.,* the presumptive standard of performance) using any control strategy. In such situations, the state must determine the standard of performance that is no less stringent than necessary by evaluating the systems of emission reduction the EPA considered in these emission guidelines, using the factors and evaluation metrics the EPA considered in assessing those systems. States may also consider additional systems of emission reduction that the EPA did not identify but that the state believes are available and may be reasonable for a particular affected EGU.

The requirement at 40 CFR 60.24a(f)(1) provides that a state must evaluate these systems of emission reduction *to the extent necessary* to determine the standard of performance that is as close as reasonably possible to the presumptive standard of performance under these emission guidelines. It will most likely not be necessary for a state to consider all of the systems that the EPA identified for a given affected EGU. For example, if the state has already determined it is not

[930] See 88 FR 33384 (May 23, 2023).

reasonably possible for an affected EGU to implement one of these control strategies, at any stringency, as part of its demonstration under 40 CFR 60.24a(e) that a less stringent standard of performance is warranted, the state does not need to evaluate that system again. Similarly, if a state starts by evaluating the system that achieves the greatest emission reductions and determines the affected EGU can implement that system, it is most likely not necessary for the state to consider the other systems on the list in order to determine that the resulting standard of performance is no less stringent than necessary. The Agency anticipates that states will leverage the information the EPA has provided regarding systems of emission reduction in these emission guidelines, as well as the wealth of other technical, cost, and related information on various control systems in the record for this final action, in conducting their evaluations under 40 CFR 60.24a(f). In many cases, it will be possible for states to use information the EPA has provided as a starting point and particularize it for the circumstances of an individual affected EGU.[931]

For systems of emission reduction that have a range of potential stringencies, states should start by evaluating the most stringent iteration that is potentially feasible for the particular affected EGU. If that level of stringency is not reasonable, the state should also evaluate other stringencies as may be needed to determine the standard of performance that is no less stringent than the applicable degree of emission limitation in these emission guidelines than necessary.

In evaluating the systems of emission reduction identified in these emissions guidelines, states must also consider the factors and evaluation metrics that the EPA considered in assessing those systems, including technical feasibility, the amount of emission reductions, any non-air quality health and environmental impacts, and energy requirements. 40 CFR 60.24a(f)(1). They may also consider, in evaluating systems of emission reduction, other factors specific to the facility that constitute a fundamental difference between the information the EPA considered and the circumstances of the particular affected EGU and that were the basis of invoking RULOF for that particular EGU. For example, if a state determined that it is physically impossible or technically infeasible and/or unreasonably costly for a long-term coal-fired affected EGU to construct a CO_2 pipeline because the EGU is located on a remote island, the state could consider that information in evaluating additional systems of emission reduction, as well.

The general implementing regulations at 40 CFR 60.24a(f)(2) provide that any less stringent standards of performance that a state applies pursuant to RULOF must be in the form required by the applicable emission guideline. The presumptive standards of performance the EPA is providing in these emission guidelines are rate-based emission limitations. In order to ensure that a source-specific standard of performance is no less stringent than the EPA's presumptive standard than necessary, the source-specific standard pursuant to RULOF must be determined and expressed in the form of a rate-based emission limitation. That is, the systems of emission reduction that states evaluate pursuant to 40 CFR 60.24a(f)(1) must be systems for reducing a source's emission rate and the state must apply a standard of performance expressed as an emission rate, in lb CO_2/MWh,[932] that is no less stringent than necessary. As discussed in section X.D.1.b of this preamble, the EPA is not providing that affected EGUs with standards of performance pursuant to consideration of RULOF can use mass-based or rate-based compliance flexibilities under these emission guidelines.

The general implementing regulations also provide that any compliance schedule extending more than twenty months past the state plan submission deadline must include legally enforceable increments of progress. 40 CFR 60.24a(d). Due to the timelines the EPA is finalizing under these emission guidelines, any affected EGU with compliance obligations pursuant to consideration of RULOF will have a compliance schedule that triggers the need for increments of progress in state plans. Because compliance obligations pursuant to RULOF are, by their nature, source-specific, the EPA is not providing particular increments of progress for sources for which RULOF has been invoked in these emission guidelines. Therefore, states must provide increments of progress for RULOF sources in their state plans that comply with the generally applicable requirements in 40 CFR 60.24a(d) and 40 CFR 60.21a(h).

Additionally, 40 CFR 60.24a(h) requires that a less stringent standard of performance must meet all other applicable requirements of both the general implementing regulations and these emission guidelines.

i. Determining a Less-Stringent Standard of Performance for Long-Term Coal Fired Steam Generating EGUs

The EPA identified four potential systems of emission reduction for long-term coal-fired steam generating EGUs: CCS with 90 percent CO_2 capture, CCS with partial CO_2 capture/lower capture rates, natural gas co-firing, and HRI. If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular affected coal-fired EGU in the long-term subcategory can install and operate CCS but cannot reasonably achieve an 88.4 percent degree of emission limitation using CCS or any other systems of emission reduction, under the process laid out in 60.24a(f)(1) the state would proceed to evaluate CCS with lower rates of CO_2 capture. The state would identify the most stringent degree of emission limitation the affected EGU can reasonably achieve using CCS and that degree of emission limitation would become the basis for the source's less stringent standard of performance.[933]

If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular affected coal-fired EGU cannot reasonably install and operate CCS as a control strategy and cannot otherwise achieve the presumptive standard of performance, the state would proceed to evaluate natural gas co-firing and HRI as potential control strategies. Because 40 CFR 60.24a(f)(1) requires that a standard of performance be no less stringent than necessary to address the fundamental differences that were the basis for invoking RULOF, states would start by evaluating natural gas co-firing at 40 percent. If the affected EGU cannot

[931] See, *e.g.,* sections VII.C.1–4 of this preamble, the final TSD, *GHG Mitigation Measures for Steam Generation* Units, the CO_2 Capture Project Schedule and Operations Memo, Documentation for the Lateral Cost Estimation, Transport and Storage Timeline Summary, and the Heat Rate Improvement Method Costs and Limitations Memo.

[932] The presumptive standards of performance for coal-fired steam-generating affected EGUs and base load and intermediate load natural gas- and oil-fired steam generating affected EGUs are in units of lb CO_2/MWh; thus, any standards of performance pursuant to consideration of RULOF must be determined in these units, as well. The presumptive standard of performance for low-load natural gas-fired and oil-fired affected EGUs are in units of lb CO_2/MMBtu. While the EPA does not expect that states will use the RULOF provisions to provide less stringent standards of performance for these sources because their BSER is based on uniform fuels, should a state do so, the standard of performance would be determined in units of lb CO_2/MMBtu.

[933] 40 CFR 60.24a(f) requires that a standard of performance pursuant to consideration of RULOF be no less stringent than necessary to address the fundamental difference identified under 40 CFR 60.24a(e). If a particular affected EGU can install and operate CCS but only at such a low CO_2 capture rate that it could reasonably achieve greater stringency based on natural gas co-firing, the state would apply a standard of performance based on natural gas co-firing.

reasonably co-fire at 40 percent, the state would proceed to evaluate lower levels of natural gas co-firing unless it has demonstrated that the EGU cannot reasonably co-fire any amount of natural gas. If that is the case, the state would then evaluate HRI as a control strategy. The EPA notes that states may also consider additional systems of emission reduction that may be available and reasonable for particular EGUs.

ii. Determining a Less-Stringent Standard of Performance for Medium-Term Coal Fired Steam Generating EGUs

The EPA identified three potential systems of emission reduction for affected coal-fired steam generating EGUs in the medium-term subcategory: CCS, natural gas co-firing, and HRI. The EPA explained in section VII.D.2.b.i of this preamble that the cost effectiveness of CCS is less favorable for medium-term steam generating EGUs based on the short periods they have to amortize capital costs and utilize the IRC section 45Q tax credit. The EPA therefore believes that it would be reasonable for states determining a less stringent standard of performance for an affected EGU in the medium-term subcategory to forgo evaluating CCS as a potential control strategy. States would therefore start by evaluating lower levels of natural gas co-firing, unless a state has demonstrated pursuant to 40 CFR 60.24a(e) that the particular EGU cannot reasonably install and implement natural gas co-firing as a system of emission reduction. If that is the case, the state would evaluate HRI as the basis for a standard of performance that is no less stringent than necessary.

The EPA expects that any coal-fired steam generating EGU to which a less stringent standard of performance is being applied will be able to reasonably implement some system of emission reduction; at a minimum, the Agency believes that all sources could institute approaches to maintain their historical heat rates.

iii. Determining a Longer Compliance Schedule

Pursuant to 40 CFR 60.24a(f)(1), a longer compliance schedule pursuant to consideration of RULOF must be no longer than necessary to address the fundamental difference identified pursuant to 40 CFR 60.24a(e). For states that are providing extensions to the schedules in the EPA's emission guidelines, implementation of this requirement is straightforward. States should provide any information and analyses discussed in other sections of this preamble as relevant to justifying the need for, and length of, any compliance schedule extensions under the RULOF provisions. For states that are applying less stringent standards of performance that are based on a system of emission reduction other than the BSER for that subcategory, states should apply a compliance schedule consistent with installation and implementation of that system that is as expeditious as practicable.[934]

Comment: One commenter asserted that the 2023 proposed rule indicated that states invoking RULOF would be required to evaluate certain controls, in a certain order, as appropriate for subcategories of affected EGUs. The commenter stated that the EPA must defer to states' consideration of other systems of emission reduction that the EPA has determined are not the BSER, including the manner in which the states choose to consider those systems.

Response: The EPA is not finalizing the proposed requirements in these emission guidelines that would have specified the systems of emission reduction that states must consider when invoking RULOF and the order in which they consider them. The EPA is instead providing that states' analyses and determinations of less stringent standards of performance pursuant to RULOF must be conducted in accordance with the generally applicable requirements of the part 60, subpart Ba implementing regulations; specifically, 40 CFR 60.24a(f). While the requirements under this regulation for determining less stringent standards of performance pursuant to RULOF are similar to the requirements proposed under these emission guidelines, they are also, as described above, more flexible because they provide (1) that states must consider other systems of emission reduction *to the extent necessary* to determine the standard of performance that is no less stringent than the EPA's degree of emission limitation than necessary, and (2) that states may consider other systems of emission reduction, in addition to those the EPA identified in the applicable emission guidelines.

c. Contingency Requirements

Per the general implementing regulations at 40 CFR 60.24a(g), if a state invokes RULOF based on an operating condition within the control of an affected EGU, such as remaining useful life or a specific level of utilization, the state plan must include such operating condition or conditions as an enforceable requirement. The state plan must also include provisions that provide for the implementation and enforcement of the operating conditions, including requirements for monitoring, reporting, and recordkeeping. The EPA notes that there may be circumstances in which an affected EGU's circumstances change after a state has submitted its state plan; states may always submit plan revisions if needed to alter an enforceable requirement therein.

Comment: One commenter stated that if a state does not accept the presumptive standards of performance for a facility, it must establish federally enforceable retirement dates and operating conditions for that facility. The commenter asserted that the CAA does not authorize the EPA to constrain states' discretion by requiring them to impose such restrictions as the price for exercising the RULOF authority granted by Congress. The commenter suggested that the EPA eliminate the requirement to include enforceable retirement dates and restrictions on operations in conjunction with a RULOF determination and stated that states should retain discretion to decide whether and when, based on RULOF, it is necessary to impose such restrictions on sources.

Response: The EPA clarifies that states are in no way required to impose enforceable retirement dates or operating restrictions on affected EGUs under these emission guidelines. It is entirely within a state's control to decide whether such a requirement is appropriate for a source. If a state determines that it is, in fact, appropriate to codify an affected EGU's intention to cease operating or limit its operations as an enforceable requirement, the state may use such considerations as the basis for applying, as warranted, a less stringent standard of performance to that source. This allowance is provided under the subpart Ba general implementing regulations, 40 CFR 60.24a(g).

d. More Stringent Standards of Performance in State Plans

States always have the authority and ability to include more stringent standards of performance and faster compliance schedules as federally enforceable requirements in their state plans. They do not need to use the RULOF provisions to do so. See 40 CFR 60.24a(i).

e. Interaction of RULOF and Other State Plan Flexibilities and Mechanisms

The EPA discusses the ability of affected EGUs with standards of performance determined pursuant to 40 CFR 60.24a(f) to use compliance

[934] See 40 CFR 60.24a(c).

flexibilities under these emission guidelines in section X.D of this preamble.

i. Use of RULOF To Address Reliability

The EPA, in determining the degree of emission limitation achievable through application of the BSER for coal-fired steam generating EGUs, analyzed potential impacts of the BSERs on resource adequacy in addition to considering multiple studies on how reliability could be impacted by these emission guidelines. In doing so, the Agency considered potential large-scale (regional and national) and long-term impacts on the reliability of the electricity system under CAA section 111(a)(1)'s ''energy requirements'' factor. In evaluating CCS as a control strategy for long-term coal-fired steam generating EGUs, the Agency determined that CCS as the BSER would have limited and non-adverse impacts on the long-term structure of the power sector or on reliability of the power sector. See section VII.C.1.a.iii.(F) and final TSD, *Resource Adequacy Analysis.* Additionally, the EPA has made several adjustments to the final emission guidelines relative to proposal that should have the effect of alleviating any reliability concerns, including changing the scope of units covered by these actions and removing certain subcategories, including one that would have included an annual capacity factor limitation. See section XII.F of this preamble for further discussion.

While the EPA has determined that the structure and requirements of these emission guidelines will not negatively impact large-scale and long-term reliability, it also acknowledges the more locationally specific, source-by-source decisions that go into maintaining grid reliability. For example, there may be circumstances in which a balancing authority may need to have a particular unit available at a certain time in order to ensure reliability of the larger system. As noted above, the structure and various mechanisms of these emission guidelines allow states and reliability authorities to plan for compliance in a manner that preserves grid operators' abilities to maintain electric reliability. Specifically, coal-fired EGUs that are planning to cease operation do not have control requirements under these emission guidelines, the removal of the imminent-term and near-term subcategories means that states and reliability authorities have greater flexibility in the earlier years of implementation, and the EPA is providing two dedicated reliability mechanisms. Given these adjustments, the Agency believes there will remain very few, if any, circumstances in which states will need to provide particularized compliance obligations for an affected EGU based on a need to address reliability. However, there may be isolated instances in which a particular affected EGU cannot reasonably comply with the applicable requirements due to a source-specific reliability issue. Such unit-specific reliability considerations may constitute an ''[o]ther circumstance[] specific to the facility'' that makes it unreasonable for a particular EGU to achieve the degree of emission limitation or compliance schedule the EPA has provided in these emission guidelines. 40 CFR 60.24a(e)(1)(iii). The EPA is therefore confirming that states may use the RULOF provisions in 40 CFR 60.24a to apply a less stringent standard of performance or longer compliance schedule to a particular affected EGU based on reliability considerations. The EPA emphasizes that the RULOF provisions should not be used to provide a less stringent standard of performance if the applicable degree of emission limitation for an affected EGU is reasonably achievable. To do so would be inconsistent with CAA sections 111(d) and 111(a)(1). Thus, to the extent states and affected EGUs find it necessary to use RULOF to particularize these emission guidelines' requirements for a specific unit based on reliability concerns, such adjustments should take the form of longer compliance schedules.

In order to meet the threshold for applying a less stringent standard of performance or longer compliance schedule based on unit-specific reliability considerations under 40 CFR 60.24a(e), a state must demonstrate a fundamental difference between the information the EPA considered on reliability and the circumstances of the specific unit. This demonstration would be made by showing that requiring a particular affected EGU to comply with its presumptive standard of performance under the specified compliance timeframe would compromise reliability, *e.g.,* by necessitating that the affected EGU be taken offline for a specific period of time during which a resource adequacy shortfall with adverse impacts would result. In order to make this demonstration, states must provide an analysis of the reliability risk if the particular affected EGU were required to comply with its applicable presumptive standard of performance by the compliance date, clearly demonstrating that the EGU is reliability critical such that requiring it to comply would trigger non-compliance with at least one of the mandatory reliability standards approved by FERC or cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region. Specifically, this requires a clear demonstration that each unit for which use of RULOF is being considered would be needed to maintain the targeted level of resource adequacy.[935] The analysis must also include a projection of the period of time for which the particular affected EGU is expected to be reliability critical. States must also provide an analysis by the relevant reliability Planning Authority[936] that corroborates the asserted reliability risk and confirms that one or both of the circumstances would result from requiring the particular affected EGU to comply with its applicable requirements, and also confirms the period of time for which the EGU is projected to be reliability critical. The state plan must also include a certification from the Planning Authority that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested.

To substantiate a reliability risk that stems from resource adequacy in particular, the analyses must also demonstrate that the specific affected EGU has been designated by the relevant Planning Authority as needed for resource adequacy and thus reliability, and that requiring that affected EGU to comply with the requirements in these emission guidelines would interfere with its ability to serve this function as intended by the Planning Authority. However, the EPA reiterates that the structure of the subcategories for coal-fired steam generating affected EGUs in these final emission guidelines differs from the proposal in ways that should provide states and affected EGUs wider latitude to make the operational decisions needed to ensure resource adequacy. Thus, again, the Agency expects that the circumstances in which states need to rely on consideration of RULOF to

[935] See, *e.g.,* the North American Electric Reliability Corporation's ''Probabilistic Assessment: Technical Guideline Document,'' August 2016. *https://www.nerc.com/comm/RSTC/PAWG/proba_technical_guideline_document_08082014.pdf.*

[936] The North American Electric Reliability Corporation (NERC)'s currently enforceable definition of ''Planning Authority'' is, ''[t]he responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.'' Glossary of Terms Used in NERC Reliability Standards, Updated April 1, 2024. *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

particularize an affected EGU's compliance obligation will be rare.

The EPA will review these analyses and documentation as part of its evaluation of standards of performance and compliance schedules that states apply based on consideration of reliability under the RULOF provisions.

As described in sections X.C.1.d and XII.F.3.b of this preamble, the EPA is providing two flexible mechanisms that states may incorporate in their plans that, if utilized, would provide a temporary delay of affected EGU's compliance obligations if there is a demonstrated reliability need.[937] The EPA anticipates that states discovering, after a state plan has been submitted and approved, that a particular affected EGU needs additional time to meet its compliance obligation as a result of a reliability or resource adequacy issue will avail themselves of these flexibilities. If a state anticipates that the reliability or resource adequacy issue will persist beyond the 1-year extension provided by these flexible mechanisms, the EPA expects that states will also initiate a state plan revision. In such a state plan revision, the state must make the demonstration and provides the analysis described above in order to use to adjust an affected EGU's compliance obligations to address the reliability or resource adequacy issue at that time.

The EPA intends to continue engagement on the topic of electric system reliability, resource adequacy, and linkages to various EPA regulatory efforts to ensure proper communication with key stakeholders and Federal counterparts including DOE and FERC. Additionally, the Agency intends to coordinate with its Federal partners with expertise in reliability when evaluating RULOF demonstrations that invoke this consideration. There are also opportunities to potentially provide information and technical support on implementation of these emission guidelines and critical reliability considerations that will benefit states, affected sources, system planners, and reliability authorities. Specifically, the DOE–EPA MOU on Electric System Reliability provides a framework for ongoing engagement, and the EPA intends to work with DOE to ensure that reliability stakeholders have additional and ongoing opportunities to engage EPA on this important topic.

Comment: The EPA received multiple comments on the use of the RULOF provisions to address reliability. Several commenters emphasized that states need the ability to adjust affected EGUs' compliance obligations for reasons linked to reliability. They elaborated that an independent system operator/regional transmission organization determination that an affected EGU is needed for reliability would be anchored in a RULOF analysis that considers forces that may drive the unit's premature retirement. Some commenters indicated that use of RULOF to address such units would allow those units to continue to operate for the required period of time, applying routine methods of operation, to address grid reliability. They similarly noted that sources that have foreseeable retirement glidepaths but are key resources could be offered a BSER that promotes the EPA's carbon reduction goals but falls outside of the Agency's one-size-fits-all BSER approach.

Another commenter suggested that states should be able to modify a subcategory in their plans to address a reliability issue, and provided the example of allowing a unit that is planning to retire at the end of 2032 but that is needed for reliability purposes at greater than 20 percent capacity factor to subcategorize as an imminent-term unit despite operating past the end date for the imminent-term subcategory. The commenter suggested that such a modification could be justified under both the remaining useful life consideration and the energy requirements consideration of RULOF. Other commenters similarly requested that the EPA clarify that the RULOF provisions can be used to accommodate the changes in the power sector, *e.g.,* the build-out of transmission and distribution infrastructure, that are ongoing and that may impact the anticipated operating horizons of some affected EGUs.

Response: As explained above, the EPA has analyzed the potential impacts of these emission guidelines and determined that they would have limited and non-adverse impacts on large-scale and long-term reliability and resource adequacy. However, the EPA acknowledges that there may be reliability-related considerations that apply at the level of a particular EGU that the Agency could not have known or foreseen and did not consider in its broader assessment. As described above, states may use the RULOF provision to address reliability or resource adequacy if they demonstrate, based on the analysis and consultation with planning authorities described in this section of this preamble, that there is a fundamental difference between the information the EPA considered in these emission guidelines and the circumstances and information relevant to a particular affected EGU that makes it unreasonable for that EGU to comply with its presumptive standard of performance by the applicable compliance date.

The EPA stresses that a generic or unsubstantiated reliability or resource adequacy concern is not sufficient to substantiate a fundamental difference or unreasonableness of complying with applicable requirements. Simply asserting that grid reliability or resource adequacy is a concern for a state and thus an affected EGU needs a less stringent standard of performance or longer compliance schedule would not be sufficient. Rather, a state would have to demonstrate, via the certification and analysis described above, that the relevant planning authority has designated a particular affected EGU as reliability or resource adequacy critical and that requiring that EGU to comply with its standard of performance by the applicable compliance date would interfere with the maintenance of reliability or resource adequacy as intended by that planning authority.

A standard of performance or compliance schedule that has been particularized for an affected EGU based on consideration of reliability or resource adequacy must, pursuant to 40 CFR 60.24a(f), be no less stringent than necessary to address the fundamental difference identified pursuant to 40 CFR 60.24a(e), which in this case would be unit-specific grid reliability or resource adequacy needs. A less stringent standard of performance does not necessarily correspond to a standard of performance based on routine methods of operation and maintenance.

The EPA notes that states do not need to use the RULOF provisions to justify the date on which a particular affected EGU plans to cease operation. RULOF only comes into play if there is a fundamental difference between the information the EPA considered and the information specific to an affected EGU with a shorter remaining useful life that makes achieving the EPA's presumptive standard of performance unreasonable,, *e.g.,* the amortized cost of control. If a state elects to rely on an affected EGU's operating conditions, such as a plan to permanently cease operation, as the basis for applying a less stringent standard of performance, those conditions must be included as an

[937] The mechanism described in section X.C.1.d of this preamble is not restricted to circumstances in which a state needs to provide an affected EGU with additional time to comply with its standard of performance specifically for reliability or resource adequacy, but it can be used for this purpose. The reliability mechanism described in section XII.F.3.b is specific to reliability and can be used to extend the date by which a source plans to cease operating by up to 1 year.

enforceable commitment in the state plan.

As explained elsewhere in this section of the preamble, the effect of RULOF is not to modify subcategories under these emission guidelines but rather to particularize the compliance obligations of an affected EGU within a given subcategory. The EPA also notes that it is not finalizing the proposed imminent-term or near-term subcategories for affected coal-fired steam generating EGUs.

ii. Use of RULOF With Compliance Date Extension Mechanism

As discussed in section X.C.1.d of the preamble to this final rule, the EPA is allowing states to include in their plans a mechanism to provide a compliance deadline extension of up to 1 year for certain affected EGUs. This mechanism would be available for affected EGUs with standards of performance that require add-on control technologies and that demonstrate the extension is needed for installation of controls due to circumstances outside the control of the affected EGU. In the event the state and affected EGU believe that 1 year will not be sufficient to remedy those circumstances, *i.e.,* that the affected EGU will not be able to comply with its standard of performance even with a 1-year extension, the state may also start the process of revising its plan to apply a longer compliance schedule based on consideration of RULOF. In order to demonstrate that there is a fundamental difference between the circumstances of the affected EGU and the information the EPA considered in determining the compliance schedule in the emission guidelines, the state should provide documentation to justify why it is unreasonable for the affected EGU to meet that compliance schedule, even with an additional year (providing that the state has allowed for a 1-year extension), based on one or more of the considerations in 40 CFR 60.24a(e)(1). This documentation should demonstrate that the need to provide a longer compliance schedule was due to circumstances outside the affected EGU's control and that the affected EGU has met all relevant increments of progress and other obligations in a timely manner up to the point at which the delay occurred. That is, the state must demonstrate that the need to invoke RULOF and to provide a longer compliance schedule was not caused by self-created circumstances. As discussed in sections X.C.1.d and X.C.2.a of this preamble, documentation such as permits obtained and/or contracts entered into for the installation of control technology, receipts, invoices, and correspondence with vendors and regulators is helpful evidence for demonstrating that states and affected EGUs have been making progress towards compliance and that the need for a longer compliance schedule is due to circumstances outside the affected EGU's control.

In establishing a longer compliance schedule pursuant to 40 CFR 60.24a(f)(1), a state must demonstrate that the revised schedule is no longer than necessary to accommodate circumstances that have resulted in the delay.

3. Increments of Progress for Medium-Term and Long-Term Coal-Fired Steam Generating EGUs

The EPA's longstanding CAA section 111 implementing regulations provide that state plans must include legally enforceable Increments of Progress (IoPs) toward achieving compliance for each designated facility when the compliance schedule extends more than a specified length of time from the state plan submission date. Under the subpart Ba revisions finalized in November 2023, IoPs are required when the final compliance deadline (*i.e.,* the date on which affected EGUs must start monitoring and reporting emissions data and other information for purposes of demonstrating compliance with standards of performance) is more than 20 months after the plan submittal deadline. These emission guidelines for steam EGUs finalize a 24-month state plan submission deadline and compliance dates of January 1, 2032 (for long-term coal-fired EGUs), and January 1, 2030 (for all other steam generating EGUs), exceeding subpart Ba's 20-month threshold. Under these emission guidelines, in particular, the lengthy planning and construction processes associated with the CCS and natural gas co-firing BSERs make IoPs an appropriate mechanism to assure steady progress toward compliance and to provide transparency on that progress.

The EPA received support for the proposed approach to IoPs from many commenters; others, however, offered adverse perspectives. Supportive commenters generally emphasized the need for clear, transparent, and enforceable implementation checkpoints between state plan submittal and the compliance dates given the lengthy timelines affected EGUs are being afforded to achieve their standards of performance. These comments were broadly consistent with the proposed rationale for the IoPs. Adverse comments are addressed at the end of this subsection of the preamble.

The EPA is finalizing IoPs for affected EGUs based on BSERs that involve installation of emissions controls: long-term coal-fired EGUs and medium-term coal-fired EGUs. Units complying through the BSER specified for each subcategory, either CCS for the long-term subcategory or natural gas co-firing for the medium-term subcategory, must use IoPs tailored to those BSERs. Units complying through a different control technology must adopt increments that correspond to each of the steps in 40 CFR 60.21a(h). As specified in the proposal, each increment must be assigned a calendar date deadline, but states have discretion to set those dates based on the unique circumstances of each unit. The EPA is also finalizing its proposal to exempt the natural gas- and oil-fired EGU subcategories from IoP requirements. These subcategories have BSERs of routine operation and maintenance, which does not require the installation of significant new emission controls or operational changes.

The EPA is finalizing the proposed approach allowing states to choose the calendar dates for all IoPs for long- and medium-term coal-fired EGUs, subject to two constraints. The IoP corresponding to 40 CFR 60.21a(h)(1), submittal of a final control plan to the air pollution control agency, must be assigned the earliest calendar date deadline among the increments, and the IoP corresponding to 40 CFR 60.21a(h)(5), final compliance, must be assigned a date aligned with the compliance date for each subcategory, either January 1, 2032, for the long-term subcategory or January 1, 2030, for the medium-term subcategory. The EPA believes that this approach will provide states and EGUs with flexibility to account for idiosyncrasies in planning processes, tailor compliance timelines to individual facilities, allow simultaneous work toward separate increments, and ensure full performance by the compliance date.

For coal-fired EGUs assigned to the long-term and medium-term subcategories and that adopt the corresponding BSER (CCS or natural gas co-firing, respectively) as their compliance strategy, the EPA is finalizing BSER-specific IoPs that correspond to the steps in 40 CFR 60.21a(h). Some increments have been adjusted to more closely align with planning, engineering, and construction steps anticipated for affected EGUs that will be complying with standards of performance with natural gas co-firing or CCS, in particular; however, these technology-specific increments retain the basic structure and substance of the increments in the general implementing regulations under subpart Ba. In addition, consistent with 40 CFR 60.24a(d), the EPA is finalizing similar additional increments of progress for the long-term and medium-term coal-fired subcategories that are specific to pipeline construction in order to ensure timely progress on the planning, permitting, and construction activities related to pipelines that may be required to enable full compliance with the applicable standard of performance. The EPA is also finalizing an additional increment of progress related to the identification of an appropriate sequestration site for the long-term coal-fired subcategory. Finally, the EPA is finalizing a requirement that state plans must require affected EGUs with increments of progress to post the activities or actions that constitute the increments, the schedule required in the state plan for achieving them, and, within 30 business days, any documentation necessary to demonstrate that they have been achieved to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, in a timely manner.

For coal-fired steam generating units in the long-term subcategory adopting CCS as their compliance approach, the EPA is finalizing the following seven IoPs as enforceable elements required to be included in a state plan: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or FEED study, the anticipated timeline to achieve full compliance, and the benchmarks anticipated along the way. (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO_2 capture on an annual basis. (4) Completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO_2 capture on an annual basis. (5) Demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process(es), a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities. (6) Submittal of a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities. (7) Final compliance with the standard of performance. States must assign calendar deadlines for each increment consistent with the following requirements: the first increment, submission of a final control plan, must be assigned the earliest calendar date among the increments; the seventh increment, final compliance must be set for January 1, 2032.

For coal-fired steam generating units in the long-term subcategory adopting a compliance approach that differs from CCS, the EPA is finalizing the requirement that states adopt IoPs for each affected EGU that are consistent with the IoPs at 40 CFR 60.21a(h). As with long-term units adopting CCS as their compliance strategy, states must assign calendar deadlines for each increment consistent with the following requirements: the first increment, corresponding to 40 CFR 60.21a(h)(1), must be assigned the earliest calendar date among the increments; the final increment, corresponding to 40 CFR 60.21a(h)(5), must be set for January 1, 2032.

For coal-fired steam generating units in the medium-term subcategory adopting natural gas co-firing as their compliance approach, the EPA is finalizing the following six IoPs as enforceable elements required to be included in a state plan: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks anticipated along the way. (2) Awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish such modifications. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (4) Completion of onsite construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (5) Demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting application process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permit applications is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities. (6) Final compliance with the standard of performance. States must also assign calendar deadlines for each increment consistent with the following requirements: the first increment, submission of a final control plan, must be assigned the earliest calendar date among the increments; the sixth increment, final compliance, must be set for January 1, 2030.

For coal-fired steam generating units in the medium-term subcategory adopting a compliance approach that differs from natural gas co-firing, the EPA is finalizing the requirement that states adopt IoPs for each affected EGU that are consistent with the increments in 40 CFR 60.21a(h).

As with medium-term units adopting natural gas co-firing as their compliance strategy, states must assign calendar deadlines for each increment consistent with the following requirements: the first increment, corresponding to 40 CFR 60.21a(h)(1), must be assigned the earliest calendar date among the increments; the final increment, corresponding to 40 CFR 60.21a(h)(5), must be set for January 1, 2030.

The EPA notes that if an affected EGU receives approval for a compliance date extension, the date for at least one, if not several, IoPs must be adjusted to align with the revised compliance date. The new dates for the relevant IoPs must be specified in the application for the extension. The EPA notes that the last increment—final compliance—should be no later than 1 year after the original compliance date, pursuant to the requirements described in section X.C.1.d.

Comment: The EPA received comments that the proposed IoPs are too restrictive and may limit certain implementation flexibilities, namely that the burden to adjust IoPs after state plan submittal will limit sources' ability to switch subcategories or adjust implementation timelines due to unforeseen circumstances.

Response: The EPA has considered these comments and notes that the final rule includes planning flexibilities to address these situations. The first of these flexibilities is embedded in the subpart Ba regulations governing optional state plan revisions. Plan revisions, including revisions to subcategory assignments and any corresponding IoPs, may be used at a state's discretion to account for changes in planned compliance approaches. 40 CFR 60.28a. Such revisions can also include RULOF-based adjustments to approved standards of performance as well as the timelines to meet those standards, including the IoPs. Further, as mentioned above, the compliance date extension mechanism described in section X.C.1.d allows for modification of the IoPs to align with an approved compliance date extension. In addition, the subcategory structure of these final emission guidelines differs from that at proposal such that it is less likely that affected coal-fired EGUs will switch subcategories. In the event that an affected EGU does switch between the long-term and medium-term subcategories, the state plan revision process is the most appropriate mechanism because a different control strategy may be appropriate. Based on this consideration and the availability of planning flexibilities to account for changes in compliance plans and changed circumstances, the EPA is finalizing the approach to IoPs as proposed.

Comment: Some commenters raised concerns related to length of time between the state plan submittal deadline and the final compliance dates, namely that some IoPs will take place too far into the future to be reliably assigned calendar date deadlines.

Response: As noted above, the EPA has concluded that length of time between the state plan submittal deadline and the compliance deadlines for units in the medium-term and long-term subcategories as well as the anticipated complexity for units to comply with the final standards of performance necessitate the use of discrete interim checkpoints prior to final compliance, formally established as increments of progress, to ensure timely and transparent progress toward each unit's compliance obligation. It would be inconsistent to determine that the same factors necessitating the increments—the length of time between the state plan submittal deadline and the compliance obligation as well as the complex nature of the implementation process—also eliminate the IoPs' core accountability function by prohibiting the assignment of calendar date deadlines. Finally, as described above, the final emission guidelines also allow states and affected EGUs significant flexibility to determine when each increment applies.

Comment: Some commenters raised concerns that the IoPs could limit affected EGUs from selecting compliance approaches that differ from the BSER technology associated with each subcategory, namely averaging and trading.

Response: Under the approach finalized in this rule, units assigned to the long-term and medium-term subcategories that do not adopt the associated BSER as part of their compliance strategy must establish date-specified IoPs consistent with the subpart Ba IoPs codified at 40 CFR 60.21a(h). That is, states will particularize the generic IoPs in subpart Ba as appropriate for affected EGUs that comply with their standards of performance using control technologies other than CCS (for long-term units) or natural gas co-firing (for medium-term units). The EPA discusses considerations relevant to averaging and trading in section X.D of this preamble.

4. Reporting Obligations and Milestones for Affected EGUs That Plan to Permanently Cease Operations

The EPA proposed legally enforceable reporting obligations and milestones for affected EGUs demonstrating that they plan to cease operations and use that voluntary commitment for eligibility for the imminent-term, near-term, or medium-term subcategory. No reporting obligations and milestones were proposed for affected EGUs within the long-term subcategory since a voluntary commitment to cease operations was not part of the subcategory's applicability criteria. The proposed rationale for the milestone requirements recognized that the proposed subcategories were based on the operating horizons of units within each subcategory, and that there were numerous steps that EGUs in these subcategories need to take in order to effectuate their commitments to cease operations. The proposed reporting obligations and milestones were intended to provide transparency and assurance that affected EGUs could complete the steps necessary to qualify for a subcategory with a less stringent standard of performance.[938]

Of the proposed subcategories for which the reporting obligations and milestones were proposed to apply, the EPA's final emission guidelines retain only the medium-term coal-fired subcategory. Though the EPA is finalizing only one subcategory with an associated operational time horizon, the Agency has determined that the original rationale for the milestones is still valid. That is, the BSER determination for EGUs assigned to the medium-term subcategory is contingent on sources within this subcategory having limited operating horizons relative to affected EGUs in the long-term subcategory, and the integrity of the subcategory approach and the environmental integrity of these emission guidelines depend on sources behaving consistent with the operating horizon they have represented in the state plan. The steps required for EGUs to cease operations are numerous and vary across jurisdictions; giving states, the EPA, and other stakeholders insight into these steps and affected EGUs' progress along these steps provides assurance that they are on track to meeting their state plan requirements. The reporting obligations and milestones the EPA is finalizing under these emission guidelines are a reasonable approach to assuring transparency and timely compliance; they can also serve as an early indication that a state plan revision may be necessary if it becomes apparent that an affected EGU is not meeting its designated milestones. Further, the agency has determined that a similar rationale for requiring reporting obligations and milestones applies to

[938] 88 FR 33390 (May 23, 2023).

affected EGUs that invoke RULOF based on a unit's remaining useful life. States may apply a less stringent standard of performance to a particular affected EGU if its shorter remaining useful life results in a fundamental difference between the circumstances of that EGU and the information the EPA considered, and that difference makes it unreasonable for the EGU to achieve the presumptive standard of performance. However, if such a unit continues to operate past the date by which it previously committed to cease operating, the basis for the less stringent standard of performance is abrogated and the environmental integrity of the emission guidelines compromised. Therefore, as for affected EGUs in the medium-term subcategory, the reporting obligations and milestones are an essential component of assuring that affected EGUs that invoke RULOF based on a unit's remaining useful life are actually able to satisfy the condition of receiving the less stringent standard in the first instance.

The EPA is finalizing the following milestones and reporting requirements, explained in more detail below, for both affected EGUs assigned to the medium-term subcategory and affected EGUs that invoke RULOF based on a unit's remaining useful life. These sources must submit an Initial Milestone Report five years before the date by which it will permanently cease operations, annual Milestone Status Reports for each intervening year between the initial report and the date operations will cease, and a Final Milestone Status Report no later than six months from the date by which the affected EGU has committed to cease operating.

Commenters expressed a range of views regarding the proposed reporting obligations and milestones. Some were broadly supportive of the reporting milestones and the EPA's stated rationale to provide a mechanism to help ensure that affected EGUs progress steadily toward a commitment to cease operations when that commitment affects the stringency of their standard of performance. Summaries of and responses to additional comments on the reporting obligations and milestones are addressed at the end of this subsection.

The discussion below refers to reporting ''milestones.'' Owners/operators of sources take a number of process steps in preparing a unit to cease operating (*i.e.,* preparing it to deactivate). The EPA is requiring that states select certain of these steps to serve as milestones for the purpose of reporting where a source is in the process; the EPA is designating two milestones in particular and states will select additional steps for reporting milestones. The requirements being established under these emission guidelines do not require milestone steps to be taken at any particular time—they merely require reporting on when a source intends to reach each of its designated milestones and whether and when it has actually done so. The reporting obligations and milestone requirements count backward from the calendar date by which an affected EGU has committed to permanently cease operations, which must be included in the state plan, to monitor timely progress toward that date. Five years before any planned date to permanently cease operations or 60 days after state plan submission, whichever is later, the owner or operator of affected EGUs must submit an Initial Milestone Report to the applicable air pollution control agency that includes the following: (1) A summary of the process steps required for the affected EGU to permanently cease operation by the date included in the state plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. (2) A list of key milestones that will be used to assess whether each process step has been met, and calendar day deadlines for each milestone. These milestones must include at least the initial notice to the relevant reliability authority of an EGU's deactivation date and submittal of an official retirement filing with the EGU's reliability authority. (3) An analysis of how the process steps, milestones, and associated timelines included in the Initial Milestone Report compare to the timelines of similar EGUs within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines. (4) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization (RTO), independent system operator (ISO), balancing authority, public utility commission (PUC), or other applicable authority; any deactivation-related reliability assessments conducted by the RTO or ISO; and any filings pertaining to the EGU with the United States Securities and Exchange Commission (SEC) or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which the plans for the EGU are mentioned; any integrated resource plans and PUC orders approving the EGU's deactivation; any reliability analyses developed by the RTO, ISO, or relevant reliability authority in response to the EGU's deactivation notification; any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and any notification to or from an RTO, ISO, or balancing authority altering the timing of deactivation for the EGU.

For each of the remaining years prior to the date by which an affected EGU has committed to permanently cease operations that is included in the state plan, it must submit an annual Milestone Status Report that addresses the following: (1) Progress toward meeting all milestones identified in the Initial Milestone Report; and (2) supporting regulatory documents and relevant SEC filings, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority to demonstrate compliance with or progress toward all milestones.

The EPA is also finalizing a provision that affected EGUs with reporting milestones associated with commitments to permanently cease operations would be required to submit a Final Milestone Status Report no later than 6 months following its committed closure date. This report would document any actions that the unit has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

The EPA is finalizing a requirement that affected EGUs with reporting milestones for commitments to permanently cease operations must post their Initial Milestone Report, annual Milestone Status Reports, and Final Milestone Status Report, including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs website, as described in section X.E.1.b, within 30 business days of being filed. The EPA recognizes that applicable regulatory authorities, retirement processes, and retirement approval criteria will vary across states and affected EGUs. The proposed milestone reporting requirements are intended to establish a general framework flexible enough to account for significant differences across jurisdictions while assuring timely planning toward the dates by which affected EGUs permanently cease operations.

Comment: Some commentors questioned the need for the milestone reports by pointing to existing closure enforcement mechanisms within their jurisdictions.

Response: The existence of enforceable mechanisms in some jurisdictions does not obviate the need for the reporting milestones under these emission guidelines. First, the closure requirements, the nature of the enforcement mechanisms, and process requirements to cease operations will vary across different jurisdictions, and some jurisdictions may lack mechanisms entirely. The reporting milestones framework sets a uniform floor for reporting progress toward a commitment to cease operations, reducing differences in the quality and scope of information available to the EPA and public regarding closures. Second, the reporting milestones under these emission guidelines serve the additional purpose of transparency and allowing all stakeholders to have access to information related to affected EGUs' ongoing compliance.

Comment: Some commentors noted the unique EGU closure processes within their own jurisdictions and expressed concern as to whether the milestones requirements were too rigid to accommodate them.

Response: The reporting milestones are designed to create a flexible reporting framework that can accommodate differences in state closure processes. States can satisfy the required elements of the milestone reports by explaining how the process steps for plant closures within their jurisdiction work and establishing milestones corresponding to the process steps required within individual jurisdictions.

5. Testing and Monitoring Requirements

a. Emissions Monitoring and Reporting

The EPA proposed to require that state plans must include a requirement that affected EGUs monitor and report hourly CO_2 mass emissions emitted to the atmosphere, total heat input, and total gross electricity output, including electricity generation and, where applicable, useful thermal output converted to gross MWh, in accordance with the 40 CFR part 75 monitoring, reporting, and recordkeeping requirements. The EPA is finalizing a requirement that affected EGUs must use a 40 CFR part 75 certified monitoring methodology and report the hourly data on a quarterly basis, with each quarterly report due to the Administrator 30 days after the last day in the calendar quarter. The 40 CFR part 75 monitoring provisions require most coal-fired boilers to use a CO_2 continuous emissions monitoring system (CEMS), including both a CO_2 concentration monitor and a stack gas flow monitor. Some oil- and gas-fired boilers may have options to use alternative measurement methodologies (*e.g.,* fuel flow meters combined with fuel quality data).

The EPA received comments supporting and opposing the requirement to use 40 CFR part 75 monitoring, reporting, and recordkeeping requirements.

Comment: Commenters generally supported these requirements, noting that the majority of EGUs affected by this rule already monitor and submit emissions reports under 40 CFR part 75 under existing programs, including the Acid Rain Program and/or Regional Greenhouse Gas Initiative—a cooperative of several states formed to reduce CO_2 emissions from EGUs. In addition, EGUs that are not required to monitor and report under one of those programs may have 40 CFR part 75 certified monitoring systems in place for the MATS or CSAPR.

Response: The EPA agrees with these comments. Relying on the same monitors that are certified and quality assured in accordance with 40 CFR part 75 reduces implementation costs and ensures consistent emissions data across regulatory programs.

Comment: Some commenters focused on potential measurement bias of 40 CFR part 75 certified monitoring systems, with commenters split on whether the data are biased high or low.

Response: The EPA disagrees that the data reported under 40 CFR part 75 are biased significantly high or low. Each CO_2 CEMS must undergo regular quality assurance and quality control activities including periodic relative accuracy test audits (RATAs) where a monitoring system is compared to an independent monitoring system using EPA reference methods and NIST-traceable calibration gases. In a May 2022 study conducted by the EPA, the absolute value of the median difference between EGUs' monitoring systems and independent monitoring systems using EPA reference methods was found to be approximately 2 percent for CO_2 concentration monitors and stack gas flow monitors in the years 2017 through 2021.[939]

b. CCS-Specific Technology Monitoring and Reporting

Affected EGUs employing CCS must comply with relevant monitoring and reporting requirements specific to CCS. As described in the proposal, the CCS process is subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The ''suppliers of carbon dioxide'' source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the ''geologic sequestration of carbon dioxide'' source category of the GHGRP (GHGRP subpart RR). In April 2024, to complement GHGRP subpart RR, the EPA finalized the ''geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916'' source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[940] [941] [942]

As discussed in section VII.C.1.a.vii, the EPA is finalizing a requirement that any affected unit that employs CCS technology that captures enough CO_2 to meet the standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility subject to the GHGRP requirements, and the facility injecting the CO_2 underground must

[939] Zintgraff, Stacey. 2022. Monitoring Insights: Relative Accuracy in EPA CAMD's Power Sector Emissions Data. *www.epa.gov/system/files/documents/2022-05/Monitoring%20Insights-%20Relative%20Accuracy.pdf.*

[940] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[941] International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as ''CSA/ANSI ISO 27916:2019'').

[942] As described in 87 FR 36920 (June 21, 2022), both subpart RR and subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

report under GHGRP subpart RR or GHGRP subpart VV. These emission guidelines do not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation, though the EPA anticipates that the quantity of CO_2 sequestered will be substantially similar to the quantity captured. To verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, we are leveraging regulatory requirements under the GHGRP. The BSER is determined to be adequately demonstrated based solely on geologic sequestration that is not associated with EOR. However, EGUs also have the compliance option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. We also emphasize that these emission guidelines do not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU transfer the captured CO_2 to an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. This will avoid duplicative monitoring, reporting, and verification requirements between this proposal and the GHGRP, while also ensuring that the facility injecting and sequestering the CO_2 (which may not necessarily be the EGU) maintains responsibility for these requirements. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of the final emission guidelines.

D. Compliance Flexibilities

In the finalized subpart Ba revisions, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d),* the EPA explained that, under its interpretation of CAA section 111, each state is permitted to include compliance flexibilities, including flexibilities that allow affected EGUs to meet their emission limits in the aggregate, in their state plans. The EPA also explained that, in particular emission guidelines, the Agency may limit compliance flexibilities if necessary to protect the environmental outcomes of the guidelines.[943] Thus, in the subpart Ba final rule the EPA returned to its longstanding position that CAA section 111(d) authorizes the EPA to approve state plans that achieve the requisite emission limitation through aggregate reductions from their sources, including through trading or averaging, where appropriate for a particular emission guideline and consistent with the intended environmental outcomes under CAA section 111.[944]

In developing both the proposed and final emission guidelines, the EPA heard from stakeholders that flexibilities are important in complying with standards of performance under these emission guidelines. The EPA proposed to allow states to incorporate emission trading and averaging into their plans under these emission guidelines, provided that states ensure that the use of such flexibilities will result in an aggregate level of emission reduction that is equivalent to each source individually achieving its standard of performance.

Specifically, a variety of commenters from states, industry, RTO/ISOs, and NGOs emphasized the importance of allowing states to incorporate not only flexibilities that allow sources to demonstrate compliance in the aggregate, such as emission trading and averaging, but also unit-specific mass-based compliance into their plans. In particular, commenters expressed a strong preference for mass-based compliance mechanisms, whether unit-specific or emission trading, and cited reliability as a key driver of their support for such mechanisms. However, for the most part commenters did not provide detail on how flexibilities could be designed under the unique circumstances of these emission guidelines. In addition, many commenters did not specify as to the usefulness of certain compliance flexibilities for steam generating EGUs versus combustion turbine EGUs. Because these final emission guidelines only apply to steam generating EGUs, there are fewer affected EGUs that could partake in these flexibilities, which may limit their usefulness. A description of and responses to general comments on these compliance flexibilities can be found at the end of this subsection.

The EPA notes that many other features of the final emission guidelines provide the type of flexibility that the commenters stated they wanted through the use of emission trading, averaging, and/or unit-specific mass-based compliance. First, as noted in section X.C.1.b of this preamble, compliance with presumptively approvable rate-based standards of performance is demonstrated on an annual basis, which already provides flexibility around mass emissions over an annual period (*i.e.,* it affords the affected EGU the ability over the course of the year to vary its emission output, which may be useful if, for example, it needs to temporarily turn off its control equipment or otherwise increase its emission rate). Second, the EPA is finalizing two mechanisms, described in section XII.F of this preamble, to address reliability concerns raised by commenters: a short-term reliability mechanism that allows affected EGUs to operate above their standard of performance for a limited time in periods of emergency and a reliability assurance mechanism to ensure sufficient capacity is available. Finally, as described in section X.C.2 of this preamble, states may invoke RULOF to provide for less stringent standards of performance for affected EGUs under certain circumstances (states may invoke RULOF both at the time of initial state plan development as well as through state plan revision should the circumstances of an affected EGU change following state plan submission).

The EPA believes that the use of compliance flexibilities, within the parameters specified in these emission guidelines, may provide some additional operational flexibility to states and affected EGUs in achieving the required emission reductions which, under these emission guidelines, are achieved specifically through cleaner performance. In particular, for aggregate compliance flexibilities like emission averaging and trading, affected EGUs may be able to capitalize on heterogeneity in economic emission reduction opportunities based on minor differences in marginal emission abatement costs and/or operating parameters among EGUs. This heterogeneity may provide some incentive among participating EGUs to overperform (*i.e.,* operate even more cleanly than required by the applicable standard of performance, because of the opportunity to sell compliance

[943] 88 FR 80533 (November 17, 2023).

[944] The EPA has authorized trading or averaging as compliance methods in several emission guidelines. See, *e.g.,* 70 FR 28606, 28617 (May 18, 2005) (Clean Air Mercury Rule authorized trading) (vacated on other grounds); 40 CFR 60.24(b)(1) (subpart B CAA section 111 implementing regulations promulgated in 2005 allow states' standards of performance to be based on an ''allowance system''); 80 FR 64662, 64840 (October 23, 2015) (CPP authorizing trading or averaging as a compliance strategy). In the recent final emission guidelines for the oil and natural gas industry, the EPA also finalized a determination that states are permitted sources to demonstrate compliance in the aggregate. 89 FR 16820 (March 8, 2024).

instruments to other units), while also providing some limited opportunity for other sources to vary their emission output.

Therefore, the EPA is finalizing a determination that the use of compliance flexibilities, including emission trading, averaging, and unit-specific mass-based compliance, is permissible for affected EGUs in certain subcategories and in certain circumstances under these emission guidelines. Specifically, the EPA is allowing affected EGUs in the medium- and long-term coal-fired subcategories to utilize these compliance flexibilities. The scope of this allowance is tailored to ensure consistency with the fundamental principle under CAA section 111 that state plans maintain the stringency of the EPA's BSER determination and associated degree of emission limitation as applied through the EPA's presumptive standards of performance in the context of these emission guidelines. In addition, the EPA believes that the scope of this allowance is consistent and appropriate for providing an incentive for overperformance. Relatedly, the EPA is also providing further elaboration on what it means for states to demonstrate that implementation of a standard of performance using a rate- or mass-based flexibility is at least as stringent as unit-specific implementation of affected EGUs' standards of performance. States are not required to allow their affected EGUs to use compliance flexibilities but can provide for such flexibilities at their discretion. In order for the EPA to find that a state plan that includes such flexibilities is ''satisfactory,'' the state plan must demonstrate how it will achieve and maintain the requisite level of emission reduction.

The EPA stresses that any flexibilities involving aggregate compliance would be used to demonstrate compliance with an already-established standard of performance, rather than be used to establish a standard of performance in the first instance. The presumptive standards of performance that the EPA is providing in these emission guidelines are based on control strategies that are applied at the level of individual units. A compliance flexibility may change the way an affected EGU demonstrates compliance with a standard of performance (*e.g.,* by allowing that EGU to surrender allowances from another unit in lieu of reducing a portion of its own emissions), but does not alter the benchmark of emission performance against which compliance is evaluated. This is in contrast to the RULOF mechanism, which, as described in section X.C.2 of this preamble, states may use to apply a different standard of performance with a different degree of emission limitation than the EPA's presumptive standard. States incorporating trading or averaging would not need to undergo a RULOF demonstration for sources participating in trading or averaging programs because they are not altering those sources' underlying standards of performance—just providing an additional way for sources to demonstrate compliance.

While the EPA acknowledges widespread interest in the use of mass-based compliance, in the context of these particular emission guidelines, the Agency has significant concerns about the ability to demonstrate that mass-based compliance approaches achieve at least equivalent emission reduction as the application of rate-based, source-specific standards of performance. As explained in further detail in sections X.D.4 and X.D.5, the EPA is requiring the use of a backstop emission limitation, or backstop rate, in conjunction with mass-based compliance approaches (*i.e.,* for both unit-specific mass-based compliance and mass-based emission trading) for both the long-term and medium-term coal-fired subcategories. However, the EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach only for affected EGUs in the long-term subcategory. The use of mass-based compliance approaches—both unit-specific and trading—for affected EGUs in the medium-term coal-fired subcategory in particular poses a high risk of undermining the stringency of these emission guidelines due to inherent uncertainty about the future utilization of these sources. While the EPA is not precluding states from attempting to design mass-based approaches for affected EGUs in the medium-term coal-fired subcategory that satisfy the requirement of achieving at least equivalent stringency as rate-based implementation, the Agency was unable to devise an appropriate, implementable presumptively approvable approach for affected EGUs in the medium-term coal-fired subcategory and is therefore not providing one here. The EPA is also not providing a presumptively approvable approach to emission trading or averaging. Instead, the EPA intends to review emission trading or averaging programs in state plans on a case-by-case basis against the foundational principles for consistency with CAA section 111, as discussed in this section of the preamble.

Section X.D.1 of this preamble discusses the fundamental requirement that compliance flexibilities maintain the level of emission reduction of unit-specific implementation, in order to inform states' consideration of such flexibilities for any use in their state plans. It also addresses why limitations on the use of compliance flexibilities for certain subcategories are necessary to maintain the intended environmental outcomes of these emission guidelines. Sections X.D.2, X.D.3, X.D.4, and X.D.5 discuss each available type of compliance flexibility and provide information on how they can be used in state plans under these emission guidelines. Section X.D.6 provides information on general implementation features of emission trading and averaging programs that states must consider if they develop such a program. Section X.D.7 discusses interstate emission trading. Finally, section X.D.8 discusses considerations related to existing state programs and the inclusion of compliance flexibilities in a state plan under these emission guidelines.

Comment: Commenters cited a variety of reasons supporting the use of compliance flexibilities, such as emission trading, averaging, and unit-specific mass-based compliance, in these emission guidelines, including the need for flexibility in meeting the degree of emission limitation defined by the BSER, the potential for more cost-effective compliance, and reliability purposes.

Response: The EPA believes that, in certain circumstances, these flexibilities can provide some operational and cost flexibility to states and affected EGUs in complying with these emission guidelines and their standards of performance in state plans. However, as described above, the EPA is addressing reliability-related concerns primarily through other structural changes and mechanisms under these emission guidelines (see section XII.F of this preamble) that may obviate the need to use compliance flexibilities specifically to address reliability concerns. As a general matter, the EPA believes that compliance flexibilities such as emission trading and averaging provide some incentive for overperformance that could be beneficial to states and affected EGUs.

The EPA is finalizing a determination that emission trading, averaging, and unit-specific mass-based compliance are permissible for certain subcategories under these emission guidelines, subject to the limitations described in section X.D.1 of this preamble. The EPA believes these limitations are necessary in the context of these emission guidelines in order to maintain the level of emission reduction of the EPA's BSER determination and corresponding degree of emission limitation.

Comment: Some commenters expressed opposition to the use of emission trading and averaging, citing the potential for emission trading and averaging programs to maintain or exacerbate existing disparities in communities with environmental justice concerns.

Response: The EPA is cognizant of these concerns and believes that emission trading and averaging are not necessarily incompatible with environmental justice. The EPA is including limitations on the use of compliance flexibilities in state plans that should help address these EJ concerns. As discussed in more detail in section X.D.1, the EPA is restricting certain subcategories from using trading or averaging as well as, for mass-based compliance mechanisms, requiring the use of a backstop rate, to ensure that the use of compliance flexibilities maintains the level of emission reduction of the EPA's BSER determination and corresponding degree of emission limitation as well as achieves the statutory objective of these emission guidelines to mitigate air pollution by requiring sources to operate more cleanly. The EPA notes that trading programs can be designed to include measures like unit-specific emission rates that assure that reductions and corresponding benefits accrue proportionally to communities with environmental justice concerns. The EPA also notes that states have the ability to add further features and requirements to emission trading and averaging programs than identified in these emission guidelines, or to forgo their use entirely.

Pursuant to the requirements of subpart Ba, states are required to conduct meaningful engagement on all aspects of their state plans with pertinent stakeholders. This would necessarily include any potential use of flexibilities for sources to demonstrate compliance with the proposed standards of performance through emissions trading or averaging. As discussed in greater detail in section X.E.1.b.i of this preamble, meaningful engagement provides an opportunity for communities most affected by and vulnerable to the impacts of a plan to provide input, including input on any impacts resulting from the use of compliance flexibilities.

Comment: Some commenters stated that allowing trading or averaging is not consistent with the legal opinion in *West Virginia* v. *EPA.*

Response: This comment is outside the scope of this action. The EPA finalized its interpretation that CAA section 111 does not preclude states from including compliance flexibilities such as trading or averaging in their state plans (although the EPA may limit those flexibilities in particular emission guidelines if necessary to protect the environmental outcomes of those guidelines) when it revised the CAA section 111(d) implementing regulations in subpart Ba.[945] As described in the final subpart Ba revisions, ''in *West Virginia* v. *EPA,* the Supreme Court did not directly address the state's authority to determine their sources' control measures. Although the Court did hold that constraints apply to the EPA's authority in determining the BSER, the Court's discussion of CAA section 111 is consistent with the EPA's interpretation that the provision does not preclude states from granting sources compliance flexibility.''[946] The EPA further explained in the preamble to the subpart Ba final rule that the *West Virginia* Court was clear that the focus of the case was exclusively on whether the EPA acted within the scope of its authority in establishing the BSER: ''The Court did not identify any constraints on the states in establishing standards of performance to their sources, and its holding and reasoning cannot be extended to apply such constraints.''[947]

The EPA reiterates that, under these emission guidelines, the BSER determinations are emission reduction technologies or strategies that apply to and reduce the emission rates of individual affected EGUs. Furthermore, states have the option of including emission trading or averaging in their states plans but are by no means required to do so. States that choose to include trading or averaging programs in their state plans are required to demonstrate that those programs are in the aggregate as stringent as each affected EGU individually achieving its rate-based standard of performance. Additionally, as explained elsewhere in sections X.D.4 and X.D.5 of this preamble, the EPA is requiring the use of a backstop emission rate in conjunction with mass-based compliance flexibilities, one result of which is that units cannot comply with their standards of performance merely by shifting their generation to other electricity generators. Therefore, the EPA's BSERs in these emission guidelines are not based on generation shifting and, even if the EPA believed that *West Virginia* v. *EPA* implicated the use of compliance flexibilities, the permissible use of trading and averaging in this particular case does not implicate the Court's concerns about generation shifting therein.

[945] 88 FR 80480 80533–35 (November 17, 2023).

[946] 88 FR 80534 (November 17, 2023).

[947] 88 FR 80535 (November 17, 2023).

1. Demonstrating Equivalent Stringency

As stated in the section above, states are permitted to use emission trading, averaging, and unit-specific mass-based compliance in their plans for certain subcategories under these emission guidelines, provided that the plan demonstrates that any such use will achieve a level of emission reduction that is in the aggregate as environmentally protective as each affected EGU achieving its rate-based standard of performance. This requirement is rooted in the structure and purpose of CAA section 111. Most commenters supported the use of compliance flexibilities in these emission guidelines, and many explicitly expressed support for the EPA's stringency criterion in this context. Commenters also requested greater clarity on how to demonstrate equivalent stringency in a state plan. In this section, the EPA describes foundational parameters for a demonstration of equivalence in the state plan as well as limitations on the availability of compliance flexibilities for certain affected EGUs, which stem from the EPA's stringency criterion. Additionally, the EPA offers further explanation of how it will review state plan submissions to determine whether plans that include compliance flexibilities achieve an equivalent (or greater) level of emission reduction as each affected EGU individually complying with its unit-specific rate-based standard of performance.

a. Requirements for Demonstrating Equivalent Stringency

In their plans, states incorporating compliance flexibilities must first clearly demonstrate how they calculated the aggregate rate-based emission limitation (for rate-based averaging), mass limit (for unit-specific mass-based compliance), or mass budget (for mass-based emission trading) from unit-specific, rate-based presumptive standards of performance. (For rate-based trading, the standard of performance coupled with, if necessary, an adjustment based on the acquisition of compliance instruments, is used to demonstrate compliance.) In doing so, states must identify the specific affected EGUs that will be using compliance flexibilities; which flexibility each unit will able to use; the unit-specific, rate-based presumptive standard of performance; and the standard of performance established in the plan for each unit (rate-based limit or mass limit) or set of units (aggregate rate-based emission limitation or mass budget). The state must document and justify the assumptions made in calculating an aggregate rate-based emission limitation, mass limit, or mass budget, such as how the calculation is weighted or, for mass-based mechanisms, the level of utilization of participating affected EGUs used to calculate the mass limit or budget. This requirement is discussed in more detail in the context of each type of compliance flexibility in the following subsections.

Next, states must demonstrate how the compliance flexibility will maintain the requisite stringency, *i.e.,* how the plan will maintain the aggregate level of emission reduction that would be achieved if each unit was individually complying with its rate-based standard of performance. As discussed in section X.C.1 of this preamble, an affected EGU's standard of performance must generally be no less stringent than the corresponding presumptive standard of performance under these emission guidelines. This is true regardless of whether a standard of performance is expressed in terms of rate or mass. However, under an aggregate compliance approach, a unit may demonstrate compliance with that standard of performance by averaging its emission performance or trading compliance instruments (*e.g.,* allowances) with other affected EGUs. Here, to ensure consistency with the level of emission reductions Congress expected under CAA section 111(a)(1), the state must also demonstrate that the plan overall achieves equivalent stringency, *i.e.,* the same or better environmental outcome, as applying the EPA's presumptive standards of performance to each affected EGU (after accounting for any application of RULOF). That is, in order for the EPA to find a state plan ''satisfactory,'' that plan must achieve at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance (again, after accounting for any application of RULOF).

The requirement that state plans achieve equivalent stringency to the EPA's degree of emission limitation flows from the structure and purpose of CAA section 111, which is to mitigate air pollution that is reasonably anticipated to endanger public health or welfare. It achieves this outcome by requiring source categories that cause or contribute to dangerous air pollution to operate more cleanly. Unlike the CAA's NAAQS-based programs, section 111 is not designed to reach a level of emissions that has been deemed ''safe'' or ''acceptable''; there is no air-quality target that tells states and sources when emissions have been reduced ''enough.'' Rather, CAA section 111 requires affected sources to reduce their emissions to the level that the EPA has determined is achievable through application of the best system of emission reduction, *i.e.,* to achieve emission reductions consistent with the applicable presumptive standard of performance. Consistent with the statutory purpose of requiring affected sources to operate more cleanly, the EPA typically expresses presumptive standards of performance as rate-based emission limitations (*i.e.,* limitations on the amount of a regulated pollutant that can be emitted per unit of output, per unit of energy or material input, or per unit of time).

In the course of complying with a rate-based standard of performance under a state plan, an affected source takes actions that may or may not affect its ongoing emission reduction obligations. For example, a source may take certain actions that remove it from the source category, *e.g.,* by switching fuel type or permanently ceasing operations. Upon doing so, the source is no longer subject to the emission guidelines. Or an affected source may choose to change its operating characteristics in a way that impacts its overall mass of emissions, *e.g.,* by changing its utilization, in which case the source is still required to reduce its emission rate consistent with cleaner performance. In either instance, the changes in operation to one affected source do not implicate the obligations of other affected sources. Although changes to certain sources' operation may reduce emissions from the source category, they do not absolve the remaining affected EGUs from the statutory obligation to reduce their emission rates consistent with the level that the EPA has determined is achievable through application of the BSER. While state plans may, when permitted by the applicable emission guidelines, allow affected sources to translate their rate-based presumptive standards of performance into mass limits and/or comply with their standards of performance in the aggregate through averaging or trading, the fundamental statutory requirement remains: the state plan must demonstrate that, even if individual affected sources are not necessarily achieving their presumptive rate-based standards of performance, the plan as a whole must provide for the same level of emission reduction for the affected EGUs as though they were. While states may choose to allow individual sources to emit more or less than the degree of emission limitation determined by the EPA, any compliance flexibilities must be designed to ensure that their use does not erode the emission reduction benefits that would result if each source was individually achieving its presumptive standard of performance (after accounting for any use of RULOF).

For rate-based averaging and trading, discussed in more detail in sections X.D.2 and X.D.3 of this preamble, demonstrating an equivalent level of emission reduction is relatively straightforward, as a rate-based program inherently provides relatively stronger assurance of equivalence with individual rate-based standards of performance. This is due to the fact that the aggregate rate-based emission limitation (for rate-based averaging) or rate-based standard of performance with adjustment for compliance instruments (for rate-based trading) is calculated based on both the emission output and gross generation output (utilization) of the participating affected EGUs. In other words., a rate-based compliance flexibility, such as a rate-based unit-specific standard of performance, inherently adjusts for changes in utilization and preserves the imperative to operate more cleanly. For unit-specific mass-based compliance and mass-based trading, demonstrating equivalent stringency is more complicated, as the use of a mass limit or mass budget on its own may not guarantee that sources are achieving emission reductions commensurate with operating more cleanly. Thus the EPA is requiring that, in order to ensure that the emission outcome that would be achieved through unit-specific rate-based standards of performance are preserved, states must also include a backstop emission rate limitation, or backstop rate, for affected EGUs using a mass-based compliance flexibility, as discussed in more detail in sections X.D.4 and X.D.5 of this preamble. In addition, states employing a mass-based mechanism in their plans must show why assumptions underlying the calculation of utilization for the purposes of establishing a mass limit or mass budget are appropriately conservative to ensure an equivalent level of emission reduction, as discussed more in sections X.D.4 and X.D.5 of this preamble.

In sum, states wishing to employ compliance flexibilities in their state plans must demonstrate that the plan achieves at least equivalent stringency with each source individually achieving its standard of performance, bearing in mind the discussion and requirements in this section, as well as the discussion and requirements in the following sections specific to each type of mechanism. The EPA will review state plan submissions that include compliance flexibilities to ensure that they are consistent with CAA section 111's purpose of reducing dangerous air pollution by requiring sources to operate more cleanly. In order for the EPA to find a state plan ''satisfactory,'' that plan must address each affected EGU within the state and demonstrate that the plan overall achieves at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance, after accounting for any application of RULOF.

b. Exclusion of Certain Affected EGUs From Compliance Flexibilities

While the use of compliance flexibilities such as emission trading, averaging, and unit-specific mass-based compliance is generally permissible under these emission guidelines, the EPA indicated in the proposal that it may be appropriate for certain groups of sources to be excluded from using these flexibilities in order to ensure an equivalent level of emission reduction with each source individually achieving its standard of performance. In the proposed emission guidelines, the EPA expressed concerns about the use of compliance flexibilities for several subcategories that have BSER determinations of routine methods of operation and maintenance as well as those sources for which states have invoked RULOF to apply a less stringent standard of performance, as their inclusion may undermine the intended level of emission reduction of the BSER for other facilities. The EPA also questioned whether trading and averaging across subcategories should be limited in order to maintain the stringency of unit-specific compliance. Finally, the EPA questioned whether affected EGUs that receive the IRC section 45Q tax credit for permanent sequestration of CO_2 may have an overriding incentive to maximize both the application of the CCS technology and total electric generation, leading to source behavior that may be non-responsive to the economic incentives of a trading program.

In response to the request for comment on these concerns related to the appropriateness of emission trading and averaging for certain subcategories and for sources with a standard based on RULOF, the EPA received mixed feedback. Some commenters agreed with the EPA's concerns about these subcategories participating in trading and averaging and that affected EGUs in these subcategories should be prevented from participating in an emission trading or averaging program. However, several commenters said that it was indeed appropriate to allow all subcategories as well as sources with a standard of performance based on RULOF to participate in trading and averaging and that the program would still achieve an equivalent level of emission reduction, even if those subcategories are of limited stringency.

In response to the request for comment on whether emission trading and averaging should be allowed across subcategories in light of concerns over differing levels of stringency for different subcategories impacting overall achievement of an equivalent level of emission reduction, the EPA also received mixed feedback. Some commenters supported restricting trading and averaging across subcategories because of concerns that EGUs in a subcategory with a relatively higher stringency could acquire allowances from EGUs in a subcategory with a relatively lower stringency in order to comply instead of operating a control technology. Several commenters stated that trading across subcategories need not be limited because, as long as state plans are of an equivalent level of emission reduction, emission trading and averaging would still require the overall aggregate limit to be met.

Taking into consideration the comments on the proposed emission guidelines as well as changes made to the subcategories in the final emission guidelines, the Agency is finalizing the following restrictions on the use of compliance flexibilities by certain subcategories.

First, emission trading or averaging programs must not include affected EGUs for which states have invoked RULOF to apply less stringent standards of performance. The Agency believes that, because RULOF sources have a standard of performance tailored to individual source circumstances that is required to be as stringent as reasonably practicable, these sources should not need further operational flexibility and are also unlikely to be able to overperform to any significant or regular degree. This means that their participation in an emission trading or averaging program is, at best, unlikely to add any value to the program (in terms of opportunity for overperformance) or, at worst, may provide an inappropriate opportunity for other sources subject to a relatively more stringent presumptive standard of performance to underperform by obtaining compliance instruments from or averaging their emission performance with affected EGUs that are subject to a relatively less stringent standard of performance based on RULOF. This outcome undermines the ability of the state plan to demonstrate an equivalent level of emission reduction, as non-RULOF sources would face a reduced incentive to operate more cleanly. In addition, affected EGUs with a standard of performance based on RULOF are prohibited from using unit-specific mass-based compliance under these emission guidelines. This is due to the compounding uncertainty regarding how states will use RULOF to particularize the compliance obligations for an affected EGU and the future utilization of affected EGUs that may be subject to RULOF. The RULOF provisions are used where a particular EGU is in unique circumstances and may result in a less stringent standard of performance based on the BSER technology, a less stringent standard of performance based on a different control technology, a longer compliance schedule, or some combination of the three. The bespoke nature of compliance obligations pursuant to RULOF makes it difficult for the EPA to provide principles for and for states to design mass-based compliance strategies that ensure an equivalent level of emission reduction. Additionally, as previously discussed, there is a significant amount of uncertainty in the future utilization of certain affected EGUs, including those with standards of performance pursuant to RULOF. While there is no risk of implicating the compliance obligation of other sources in unit-specific mass-based compliance, the EPA believes that allowing RULOF sources to use unit-specific mass compliance would pose a significant risk in undermining the stringency of the state plan such that these sources may not be achieving the level of emission reduction commensurate with cleaner performance.

Second, emission trading or averaging programs may not include affected EGUs in the natural gas- and oil-fired steam subcategories. The BSER determination and associated degree of emission limitation for affected EGUs in these subcategories do not require any improvement in emission performance and already offer flexibility to sources to account for varying efficiency at different operating levels. As a result, these sources are unlikely to be responsive to an incentive towards overperformance, which means that their participation in an emission trading or averaging program is unlikely to add any value to the program (in terms of opportunity for overperformance). In addition, the EPA is concerned that the participation of these sources may undermine the program's equivalence with the presumptive standards of performance, because other steam sources, which have a relatively more stringent degree of emission limitation, may be inappropriately incentivized to underperform by obtaining compliance instruments from or averaging their emission performance with affected EGUs in the natural gas- and oil-fired steam subcategories. This outcome undermines the ability of the state plan to demonstrate equivalent stringency by reducing the incentive for sources to operate more cleanly. In addition, affected EGUs in the natural gas- and oil-fired steam subcategories are prohibited from using unit-specific mass-based compliance. While there is no risk of implicating the compliance obligation of other sources in unit-specific mass-based compliance, the EPA believes, as previously stated, there is already sufficient flexibility offered to sources in the natural gas- and oil-fired steam subcategories, as the basis for subcategorizing these sources takes into account their varying efficiency at different operating levels.

The EPA is allowing both coal-fired subcategories (both the medium- and long-term) to participate in all types of compliance flexibilities, within the parameters set by the EPA described in the following sections. The Agency believes, and many commenters agreed, that affected EGUs taking advantage of the IRC section 45Q tax credit may still benefit from the operational flexibility provided by emission trading and averaging, as well as unit-specific mass-based compliance. The Agency also believes that overperformance among these sources is possible and worth incentivizing through the use of compliance flexibilities. Incentivizing overperformance can lead to innovation in control technologies that, in turn, can lead to lower costs for, and greater emissions reductions from, control technologies.

The EPA is not finalizing a restriction on trading or averaging across subcategories for the two subcategories that are permitted to participate in these flexibilities. This means that affected EGUs in the medium-term coal-fired subcategory may trade or average their compliance with affected EGUs in the long-term coal-fired subcategory. With the aforementioned restrictions on participation in trading and averaging, the EPA does not see a need to further restrict the ability of eligible sources to trade or average with other sources.

2. Rate-Based Emission Averaging

The EPA proposed to permit states to incorporate rate-based averaging into their state plans under these emission guidelines. In general, rate-based averaging allows multiple affected EGUs to jointly meet a rate-based standard of performance. The scope of such averaging could apply at the facility level (*i.e.,* units located within a single facility) or at the owner or operator level (*i.e.,* units owned by the same utility). A description of and responses to comments received on rate-based averaging can be found at the end of this subsection.

As discussed in the proposed emission guidelines, averaging can provide potential benefits to affected sources by allowing for more cost effective and, in some cases, more straightforward compliance. First, averaging offers some flexibility for owners or operators to target cost effective reductions at certain affected EGUs. For example, owners or operators of affected EGUs might target installation of emission control approaches at units that operate more. Second, averaging at the facility level provides greater ease of compliance accounting for affected EGUs with a complex stack configuration (such as a common- or multi-stack configuration). In such instances, unit-level compliance involves apportioning reported emissions to individual affected EGUs that share a stack based on electricity generation or other parameters; this apportionment can be avoided by using facility-level averaging.

The EPA is finalizing a determination that rate-based averaging is permissible for affected EGUs in the medium- and long-term coal-fired subcategories. The scope of rate-based averaging may be at the facility level or at the owner/operator level within the state, as these are the circumstances under which rate-based averaging can provide significant benefits, as identified above, with minimal implementation complexity. Above this level (*i.e.,* across owner/operators or at the state or interstate level), the EPA has determined that a rate-based compliance flexibility must be implemented through rate-based trading, as described in section X.D.3 of this preamble. The EPA is establishing this limitation on the scope of averaging because it believes that the level of complexity associated with utilities, independent power producers, and states attempting to coordinate the real-time compliance information needed to assure that either all affected EGUs are meeting their individual standard of performance, or that a sufficient number of affected EGUs are overperforming to allow operational flexibility for other affected EGUs such that the aggregate standard of performance is being achieved, would curtail transparency and limit states', the EPA's, and stakeholders' abilities to track timely compliance. For example, dozens of units trying to average their emission rates would require owners or operators from different utilities and independent power producers to share operating and emissions data in real time. Thus, due to likely limitations on the timely availability of compliance-related information across owners and operators and across states, which is necessary to ensure aggregate compliance, the EPA believes that it is appropriate to limit the scope of rate-based averaging to the facility level or the owner/operator level within one state in order to provide greater compliance certainty and thus better demonstrate an equivalent level of emission reduction.

Demonstrating equivalence with unit-specific implementation of rate-based standards of performance in a rate-based averaging program is straightforward. A state would need to specify in its plan the group of affected EGUs participating in the averaging program that will demonstrate compliance on an aggregate basis, the unit-specific rate-based presumptive standard of performance that would apply to each participating affected EGU, and the aggregate compliance rate that must be achieved for the group of participating affected EGUs and how that aggregate rate is calculated, as described below. For states incorporating owner/operator-level averaging, the state plan would also need to include provisions that specify how the program will address any changes in the owner/operator for one or more participating affected EGUs during the course of program implementation to ensure effective implementation and enforcement of the program. Such provisions should be specified upfront in the plan and be self-executing, such that a state plan revision is not required to address such changes.

To ensure an equivalent level of emission reduction with application of individual rate-based standards of performance, the EPA is requiring that the weighting of the aggregate compliance rate is done on an output basis; in other words, participating affected EGUs must demonstrate compliance through achievement of an aggregate CO_2 emission rate that is a gross generation-based weighted average of the required standards of performance of each of the affected EGUs that participate in averaging. Such an approach is necessary to ensure that the aggregate compliance rate is representative of the unit-specific standards of performance that apply to each of the participating affected EGUs. Commenters were generally supportive of this method of calculating an aggregate rate for a group of sources participating in averaging. The Agency emphasizes that only affected EGUs are permitted to be included in the calculation of an aggregate rate-based standard of performance as well as in an aggregate compliance demonstration of a rate-based standard of performance.

Comment: Commenters supported the use of rate-based averaging on the grounds that it can provide operational flexibility to affected EGUs as well as the opportunity for owners and operators to optimize control technology investments. Many commenters supported averaging at the facility- and owner/operator-level as well as on a statewide or interstate basis.

Response: The EPA believes that rate-based trading can provide some additional operational flexibility and is finalizing that rate-based averaging is permissible at the facility- and owner/operator-level for affected EGUs in the medium- and long-term coal-fired subcategories. However, for reasons discussed above, the EPA believes that rate-based trading, rather than rate-based averaging, should be implemented where a state would like to implement a rate-based compliance flexibility at a state or interstate basis.

3. Rate-Based Emission Trading

The EPA proposed to permit states to incorporate rate-based trading into their state plans under these emission guidelines. In general, a rate-based trading program allows affected EGUs to trade compliance instruments that are generated based on their emission performance. A description of and responses to comments on rate-based trading can be found at the end of this subsection.

The EPA notes that, like rate-based averaging, rate-based trading can provide some flexibility for owners or operators to target cost effective reductions at specific affected EGUs, but can heighten the flexibility relative to averaging by further increasing the number of participating affected EGUs. In addition, emission trading can provide incentive for overperformance.

The proposed emission guidelines described how rate-based trading could work in this context. First, the EPA discussed how it expects states to denote the tradable compliance instrument in a rate-based trading programs as one ton of CO_2. A tradable compliance instrument denominated in another unit of measure, such as a MWh, is not fungible in the context of a rate-based emission trading program. A compliance instrument denominated in MWh that is awarded to one affected EGU most likely does not represent an equivalent amount of emissions credit when used by another affected EGU to demonstrate compliance, as the CO_2 emission rates (lb CO_2/MWh) of the two affected EGUs are likely to differ.

Each affected EGU is required under these emission guidelines to have a particular standard of performance, based on the degree of emission limitation achievable through application of the BSER, with which it would have to demonstrate compliance. Under a rate-based trading program, affected EGUs performing at a CO_2 emission rate below their standard of performance would be awarded compliance instruments at the end of each calendar year denominated in tons of CO_2. The number of compliance instruments awarded would be equal to the difference between their standard of performance CO_2 emission rate and their actual reported CO_2 emission rate multiplied by their gross generation in MWh. Affected EGUs demonstrating compliance through a rate-based averaging program that are performing worse than their standard of performance would be required to obtain and surrender an appropriate number of compliance instruments when demonstrating compliance, such that their demonstrated CO_2 emission rate is equivalent to their rate-based standard of performance. Transfer and use of these compliance instruments would be accounted for in the numerator (sum of total annual CO_2 emissions) of the CO_2 emission rate as each affected EGU performs its compliance demonstration. Compliance would be demonstrated for an affected EGU based on its reported CO_2 emission performance (in lb CO_2/MWh) and, if necessary, the surrender of an appropriate number of tradable compliance instruments, such that the demonstrated lb CO_2/MWh emission performance is equivalent to (or lower than) the rate-based standard of performance for the affected EGU.

The EPA is finalizing a determination that rate-based trading is permissible for affected EGUs in the medium- and long-term coal-fired subcategories. The Agency notes, as previously discussed, that rate-based trading (rather than averaging) must be utilized if the state wishes to establish a statewide or interstate rate-based compliance flexibility, in order to ensure compliance and equivalent stringency. For similar reasons, rate-based trading should also be utilized in lieu of owner/operator-level averaging when an owner/operator wishes to use a rate-based compliance flexibility for a group of its units that are located in more than one state.

Demonstrating equivalence with unit-specific implementation of rate-based standards of performance in a rate-based trading program is relatively straightforward. States would need to specify in their plans the affected EGUs participating in the trading program and their individual standards of performance. Under the method of rate-based trading described in this section, a compliance demonstration would be done for each participating affected EGU based on a combination of the reported emission performance and, if relevant, the surrender of compliance instruments. In addition, the EPA is requiring that the compliance instrument be denominated as one ton of CO_2 (rather than another unit such as MWh). The Agency believes this requirement is necessary to ensure an equivalent level of emission reduction as application of individual rate-based standards of performance.

An additional aspect of demonstrating equivalence is ensuring that the program achieves and maintains an equivalent level of emission reduction with standards of performance over time, which is much more certain in a rate-based trading program than in a mass-based program. Unlike mass-based trading programs, under which states must make assumptions about units' future utilization that may become inaccurate as those units' operations shift over time, rate-based trading programs do not rely on utilization assumptions. Utilization is already accounted for by default in a rate-based trading program. Thus, while mass-based compliance flexibilities require additional design features to ensure the continued accuracy of assumptions about utilization and thus emission limits or budgets over time, such features are not necessary in a rate-based trading program.

Comment: While commenters broadly supported the use of rate-based emission trading under these emission guidelines, as it provides operational flexibility to affected EGUs, some commenters expressed concern that rate-based trading could lead to an absolute increase in emissions.

Response: The EPA notes that, as a general matter, CAA section 111 reduces emissions of dangerous air pollutants by requiring affected sources to operate more cleanly. Under the construct of these emission guidelines, so long as a rate-based trading program is appropriately designed to maintain the level of emission reduction that would be achieved through unit-specific, rate-based standards of performance, it would be consistent with CAA section 111.

4. Unit-Specific Mass-Based Compliance

Although the EPA discussed mass-based trading in the proposed emission guidelines, it did not specifically address whether states may include a related flexibility, unit-specific mass-based compliance, in their plans. Several commenters supported mass-based mechanisms, including both unit-specific mass-based compliance and mass-based trading. A description of and responses to comments on unit-specific mass-based compliance can be found at the end of this subsection.

The EPA's CAA section 111 implementing regulations generally permit states to include mass-based limits in their plans, see 40 CFR 60.21a(f), subject to the requirement that standards of performance must be no less stringent than the presumptive standards of performance in the corresponding emission guidelines. 40 CFR 60.24a(c). However, the EPA has significant concerns about the use of unit-specific mass-based compliance in the context of these emission guidelines and the ability of states using this mechanism to ensure that such use will result in the same level of emission reduction that would be achieved by applying the rate-based standard of performance. These concerns arise both from the particular focus of these emission guidelines on emission reduction strategies that result in cleaner performance of affected EGUs, and the inherent uncertainty in predicting the utilization of affected EGUs during the compliance period, especially given the long lead times provided.

Therefore, while the EPA is allowing states to include unit-specific mass-based compliance in their plans for affected coal-fired EGUs in the medium- and long-term subcategories, it is also requiring states to use a backstop emission rate in conjunction with the mass-based compliance demonstration. As discussed in section X.D.1 of this preamble, the EPA believes the use of a backstop rate is consistent with the focus on achieving cleaner performance. CAA section 111 requires the mitigation of dangerous air pollution, which is generally achieved under this provision by requiring affected sources to operate more cleanly. Thus, standards of performance are typically expressed as a rate. In these emission guidelines, in particular, the BSERs for affected EGUs are control technologies and other systems of emission reduction that reduce the amount of CO_2 emitted per unit of electricity generation. The EPA is not precluding states from translating those unit-specific rate-based standards of performance into a mass-based limit (for unit-specific mass-based compliance) or budget (for emission trading). However, in order to ensure that the emission reductions required under CAA section 111 are achieved, mass-based limits or budgets must be accompanied by a backstop rate for purposes of demonstrating compliance. In addition, for coal-fired EGUs in the medium-term coal-fired subcategory in particular, it is critical that states' assumptions about future utilization do not result in inaccurate mass-based limits or budgets that allow units to emit more than they would be permitted to under unit-specific, rate-based compliance.

The EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach for affected EGUs in the long-term coal-fired subcategory, including a methodology for the applicable backstop rate, but is not finalizing a presumptively approvable approach for affected EGUs in the medium-term coal-fired subcategory. As explained below, the EPA has not been able to determine a unit-specific mass-based compliance mechanism for medium-term coal-fired EGUs that would ensure that the mass limit is no less stringent than the presumptive standard of performance under these emission guidelines.

In general, unit-specific mass-based compliance establishes a budget of allowable mass emissions (a mass limit) for an individual affected EGU based on the degree of emission limitation defined by its subcategory and a specified level of anticipated utilization. Standards of performance would be provided in the form of mass limits in tons of CO_2 for each individual affected EGU, and compliance would be demonstrated through surrender of allowances, with each allowance representing a permit to emit one ton of CO_2. Unlike mass-based emission trading, under a unit-specific mass compliance mechanism, these allowances would not be tradable with other affected EGUs. To demonstrate compliance, the affected EGU would be required to surrender allowances in a number equal to its reported CO_2 emissions during each compliance period.

As detailed in section VII.C.1.a.i(B)(7), for affected coal-fired EGUs in the long-term subcategory that are installing CCS, considering the potential impacts of variable load, startups, and shutdowns, 90 percent CO_2 capture is, in general, achievable over the course of a year. However, the EPA believes unit-specific mass-based compliance could provide some benefit by affording long-term affected coal-fired EGUs that adopt this mechanism even greater operational flexibility.[948] For example, if an affected EGU encounters challenges related to the start-up of the CCS technology or needs to conduct maintenance of the capture equipment, unit-specific mass-based compliance would provide a path for the affected EGU to continue operating. At the same time, unit-specific mass-based compliance coupled with a backstop rate would generally ensure that units operate more cleanly and that the required level of emission reduction is achieved. As explained in more detail below, the EPA's confidence regarding the equivalent stringency of this mass-based compliance approach for units in the long-term subcategory depends on the Agency's confidence in the likely utilization of a unit that has adopted emissions controls—in this case, CCS.

For affected EGUs in the long-term coal-fired subcategory, the EPA is providing a presumptively approvable approach to unit-specific mass-based compliance. To establish the presumptively approvable mass limit, the presumptively approvable rate (as described in section X.C.1.b.i of this preamble) would be multiplied by a level of gross generation (*i.e.,* utilization level) corresponding to an annual capacity factor of 80 percent, which is the capacity factor used for the BSER analysis (see section VII.C.1.a.ii of this preamble) and represents expected utilization based on the incentive provided by the IRC section 45Q tax credit. In addition, under this approach, affected EGUs would need to meet a backstop emission rate, expressed in lb CO_2 per MWh on a gross basis, equivalent to a reduction relative to baseline emission performance of 80 percent, on an annual calendar-year basis. The EPA believes this backstop rate represents a reasonable level of operational flexibility for affected EGUs

[948] States may also elect to include the short-term reliability mechanism described in section XII.F.3.a in their plans to address grid emergency situations.

in the long-term subcategory, and it could provide flexibility for sources to employ other technologies (*e.g.,* membrane and chilled ammonia capture technologies) that can achieve a similarly high degree of emission limitation to CCS with amine-based capture. States may deviate from this approach (however, as previously discussed, the approach must include a backstop rate) and deviations will be reviewed to ensure consistency with the statute and this rule when the EPA reviews the state plan. For example, states may wish to use an assumed utilization level of greater than 80 percent to establish a mass limit. In reviewing such an approach for reasonableness, the EPA would consider, among other things, whether an affected EGU's capacity factor has historically been greater than 80 percent for any continuous 8 quarters of data. The EPA would review the supporting data and resulting mass limit for consistency with the statute. The EPA has confidence that the presumptively approvable approach achieves an equivalent level of emission reduction as the implementation of the individual presumptive standard of performance because of the high degree of stringency associated with this subcategory as well as the 45Q tax credit, which incentivizes units to maximize capture of CO_2 as well as the utilization of the affected EGU.

On the other hand, the EPA does not have the same confidence in a mass-based approach to unit-specific compliance for the medium-term coal-fired subcategory for two reasons: the uncertainty in the utilization of these affected EGUs and the relatively lower stringency of the subcategory (*i.e.,* 16 percent reduction relative to baseline emission performance), particularly as compared to the long-term subcategory. The EPA has not been able to develop a workable approach to mass-based compliance for these units that both preserves the stringency of the presumptive standard of performance and results in an implementable program for affected EGUs.

First, there are significant challenges in selecting an appropriate utilization assumption for the purposes of generating a mass limit for affected EGUs in the medium-term subcategory. When setting the mass limit for a future time period, as would occur in a state plan under these emission guidelines, assumptions about the source's anticipated level of utilization must be made. Estimating future utilization of affected EGUs in the medium-term subcategory is subject to a significant degree of uncertainty, driven by sector-wide factors including changes in relative fuel prices, new incentives for technology deployment provided by the IIJA and the IRA, and increasing electrification, as well as EGU-specific factors related to its age and/or operating characteristics. As described in the *Power Sector Trends* TSD, coal-fired EGUs tend to become less efficient as they age, which may impact utilities' investment decisions and the utilization of these EGUs. In addition, affected EGUs in this subcategory are unlikely to be earning the IRC section 45Q tax credit, meaning they lack an incentive to maximize both utilization and control of emissions beyond what is required by the subcategory.

The accuracy of this estimate of utilization is critical to maintaining the environmental integrity established by unit-specific, rate-based compliance under these emission guidelines. If a state assumes a level of utilization that is higher than an affected EGU actually operates during the compliance period, the resulting mass limit will be non-binding, *i.e.,* may not reflect any emission reductions relative to what the unit would have emitted in the absence of these emission guidelines. In this case a backstop emission rate helps, but the unit would become subject to a de facto less-stringent standard of performance. This result does not preserve environmental integrity consistent with CAA section 111(a)(1). Conversely, assuming a level of utilization for the purpose of setting a mass limit that is lower than an affected EGU actually operates during the compliance period maintains the level of emission reduction of unit-specific, rate-based implementation but may have unintended effects on operational flexibility. Thus, the EPA believes that in many, if not most circumstances it will not be possible for states to accurately predict the future utilization of medium-term affected EGUs.

Second, the EPA notes that the relatively lower stringency of the subcategory further complicates the calculation of an appropriate mass limit. Under mass-based compliance, the quantity of emission reductions that corresponds to a 16 percent reduction in CO_2 emission rate is a relatively small reduction in terms of tons of CO_2. This relatively small reduction is likely to be subsumed by the uncertainty inherent in predicting the utilization of an affected EGU for purposes of determining its mass limit. That is, an EGU in the medium-term subcategory that assumes future utilization consistent with its historical baseline but reduces its emission rate by 16 percent would achieve, on paper at least, an emission reduction of 16 percent. However, if its utilization during the compliance period is more than 16 percent lower than it was in the past, the EGU using a mass-based compliance approach would face a reduced or completely eliminated obligation to improve its emission performance. In this case, mass-based compliance results in a lower level of emission reduction than unit-specific rate-based compliance. While this phenomenon is not likely to occur for long-term coal-fired affected EGUs given the much higher degree of stringency of the rate-based emission limitation and the greater certainty in future utilization, the EPA believes it would be widespread amongst medium-term affected EGUs.

Thus, the EPA is not providing a presumptively approvable approach for unit-specific mass-based compliance for affected EGUs in the medium-term coal-fired subcategory. However, it is also not prohibiting states from, in their discretion, allowing the use of unit-specific mass-based compliance. For such use to be approvable in state plans it must meet two requirements. First, as previously noted in section X.D.1 of this preamble, the state must apply a backstop rate in conjunction with a mass limit for the purposes of demonstrating compliance. As a starting point, states could consider basing their backstop rate for medium-term affected EGUs on the percentage reduction from the degree of emission limitation used for the presumptively approvable backstop rate for the long-term coal-fired subcategory, *i.e.,* the 80 percent reduction relative to baseline emission performance is approximately 90.5 percent of the 88.4 percent degree of emission limitation. Applying that to the degree of emission limitation for the medium-term coal-fired subcategory is 14.5 percent, so the backstop rate, expressed in lb CO_2 per MWh on a gross basis, could be set as a 14.5 percent reduction relative to baseline emission performance on an annual calendar-year basis. Second, as described in section X.D.1 of this preamble, states must demonstrate that their plan would achieve an equivalent level of emission reduction as the application of unit-specific, rate-based standards of performance, including showing how the mass limit has been calculated and the basis for any assumptions made (*e.g.,* about utilization). As explained in this section, the EPA believes it will be very difficult for states to accurately predict the future utilization of these units, which substantially increases the risk of establishing a mass limit that does not ensure at least an equivalent level of emission reduction. The EPA will therefore apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs employing this flexibility in state plans. Only state plans that demonstrate that use of compliance flexibilities will not erode the emission reductions required under these emission guidelines are approvable.

Comment: Commenters were generally supportive of the use of mass-based compliance mechanisms (both unit-specific and aggregate mechanisms such as emission trading) for these emission guidelines. Commenters said that mass-based compliance can help ensure environmental outcomes while also allowing sources to cycle, incorporate variable resources, and respond to grid conditions.

Response: The EPA is finalizing that mass-based compliance mechanisms are permissible when they assure an equivalent level of emission reduction with each source individually achieving its standard of performance, subject to the parameters described by the EPA in this preamble. For unit-specific mass-based compliance, affected EGUs in the medium- and long-term coal-fired subcategories may demonstrate compliance with their standards of performance through a mass limit. The EPA believes unit-specific mass-based compliance may offer some additional operational flexibility to states and affected EGUs, which could include allowing for cycling and incorporating variable resources. The EPA notes that sources must still be in compliance with the requisite backstop rate.

Comment: Many commenters expressed support for mass-based compliance mechanisms on the grounds that it facilitates calibration with existing state programs affecting the same sources that are affected under these emission guidelines.

Response: The EPA acknowledges that states may find it more straightforward to compare emission reduction obligations under these emission guidelines and existing state programs by using mass-based compliance mechanisms for state plans under these emission guidelines. However, the EPA notes that mass-based compliance mechanisms, including unit-specific mass-based compliance, are only available to certain sources affected by these emission guidelines, as described in this section of the preamble, which may be a smaller universe of sources than are affected by existing state programs. State plans must ensure an equivalent level of emission reduction from the sources that are affected sources under these emission guidelines. That is, states cannot rely on or account for emission reductions occurring at non-affected sources.

Section X.D.8 of this preamble discusses more considerations related to the relationship between the inclusion of compliance flexibilities in state plans under these emission guidelines and existing state programs.

Comment: Many commenters requested presumptively approvable mass-based standards of performance.

Response: As discussed above, the EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach for units in the long-term coal-fired subcategory that includes a backstop rate to ensure an equivalent level of emission reduction. The EPA emphasizes that states should take into account the discussions of stringency in section X.B and of demonstrating equivalence in section X.D.1 of this document, as well as guidance in each subsection on particular compliance flexibilities in considering mass-based compliance approaches that deviate from the presumptively approvable method or for sources for which the EPA is not providing a presumptively approvable approach.

5. Mass-Based Emission Trading

The EPA proposed that states would be permitted to incorporate mass-based trading into their state plans under these emission guidelines. While several commenters supported the use of mass-based emission trading, as with unit-specific mass-based compliance, the EPA has significant concerns about states' ability using this mechanism to maintain an equivalent level of emission reduction to unit-specific, rate-based standards of performance. A description of and responses to comments on mass-based trading can be found at the end of this subsection.

Under these final emission guidelines, the EPA is allowing states to include mass-based emission trading for affected coal-fired EGUs in the medium- and long-term subcategories in their plans. The same requirements and caveats discussed in section X.D.4 of this preamble above apply to the respective subcategories as for unit-specific mass-based compliance. Specifically, the EPA is requiring the use of a unit-specific backstop rate in conjunction with the mass-based compliance demonstration, which is necessary for consistency with the purpose of these emission guidelines to achieve the emission reductions required under CAA section 111(a)(1) through cleaner emission performance. The Agency similarly believes it will be very difficult for states to design mass-based trading programs that include affected EGUs in the medium-term coal-fired subcategory and that maintain the level of emission reduction that would be achieved under unit-specific compliance with the presumptive standards of performance.

In general, a mass-based trading program establishes a budget of allowable mass emissions for a group of affected EGUs, with tradable instruments (typically referred to as "allowances") issued to affected EGUs in the amount equivalent to the mass emission budget. To establish a mass budget under these emission guidelines, states would use the rate-based standard of performance and an assumed level of utilization for each participating affected EGU, and sum the resulting individual mass limits to an aggregate mass budget. Additionally, states would need to specify in the plan how allowances would be distributed to participating affected EGUs. Each allowance would represent a tradable permit to emit one ton of CO_2, with affected EGUs required to surrender allowances at the end of the compliance period in a number determined by their reported CO_2 emissions. Total emissions from all participating affected EGUs should be no greater than the total mass budget. In addition, each participating affected EGU would need to demonstrate compliance with the unit-specific backstop rate.

The EPA sees similar potential benefits related to operational flexibility of mass-based emission trading as with unit-specific mass-based compliance, discussed in section X.D.4 of this preamble. These benefits could be heightened by having a larger pool of allowances available to affected EGUs. In addition, the EPA notes that emission trading can provide incentive for overperformance.

While there is indeed the potential for heightened benefits from mass-based emission trading due to a larger pool of allowances resulting from the inclusion of multiple sources, the EPA believes that there is also a heightened risk that the mass budget will not be appropriately calculated due to the compounding uncertainty resulting from multiple participating sources. As noted in section X.D.4 of this preamble, projecting the utilization of affected EGUs has become increasingly challenging, driven by changes in technology, fuel prices, and electricity demand. In generating a mass budget, assumptions about utilization must be made for each participating source, which magnifies the risk, particularly for affected EGUs in the medium-term coal-fired subcategory, that an improper assumption about utilization for one affected EGU implicates the compliance obligation of other affected EGUs. Based on the understanding that a trading program that ensures the level of emission reduction of unit-specific, rate-based compliance under these emission guidelines would necessarily have to be designed with highly conservative utilization assumptions, the EPA is not providing a presumptively approvable approach for mass-based trading. The EPA additionally does not believe a presumptively approvable mass-based trading approach is warranted because, as noted in the introduction to this section, there are fewer sources covered by the final emission guidelines than the proposed emission guidelines, which may limit interest in and the utility of the use of mass-based trading for these emission guidelines.

The EPA is not prohibiting states from developing their own approaches to mass-based trading under these emission guidelines; however, they must apply a unit-specific backstop rate for all participating affected EGUs (see section X.D.4 of this preamble for a discussion of the backstop rate under unit-specific mass-based compliance), and they must demonstrate, as described in section X.D.1 of this preamble, that their plan would achieve an equivalent level of emission reduction as the application of individual rate-based standards of performance, including showing how the mass limit has been calculated and the basis for any assumptions made (*e.g.,* about utilization). As with unit-specific mass-based compliance, the EPA will apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs participating in a mass-based trading program in state plans. States must also specify the structure and purpose of any other trading program design feature(s) (*e.g.,* mass budget adjustment mechanism) and how they impact the demonstration of an equivalent level of emission reduction.

Comment: Many commenters supported the use of mass-based trading under these emission guidelines. Commenters stated that because many states are familiar with the mechanism, having used it for other pollutants in this sector or, in the case of some existing state programs, for CO_2, it would be easy to employ in the context of these emission guidelines and provide needed flexibility. In addition, commenters cited ensuring reliability as a motivation for using mass-based trading.

Response: While the EPA is finalizing that mass-based trading is permissible under these emission guidelines for affected EGUs in the medium- and long-term coal-fired subcategories, the EPA believes that some of the flexibility desired by commenters is addressed by other features of and changes made to the final emission guidelines, as described in the beginning of section X.D of this preamble. Despite familiarity on the part of states and sources with mass-based trading programs, the EPA is concerned that the unique circumstances of the EGUs affected by these final emission guidelines, including uncertainty over their future utilization as well as the relatively lower stringency of the medium-term coal-fired subcategory, pose a challenge for states in demonstrating an equivalent level of emission reduction of mass-based trading programs to the application of individual rate-based standards.

Comment: Some commenters expressed concern with whether and how mass-based trading would achieve and sustain the emission performance identified in the determination of BSER.

Response: The EPA shares these concerns, and for that reason is requiring the use of a unit-specific backstop rate in conjunction with mass-based compliance flexibilities, including mass-based trading. The EPA has also described its concerns over states' ability to estimate future utilization and will thus apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs participating in mass-based trading in state plans.

6. General Emission Trading and Averaging Program Implementation Features

As noted in the proposed emission guidelines, states would need to establish the procedures and systems necessary to implement and enforce an emission averaging or trading program, whether it is rate-based or mass-based, if they elect to incorporate such flexibilities into their state plans. This would include, but is not limited to, establishing the mechanics for demonstrating compliance under the program (*e.g.,* surrender of compliance instruments as necessary based on monitoring and reporting of CO_2 emissions and generation); establishing requirements for continuous monitoring and reporting of CO_2 emissions and generation; and developing a tracking system for tradable compliance instruments. The EPA requested comment on whether there was interest in capitalizing on the existing trading program infrastructure developed by the EPA for other trading programs, and some states and one utility expressed support for states' ability to use EPA's allowance management system for such programs. In addition to providing such resources for regional and national emission trading and averaging programs, the EPA has also provided technical support and resources to various non-EPA state and regional emission trading programs. In the event states choose to create emission averaging or trading programs under these emission guidelines, the EPA can provide technical support for such programs, including through the use of the Agency's existing trading program infrastructure, and is available to consult with states during the plan development process about the appropriateness of using such resources, such as the EPA's allowance management system, based on the design of state programs.

States may also need to consider how to handle differing compliance dates for affected EGUs in an emission averaging or trading program, given that under these emission guidelines the date when standards of performance apply varies depending on the subcategory for the affected EGU. The most straightforward way to address this, and which commenters supported, is to initially only include those sources with a compliance date of January 1, 2030, and then subsequently add sources into the program (and thus factor them into the aggregate standard of performance that must be achieved in the case of rate-based averaging or mass-based budget in the case of mass-based compliance approaches) at the start of the first year in which their standard of performance applies.

Another topic that states incorporating emission averaging or trading would need to consider is whether to provide for banking of tradable compliance instruments (hereafter referred to as ''allowance banking,'' although it is relevant for both mass-based and rate-based trading programs). Allowance banking has potential implications for a trading program's ability to maintain the requisite level of emission reduction of the standards of performance. The EPA recognizes that allowance banking—that is, permitting allowances that remain unused in one control period to be carried over for use in future control periods—may provide incentives for earlier emission reductions, promote operational flexibility and planning, and facilitate market liquidity. Many commenters supported allowing banking for these reasons. However, the

EPA has observed that unrestricted allowance banking from one control period to the next (absent provisions that adjust future control period budgets to account for banked allowances) may result in a long-term allowance surplus that has the potential to undermine a trading program's ability to ensure that, at any point in time, the affected sources are achieving the required level of emission performance. In the Good Neighbor Plan's trading program provisions, for example, the EPA implemented an annual allowance bank recalibration to prevent allowance surpluses from accumulating and adversely impacting program stringency.[949] While the requirement to include a backstop rate for mass-based compliance flexibilities can mitigate some concerns that unrestricted allowance banking will undermine the program's calibration towards achieving emission reductions through cleaner performance, the EPA urges that states considering allowing trading also consider restricting allowance banking (whether all or only a portion) in order to ensure that a program continues to be calibrated towards equivalent stringency with individual rate-based standards of performance, which several commenters did support.

Comment: Many commenters expressed the need for expanding the state plan submission timeline beyond 24 months to allow more time to design emission trading and averaging programs.

Response: As discussed in section X.E.2 of this preamble, the EPA is finalizing a 24-month state plan development timeframe. Because there are significantly fewer sources covered under the final emission guidelines and because the EPA is restricting certain subcategories from using compliance flexibilities such as emission averaging and trading and unit-specific mass-based compliance, the EPA believes 24 months is a reasonable amount of time to develop state plans, including time necessary to develop compliance flexibility approaches. Moreover, the EPA is offering a presumptively approvable approach to unit-specific mass-based compliance for affected EGUs in the long-term coal-fired subcategory, which can further simplify the process for developing compliance approaches in state plans.

7. Interstate Emission Trading

In the proposed emission guidelines, the EPA requested comment on whether, and under what circumstances or conditions, to allow interstate emission trading under these emission guidelines. Given the interconnectedness of the power sector and given that many utilities and power generators operate in multiple states, interstate emission trading may increase compliance flexibility. The EPA also took comment on whether the scope of rate-based averaging should be limited to a certain level of geographic aggregation (*i.e.,* intrastate but not interstate).

Many commenters expressed support for interstate trading and averaging, arguing that it further augments the flexibility offered by these mechanisms. Because electricity markets are often operated on an interstate basis, commenters stated that interstate trading and averaging would facilitate better electricity market planning. In particular, some commenters noted that interstate programs would also allow for better grid reliability planning across areas with regional planning entities.

While the EPA is finalizing a determination that states can incorporate both rate- and mass-based interstate emission trading programs into their state plans, the EPA has significant stringency-related and logistical concerns about the use of interstate emission trading for these particular emission guidelines. For mass-based trading in particular, the EPA has concerns that further increasing the number of sources participating in the program heightens the risk that the mass budget will not be appropriately calculated due to the uncertainty in estimating future utilization of affected EGUs, thus inhibiting the ability of states to demonstrate that their program achieves an equivalent level of emission reduction. This concern is somewhat alleviated for rate-based compliance flexibilities, but the EPA notes that states that wish to implement such flexibilities on an interstate basis should do so through rate-based trading, as discussed in section X.D.2. Interstate trading programs must adhere to the same requirements described in section X.D.1 and must demonstrate equivalence of the program for all participating affected EGUs.

For interstate emission trading programs to function successfully, all participating states would need to, at a minimum, use the same form of trading and have consistent design elements and identical trading program requirements. Each state participating in an interstate trading program would need to submit their own individual state plan, subject to the state plan component and submission requirements described in section X.E, but the states would coordinate their individual plan provisions addressing the interstate trading program. Additionally, each state plan would need provisions to ensure that affected EGUs within their state are in compliance taking into account the actions of affected EGUs participating in the interstate trading program in other states. The EPA would need all state plan submissions that incorporate interstate emission trading before evaluating any of the individual state plans in order to ensure consistency among all participating states. The EPA is willing to provide technical assistance to states during the state plan development process about the use of interstate emission trading, but notes that states may need to coordinate their individual state plan submissions among different EPA regions.

8. Relationship to Existing State Programs

As described in the proposed emission guidelines, the EPA recognizes that many states have adopted policies and programs (with both a supply-side and demand-side focus) under their own authorities that have significantly reduced CO_2 emissions from EGUs, that these policies will continue to achieve future emission reductions, and that states may continue to adopt new power sector policies addressing CO_2 emissions. States have exercised their power sector authorities for a variety of purposes, including economic development, energy supply and resilience goals, conventional and GHG pollution reduction, and generating allowance proceeds for investments in communities disproportionately impacted by environmental harms. The scope and approach of the EPA's final emission guidelines differ significantly from the range of policies and programs employed by states to reduce power sector CO_2 emissions, and these emission guidelines operate more narrowly to improve the CO_2 emission performance of a subset of EGUs within the broader electric power sector.

Several commenters requested guidance on how states can count existing state programs, many of which include requirements to reduce CO_2 emissions at sources not affected by this

[949] Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards, 88 FR 36654 (June 5, 2023). Under the allowance bank recalibration provisions, EPA will recalibrate the ''Group 3'' allowance bank for the 2024–2029 control periods to meet the target bank level of 21 percent of the sum of the state emission budgets for that control period. For control periods 2030 and later, the target bank level is 10.5 percent of the sum of the state emission budgets. If the overall bank is less than the target bank level for a given control period, then no bank recalibration will occur for that control period.

rule, in their state plans under these emission guidelines. The EPA is not providing such guidance in this action but would be open to consulting with states during the state plan development process about the requirements of these emission guidelines in relation to existing state programs. States may make determinations about whether and how to design their plans, accounting for state-specific programs or requirements that apply to the same affected EGUs included in a state plan. However, as noted in section X.B, emission reductions from sources not affected by this rule cannot be used to demonstrate compliance with a standard of performance established to meet the emission guidelines. Only emission reductions at affected EGUs may count towards compliance with the state plan, including towards demonstrating compliance with the equivalent stringency criterion applied to compliance flexibilities. States may employ compliance flexibilities (such as mass-based mechanisms) described in this section in order to facilitate comparison between the requirements under existing state programs and under these emission guidelines; however, the EPA emphasizes that individual affected EGUs or groups of affected EGUs must comply with the requirements established for such units in the state plan, and that such compliance cannot incorporate measures taken by EGUs not affected by these emission guidelines.

E. State Plan Components and Submission

This section describes the requirements for the contents of state plans and the timing of state plan submissions as well as the EPA's review of and action on state plan submissions. This section also discusses issues related to the applicability of a Federal plan and timing for the promulgation of any Federal Plan, if necessary.

As explained earlier in this preamble, the requirements of 40 CFR part 60, subpart Ba, govern state plan submissions under these emission guidelines. Where the EPA is finalizing requirements that add to, supersede, or otherwise vary from the requirements of subpart Ba for the purposes of state plan submissions under these particular emission guidelines,[950] those requirements are addressed explicitly in section X.E.1.b on specific state plan requirements and in other parts of section X of this preamble. Unless expressly amended or superseded in these final emission guidelines, the provisions of subpart Ba apply.

1. Components of a State Plan Submission

A state plan must include a number of discrete components, including but not limited to those that apply for all state plans pursuant to 40 CFR part 60, subpart Ba. In this action, the EPA is also finalizing additional plan components that are specific to state plans submitted pursuant to these emission guidelines. For example, the EPA is finalizing plan components that are necessary to implement and enforce the specific types of standards of performance for affected EGUs that would be adopted by a state and incorporated into its state plan.

a. General Components

The CAA section 111 implementing regulations at 40 CFR part 60, subpart Ba, provide separate lists of administrative and technical criteria that must be met in order for a state plan submission to be deemed complete.[951] The complete list of applicable administrative completeness criteria for state plan submissions is: (1) A formal letter of submittal from the Governor or the Governor's designee requesting EPA approval of the plan or revision thereof; (2) Evidence that the state has adopted the plan in the state code or body of regulations; or issued the permit, order, or consent agreement (hereafter ''document'') in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date; (3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan; (4) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan, including indication of the changes made (such as redline/strikethrough) to the existing approved plan, where applicable. The submittal must be a copy of the official state regulation or document signed, stamped, and dated by the appropriate state official indicating that it is fully enforceable by the state. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. If the regulation/document provided by the state for approval and incorporation by reference into the plan is a copy of an existing publication, the state submission should, whenever possible, include a copy of the publication cover page and table of contents; (5) Evidence that the state followed all applicable procedural requirements of the state's regulations, laws, and constitution in conducting and completing the adoption/issuance of the plan; (6) Evidence that public notice was given of the plan or plan revisions with procedures consistent with the requirements of 40 CFR 60.23a, including the date of publication of such notice; (7) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23a; (8) Compilation of public comments and the state's response thereto; and (9) Documentation of meaningful engagement, including a list of pertinent stakeholders, a summary of the engagement conducted, a summary of stakeholder input received, and a description of how stakeholder input was considered in the development of the plan or plan revisions.

Pursuant to subpart Ba, the technical criteria that all plans must meet include the following: (1) Description of the plan approach and geographic scope; (2) Identification of each designated facility (*i.e.,* affected EGU); identification of standards of performance for each affected EGU; and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility; (3) Identification of compliance schedules and/or increments of progress; (4) Demonstration that the state plan submission is projected to achieve emission performance under the applicable emission guidelines; (5) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and (6) Demonstration that each standard is quantifiable, permanent, verifiable, enforceable, and nonduplicative.

b. Specific State Plan Requirements for These Emission Guidelines

To ensure that state plans submitted pursuant to these emission guidelines are consistent with the statutory requirements and the requirements of subpart Ba, the EPA is finalizing additional regulatory requirements that state plans must meet for all affected EGUs subject to a standard of performance, as well as certain subcategory-specific requirements. The EPA reiterates that standards of performance for affected EGUs included in a state plan must be quantifiable,

[950] 40 CFR 60.20a(a)(1).

[951] 40 CFR 60.27a(g)(2) and (3).

verifiable, permanent, enforceable, and non-duplicative. Additionally, per CAA section 302(l), standards of performance must be continuous in nature. Additional state plan requirements finalized as part of this action include:

• Identification of each affected EGU and the subcategory to which each affected EGU is assigned;

• A requirement that state plans include, in the regulatory portion of the plan, a list of coal-fired steam-generating EGUs that are existing sources at the time of state plan submission and that plan to permanently cease operation before January 1, 2032, and the calendar dates by which they have committed to do so. The state plan must provide that an EGU operating past the date listed in the plan is no longer exempt from these emission guidelines and is in violation of that plan, except to the extent the existing coal-fired steam generating EGU has received a time-limited extension of its date for ceasing operation pursuant to the reliability assurance mechanism described in section XII.F.3.b of this preamble;

• Standards of performance for each affected EGU, including provisions for implementation and enforcement of such standards as well as identification of the control technology or other system of emission reduction affected EGUs intend to implement to achieve the standards of performance. Standards of performance must be expressed in lb CO_2/MWh gross basis or, for affected EGUs in the low load natural gas- and oil-fired subcategory, lb CO_2/MMBtu, or, if a state is allowing the use of mass-based compliance, tons CO_2 per year;

• For each affected EGU, identification of baseline emission performance, including CO_2 mass and electricity generation data or, for affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, heat input data from 40 CFR part 75 reporting for the 5-year period immediately prior to the date this final rule is published in the **Federal Register** and what continuous 8-quarter period from the 5-year period was used to calculate baseline emission performance;

• Where a state plan provides for the use of a compliance flexibility, such as an alternative form of the standard (*e.g.,* mass limit; aggregate emission rate limitation) and/or the use of emission averaging or trading, identification of the presumptive unit-specific rate-based standard of performance in lb CO_2/MWh-gross that would apply for each affected EGU in the absence of the compliance flexibility mechanism; the standard of performance (aggregate emission rate limitation, mass limit, or mass budget) that is actually applied for affected EGUs under the compliance flexibility mechanism and how it is calculated; provisions for the implementation and enforcement of the compliance flexibility mechanism, which includes provisions that address assurance of achievement of equivalent emission reduction, including, for mass-based compliance flexibilities, identification of the unit-specific backstop emission limitation; and a demonstration that the state plan will achieve an equivalent level of emission reduction with individual rate-based standards of performance through incorporation of the compliance flexibility mechanism;

• Increments of progress and reporting obligations and milestones as required for affected EGUs within the applicable subcategories or pursuant to consideration of RULOF, included as enforceable elements of a state plan;

• For affected EGUs in the medium-term coal-fired steam generating EGU subcategory and affected EGUs relying on a plan to permanently cease operation for application of a less stringent standard of performance pursuant to RULOF, the state plan must include an enforceable commitment to permanently cease operation by a date certain. The state plan must clearly identify the calendar dates by which such affected EGUs have committed to permanently cease operation;[952]

• A requirement that state plans provide that any existing coal-fired steam generating EGU shall operate only subject to a standard of performance pursuant to these emission guidelines or under an exemption from applicability provided under 40 CFR 60.5850b (including any time-limited extension of the date by which an EGU has committed to permanently cease operations pursuant to the reliability assurance mechanism); and

• Monitoring, reporting, and recordkeeping requirements for affected EGUs.

These final emission guidelines include requirements pertaining to the methodologies for establishing a presumptively approvable standard of performance for an affected EGU within a given subcategory. These presumptive methodologies are specified for each of the subcategories of affected EGUs in section X.C.1 of this preamble.

As discussed in sections X.C and X.D of this preamble, in order for the EPA to find a state plan ''satisfactory,'' that plan must demonstrate that it achieves the level of emission reduction that would result if each affected source was individually achieving its presumptive standard of performance, after accounting for any application of RULOF. That is, while states have the discretion to establish the applicable standards of performance for affected sources in their state plans (including whether to allow compliance to be demonstrated through the use of compliance flexibilities), the structure and purpose of CAA section 111 require that those plans achieve an equivalent level of emission reduction as applying the EPA's presumptive standards of performance to those sources (again, after accounting for any application of RULOF).

Thus, state plans must adequately document and support the process and underlying data used to establish standards of performance pursuant to these emission guidelines. Providing such documentation is critical to the EPA's review of state plans to determine whether they are satisfactory. In particular, states must include in their plan submissions information and data related to affected EGUs' emissions and operations, including CO_2 mass emissions and corresponding electricity generation data or, for affected EGUs in either the low load natural gas-fired subcategory or the oil-fired subcategory, heat input data, from 40 CFR part 75 reporting for the 5-year period immediately prior to the date the final rule is published in the **Federal Register** and identify the period from which states and affected EGUs select 8 continuous quarters of data to determine unit-specific baselines. States must include data and documentation sufficient for the EPA to understand and replicate their calculations in applying the applicable degree of emission

[952] Consistent with CAA section 111(d)(1), state plans must include commitments to cease operation as necessary for the implementation and enforcement of standards of performance. When such commitments are the predicate for receiving a particular standard of performance, adherence to those commitments is necessary to maintain the level of emission reduction Congress required under CAA section 111(a)(1). See 40 CFR 60.24a(g) (operating conditions within the control of a designated facility that are relied on for purposes of RULOF must be included as enforceable requirements in state plans); see also, *e.g.,* ''Affordable Clean Energy Rule,'' 84 FR 32520, 32558 (July 8, 2019) (repealed on other grounds) (requiring that retirement dates associated with standards of performance be included in state plans and become federally enforceable upon approval by the EPA); 76 FR 12651, 12660–63 (March 8, 2011) (best available retrofit technology requirements based on enforceable retirements that were made federally enforceable in state implementation plan); Guidance for Regional Haze State Implementation Plans for the Second Implementation Period at 34, EPA–457/B–19–003, August 2019 (to the extent a state replies on an enforceable shutdown date for a reasonable progress determination, that measure would need to be included in the SIP and/or be federally enforceable).

limitation to individual affected EGUs to establish their standards of performance. They must also provide any methods, assumptions, and calculations necessary for the EPA to review plans containing compliance flexibilities and to determine whether they achieve an equivalent (or better) level of emission reduction as unit-specific implementation of rate-based standards of performance. Plans must also adequately document and demonstrate the methods employed to implement and enforce the standards of performance such that the EPA can review and identify measures that assure transparent and verifiable implementation.

i. Requirements Related to Meaningful Engagement

Public engagement is a cornerstone of CAA section 111(d) state plan development. In November 2023, the EPA finalized requirements in the CAA section 111(d) implementing regulations at 40 CFR part 60 subpart Ba to ensure that that all affected members of the public, not just a particular subset, have an opportunity to participate in the state plan development process. These requirements are intended to ensure that the perspectives, priorities, and concerns of affected communities, including communities that are most affected by and vulnerable to emissions from affected EGUs as well as energy communities and energy workers that are affected by EGU operation and construction of pollution controls, are included in the process of establishing and implementing standards of performance for existing EGUs, including decisions about compliance strategies and compliance flexibilities that may be included in a state plan. The final requirements for meaningful engagement in subpart Ba are in addition to the preexisting public notice requirements under subpart Ba that apply to state plan development. This section describes the meaningful engagement requirements finalized separately in subpart Ba and provides guidance to states in the application of these requirements to the development of state plans under these emission guidelines.

The fundamental purpose of CAA section 111 is to reduce emissions from categories of stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the state's development of a state plan is the potential impact of the proposed plan requirements on public health and welfare. Meaningful engagement is a corollary to the longstanding requirement for public participation, including through public hearings, in the course of state plan development under CAA section 111(d).[953] A robust and meaningful engagement process is critical to ensuring that the entire public has an opportunity to participate in the state plan development process and that states understand and consider the full range of impacts of a proposed plan on public health and welfare.

The EPA finalized the following definition of meaningful engagement in the final subpart Ba revisions in November 2023: ''timely engagement with pertinent stakeholders and/or their representatives in the plan development or plan revision process.'' [954] Furthermore, the definition provides that ''[s]uch engagement should not be disproportionate in favor of certain stakeholders and should be informed by available best practices.'' [955] The regulations also define pertinent stakeholders, which ''include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision.'' [956] The preamble for the final revisions to subpart Ba notes that ''[i]ncreased vulnerability of communities may be attributable to, among other reasons, an accumulation of negative environmental, health, economic, or social conditions within these populations or communities, and a lack of positive conditions.'' [957] Consistent with the requirements of subpart Ba, it is important for states to recognize and engage the communities most affected by and/or vulnerable to the impacts of a state plan, particularly as these communities may not have had a voice when the affected EGUs were originally constructed.

Most commenters were generally supportive of the requirement to conduct meaningful engagement. Commenters acknowledged that some states and utilities have already started to conduct meaningful engagement with stakeholders like that which is required by the final subpart Ba revisions in other policy contexts. Some commenters requested more time in the state plan development process specifically to facilitate conducting meaningful engagement (comments related to the state plan development timeline are addressed section X.E.2).

In the proposed emission guidelines, the EPA provided some information to assist states in identifying potential pertinent stakeholders. Some commenters sought more guidance from the EPA on how to identify pertinent stakeholders. The Agency is providing the following discussion of the potential impacts of the emission guidelines to assist states in identifying their pertinent stakeholders. The EPA believes that this discussion provides a starting point and expects that states will use their more targeted knowledge of state- and source-specific circumstances to hone the identification of pertinent stakeholders and conduct the necessary meaningful engagement. As acknowledged by the EPA in the final revisions to subpart Ba, ''states are highly diverse in, among other things, their local conditions, resources, and established practices of engagement,'' [958] so the EPA is not finalizing any additional requirements regarding the states' identification of a pertinent stakeholders for the purposes of these emission guidelines. States should consider the unique circumstances of their state and the sources within their state, with the following discussion in mind, to tailor their meaningful engagement. In addition, the EPA notes that the preamble to the final subpart Ba revisions provides discussion of best practices related to meaningful engagement.[959]

The air pollutant of concern in these emission guidelines is defined as greenhouse gases, and the air pollution addressed is elevated concentrations of these gases in the atmosphere. These elevated concentrations result in warming temperatures and other changes to the climate system that are leading to serious and life-threatening environmental and human health impacts, including increased incidence of drought and flooding, damage to crops and disruption of associated food, fiber, and fuel production systems, increased incidence of pests, increased incidence of heat-induced illness, and impacts on water availability and water quality. The Agency therefore expects that states' pertinent stakeholders will include communities within the state that are most affected by and/or vulnerable to the impacts of climate change, including those exposed to more extreme drought, flooding, and other severe weather impacts, including extreme heat and cold (states should

[953] 40 CFR 60.23(c)–(g); 40 CFR 60.23a(c)–(h).

[954] 40 CFR 60.21a(k); 88 FR 80480, 80500 (November 17, 2023).

[955] *Id.*

[956] 40 CFR 60.21a(l); 88 FR 80480, 80500 (November 17, 2023).

[957] 88 FR 80480, 80500 (November 17, 2023).

[958] *Id.*

[959] *See id.* at 80502.

refer to section III of this preamble, on climate impacts, to further assist them in identifying their pertinent stakeholders that are impacted by the pollution at issue in these emission guidelines). Commenters were supportive of the notion that those impacted by climate change are pertinent stakeholders.

Additionally, the EPA expects that another set of pertinent stakeholders will be communities located near affected EGUs and those near pipelines. These communities may experience impacts associated with implementation of the state plan, including the construction and operation of infrastructure required under a state plan. Activities related to the construction and operation of new natural gas and CO_2 pipelines may impact individuals and communities both locally and at larger distances from affected EGUs but near any associated pipelines. Commenters were supportive of the notion that communities impacted by infrastructure development required by the state plan are pertinent stakeholders.

Because these emission guidelines address air pollution that becomes well mixed and is long-lived in the atmosphere, the collective impact of a state plan is not limited to the immediate vicinity of EGUs and any associated infrastructure. The EPA therefore expects that states will consider communities and populations within the state that are both most impacted by particular affected EGUs and associated pipelines as well as those that will be most affected by the overall stringency of state plans.

The EPA also expects that states will include the energy communities impacted by each affected EGU, including the energy workers employed at affected EGUs (including employment in operation and maintenance), workers who may construct and install pollution control technology, and workers employed in associated industries such as fuel extraction and delivery and CO_2 transport and storage, as pertinent stakeholders. These communities are impacted by power sector trends on an ongoing basis. The EPA acknowledges that a variety of Federal programs are available to support these communities and encourages states to consider these programs when conducting meaningful engagement and analyzing the impacts of compliance choices.[960] Commenters supported encouraging states to both consider these communities as part of meaningful engagement under these emission guidelines as well as to take advantage of Federal resources available for employment and training assistance, and highlighted a Colorado state law [961] requiring utilities to share workforce data and develop a workforce transition plan. The EPA supports such approaches to workforce data transparency and encourages states to provide such data in the course of meaningful engagement and the development of state plans.

The EPA also expects that states will include relevant balancing authorities, systems operators and reliability coordinators that have authority to maintain electric reliability in their jurisdiction as part of their constructive engagement under these requirements. These stakeholders are impacted by a state plan as they are the entities authorized to plan for electric reliability. Visibility into unit-specific compliance plans will help ensure those entities have adequate lead time to plan and address any potential reliability-related issues. Early notification and periodic follow up on unit-specific decisions, including control technology installation and voluntary cease operation choices and timeframes will greatly assist reliability planning authorities.

Several commenters noted the need for consideration of communities overburdened by existing air pollution issues, including both greenhouse gases and co-pollutants, as pertinent stakeholders in these emission guidelines. The Agency urges states to consider the cumulative burden of pollution when identifying their pertinent stakeholders for these emission guidelines, as these stakeholders may be especially vulnerable to the impacts of a state plan or plan revision due to ''an accumulation of negative environmental . . . conditions,'' as defined in the final subpart Ba revisions. Many states are already implementing policies to consider cumulative impacts in overburdened communities, including California and New Jersey. It is also important to note that the EPA is ''prioritizing cumulative impacts research to address the multiple stressors to which people and communities are exposed, and studying how combinations of stressors affect health, well-being, and quality of life at each developmental stage throughout the course of one's life.'' [962] Additionally, the EPA is in the process of developing a workplan that lays out actions the agency will take to integrate and implement cumulative impacts within the EPA's work through FY25. The EPA's commitments, as stated in the EPA's response to the OIG Report, include continuing to refine analytic techniques based on best available science, increasing the body of relevant data and knowledge, and using outcome-based metrics to measure progress, including quantifiable pollution reduction benefits in communities.[963]

The EPA recognizes that facility- and community-specific circumstances, including the exposure of overburdened communities to additional chemical and non-chemical stressors, may also exist. The meaningful engagement process is designed to allow states to identify and to enable consideration of these and other facility- and community-specific circumstances. This includes consideration of facility- and community-specific concerns with emissions control systems, including CCS. States should design meaningful engagement to elicit input from pertinent stakeholders on facility- and community-specific issues related to implementation of emissions control systems generally, as well as on any considerations for particular systems.

The EPA encourages states to consider regional implications, explore opportunities for collaboration, and to share best practices. In some cases, an affected EGU may be located near state

[960] An April 2023 report of the Federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) summarizes how the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act have greatly increased the amount of Federal funding relevant to meeting the needs of energy communities, as well as how the Energy Communities IWG has launched an online Clearinghouse of broadly available Federal funding opportunities relevant for meeting the needs and interests of energy communities, with information on how energy communities can access Federal dollars and obtain technical assistance to make sure these new funds can connect to local projects in their communities. Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization. ''Revitalizing Energy Communities: Two-Year Report to the President'' (April 2023). *https://energycommunities.gov/wp-content/uploads/2023/04/IWG-Two-Year-Report-to-the-President.pdf.*

[961] Colorado Legislature, Senate Law 19–236. *https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf.*

[962] Nicolle S. Tulve, Andrew M. Geller, Scot Hagerthey, Susan H. Julius, Emma T. Lavoie, Sarah L. Mazur, Sean J. Paul, H. Christopher Frey, Challenges and opportunities for research supporting cumulative impact assessments at the United States environmental protection agency's office of research and development, The Lancet Regional Health—Americas, Volume 30, 2024, 100666, ISSN 2667–193X, *https://doi.org/10.1016/j.lana.2023.100666.*

[963] EPA Response to Draft Office of Inspector General Report, The EPA Lacks Agencywide Policies and Guidance to Address Cumulative Impacts and Disproportionate Health Effects on Communities with Environmental Justice Concerns. *https://www.epaoig.gov/sites/default/files/reports/2023-08/_epaoig_20230822-23-p-0029.pdf.*

or Tribal borders and impact communities in neighboring states or Tribal lands. Some commenters suggested that those near state or Tribal borders may be pertinent stakeholders. The EPA agrees that it could be reasonable, in cases where EGUs are located near borders, for the state to consider identifying pertinent stakeholders in the neighboring state or Tribal land and to work with the relevant air pollution control authority of that state or Tribe to conduct meaningful engagement that addresses cross-border impacts. Some commenters supported the notion that those near state or Tribal borders may be pertinent stakeholders.

The revisions to subpart Ba in November of 2023 established requirements for demonstrating how states provided meaningful engagement with pertinent stakeholders, and these requirements apply here. According to the requirements under subpart Ba, the state will be required to describe, in its plan submittal: (1) A list of the pertinent stakeholders identified by the state; (2) a summary of engagement conducted; (3) a summary of the stakeholder input received; and (4) a description of how stakeholder input was considered in the development of the plan or plan revisions. The EPA will review the state plan to ensure that it includes these required descriptions regarding meaningful public engagement as part of its completeness evaluation of a state plan submittal. If a state plan submission does not include the required elements for notice and opportunity for public participation, including the procedural requirements at 40 CFR 60.23a(i) and 60.27a(g)(2)(ix) for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or (where a plan has become complete by operation of law) to disapprove the plan.

In approaching meaningful engagement, states should first identify their pertinent stakeholders. As previously noted, the state should allow for balanced participation, including communities most vulnerable to the impacts of the plan. Next, states should develop a strategy for engagement with the identified pertinent stakeholders. This includes ensuring that information is made available in a timely and transparent manner, with adequate and accessible notice. As part of this strategy for engagement, states should also ensure that they share information and solicit input on plan development and on any accompanying assessments or analyses. In providing transparent and adequate notice of plan development, states should consider that internet notice alone may not be appropriate for all stakeholders, given lack of access to broadband infrastructure in many communities. Thus, in addition to internet notice, examples of prominent advertisement for engagement and public hearing may include notice through newspapers, libraries, schools, hospitals, travel centers, community centers, places of worship, gas stations, convenience stores, casinos, smoke shops, Tribal Assistance for Needy Families offices, Indian Health Services, clinics, and/or other community health and social services as appropriate for the emission guideline addressed. The state should also consider any geographic, linguistic, or other barriers to participation in meaningful engagement for members of the public.

The EPA notes that several EPA resources are available to assist states and stakeholders in considering options for state plans. For example, included in the docket for this rulemaking is a unit-level proximity analysis that includes information about the population within 5 kilometers and 10 kilometers of each EGU covered by this rule. This analysis includes information about air emissions from each facility, and the potential emission implications of installing CCS. Additionally, the EPA's Power Plant Environmental Justice Screening Methodology (PPSM) [964] incorporates several peer-reviewed approaches that combine air quality modeling with environmental burden and population characteristics data to identify and connect power plants to geographic areas potentially exposed to air pollution by those power plants and to quantify the relative potential for environmental justice concern in those areas. This information provides states and stakeholders with the ability to identify the census block groups that are potentially exposed to air pollution by each EGU, including air pollutants in the vicinity of each EGU as well as pollutants that can travel significant distances. Another resource available to assist states and stakeholders is the EPA's Environmental Justice Screening and Mapping Tool (EJScreen),[965] which includes information at the census block group level about existing environmental burdens as well as socioeconomic information. Other federal resources include the Energy Communities Interagency Working Group's online Clearinghouse, which lists federal funding opportunities relevant for meeting the needs and interests of energy communities, some of which may be relevant for state plan development.

In their plan submittal, states must demonstrate evidence that they conducted meaningful engagement. In addition to a list of pertinent stakeholders and a summary of the engagement conducted, states must provide a summary of the input received and a description of how the input they received was considered in plan development. The type of information states may receive from their pertinent stakeholders could include data on the population and demographics of communities located near affected EGUs and associated pipelines; identification of and data on any overburdened communities vulnerable to the impacts of the state plan; data on the energy workers affected by anticipated compliance strategies on the part of owners and operators; data on workforce needs (*e.g.,* expected number and type of jobs created, and skills required in anticipation of compliance with the state plan); and, if relevant, data on the population and demographics of communities near state and Tribal borders that may be vulnerable to the impacts of the state plan. The EPA encourages states to include such data in their demonstration of meaningful engagement in their state plan submittal.

The EPA emphasizes to states that the meaningful engagement process is intended to include community perspectives, particularly those communities that, historically, may not have had a role in the state plan development process, in the development of standards of performance, compliance strategies, and compliance flexibilities for affected EGUs by which they are impacted.

ii. Requirements for Transparency and Compliance Assurance

The EPA proposed and requested comment on several requirements designed to help states ensure timely compliance by affected EGUs with standards of performance, as well as to assist the public in tracking affected EGUs' progress towards their compliance dates.

First, the EPA requested comment on whether to require that an affected EGU's enforceable commitment for subcategory applicability (*e.g.,* a state elects to rely on an affected coal-fired steam-generating unit's commitment to permanently cease operations before January 1, 2039, to meet the applicability requirements for the medium-term subcategory), must be in

[964] *https://www.epa.gov/power-sector/power-plant-environmental-justice-screening-methodology.*

[965] *https://www.epa.gov/ejscreen.*

the form of an emission limit of 0 lb CO_2/MWh that applies on the relevant date. Such an emission limit would be included in a state regulation, permit, order, or other acceptable legal instrument and submitted to the EPA as part of a state plan. If approved, the affected EGU would have a federally enforceable emission limit of 0 lb CO_2/MWh that would become effective as of the date that the EGU permanently ceases operations. The EPA requested comment on whether such an emission limit would have any advantages or disadvantages for compliance and enforceability relative to the alternative, which is an enforceable commitment in a state plan to cease operation by a certain date.

The EPA received few comments on this topic. One commenter,[966] in particular, did not support a specific requirement that the permit or other enforceable commitment must be in the form of an emission limit of 0 lb CO_2/MWh, claiming it seems needlessly prescriptive. This commenter also encouraged the EPA to recognize delegated or SIP-approved states' enforceable permit conditions, certifications, and voiding of authorizations, as practically enforceable.

The EPA is not finalizing a requirement that states must include commitments to permanently cease operating in state plans in the form of 0 lb CO_2/MWh emission limits. The Agency is concluding that it is within the discretion of the state to create an enforceable commitment to permanently cease operation, where applicable, in the form it deems appropriate. Such commitments may be codified in a state regulation, permit, order, or other acceptable legal instrument and submitted to the EPA as part of a state plan. It is important to note that if an emission limit or some other requirement that creates an enforceable commitment to cease operation is initially included in a title V permit before the submission of a state plan, that condition must be labeled as ''state-only'' or ''state-only enforceable'' until the EPA approves the state plan, at which point the permit should be revised to make that requirement federally enforceable. Including state instruments (such as state permits, certifications, and other authorizations) reflecting affected EGUs' intent to permanently cease operation in the state plan, when such intent is the basis of receiving a less stringent standard of performance, is necessary because state instruments can be revised without a corresponding revision to the state plan or standard of performance. This outcome—a source continuing to operate into the future with a less-stringent standard of performance that is not necessarily warranted—would undermine the integrity of these emission guidelines.

Second, the EPA proposed and is finalizing a requirement that state plans that include affected EGUs that plan to permanently cease operation must require that each such affected EGU comply with applicable state and Federal requirements for permanently ceasing operation, including removal from its respective state's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU. This requirement covers affected coal-fired steam generating EGUs in the medium-term subcategory as well as affected EGUs that are relying on a commitment to permanently cease operating to obtain a less stringent standard of performance pursuant to consideration of RULOF. This requirement merely reinforces the application of requirements under state and Federal laws that are necessary in this context for transparency and the orderly administration of these emission guidelines.

Third, the EPA proposed and is finalizing a requirement that each state plan must require owners and operators of affected EGUs to establish publicly accessible websites, referred to here as a ''Carbon Pollution Standards for EGUs website,'' to which all reporting and recordkeeping information for each affected EGU subject to the state plan would be posted, including the aforementioned information required to be submitted as part of the state plan. This information includes, but is not limited to, emissions data and other information relevant to determining compliance with applicable standards of performance, information relevant to the designation and determination of compliance with increments of progress and reporting obligations including milestones for affected EGUs that plan to permanently cease operations, and any extension requests made and granted pursuant to the compliance date extension mechanism or the reliability assurance mechanism. Although this information will also be required to be submitted directly to the EPA and the relevant state regulatory authority, both the EPA and stakeholders have an interest in ensuring that the information is made accessible in a timely manner. Some commenters agreed with these requirements. The EPA anticipates that the owners or operators of some affected EGUs may already be posting comparable reporting and recordkeeping information to publicly available websites under the EPA's April 2015 Coal Combustion Residuals Rule,[967] such that the burden of this website requirement for these units could be minimal.

Comment: Several commenters argued that this was a duplicative requirement, noting that utilities already report GHG emissions data under the Acid Rain Program and Mandatory GHG Reporting Program. Commenters also stated that this requirement would pose a burden for companies who would have to dedicate staff to maintaining the website. One commenter[968] suggested that EPA include more specific requirements related to the format of data, notification of uploads and removal of documentation, and summarization of content.

Response: The EPA disagrees that this requirement is duplicative of reporting requirements under other programs. In addition to affected EGUs having unique standards of performance and compliance schedules under these emission guidelines, these emission guidelines also include unique reporting requirements that are not covered by the programs identified by the commenters, including increments of progress and reporting on milestones. In addition, the EPA believes that this information should be made broadly available to all stakeholders in a timely manner, which is not necessarily accomplished via the programs and reporting mechanisms identified by the commenters. Accordingly, the EPA is finalizing a requirement that each state plan must require owners and operators of affected EGUs to establish publicly accessible websites and to post the relevant information described in this section. Additionally, data should be available in a readily downloadable format.

Fourth, to promote transparency and to assist the EPA and the public in assessing progress towards compliance with state plan requirements, the EPA proposed and is finalizing a requirement that state plans include a requirement that the owner or operator of each affected EGU shall report any deviation from any federally enforceable state plan increment of progress or reporting milestone within 30 business days after

[966] See Document ID No. EPA–HQ–OAR–2023–0072–0781.

[967] See *https://www.epa.gov/coalash/list-publicly-accessible-internet-sites-hosting-compliance-data-and-information-required* for a list of websites for facilities posting Coal Combustion Residuals Rule compliance information, *see also* 80 FR 21301 (April 17, 2015).

[968] See Document ID No. EPA–HQ–OAR–2023–0072–0813.

the owner or operator of the affected EGU knew or should have known of the event. That is, the owner or operator must report within 30 business days if it is behind schedule such that it has missed an increment of progress or reporting milestone. In the report, the owner or operator of the affected EGU will be required to explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. The owner or operator of the EGU must submit the report to the state regulatory agency and concurrently post the report to the affected EGU's Carbon Pollution Standards for EGUs website.

Fifth, in the proposed action, the EPA explained its general approach to exercising its enforcement authorities through administrative compliance orders (''ACOs'') to ensure compliance while addressing genuine risks to electric system reliability. The EPA solicited comment on whether to promulgate requirements in the final emission guidelines pertaining to the demonstrations, analysis, and information the owner or operator of an affected EGU would have to submit to the EPA in order to be considered for an ACO. The EPA is not finalizing the proposed approach to use ACOs to address risks to grid reliability.

Comment: One commenter argued that the conditions to qualify for an ACO would make it challenging for an EGU to obtain an ACO in instances of urgent reliability.[969] Commenters argued that there are not any guarantees that the EPA would act on such requests for an ACO in a timely manner, particularly because the EPA has not set any deadline for review and presumably would argue that any decision falls within the EPA's enforcement discretion and is not subject to judicial review. Additionally, one commenter argued that the proposal is unworkable for the purposes of addressing more immediate reliability needs, specifying that EGUs may not be able to readily obtain the information or analysis necessary for preparing documentation for the EPA from their regional entity or state.[970]

Another commenter argued that the proposed mechanism provides no relief during an energy crisis because they would be offered only after the fact to resolve any alleged violations. Therefore, the possibility of future enforcement discretion and ACOs will not help a power generator decide in the moment whether to keep running and risk a violation or shut down, risking grid reliability and affecting our customers. the commenter also stated that ACOs are enforcement actions that carry negative implications and the potential for significant civil penalties, and citizen groups are unlikely to exercise discretion similar to that of the EPA, even if the EPA decides that a low (or no) penalty is appropriate. Lastly, this commenter noted that ACOs are typically intended to resolve relatively short-term noncompliance events that can be remedied and that do not reflect a fundamental inability to comply.

Response: As discussed in section XII.F and elsewhere in this preamble, the EPA has made several adjustments and provided several mechanisms in this final rule that have the effect of or are expressly intended to provide grid operators and reliability authorities methods to address grid reliability. For example, the EPA is providing that states may include in their state plans a short-term reliability mechanism that allows affected EGUs to comply with an emission limitation corresponding to their baseline emission rate during periods of grid emergency. For further detail, see section XII.F.3.a of this preamble. This mechanism is intended to allow states to respond quickly to emergency situations, and to avoid affected EGUs being out of compliance or needing to work towards compliance through an ACO. Considering the structural changes the EPA has made in these final emission guidelines and the mechanisms it is providing states to address grid reliability, the EPA does not believe that states and affected EGUs will need to rely on ACOs to address compliance during periods of grid emergency.

Finally, as explained in section VII.B of this preamble, coal-fired steam generating EGUs that plan to permanently cease operating before January 1, 2032, are not covered by these emission guidelines, *i.e.,* they are not affected EGUs. However, to maintain the environmental integrity of these emission guidelines, it is critical that any existing sources that are operating as of January 1, 2032, are doing so subject to a requirement to operate more cleanly, and therefore essential that sources report on their actions to qualify for the exemption. As explained in the preamble to the proposed rule and section X.C.4 of this preamble, there are many steps the owners or operators of EGUs must take as they get ready to permanently cease operations and those steps vary between units and jurisdictions. Procession in a timely manner through these steps is the best indicator the EPA has of whether or not an existing source remains qualified for an exemption from these emission guidelines. Should a source's plans to cease operating change, *e.g.,* because the relevant planning authority has called on it to remain in operation for reliability or resource adequacy, the state, the public, and the EPA need to be aware of that change as soon as possible in order to appropriately address the source under these emission guidelines. The EPA therefore believes that having sources that plan to cease operation before January 1, 2032, report to the Agency on the steps they have taken towards doing so is critical to ensuring that those sources remain qualified for the exemption and thus to maintaining the environmental integrity of these emission guidelines.

The EPA is requiring existing coal-fired steam generating EGUs that are in existence as of the date of a state plan submission but plan to cease operating before January 1, 2032, to comply with certain reporting requirements pursuant to CAA section 114(a). Among other things, this provision gives the EPA authority to require recordkeeping and reporting of sources for the purpose of ''developing or assisting in the development of any implementation plan under . . . section 7411(d) of this title[or] any standard of performance under section 7411 of this title,'' ''determining whether any person is in violation of any such standard of any requirement of such a plan,'' or ''carrying out any provision of this chapter.'' Owners or operators of coal-fired steam generating EGUs that would be covered by these emission guidelines but for their plans to permanently cease operating are required to make reports necessary to ascertain whether they will in fact qualify for the exemption. This reporting obligation is necessary for preserving the integrity of the rule, and is consistent with ensuring that states develop plans that include standards of performance for all existing sources and for anticipating whether a state plan may need to be revised to include a standard of performance for an existing source that will not be eligible for an exemption from these emission guidelines.[971]

[969] See Document ID No. EPA–HQ–OAR–2023–0072–0770.

[970] *Id.*

[971] The milestone reporting requirements for affected coal-fired steam generating EGUs in the medium-term subcategory and those relying on a shorter remaining useful life for a less-stringent standard of performance pursuant to RULOF are authorized under both CAA sections 114(a) and 111(d)(1), the latter of which provides that state plans shall provide for the implementation and enforcement of standards of performance. In that

The reporting requirements the EPA is promulgating for sources that plan to permanently cease operation before January 1, 2032, are similar to the reporting requirements the Agency is requiring for medium-term coal-fired steam generating affected EGUs and affected EGUs relying on a shorter remaining useful life for a less-stringent standard of performance through RULOF. Those requirements are described in section X.C.4 of this preamble and require the definition of milestones tailored to individual units which are then embedded in periodic reporting requirements to assess progress toward the cessation of operations. However, consistent with CAA section 114, the requirements for sources that are exempt from these emission guidelines are limited to reporting and do not include the establishment of milestones. Thus, the requirements are as follows: Five years before any planned date to permanently cease operations or by the date upon which state plan is submitted, whichever is later, the owner or operator of the EGU must submit an initial report to the EPA that includes the following: (1) A summary of the process steps required for the EGU to permanently cease operation by the date included in the state plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. These process steps may include, *e.g.,* initial notice to the relevant reliability authority of the deactivation date and submittal of an official retirement filing (or equivalent filing) made to the EGU's reliability authority. (2) Supporting regulatory documents, including correspondence and official filings with the relevant regional RTO, ISO, balancing authority, PUC, or other applicable authority; any deactivation-related reliability assessments conducted by the RTO or ISO; and any filings pertaining to the EGU with the SEC or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which the plans for the EGU are mentioned; any integrated resource plans and PUC orders referring to or approving the EGU's deactivation; any reliability analyses developed by the RTO, ISO, or relevant reliability authority in response to the EGU's deactivation notification; any notification from a reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and any notification to or from an RTO, ISO, or relevant reliability authority altering the timing of deactivation for the EGU.

For each of the remaining years prior to the date by which an EGU has committed to permanently cease operations, the operator or operator of an EGU must submit an annual status report to the EPA that includes: (1) Progress on each of the process steps identified in the initial report; and (2) supporting regulatory documents, including correspondence and official filings with the relevant RTO, balancing authority, PUC, or other applicable authority to demonstrate progress toward all steps; and (3) regulatory documents, and relevant SEC filings (listed in the preceding paragraph) that have been issued, filed or received since the prior report.

The EPA is also requiring that EGUs that plan to permanently cease operation by January 1, 2032, submit a final report to the EPA no later than 6 months following its committed closure date. This report would document any actions that the unit has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

2. Timing of State Plan Submissions

The EPA proposed a state plan submission deadline that is 24 months from the date of publication of the final emission guidelines, which, at that time was 9 months longer than the default state plan submission timeline in the proposed 40 CFR part 60, subpart Ba implementing regulations. The EPA finalized subpart Ba with a default timeline of 18 months for state plan submissions, 40 CFR 60.23a(a)(1); regardless, the EPA is superseding subpart Ba's timeline under these emission guidelines and is requiring that state plans be submitted 24 months after publication of this final rule in the **Federal Register**.

As discussed in the preamble to the proposed rule,[972] these emission guidelines apply to a relatively complex source category and state plan development will require significant analysis, consultation, and coordination between states, utilities, reliability authorities, and the owners or operators of individual affected EGUs. The power sector is subject to layers of regulatory and other requirements under different authorities (*e.g.,* environmental, electric reliability, SEC) and the decisions states make under these emission guidelines will necessarily have to accommodate overlapping considerations and processes. States' plan development may have to integrate decision making by not only the relevant air agency or agencies, but also ISOs, RTOs, or other balancing authorities. While 18 months is a reasonable timeframe to accommodate state plan development for source categories that do not require this level of coordination, the EPA does not believe it is reasonable to expect states and affected EGUs to undertake the coordination and planning necessary to ensure that plans for implementing these emission guidelines are consistent with the broader needs and trajectory of the power sector within the default period provided under subpart Ba.

However, there are also notable differences between the circumstances of the proposed versus these final emission guidelines that are relevant to the state plan submission timeline. First, the EPA is not finalizing emission guidelines applicable to combustion turbine EGUs, which will significantly decrease the number of affected EGUs that states must address in their plans. Relative to proposal, there are approximately 184 fewer individual units to which these emission guidelines will apply (based on information at the time of the final rule), and the final emission guidelines do not include co-firing with low-GHG hydrogen as a BSER. The analytical and other burdens associated with state planning will thus be significantly lighter than anticipated at proposal, as states will have to address not only fewer sources but also a smaller universe of potential control strategies. Additionally, as explained in section VII.B.1 of this preamble, these final emission guidelines do not apply to existing coal-fired EGUs that plan to permanently cease operation prior to January 1, 2032. While under the proposed emission guidelines states would have had to establish standards of performance for every existing source operating as of January 1, 2030, states will be able to forgo addressing a subset of these existing sources under this final rule.

In addition to states needing to address far fewer existing sources in their state plans than anticipated under the proposed emission guidelines, it is also not expected that the owners or operators of sources will begin implementation of control strategies before state plan submission. At proposal the EPA believed that some owners or operators of affected EGUs would do feasibility and FEED studies for CCS during state plan development,

case, reporting requirements are necessary to ensure that the predicate conditions for the sources' standards of performance are satisfied.

[972] 88 FR 33240, 33402–03 (May 23, 2023).

i.e., before state plan submission. For other affected coal-fired EGUs, the EPA anticipated that owners or operators would undertake certain planning, design, and permitting steps prior to state plan submission.[973] In developing these final emission guidelines, the EPA changed its earlier assumption that states and affected EGUs would take significant steps towards planning and implementing control strategies prior to state plan submission. There are certain preliminary steps, such as an initial feasibility study, that the EPA expects that states and/or affected EGUs will undertake as a typical part of the state planning process. Under any rule or circumstances, it would not be reasonable for a state to commit an affected EGU to installation and operation of a certain control technology without undertaking at least an initial assessment of that technology—this is what is accomplished by feasibility studies. However, while the Agency believes that some sources are currently or will be undertaking FEED studies or other significant steps towards implementing pollution controls independent of these emission guidelines at earlier times, the EPA is not assuming when setting the compliance deadline that EGUs will be taking such steps prior to the existence of a state law requirement to do so (*i.e.,* prior to state plan adoption and submission).

The EPA received a number of comments on the proposed 24-month timeline for state plan submissions, which are discussed in detail below. As a general matter, many of these comments requested a longer timeframe for developing and submitting state plans. However, given that the number of affected EGUs state plans will have to cover under these final emission guidelines is very likely to be significantly lower than anticipated based on the proposal and that the EPA is not expecting states or owners or operators of affected EGUs to conduct FEED studies or otherwise start work on implementation prior to state plan submission, the EPA continues to believe that 24 months is an appropriate timeframe. Additionally, as discussed in the preamble to the recent revisions to the 40 CFR part 60, subpart Ba implementing regulations, the EPA's approach to timelines for state plan submission and review under CAA section 111(d) is informed by the need to minimize the impacts of emissions of dangerous air pollutants on public health and welfare by proceeding as expeditiously and as reasonably possible while accommodating the time needed for states to develop an effective plan.[974] To this end, the EPA is promulgating a timeframe for state plan submissions that is based on the minimum administrative time that is reasonably necessary given the need for states and owners or operators of affected EGUs to coordinate with reliability authorities in the development of state plans. In this case, the EPA believes that providing an additional 6 months beyond subpart Ba's 18 months for state plan submissions is sufficient to accommodate this additional coordination, particularly given that the number of affected EGUs that states will be addressing in their plans is far fewer than expected under the proposed emission guidelines.

Comment: Several commenters supported the EPA's proposed 24-month timeframe for state plan submissions and stressed the importance of achieving emission reductions as quickly as possible. Commenters also noted that, based on anecdotal evidence, 24 months is generally sufficient to incorporate legislative, regulatory, and other administrative procedures associates with submitting state plans. Many commenters, however, requested that the EPA provide additional time for states to develop and submit their state plans; many requested 36 months with some commenters asserting that even more time would be required. Commenters asking for a longer timeframe cited reasons including the size of states' EGU fleets and the specific BSERs proposed for certain subcategories (*i.e.,* CCS and hydrogen co-firing), the need for owners or operators of affected EGUs to conduct systems analyses and update their integrated resource plans (IRPs) prior to making final decisions for state plans, and the need for states to get their choices approved by the appropriate reliability and other regulatory commissions.

Response: As explained above, the EPA has made a number of changes in these final emission guidelines that have the effect of decreasing the planning burden on states, including not finalizing requirements for combustion turbine EGUs, exempting coal-fired EGUs that plan to cease operating by January 1, 2032, finalizing fewer subcategories for coal-fired EGUs, and not finalizing the subcategory for coal-fired EGUs that was based on utilization level. In general, these changes will decrease the number of units that state plans must address and also decrease the number and complexity of decisions states must make with regard to those units. Furthermore, 24 months is sufficient time for states to complete the steps necessary to develop and submit a state plan. Owners and operators are already or should already be considering how they will operate in a future environment where sources operating more cleanly are valued more. The EPA expects that states are already working or will work closely with the operators and operators of affected EGUs as those owners and operators update their IRPs and proceed through any necessary processes with, *e.g.,* PUCs and reliability authorities. Thus, the Agency expects that consultation with and between owners and operators, PUCs, and reliability authorities is currently ongoing and will remain so throughout state plan development and implementation. Against this backdrop of ongoing planning and consultation, the EPA's obligation in these emission guidelines is to ensure that state plan development and submission occurs within a timeframe consistent with the "adherence to [the EPA's] 2015 finding of an urgent need to counteract the threats posed by unregulated carbon dioxide emissions from coal-fired power plants." [975] The timeframe the EPA is providing for state plan development upfront coupled with the long lead times it is providing for compliance with standards of performance provides states and owners or operators ample time to ensure the orderly implementation of the control requirements under these emission guidelines.

Comment: Several commenters asserted that the EPA should provide longer than 24 months for state plan submissions to provide time for states to work through their necessary rulemaking, legislative, and/or administrative processes. Some commenters similarly stated that more than 24 months is needed in order to accommodate meaningful engagement on draft state plans.

Response: The default timeline provided for state plan development and submission under 40 CFR part 60, subpart Ba is 18 months. As the EPA acknowledged when it promulgated this timeframe, state regulatory and legislative processes and resources can vary significantly and influence the time needed to develop and submit state plans.[976] However, the CAA contains

[973] 88 FR 33240, 33402 (May 23, 2023).

[974] See, *e.g.,* 88 FR 80480, 80486 (November 17, 2023).

[975] *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914, 994 (D.C. Cir. 2021).

[976] 88 FR 80480, 80488 (November 17, 2023).

numerous, long-standing requirements under other programs for states to develop and submit plans in 18 or fewer months. The EPA therefore believes that states should be well positioned to accommodate an 18-month state plan submission timeframe, let alone at 24-month timeframe, from the perspective of the timing of state processes. The Agency does not believe it would be reasonable or consistent with CAA section 111's purpose of reducing air pollution that endangers public health and the environment to extend state plan submission deadlines to defer to lengthy state administrative processes.

Similarly, the EPA believes that 24 months provides sufficient time for states to conduct meaningful engagement with pertinent stakeholders under these emission guidelines. As discussed in section X.E.1.b.i of this preamble, the EPA is providing additional information in these final emission guidelines that states may use to inform their meaningful engagement strategies and that can help them to fulfill their obligations in a timely and diligent fashion. For example, the EPA has noted a number of types of stakeholder communities to assist states in identifying their pertinent stakeholders. It has also provided information and tools that states may use in considering options for state plans, including facility-specific information on air emissions and the potential emissions implications of installing CCS. Commenters also pointed out that several states have recently adopted regulations, programs, and tools relevant to identifying pertinent stakeholders and conducting meaningful engagement; such programs and tools, in addition to states' growing body of knowledge and experience pursuant to state initiatives and priorities, will aid states and stakeholders alike in conducting robust meaningful engagement in the timeframe for state plan development.

3. State Plan Revisions

As discussed in the preamble of the proposed action, the EPA expects that the 24-month state plan submission deadline for these emission guidelines would give states, utilities and independent power producers, and stakeholders sufficient time to determine into which subcategory each of the affected EGUs should fall and to formulate and submit a state plan accordingly. However, the EPA also acknowledges that, despite states' best efforts to accurately reflect the plans of owners or operators with regard to affected EGUs at the time of state plan submission, such plans may subsequently change. In general, states have the authority and discretion to submit revised state plans to the EPA for approval.[977] State plan revisions are generally subject to the same requirements as initial state plan submissions under these emission guidelines and the subpart Ba implementing regulations, including meaningful engagement, and the EPA reviews state plan revisions against the applicable requirements of these emission guidelines and the subpart Ba implementing regulations in the same manner in which it reviews initial state plan submissions pursuant to 40 CFR 60.27a. Requirements of the initial state plan approved by the EPA remain federally enforceable unless and until the EPA approves a plan revision that supersedes such requirements. States and affected EGUs should plan accordingly to avoid noncompliance.

The EPA is finalizing a state plan submission date that is 24 months after the publication of the final emission guidelines and is finalizing the first compliance date for affected coal-fired EGUs in the medium-term subcategory and affected natural gas- and oil-fired EGUs of January 1, 2030. A state may choose to submit a plan revision prior to the compliance dates in its existing state plan; however, the EPA reiterates that any already approved federally enforceable requirements, including milestones, increments of progress, and standards of performance, will remain in place unless and until the EPA approves the plan revision.

The EPA requested comment on whether it would be helpful to states to impose a cutoff date for the submission of plan revisions before the first compliance date. This would, in effect, establish a temporary moratorium on plan submissions in order to allow the EPA to act on the plans. State plan revisions would again be permitted after the final compliance date. The EPA is not finalizing such cutoff date to provide more flexibility to states in submitting revisions closer to the first compliance date, in the case that EPA may be able to review those revisions before the first compliance date.

Comment: Several commenters generally disagreed with establishing a cutoff date for state plan revisions before the first compliance date, arguing these timelines would be unworkable because state plan revisions may require public notice and stakeholder engagement.

Response: The EPA is not finalizing an explicit cutoff date that would in effect establish a temporary moratorium on plan submissions; however, the EPA notes that, because the first compliance date under the final emission guidelines is January 1, 2030, a plan revision submitted after November 1, 2028 (taking into consideration 1 year for EPA action on a state plan revision plus up to 60 days, approximately, for a completeness determination) may not provide sufficient time for the EPA to review and approve the plan sufficiently in advance of that compliance date to allow sources to appropriately plan for compliance. The EPA reiterates that EGUs will be expected to comply with any requirements already approved in the state plan until such time as the plan revision is approved.

4. Dual-Path Standards of Performance for Affected EGUs

As discussed in the proposed action, under the structure of these emission guidelines, states would assign affected coal-fired EGUs to subcategories in their state plans, and an affected EGU would not be able to change its applicable subcategory without a state plan revision. This is because, due to the nature of the BSERs for coal-fired steam generating units, an affected EGU that switches into either the medium-term or long-term subcategory may not be able to meet the compliance obligations for a new and different subcategory without considerable lead time; in order to ensure timely emission reductions, it is important that states identify which subcategories affected EGUs fall into in their state plan submissions so that affected EGUs have certainty about their expected regulatory obligations. Therefore, as a general matter, states must assign each affected EGU to a subcategory and have in place all the legal instruments necessary to implement the requirements for that subcategory by the time of state plan submission.

However, the EPA also solicited comment on a dual-path approach that would allow coal-fired steam generating units to have two different standards of performance submitted to the EPA in a state plan based on potential inclusion in two different subcategories. This proposal was based in large part on the proposed structure of the subcategories for coal-fired affected EGUs, under which it would have been realistic to expect that sources could prepare to comply with either the presumptive standard of performance for, *e.g.,* the imminent-term subcategory and the near-term subcategory or the imminent-term subcategory and the medium-term subcategory.

Because the final emission guidelines include only two subcategories for coal-

[977] 40 CFR 60.23a(a)(2), 60.28a.

fired affected EGUs and do not include the two subcategories for which the dual-path approach would have been appropriate, the EPA is not finalizing an approach that allows coal-fired steam generating units to have two different standards of performance submitted to the EPA in a state plan based on potential inclusion in two different subcategories.

Comment: In general, commenters supported a dual-path approach; however, several commenters requested that the EPA accommodate a multi-pathway approach (three or more pathways) due to the complexity of state plans and potential for numerous compliance pathways because of factors beyond the EGU owner or operator's control, such as infrastructure for CCS projects and increase in electric power demand due to electrification of the transportation sector.

Response: As stated above, the EPA is not finalizing the dual-path approach, nor a multi-pathway approach. If an affected EGU wishes to switch subcategories after the initial state plan approval, the state should submit a state plan revision sufficiently in advance of the compliance date for the subcategory into which it was assigned to permit the EPA's review and action on that plan revision.

5. EPA Action on State Plans

Pursuant to the final revisions to 40 CFR part 60, subpart Ba, in this action, the EPA is subject to a 60-day timeline for the Administrator's determination of completeness of a state plan submission and a 12-month timeline for action on state plans.[978] The timeframes and requirements for state plan submissions described in this section also apply to state plan revisions.[979]

As discussed in the proposed action, the EPA would first review the components of the state plan to determine whether the plan meets the completeness criteria of 40 CFR 60.27a(g). The EPA must determine whether a state plan submission has met the completeness criteria within 60 days of its receipt of that submission. If the EPA has failed to make a completeness determination for a state plan submission within 60 days of receipt, the submission shall be deemed, by operation of law, complete as of that date. Subpart Ba requires the EPA to take final action on a state plan submission within 12 months of that submission's being deemed complete. The EPA will review the components of state plan submissions against the applicable requirements of subpart Ba and these emission guidelines, consistent with the underlying requirement that state plans must be ''satisfactory'' per CAA section 111(d). The Administrator would have the option to fully approve; fully disapprove; partially approve and partially disapprove; or conditionally approve a state plan submission.[980] Any components of a state plan submission that the EPA approves become federally enforceable.

The EPA solicited comment on the use of the timeframes regarding EPA action on state plans in subpart Ba and commenters encouraged reconsidering the schedule, suggesting either increasing or decreasing the amount of time for action on state plans. In the final emission guidelines, the EPA is not superseding the timeframes in subpart Ba regarding EPA action on state plans and plan revisions.

Comment: One commenter suggested that the EPA should provide for automatic extension of compliance dates for affected EGUs if the Agency does not meet its 12-month deadline for plan approval.[981] Other commenters expressed concerns that the EPA will be unable to review all plans in the 12-month timeframe. One commenter suggested that the EPA should strive to review plans in less than the proposed 12-month timeframe.[982]

Response: The EPA does not believe it is appropriate to provide automatic extensions of compliance dates based on the timeframe for EPA action on state plan submissions. While there may be some degree of regulatory uncertainty that stems from waiting for the Agency to act on a state plan submission, it would not be a reasonable solution to add to that uncertainty by also making compliance dates contingent on the date of EPA's action. This additional uncertainty could have the effect of unnecessarily extending the compliance schedule and delaying emission reductions. Given that the dates on which the EPA takes final action on individual state plans are likely to be many and varied (based on, *inter alia,* when each state plan was submitted to the Agency), such extensions would create unnecessary confusion and potentially uneven application of the requirements for state plans. In this action, the EPA does not find a reason to supersede the timelines finalized in subpart Ba; therefore, review of and action on state plan submissions will be governed by the requirements of revised subpart Ba.

6. Federal Plan Applicability and Promulgation Timing

The provisions of 40 CFR part 60, subpart Ba, apply to the EPA's promulgation of any Federal plans under these emission guidelines. The EPA's obligation to promulgate a Federal plan is triggered in three situations: where a state does not submit a plan by the plan submission deadline; where the EPA determines that a state plan submission does not meet the completeness criteria and the time period for state plan submission has elapsed; and where the EPA fully or partially disapproves a state's plan.[983] Where a state has failed to submit a plan by the submission deadline, subpart Ba gives the EPA 12 months from the state plan submission due date to promulgate a Federal plan; otherwise, the 12-month period starts, as applicable, from the date the state plan submission is deemed incomplete or from the date of the EPA's disapproval. If the state submits and the EPA approves a state plan submission that corrects the relevant deficiency within the 12-month period, before the EPA promulgates a Federal plan, the EPA's obligation to promulgate a Federal plan is relieved.[984]

As provided by 40 CFR 60.27a(e), a Federal plan will prescribe standards of performance for affected EGUs of the same stringency as required by these emission guidelines and will require compliance with such standards as expeditiously as practicable but no later than the final compliance date under these guidelines. However, 40 CFR 60.27a(e)(2) provides that, upon application by the owner or operator of an affected EGU, the EPA may provide for the application of a less stringent standard of performance or longer compliance schedule than provided by these emission guidelines, in which case the EPA would follow the same process and criteria in the regulations that apply to states' provision of RULOF standards. Under subpart Ba, the EPA is also required to conduct meaningful engagement with pertinent stakeholders prior to promulgating a Federal plan.[985]

As discussed in section X.E.2 of this preamble, the EPA is finalizing a deadline for state plan submissions of 24 months after publication of these final emission guidelines in the **Federal Register**. Therefore, if a state fails to timely submit a state plan, the EPA

[978] 40 CFR 60.27a(b), (g)(1).

[979] See generally 40 CFR 60.27a.

[980] 40 CFR 60.27a(b).

[981] See Document ID No. EPA–HQ–OAR–2023–0072–0660.

[982] See Document ID No. EPA–HQ–OAR–2023–0072–0764.

[983] 40 CFR 60.27a(c).

[984] 40 CFR 60.27a(d).

[985] 40 CFR 60.27a(f).

would be obligated to promulgate a Federal plan within 36 months of publication of these final emission guidelines. Note that this will be the earliest possible obligation for the EPA to promulgate a Federal plan and that different triggers (*e.g.,* a disapproved state plan) will result in later obligations to promulgate Federal plans for other states, contingent on when the obligation is triggered.

Finally, the EPA acknowledges that, if a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for areas of Indian country where designated facilities are located. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves an applicable TIP applicable to those facilities.

XI. Implications for Other CAA Programs

A. New Source Review Program

The CAA's New Source Review (NSR) preconstruction permitting program applies to stationary sources that emit pollutants resulting from new construction and modifications of existing sources. The NSR program is authorized by CAA section 110(a)(2)(C), which requires that each state implementation plan (SIP) ''include a program to provide for the . . . regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that [NAAQS] are achieved, including a permit program as required in parts C and D [of title I of the CAA].'' The ''permit program as required in parts C and D'' refers to the ''major NSR'' program, which applies to new ''major stationary sources'' [986] and ''major modifications'' [987] of existing stationary sources. The ''minor NSR'' program applies to new construction and modifications of stationary sources that do not meet the emission thresholds for major NSR. NSR applicability is pollutant-specific, so a source seeking to newly construct or modify may need to obtain both major NSR and minor NSR permits before it can begin construction.

Under the CAA, states have primary responsibility for issuing NSR permits, and they can customize their programs within the limits of EPA regulations. The Federal NSR rules applying to state permitting authorities are found at 40 CFR 51.160 to 51.166. The EPA's primary role is to approve state program regulations and to review, comment on, and take any other necessary actions on draft and final permits to assure consistency with the EPA's rules, the SIP, and the CAA. When a state does not have EPA-approved authority to issue NSR permits, the EPA issues the NSR permits within the state, or delegates authority to the state to issue the NSR permits on behalf of the EPA, pursuant to rules at 40 CFR 49.151–173, 40 CFR 52.21, and 40 CFR 124.

For the major NSR program, the requirements that apply to a source depend on the air quality designation at the location of the source for each of its emitted pollutants at the time the permit is issued. Major NSR permits for sources located in an area that is designated as attainment or unclassifiable for the NAAQS for its pollutants are referred to as Prevention of Significant Deterioration (PSD) permits. PSD permits can include requirements for specific pollutants for which there are no NAAQS.[988] Sources subject to PSD must, among other requirements, comply with emission limitations that reflect the Best Available Control Technology (BACT) for ''each pollutant subject to regulation'' as specified by CAA sections 165(a)(4) and 169(3). Major NSR permits for sources located in nonattainment areas and that emit at or above the specified major NSR threshold for the pollutant for which the area is designated as nonattainment are referred to as Nonattainment NSR (NNSR) permits. Sources subject to NNSR must, among other requirements, meet the Lowest Achievable Emission Rate (LAER) pursuant to CAA sections 171(3) and 173(a)(2) for any pollutant subject to NNSR. For the minor NSR program, neither the CAA nor the EPA's rules set forth a minimum control technology requirement.

In keeping with the goal of progress toward attaining the NAAQS, sources seeking NNSR permits must provide or purchase ''offsets''—*i.e.,* decreases in emissions that compensate for the increases from the new source or modification. For sources seeking PSD permits, offsets are not required, but they must demonstrate that the emissions from the project will not cause or contribute to a violation of the NAAQS or the ''PSD increments'' (*i.e.,* margins of ''significant'' air quality deterioration above a baseline concentration that establish an air quality ceiling, typically below the NAAQS, for each PSD area). Sources can often make this air quality demonstration based on the BACT level of control or by accepting more stringent air quality-based limitations. However, if these methods are insufficient to show that increased emissions from the source will not cause or contribute to a violation of air quality standards, applicants may undertake mitigation measures that are analogous to offsets in order to satisfy this PSD permitting criterion.

When the EPA is making NSR permitting decisions, it has legal authority to consider potential disproportionate environmental burdens on a case-by-case basis. Based on Executive Order (E.O.) 12898, the EPA's Environmental Appeals Board (EAB) has held that environmental justice considerations must be considered in connection with the issuance of Federal PSD permits issued by EPA Regional Offices or states acting under delegations of Federal authority. The EAB ''has . . . encouraged permit issuers to examine any 'superficially plausible' claim that a minority or low-income population may be disproportionately affected by a particular facility.'' [989] EPA guidance and EAB decisions do not advise EPA Regional Offices or delegated NSR permitting authorities to integrate environmental justice considerations into any particular component of the PSD permitting review, such as the determination of BACT. The practice of EPA Regional Offices and delegated states has been to conduct a largely freestanding environmental justice analysis for PSD permits that can take into account case-specific factors germane to any individual permit decision.

The minimum requirements for an approvable state NSR permitting program do not require state permitting authorities to reflect environmental justice considerations in their permitting decisions. However, states that implement NSR programs under an EPA-approved SIP have discretion to consider environmental justice in their NSR permitting actions and adopt additional requirements in the permitting decision to address potential disproportionate environmental burdens. Additionally, in some cases, a

[986] 40 CFR 52.21(b)(1)(i).

[987] 40 CFR 52.21(b)(2)(i) and the term ''net emissions increase'' as defined at 40 CFR 52.21(b)(3).

[988] For the PSD program, ''regulated NSR pollutant'' includes any pollutant for which a NAAQS has been promulgated (''criteria pollutants'') and any other air pollutant that meets the requirements of 40 CFR 52.21(b)(50). Some of these non-criteria pollutants include greenhouse gases, fluorides, sulfuric acid mist, hydrogen sulfide, and total reduced sulfur.

[989] *In re Shell Gulf of Mexico, Inc.,* 15 E.A.D. 103, 149 and n.71 (EAB 2010) (internal citations omitted).

state law requires consideration of environmental justice in the state's permitting decisions.

Through the NSR permit review process, permitting authorities have requirements for public participation in decision-making, which provide discretion for permitting authorities to provide enhanced engagement for communities with environmental justice concerns. This includes opportunities to enhance environmental justice by facilitating increased public participation in the formal permit consideration process (*e.g.,* by granting requests to extend public comment periods, holding multiple public meetings, or providing translation services at hearings in areas with limited English proficiency). The permitting authority can also take informal steps to enhance participation earlier in the process, such as inviting community groups to meet with the permitting authority and express their concerns before a draft permit is issued.

Additionally, in accordance with CAA 165(a)(2), the PSD regulations require the permitting authority to ''[p]rovide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations.'' 40 CFR 51.166(q)(2)(v). The ''alternatives'' and ''other appropriate considerations'' language in CAA 165(a)(2) can be interpreted to provide the permitting authority with discretion to incorporate siting and environmental justice considerations when issuing PSD permits—specifically, to impose permit conditions on the basis of environmental justice considerations raised in public comments regarding the air quality impacts of a proposed source. The EAB has recognized that consideration of the need for a facility is within the scope of CAA 165(a)(2) when a commenter raises the issue. The EPA has recognized that this language provides a potential statutory foundation in the CAA for this discretion.[990] The Federal regulations for NNSR permits also have an analysis of alternatives required by CAA 173(a)(5). 40 CFR 51.165(i).

1. Control Technology Reviews for Major NSR Permits

The statutory and regulatory basis for a control technology review for a source undergoing major NSR permitting differs from the criteria required in establishing an NSPS or emission guidelines. As such, sources that are permitted under major NSR may have differing control requirements for a pollutant than what is required by an applicable standard under CAA section 111. As noted above, sources permitted under the minor NSR program do not have a minimum control technology standard specified by statute or EPA rule, so a permitting authority has more flexibility in its determination of control technology for aminor NSR permit.

For PSD permits, the permitting authority must establish emission limitations based on BACT for each pollutant that is subject to PSD at the new major stationary source or at each emissions unit involved in the major modification. BACT is assessed on a case-by-case basis, and the permitting authority, in its analysis of BACT for each pollutant, evaluates the emission reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic, and other costs associated with each technology or technique. The CAA also specifies that BACT cannot be less stringent than any applicable standard of performance under the NSPS.[991]

In conducting a BACT analysis, many permitting authorities apply the EPA's five-step ''top-down'' approach, which the EPA recommends to ensure that all the criteria in the CAA's definition of BACT are considered. This approach begins with the permitting authority identifying all available control options that have the potential for practical application for the regulated NSR pollutant and emissions unit under evaluation. The analysis then evaluates each option and eliminates options that are technically infeasible, ranks the remaining options from most to least effective, evaluates the energy, environmental, economic impacts, and other costs of the options, eliminates options that are not achievable based on these considerations from the top of the list down, and ultimately selects the most effective remaining option as BACT.[992]

While the BACT review process is intended to capture a broad array of potential options for pollution control, the EPA has recognized that the list of available control options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. Thus, BACT should generally not be applied to regulate the permit applicant's purpose or objective for the proposed facility. However, this approach does not preclude a permitting authority from considering options that would change aspects (either minor or significant) of an applicants' proposed facility design in order to achieve pollutant reductions that may or may not be deemed achievable after further evaluation at later steps of the process. The EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire. The ''redefining the source'' issue is ultimately a question of degree that is within the discretion of the permitting authority, and any decision to exclude an option on ''redefining the source'' grounds should be explained and documented in the permit record.

In conducting the analysis of energy, environmental and economic impacts arising from each control option remaining under consideration, permitting authorities have considerable discretion in deciding the specific form of the BACT analysis and the weight to be given to the particular impacts under consideration. The EPA and other permitting authorities have most often used this analysis to eliminate more stringent control technologies with significant or unusual effects that are unacceptable in favor of the less stringent technologies with more acceptable collateral environmental effects. Permitting authorities may consider a wide variety of environmental impacts in this analysis, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, demand on local water resources, and emissions of other pollutants subject to NSR or pollutants not regulated under NSR such as air toxics. A permitting authority could place more weight on the collateral environmental effect of a control alternative on local communities—*e.g.,* if emission increases of co-pollutants from operating the control device may disproportionately

[990] See Memorandum from Gary S. Guzy, EPA General Counsel, titled *EPA Statutory and Regulatory Authorities Under Which Environmental Justice Issues May Be Addressed in Permitting* (December 1, 2000).

[991] 42 U.S.C. 7479(3) (''In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to [CAA Section 111 or 112].'').

[992] For more information on EPA's recommended BACT approach, see U.S. Environmental Protection Agency, New Source Review Workshop Manual (October 1990; Draft) at *https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf* and U.S. Environmental Protection Agency, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011; EPA–457/B–11–001) at *https://www.epa.gov/sites/default/files/2015-07/documents/ghgguid.pdf.*

affect a minority or low-income population—which may result in the permitting authority eliminating that control option and ultimately selecting a less stringent control technology for the target pollutant as BACT because it has more acceptable collateral impacts.

In addition, this analysis may extend to considering reduced, or excessive, energy or environmental impacts of the control alternative at an offsite location that is in support the operation of the facility obtaining the permit. For example, in the case of a facility that proposes to co-fire its new stationary combustion turbines with hydrogen procured from an offsite production facility, a permitting authority may determine it is appropriate to weigh favorably a control option that involves co-firing with hydrogen produced from low-GHG emitting processes, such as electrolysis powered by renewable energy, to recognize the reduced environmental impact of producing the fuel for the control option.

For NNSR permits, the statutory requirement for establishing LAER is more prescriptive and, consequently, tends to provide less discretion to permitting authorities than the discretion allowed under BACT. For new major stationary sources and major modifications in nonattainment areas, LAER is defined as the most stringent emission limitation required under a SIP or achieved in practice for a class or category of sources. Thus, unlike BACT, the LAER requirement does not consider economic, energy, or other environmental factors, except that LAER is not considered achievable if the cost of control is so great that a major new stationary source could not be built or operated.[993] As with BACT determinations, a determination of LAER cannot be less stringent than any applicable NSPS.[994]

2. NSR Implications of the NSPS

Any source that is planning to install a new or reconstructed EGU that meets the applicability of this final NSPS will likely require an NSR permit prior to its construction. In addition to including conditions for GHG emissions, the NSR permit would contain emission limitations for the non-GHG pollutants emitted by the new or reconstructed EGU. Depending on the level of emissions for each pollutant, the source may require a major NSR permit, minor NSR permit, or a combination of both types of permits.

As GHGs are regulated pollutants under the PSD program, this NSPS serves as the minimum level of control in determining BACT for any new major stationary source or major modification that meets the applicability of this NSPS and commences construction on its affected EGU(s) after the date of publication of the proposed NSPS in the **Federal Register**. However, as explained above, the fact that a minimum control requirement for BACT is established by an applicable NSPS does not mean that a permitting authority cannot select a more stringent control level for the PSD permit or consider control technologies for BACT beyond those that were considered in developing the NSPS. The authority for BACT is separate from that of BSER, and it requires a case-by-case review of a specific stationary source at the time its owner or operator applies for a PSD permit. Accordingly, the BACT analysis for a source with an applicable NSPS should reflect source-specific factors and any advances in control technology, reductions in the costs or other impacts of using particular control strategies, or other relevant information that may have become available after the EPA issued the NSPS.

3. NSR Implications of the Emission Guidelines

With respect to the final emission guidelines, each state will develop a plan that establishes standards of performance for each affected EGU in the state that meets the applicability criteria of this emission guidelines. In doing so, a state agency may develop a plan that requires an existing stationary source to undertake a physical or operational change. Under the NSR program, when a stationary source undertakes a physical or operational change, even if it is doing so to comply with a national or state level requirement, the source may need to obtain a preconstruction NSR permit, with the type of permit (*i.e.,* NNSR, PSD, or minor NSR) depending on the amount of the emissions increase resulting from the change and the air quality designation at the location of the source for its emitted pollutants. However, since emission guidelines are intended to reduce emissions at an existing stationary source, a NSR permit may not be needed to perform the physical or operational change required by the state plan if the change will not increase emissions at the source.

As noted elsewhere in this preamble, sources that will be complying with their state plan's standards of performance by installing and operating CCS could experience criteria pollutant emission increases that may result in the source triggering major NSR requirements. If a source with an affected EGU does trigger major NSR requirements for one or more pollutants as a result of complying with its standards of performance, the permitting authority would conduct a control technology review (*i.e.,* BACT or LAER, as appropriate) for each of the pollutants and require that the source comply with the other applicable major NSR requirements. As noted in section VII of this preamble, in light of concerns expressed by stakeholders over possible co-pollutant increases from CCS retrofit projects, the EPA plans to review its NSR guidance and determine how it can be updated to better assist permit applicants and permitting authorities in conducting BACT reviews for sources that intend to install CCS.

States may also establish the standards of performance in their plans in such a way so that their affected sources, in complying with those standards, in fact would not have emission increases that trigger major NSR requirements. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the standards of performance, their emissions would not increase in a way that trigger major NSR requirements. For example, a state could, as part of its state plan, develop enforceable conditions for a source expected to trigger major NSR that would effectively limit the unit's ability to increase its emissions in amounts that would trigger major NSR (effectively establishing a synthetic minor limitation).[995] Some commenters asserted that base load units may not be able to readily rely on this option to limit their emission increases given the need for those units to respond to demand and maintain grid reliability. In these cases, states may adopt other strategies in their state plans to ensure that base load units have the needed flexibility to operate and do so without triggering major NSR requirements.

[993] New Source Review Workshop Manual (October 1990; Draft), page G.4.

[994] 42 U.S.C. 7501(3); 40 CFR 51.165(a)(1)(xiii); 40 CFR part 51, appendix S, section II.A.18.

[995] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. See, *e.g.,* CAA sections 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or title V permitting programs. See, *e.g.,* 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of ''potential to emit'').

B. Title V Program

Title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements. Requirements resulting from these rules that are imposed on EGUs or other potentially affected entities that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into the source's title V permit in accordance with the schedule established in the title V regulations. For example, if the permit has a remaining life of 3 years or more, a permit reopening to incorporate the newly applicable requirement shall be completed no later than 18 months after promulgation of the applicable requirement. If the permit has a remaining life of less than 3 years, the newly applicable requirement must be incorporated at permit renewal.[996] Additionally, proceedings to reopen and issue a permit shall follow the same procedures that apply to initial permit issuance and only affect the parts of the permit for which cause to reopen exists. The reopening of permits is expected to be made as expeditiously as possible.[997]

In the proposal, the EPA also indicated that if a state needs to include provisions related to the state plan in a source's title V permit before submitting the plan to the EPA, these limits should be labeled as ''state-only'' or ''not federally enforceable'' until the EPA has approved the state plan. The EPA solicited comments on whether, and under what circumstances, states might use this mechanism. While no specific comments were received on this point, the EPA would like to further clarify that in finalizing this direction, the intention is to ensure that meaningful public participation is available during the development of a state plan, rather than limiting engagement to the permitting process. While the public would have the opportunity to comment on the individual permit provisions, this would not allow for the opportunity to comment on the plan as a whole before it is finalized.

XII. Summary of Cost, Environmental, and Economic Impacts

In accordance with E.O. 12866 and 13563, the guidelines of the Office of Management and Budget (OMB) Circular A–4 and the EPA's Guidelines for Preparing Economic Analyses, the EPA prepared an RIA for these final actions. The RIA is separate from the EPA's statutory BSER determinations and did not influence the EPA's choice of BSER for any of the regulated source categories or subcategories. This RIA presents the expected economic consequences of the EPA's final rules, including analysis of the benefits and costs associated with the projected emission reductions for three illustrative scenarios. The first scenario represents the final NSPS and emission guidelines in combination. The second and third scenarios represent different stringencies of the combined policies. All three illustrative scenarios are compared against a single baseline. For detailed descriptions of the three illustrative scenarios and the baseline, see section 1 of the RIA, which is titled ''Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from new, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule'' and is available in the rulemaking docket.[998]

The three scenarios detailed in the RIA, including the final rules scenario, are illustrative in nature and do not represent the plans that states may ultimately pursue. As there are considerable flexibilities afforded to states in developing their state plans, the EPA does not have sufficient information to assess specific compliance measures on a unit-by-unit basis. Nonetheless, the EPA believes that such illustrative analysis can provide important insights.

In the RIA, the EPA evaluates the potential impacts of the three illustrative scenarios using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2024 to 2047 from the perspective of 2019. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with the Agency's historic practice. These specific snapshot years are 2028, 2030, 2035, 2040, and 2045. In addition to the core benefit-cost analysis, the RIA also includes analyses of anticipated economic and energy impacts, environmental justice impacts, and employment impacts.

The analysis presented in this preamble section summarizes key results of the illustrative final rules scenario. For detailed benefit-cost results for the three illustrative scenarios and results of the variety of impact analysis just mentioned, please see the RIA, which is available in the docket for this action.

It should be noted that for the RIA for this rulemaking, the EPA undertook the same approach to determine benefits and costs as it has generally taken in prior rulemakings concerning the electric power sector. It does not rely on the benefit-cost results included in the RIA as part of its BSER analysis. Rather, the BSER analysis considers the BSER criteria as set out in CAA section 111(a)(1) and the caselaw—including the costs of the controls to the source, the amount of emission reductions, and other criteria—as described in section V.C.2.

A. Air Quality Impacts

For the analysis of the final rules, total cumulative power sector CO_2 emissions between 2028 and 2047 are projected to be 1,382 million metric tons lower under the illustrative final rules scenario than under the baseline. Table 4 shows projected aggregate annual electricity sector emission changes for the illustrative final rules scenario, relative to the baseline.

TABLE 4—PROJECTED ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE

	CO_2 (million metric tons)	Annual NO_X (thousand short tons)	Ozone season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)	Mercury (tons)
2028	−38	−20	−6	−34	−2	−0.1

[996] *See* 40 CFR 70.7(f)(1)(i).

[997] *See* 40 CFR 70.7(f)(2).

[998] The EPA also examined the final rules under a variety of different assumptions regarding demand, gas price, and contemporaneous rulemakings and determined that those alternative projections, inclusive of CCS buildout and cost profiles, would not alter any BSER design parameters selected in this action. For further discussion, see the technical memorandum, *IPM Sensitivity Runs*, available in the rulemaking docket.

TABLE 4—PROJECTED ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE—Continued

	CO_2 (million metric tons)	Annual NO_X (thousand short tons)	Ozone season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)	Mercury (tons)
2030	−50	−20	−7	−20	−2	−0.1
2035	−123	−49	−19	−90	−1	−0.1
2040	−54	−6	−6	−4	2	0.2
2045	−42	−24	−14	−41	−2	−0.2

Note: Ozone season is the May through September period in this analysis.

B. Compliance Cost Impacts

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and illustrative scenarios, including the cost of monitoring, reporting, and recordkeeping. In simple terms, these costs are an estimate of the increased power industry expenditures required to comply with the final actions.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative final rules scenario is designed to reflect, to the extent possible, the scope and nature of the final rules. However, there is uncertainty with regards to the precise measures that states will adopt to meet the requirements because there are flexibilities afforded to the states in developing their state plans.

The IRA is projected to accelerate the ongoing shift towards lower-emitting technology. In particular, under the baseline tax credits for low-emitting technology results in growing generation share for renewable resources and the deployment of 11 GW of CCS retrofits on existing coal-fired steam generating units by 2035. New combined cycle builds are 20 GW by 2030, and existing coal capacity continues to decline, falling to 84 GW by 2030 and 31 GW by 2040. Under the illustrative final rules scenario, the EPA projects an incremental 8 GW of CCS retrofits on existing coal-fired steam generating units by 2035 relative to the baseline. By 2035, relative to the baseline, new combined cycle builds are 2 GW lower, new combustion turbine builds are 10 GW higher, and wind and solar additions are 15 GW higher. Total coal capacity is projected to be 73 GW in 2030 and 19 GW by 2040. As a result, the compliance cost of the final rules is lower than it would be absent the IRA.

We estimate the PV of the projected compliance costs for the analysis of the final standards for new combustion turbines and for existing steam generating EGUs over the 2024 to 2047 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. The EAV represents a flow of constant annual values that, had they occurred annually, would yield a sum equivalent to the PV. All dollars are in 2019 dollars. We estimate the PV and EAV using discount rates of 2 percent, 3 percent, and 7 percent.[999] The PV of compliance costs discounted at the 2 percent rate is estimated to be about 19 billion, with an EAV of about 0.98 billion. At the 3 percent rate, the PV of compliance costs is estimated to be about 15 billion, with an EAV of about 0.91 billion. At the 7 percent discount rate, the PV of compliance costs is estimated to be about 7.5 billion, with an EAV of about 0.65 billion. To put this in perspective, this levelized compliance cost is roughly one percent of the total projected levelized cost to produce electricity over the same timeframe under the baseline.

Section 3 of the RIA presents detailed discussions of the compliance cost projections for the final rule requirements, as well as projections of compliance costs for less and more stringent regulatory options.

C. Economic and Energy Impacts

These final actions have economic and energy market implications. The energy impact estimates presented here reflect the EPA's illustrative analysis of the final rules. States are afforded flexibility to implement the final rules, and thus the estimated impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. In addition, as discussed in section VII.E.1 of this preamble, the factors driving these impacts, including potential revenue streams for captured carbon, may change over the next 25 years, leading the estimated impacts to be different than reality. Table 5 presents a variety of energy market impact estimates for 2028, 2030, 2035, 2040, and 2045 for the illustrative final rules scenario, relative to the baseline.

TABLE 5—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE

[Percent change]

	2028 (%)	2030 (%)	2035 (%)	2040 (%)	2045 (%)
Retail electricity prices	−1	0	1	0	1
Average price of coal delivered to power sector	−1	−1	0	0	−32
Coal production for power sector use	−6	−4	−21	15	−84
Price of natural gas delivered to power sector	−2	0	3	0	0
Price of average Henry Hub (spot)	−2	−1	3	0	0

[999] Results using the 2 percent discount rate were not included in the proposals for these actions. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rules used these two recommended rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates). The Circular A–4 update also recommended consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. As a result of the update to Circular A–4, we include cost and benefits results calculated using a 2 percent discount rate.

TABLE 5—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE—Continued

[Percent change]

	2028 (%)	2030 (%)	2035 (%)	2040 (%)	2045 (%)
Natural gas use for electricity generation	−1	−2	4	0	2

These and other energy market impacts are discussed more extensively in section 3 of the RIA.

More broadly, changes in production in a directly regulated sector may have effects on other markets when output from that sector—for these rules, electricity—is used as an input in the production of other goods. It may also affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as these suppliers alter production processes in response to changes in factor prices. In addition, households may change their demand for particular goods and services due to changes in the price of electricity and other final goods prices. Economy-wide models—and, more specifically, computable general equilibrium (CGE) models—are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy.

In 2015, the EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory analysis. In its final report, the SAB recommended that the EPA begin to integrate CGE modeling into applicable regulatory analysis to offer a more comprehensive assessment of the effects of air regulations.[1000] In response to the SAB's recommendations, the EPA developed a new CGE model called SAGE designed for use in regulatory analysis. A second SAB panel performed a peer review of SAGE, and the review concluded in 2020.[1001]

The EPA used SAGE to evaluate potential economy-wide impacts of these final rules, and the results are contained in section 5.2 of the RIA. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. The annualized social cost estimated in SAGE for the finalized rules is approximately $1.32 billion (2019 dollars) between 2024 and 2047 using a 4.5 percent discount rate that is consistent with the internal discount rate in the model. Under the assumption that compliance costs from IPM in 2056 continue until 2081, the equivalent annualized value for social costs in the SAGE model is $1.51 billion (2019 dollars) over the period from 2024 to 2081, again using a 4.5 percent discount rate that is consistent with the internal discount rate of the model. The social cost estimate reflects the combined effect of the final rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the final rules. We are not able to identify their relative roles currently.

At proposal, the EPA solicited comment on the SAGE analysis presented in the RIA appendix. The SAGE analysis of the final rules is responsive to those comments. The comments received were supportive of the use of SAGE for estimating economy-wide social costs and other economy-wide impacts alongside the IPM-based cost and benefit estimates. The comments also suggested a variety of sensitivity analyses and several longer-term research goals for improving the capabilities of SAGE, such as adding a representation of emissions changes. For more detailed comment summaries and responses, see the response to comments in the docket for these actions.

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Employment impacts of these final actions are discussed more extensively in section 5 of the RIA.

D. Benefits

This section includes the estimated total benefits and the estimated net benefits of the final rules.

1. Total Benefits

Pursuant to E.O. 12866, the RIA for these actions analyzes the benefits associated with the projected emission changes under the final rules to inform the EPA and the public about these projected impacts. These final rules are projected to reduce national emissions of CO_2, SO_2, NO_X, and $PM_{2.5}$, which we estimate will provide climate benefits and public health benefits. The potential climate, health, welfare, and water quality impacts of these emission changes are discussed in detail in the RIA. In the RIA, the EPA presents the projected monetized climate benefits due to reductions in CO_2 emissions and the monetized health benefits attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions, based on the emissions estimates in illustrative scenarios described previously. We monetize benefits of the final rules and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize that there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified or monetized.

We emphasize that the monetized benefits analysis is entirely distinct from the statutory BSER determinations finalized herein and is presented solely for the purposes of complying with E.O. 12866. As discussed in more detail in the proposal and earlier in this action, the EPA weighed the relevant statutory factors to determine the appropriate standards and did not rely on the monetized benefits analysis for purposes of determining the standards. E.O. 12866 separately requires the EPA to perform a benefit-cost analysis, including monetizing costs and benefits where practicable, and the EPA has conducted such an analysis.

The EPA estimates the climate benefits of GHG emissions reductions expected from the final rules using estimates of the social cost of greenhouse gases (SC–GHG) that reflect recent advances in the scientific

[1000] U.S. EPA. 2017. SAB Advice on the Use of Economy-Wide Models in Evaluating the Social Costs, Benefits, and Economic Impacts of Air Regulations. EPA–SAB–17–012.

[1001] U.S. EPA. 2020. Technical Review of EPA's Computable General Equilibrium Model, SAGE. EPA–SAB–20–010.

literature on climate change and its economic impacts and that incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[1002] The EPA published and used these estimates in the RIA for the Final Oil and Gas Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* which was signed by the EPA Administrator on December 2, 2023.[1003] The EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 Oil and Gas Supplemental Proposal and has conducted an external peer review of these estimates, as described further below. Section 4 of the RIA lays out the details of the updated SC–GHG used within this final rule.

The SC–GHG is the monetary value of the net harm to society associated with a marginal increase in GHG emissions in a given year, or the benefit of avoiding that increase. In principle, SC–GHG includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–GHG, therefore, reflects the societal value of reducing emissions of the gas in question by 1 metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect GHG emissions. In practice, data and modeling limitations restrain the ability of SC–GHG estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Since 2008, the EPA has used estimates of the social cost of various greenhouse gases (*i.e.,* SC–CO_2, SC–CH_4, and SC–N_2O), collectively referred to as the ''social cost of greenhouse gases'' (SC–GHG), in analyses of actions that affect GHG emissions. The values used by the EPA from 2009 to 2016, and since 2021—including in the proposal—have been consistent with those developed and recommended by the IWG on the SC–GHG; and the values used from 2017 to 2020 were consistent with those required by E.O. 13783, which disbanded the IWG. During 2015–2017, the National Academies conducted a comprehensive review of the SC–CO_2 and issued a final report in 2017 recommending specific criteria for future updates to the SC–CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process.[1004] The IWG was reconstituted in 2021 and E.O. 13990 directed it to develop a comprehensive update of its SC–GHG estimates, recommendations regarding areas of decision-making to which SC–GHG should be applied, and a standardized review and updating process to ensure that the recommended estimates continue to be based on the best available economics and science going forward.

The EPA is a member of the IWG and is participating in the IWG's work under E.O. 13990. As noted in previous EPA RIAs (including in the proposal RIA for this rulemaking), while that process continues, the EPA is continuously reviewing developments in the scientific literature on the SC–GHG, including more robust methodologies for estimating damages from emissions, and is looking for opportunities to further improve SC–GHG estimation.[1005] In the December 2022 Oil and Gas Supplemental Proposal RIA,[1006] the Agency included a sensitivity analysis of the climate benefits of that rule using a new set of SC–GHG estimates that incorporates recent research addressing recommendations of the National Academies[1007] in addition to using the interim SC–GHG estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*[1008] that the IWG recommended for use until updated estimates that address the National Academies' recommendations are available.

The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, *External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,* which explains the methodology underlying the new set of estimates and was included as supplemental material to the RIA for the December 2022 Oil and Gas Supplemental Proposal.[1009] The response to comments document can be found in the docket for that action.

To ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, the EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. The peer reviewers commended the Agency on its development of the draft update, calling it a much-needed improvement in estimating the SC–GHG and a significant step toward addressing the National Academies' recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates were incorporated in the technical report to address peer reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available on

[1002] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

[1003] U.S. EPA. (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.'' Washington, DC: U.S. EPA.

[1004] Ibid.

[1005] The EPA strives to base its analyses on the best available science and economics, consistent with its responsibilities, for example, under the Information Quality Act.

[1006] U.S. EPA. (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.'' Washington, DC: U.S. EPA.

[1007] Ibid.

[1008] Interagency Working Group on Social Cost of Carbon (IWG). 2021 (February). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990. United States Government.

[1009] Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,'' Docket ID No. EPA–HQ–OAR–2021–0317, November 2023.

the EPA's website.[1010] An overview of the methodological updates incorporated into the new SC–GHG estimates is provided in the RIA section 4.2. A more detailed explanation of each input and the modeling process is provided in the technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.*[1011]

In addition to CO_2, these final rules are expected to reduce annual, national total emissions of NO_X and SO_2 and direct $PM_{2.5}$. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to annual average ambient $PM_{2.5}$ and would reduce the incidence of $PM_{2.5}$-attributable health effects. These final rules are also expected to reduce national ozone season NO_X emissions. In the presence of sunlight, NO_X and VOCs can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. The RIA estimates the health benefits of changes in $PM_{2.5}$ and ozone concentrations. The health effect endpoints, effect estimates, benefit unit-values, and how they were selected are described in the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD.[1012] Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in section 4 of the RIA.

The following PV and EAV estimates reflect projected benefits over the 2024 to 2047 period, discounted to 2024 in 2019 dollars, for the analysis of the final rules. We monetize benefits of the final rules and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize that there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified. The projected PV of monetized climate benefits is about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent.[1013] The projected PV of monetized health benefits is about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Combining the projected monetized climate and health benefits yields a total PV estimate of about $390 billion and EAV estimate of $21 billion.

At a 3 percent discount rate, these final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$. Thus, these final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at a 3 percent rate.

At a 7 percent discount rate, these final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$. Thus, these final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at a 7 percent rate.

The results presented in this section provide an incomplete overview of the effects of the final rules. The monetized climate benefits estimates do not include important benefits that we are unable to fully monetize due to data and modeling limitations. In addition, important health, welfare, and water quality benefits anticipated under these final rules are not quantified. We anticipate that taking non-monetized effects into account would show the total benefits of the final rules to be greater than this section reflects. Discussion of the non-monetized health, climate, welfare, and water quality benefits is found in section 4 of the RIA.

2. Net Benefits

The final rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent. The final rules are also projected to reduce emissions of NO_X, SO_2 and direct $PM_{2.5}$ leading to national health benefits from $PM_{2.5}$ and ozone in most years, producing a projected PV of monetized health benefits of about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Thus, these final rules are expected to generate a PV of monetized benefits of $390 billion, with an EAV of $21 billion discounted at a 2 percent rate. The PV of the projected compliance costs are $19 billion, with an EAV of about $0.98 billion discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $370 billion and EAV of about $20 billion.

At a 3 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at 3 percent. The PV of the projected compliance costs are about $15 billion, with an EAV of $0.91 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $360 billion and an EAV of about $19 billion.

At a 7 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at 7 percent. The PV of the projected compliance costs are about $7.5 billion,

[1010] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review.*

[1011] U.S. EPA (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances." Washington, DC: U.S. EPA.

[1012] U.S. EPA. (2023). *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits.* Research Triangle Park, NC: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Health and Environmental Impact Division.

[1013] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with the EPA's updated estimates of the SC–CO_2. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC–CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A–4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC–CO_2. See section 4.2 of the RIA for more discussion.

with an EAV of $0.65 billion discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $320 billion and an EAV of about $19 billion.

See section 7 of the RIA for additional information on the estimated net benefits of these rules.

E. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

For this action, the analysis described in this section and in the RIA is presented for the purpose of providing the public with an analysis of potential EJ concerns associated with these rulemakings, consistent with E.O. 14096. This analysis did not inform the determinations made to support the final rules.

The EPA defines EJ as ''the just treatment and meaningful involvement of all people regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment so that people: (i) Are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards, including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers; and (ii) have equitable access to a healthy, sustainable, and resilient environment in which to live, play, work, learn, grow, worship, and engage in cultural and subsistence practices.'' [1014] In recognizing that particular communities of EJ concern often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

1. Analytical Considerations

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' [1015] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) Create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (1) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (2) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (3) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [1016]

To address these questions in the context of these final rules, the EPA developed a unique analytical approach that considers the purpose and specifics of these rulemakings, as well as the nature of known and potential disproportionate and adverse exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential EJ characteristics (*e.g.,* residence of historically redlined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated. Also due to data and resource limitations, we discuss climate EJ impacts of this action qualitatively (section 6.3 of the RIA).

For these rules, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analysis can inform whether there are potential EJ concerns for population groups of concern in the baseline (question 1).[1017] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns due to the implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3).

In section 6 of the RIA, we utilize the two types of analysis to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to populations of potential EJ concern (section 6.4); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, life expectancy, redlining, Tribal land, age, sex, educational attainment, and degree of linguistic isolation (section 6.5). It is important to note that due to the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes relative to the baseline concentrations in each modeled future year, these rules are expected to have a small impact on the distribution of exposures across each demographic group. Each of these analyses should be considered independently of each other as each was performed to answer separate questions and is associated with unique limitations and uncertainties.

a. Proximity Analyses

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local environmental stressors, such as local NO_2 and SO_2 emitted from affected sources in these final rules, traffic, or noise. The Agency has conducted a demographic analysis of the populations living near facilities impacted by these rules including 114 facilities for which the EPA is unaware of existing retirement plans by 2032, 23 facilities (a subset of the 114 facilities) with known retirement plans between 2033–2040, and 94 facilities (also a subset of the 114 facilities) without known retirement plans before 2040. The baseline analysis indicates that on average the populations living within 5 km and 10 km of 114 facilities impacted by the final rules without announced retirement by 2032 have a higher percentage of the population that is American Indian, below the Federal poverty level, and below two times the Federal poverty level than the national average. In addition, the population living within 50 kilometers of the same 114 facilities has a higher percentage of the population that is Black. Relating these results to EJ question 1, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by

[1014] *https://www.federalregister.gov/documents/2023/04/26/2023-08955/revitalizing-our-nations-commitment-to-environmental-justice-for-all.*

[1015] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[1016] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[1017] The baseline for proximity analyses is current population information, whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

the regulatory actions for certain population groups of concern in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposures across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure impact. The full results of the demographic analysis can be found in RIA section 6.4. The methodology and the results of the demographic analysis for the final rules are presented in a technical report, *Analysis of Demographic Factors for Populations Living Near Coal-Fired Electric Generating Units (EGUs) for the Section 111 NSPS and Emissions Guidelines—Final,* available in the docket for these actions.

b. Exposure Analyses

While the exposure analyses can respond to all three EJ questions, correctly interpreting the results requires an understanding of several important caveats. First, recognizing the flexibility afforded to each state in implementing the final guidelines, the results below are based on analysis of several illustrative compliance scenarios which represent potential compliance outcomes in each state. This analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. It is also important to note that the potential emissions changes discussed below are relative to a projected baseline, and any localized decreases or increases are subject to the uncertainty of the baseline projections discussed in section 3.7 of the RIA. This uncertainty becomes increasingly relevant in later years in which baseline modeling projects substantial reductions in emissions relative to today. Furthermore, several additional caveats should be noted that are specific to the exposure analysis. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the NAAQS whereas the $PM_{2.5}$ metric is more similar to the long-term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state and fuel level emission data paired with facility-level baseline emissions and provided at a resolution of 12 square kilometers. Additionally, here we focus on air quality changes due to these rulemakings and infer post-policy ozone and $PM_{2.5}$ exposure burden impacts. Note, we discuss climate EJ impacts of these actions qualitatively (section 6.3 of the RIA).

Exposure analysis results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

These rules are also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$ and because NO_X is a precursor to ozone formation, reducing these emissions would impact human exposure. Quantitative ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions, so they are performed to evaluate potential disproportionate impacts of these rulemakings. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from the EPA's EJ technical guidance more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. As discussed in the RIA, our analysis indicates that baseline ozone and $PM_{2.5}$ concentration will decline substantially relative to today's levels for all demographic groups in all future modeled years, and these baseline levels of ozone and $PM_{2.5}$ can be considered to be relatively low. However, there are differences in exposure among demographic groups within these relatively low levels of baseline exposure. Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic populations, Asian populations, and those without a high school diploma may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian populations, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and unemployed populations may also experience disproportionately higher ozone concentrations than the reference group. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group. Therefore, also in response to question 1, there likely are potential EJ concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory actions for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications.

Relative to the low baseline levels of exposure modeled in future years for $PM_{2.5}$ and ozone, exposure analyses show that the final rules will result in modest but widespread reductions in $PM_{2.5}$ and ozone concentrations in virtually all areas of the country, although some limited areas may experience small increases in ozone concentrations relative to forecasted conditions without the rule. The extent of areas experiencing ozone increases varies among snapshot years. Due to the small magnitude of the exposure changes across population demographics associated with these rulemakings relative to the magnitude of the baseline disparities, we infer that post-policy EJ ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated compared to the baseline. Due to the very small magnitude of differences across demographic population post-policy impacts, we do not find evidence that disparities among communities with EJ concerns will be exacerbated or mitigated by the regulatory alternatives under consideration regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures for most demographic groups in the future years evaluated. In 2035, under the illustrative compliance scenarios analyzed, it is possible that Asian populations, Hispanic populations, and those linguistically isolated, and those living on Tribal land may experience a slight exacerbation of ozone exposure disparities at the national level (question 3), compared to baseline ozone levels. Additionally at the national level, those living on Tribal land may experience a slight exacerbation of ozone exposure disparities in 2040 and a slight mitigation of ozone exposure disparities in 2028 and 2030. At the state level, ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups, also to a small degree. As discussed above, it is important to note that this analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

2. Outreach and Engagement

As part of the regulatory development process for these rulemakings, and consistent with directives set forth in multiple Executive Orders, the EPA conducted extensive outreach with interested parties including Tribal nations and communities with environmental justice concerns. This outreach allowed the EPA to gather information from a variety of viewpoints while also providing parties with an overview of the EPA's work to reduce GHG emissions from the power sector.

Prior to the May 2023 proposal, the EPA opened a public docket for pre-proposal input.[1018] The EPA continued to engage with interested parties by speaking on the EPA National Community Engagement call and the National Tribal Air Association Policy Update call in September 2022. Following publication of the proposal, the EPA hosted two informational webinars on June 6 and 7, 2023, specially targeted towards tribal environmental professionals, tribal nations, and communities with environmental justice concerns. The purpose of these webinars was to provide an overview of the proposal, information on how to effectively engage in the regulatory process and provide the EPA an opportunity to answer questions. The EPA held virtual public hearings on June 13, 14, and 15, 2023, that allowed the public an opportunity to present comments and information regarding the proposed rules.

The EPA recently finalized revisions to the subpart Ba implementing regulations requiring states to conduct meaningful engagement with pertinent stakeholders as part of the state plan development process. The EPA underscores the importance of this part of the state plan development process. For more detailed information on meaningful engagement, see section X.E.1.b.i of this preamble.

[1018] EPA–HQ–OAR–2022–0723.

F. Grid Reliability Considerations and Reliability-Related Mechanisms

1. Overview

The Federal Energy Regulatory Commission (FERC) is the federal agency with vested authority to ensure reliability of the bulk power system (16 U.S.C. 824o). FERC oversees and approves reliability standards that are developed by NERC and then become mandatory for all owners and operators of the bulk power system. Regional wholesale energy markets, like RTOs, ISOs, public service commissions, balancing authorities, and reliability coordinators all have reliability related responsibilities. The EPA's role under the CAA section 111 is to reduce emissions of dangerous air pollutants, including those emitted from the electric power sector. In doing so, it has a long, and exemplary history of ensuring its public-health-based emissions standards and guidelines that impact the power sector are sensitive to reliability-related issues and constructed in a manner that does not interfere with grid operators' responsibility to deliver reliable power. The EPA met with many entities with responsibility over the reliability of the bulk power system in crafting these final rules to make certain the rules will not impede their ability to ensure reliability of the bulk power system. This section outlines the array of modifications made in these final actions, outlined in section I.G of this preamble, that collectively help ensure that these final actions will not interfere with systems operators' ability to continue providing reliable power. Additional to this suite of adjustments, the EPA is introducing both a short-term reliability mechanism for emergency situations and a reliability assurance mechanism available for states to include in their state plans for additional flexibility. In response to the May 2023 proposed rule, the EPA received extensive comments regarding grid reliability and resource adequacy from balancing authorities, independent system operators and regional transmission organizations, state regulators, power companies, and other stakeholders. The EPA engaged with each of these group of commenters to garner a granular understanding of their reliability-related concerns. Additionally, the EPA met repeatedly with technical staff and Commissioners of FERC, DOE, NERC, and other reliability experts during the course of this rulemaking. At FERC's invitation, the EPA participated in FERC's Annual Reliability Technical Conference on November 9, 2023. Further, the EPA solicited additional comment on reliability-related mechanisms as part of the November 2023 supplemental proposed rule.

Comment: Several comments from grid operators raised the concern that the proposed rules have the potential to trigger material negative impacts to grid reliability. Concerns coalesced around the loss of firm dispatchable assets which they view as outpacing the development and interconnection of new assets that do not possess commensurate reliability attributes. Other commenters maintained that the proposals included adequate lead times for reliability planning, and that reliability attributes are currently sourced by a collection of assets, and as such a collection of future assets will be able to provide the requisite reliability attributes. Some commenters also asserted that the proposals would actually improve transparency around unit-specific decisions, which are often not communicated transparently with adequate notice, leading to a better reliability planning process.

Response: These final rules include a number of flexibilities and rule adjustments that will accommodate appropriate planning decisions by affected sources, system planners, and reliability authorities in a way that allows for the continued reliable operation of the electric grid. These final actions also include adjustments and improvements, with specific provisions related to compliance timing and system emergencies, that address reliability concerns. The rules do not interfere with ongoing efforts by key stakeholders to appropriately plan for an evolving electric system. The EPA agrees that transparency around unit-specific planning is of paramount importance to enabling systems operators advanced notice to plan for continued reliable bulk power operations.

The EPA initiated follow-up conversations with all balancing authorities and systems operators that submitted public comments to ensure a granular and thorough understanding of all reliability-related concerns raised in response to the proposed rules. In addition, the EPA solicited additional comment on reliability related mechanisms in the supplemental proposal issued in November 2023. The EPA examined the record carefully and responded with a suite of changes to the proposal that, though not always explicitly directed at addressing concerns raised with respect to reliability, nonetheless collectively help ensure EPA's rules will not interfere with grid operators' responsibilities to provide reliable power.

As discussed earlier in this preamble, the EPA is finalizing several adjustments to provisions in the proposed rules that address reliability concerns and ensure that these rules provide adequate flexibilities and assurance mechanisms that allow grid operators to continue to fulfill their responsibilities to maintain the reliability of the bulk-power system. These adjustments include restructuring the subcategories for coal-fired steam generating EGUs: the EPA is not finalizing the proposed imminent or near term subcategory structure which should provide states with a wider planning latitude, and units with cease operations dates prior to January 1, 2032 are not regulated by this final rule. Importantly, the compliance timeline for installing CCS in the long-term subcategory has been extended by an additional 2 years. The EPA is not finalizing the 30 percent hydrogen co-firing BSER for the intermediate subcategory for new combustion turbines. These changes facilitate reliability planning and operations by providing more lead time for CCS installation-related compliance. The adjusted scope of these actions also provides additional time for the EPA to consult with a broad range of stakeholders, including grid operators, to deliberate and determine the best way to address emissions from existing gas turbines while respecting their contribution to electric reliability in the foreseeable future. In addition to these adjustments, as detailed in section X.D of this preamble, the EPA is offering states a suite of voluntary compliance flexibilities that could be used to address reliability concerns. These compliance flexibilities include clarifying the circumstances under which it may be appropriate for states to employ RULOF to establish source specific standards of performance and compliance schedules for affected EGUs to address reliability, allowing emission averaging, trading, and unit-specific mass-based compliance mechanisms for certain subcategories—provided that they achieve an equivalent level of emission reduction consistent with the application of individual rate-based standards of performance, and, for certain mechanisms, that they include a backstop emission rate, and offering a compliance date extension for affected new and existing EGUs that encounter unanticipated delays with control technology implementation.

The EPA believes the adjustments made to the final rules outlined above are sufficient to ensure the rules can be implemented without impairing the ability of grid operators to deliver reliable power. The EPA is nonetheless finalizing additional reliability-related instruments to provide further certainty that implementation of these final rules will not intrude on grid operators' ability to ensure reliability. The short-term reliability mechanism is available for both new and existing units and is designed to provide additional flexibility through an alternative compliance strategy during acute system emergencies that threaten reliability. The reliability assurance mechanism will be available for existing units that intend to cease operating, but, for unforeseen reasons, need to temporarily remain online to support reliability beyond the planned cease operation date. This reliability assurance mechanism, which requires a specific and adequate showing of reliability need that is satisfactory to the EPA, is intended for circumstances where there is insufficient time to complete a state plan revision, and it is limited to the amount of time substantiated, which may not exceed 1 year. The EPA intends to consult with FERC for advice on applications of reliability need that exceed 6 months. These instruments will be presumptively approvable, provided they meet the requirements defined in these emission guidelines, if states choose to incorporate them into their plans.

Comment: Commenters from industry and grid operators expressed support for the inclusion of a requirement that states include in their state plans a demonstration of consultation with all relevant reliability authorities to facilitate planning. Other commenters asserted that the proposals included sufficient coordination with reliability authorities, through the Initial Reporting Milestone Status Report requirements.

Response: The EPA agrees that planning for reliability is critically important. Indeed, all stakeholders generally agree that effective planning is essential to ensuring electric reliability is maintained.[1019] State planning, including coordination and transparency across jurisdictions, is particularly important given that state plans in one jurisdiction can impact the reliability and resource adequacy of other system operators. The EPA is finalizing, as part of the state plan development process, that states are required to conduct meaningful engagement with stakeholders. As part of this required meaningful engagement, states are strongly encouraged to consult with the relevant balancing authorities and reliability coordinators for their affected sources and to share available unit-specific requirements and compliance information in a timely fashion. Sharing regulatory requirements and unit-specific compliance information with balancing authorities and reliability coordinators in a timely manner will promote early and informed reliability planning. Strong system-planning processes of utility transmission companies and RTOs are among the most important tools to assure that reliability will not be adversely affected by regulations.[1020] [1021] A robust planning process that recognizes the different roles of states and their relevant balancing authorities, transmission planners, and reliability coordinators should help to identify potential resource adequacy or reliability issues early in the state planning process. States will also be able to address reliability-related issues through a revision in their state plan, including to address issues that were not foreseen during the state planning process.

In addition to these measures, DOE has authority pursuant to section 202(c) of the Federal Power Act to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including during events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements. Such orders may be issued for 90 days and may be extended in 90-day increments after consultation with EPA. DOE has historically issued section 202(c) orders at the request of electric generators and grid operators such as RTOs in order to enable the supply of additional generation in times of expected emergency-related generation shortfalls.

Congress provided section 202(c) as the primary mechanism to ensure that when generation is needed to meet an emergency, environmental protections will not prevent a source from meeting that need. To date, section 202(c) has worked well, allowing, for example,

[1019] ''Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023,'' Susan Tierney, Analysis Group, November 7, 2023.

[1020] ''Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023,'' Susan Tierney, November 7, 2023.

[1021] ''Modernizing Governance: Key to Electric Grid Reliability'', Kleinman Center for Energy Policy, University of Pennsylvania, March 2024.

additional generation to come online to meet demand in the California Independent System Operator and PJM territories in 2022.[1022] Section 202(c) has also been used to allow generators to remain online pending completion of infrastructure needed to facilitate reliable replacement of those generators. The EPA continues to believe that section 202(c) is an effective mechanism for meeting the purpose of ensuring that all physically available generation will be available as needed to meet an emergency situation, regardless of environmental regulatory constraints. Given the heightened concerns about reliability expressed by commenters in the context of this rule and ongoing changes in the electricity sector, however, this final action includes an additional supplemental short-term reliability mechanism that states may elect to include in their state plans. States that adopt this mechanism could make it available for sources to use without needing action by DOE under section 202(c). Of course, section 202(c) would continue to be available for sources subject to this rule for emergency situations where EPA's short-term reliability mechanism would not apply.

Many electric reliability and bulk-power system authorities, including FERC and the regulated wholesale markets, are actively engaged in activities to ensure the reliability of the transmission grid, while paying careful attention to the changing resource mix and the ongoing trends in the power sector.[1023] [1024] There are multiple agencies and entities that have some authority and responsibility to ensure electric reliability. These include state utility commissions, balancing authorities, reliability coordinators, DOE, FERC, and NERC. The EPA's central mission is to protect human health and the environment and the EPA does not have direct authority or responsibility to ensure electric reliability. Still, the EPA believes reliability of the bulk power system is of paramount importance, and has included additional measures in these final actions that are delineated throughout this section, evaluated the resource adequacy implications in the final TSD, *Resource Adequacy Analysis,* and conducted capacity expansion modeling of the final rules in a manner that takes into account resource adequacy needs. Additionally, the EPA performed a variety of other sensitivity analyses including an examination of higher electricity demand (many areas are reporting accelerated load growth forecasts due to data centers, increased manufacturing, crypto currency, electrification and other factors) and the impact of the EPA's additional regulatory actions affecting the power sector. These sensitivity analyses indicate that, in the context of higher demand and other pending power sector rules, the industry has available pathways to comply with this rule that respect NERC reliability considerations and constraints. These results are detailed in the technical memoranda in the docket titled, *IPM Sensitivity Runs* and *Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS.*

The EPA has carefully examined all comments related to reliability that were submitted during the public comment period for the proposal and for the supplemental notice. The Agency has engaged in dialogue with each of the balancing authorities regarding the content of their submitted comments. Based on this extensive engagement and consultation, the Agency's analysis of the impacts of these rules, and the various features of this rule that will work in tandem to ensure the standards and emission guidelines finalized here are achievable and can respond to future reliability and resource adequacy needs, the EPA has concluded these final rules will not interfere with grid operators' ability to continue delivering reliable power.

The EPA received a range of opinions during the comment process, and also during FERC's Annual Reliability Conference, some of which expressed that the proposed rule could provide a net benefit to reliability planning given the enhanced visibility into unit-specific compliance plans.[1025] This section discusses the additional compliance flexibilities and reliability instruments that have been included in these final rules.

The EPA has carefully considered the importance of reliability of the bulk-power system in developing these final rules. Stakeholders have recognized the EPA's long and successful history of ensuring its power sector rules are crafted to deliver significant public health benefits while not impairing the ability of grid operators to ensure reliable power.[1026] The entities responsible for ensuring reliability, which encompass electric utilities, RTOs and ISOs, reliability coordinators, other grid operators, utility and non-utility energy companies, and Federal and state regulators, have also historically met challenges in navigating power sector environmental obligations while maintaining reliability.[1027]

2. Compliance Flexibilities for New and Existing Affected EGUs

These final rules include three key compliance flexibilities for new and existing sources and reliability coordinators so that they can continue to plan for the reliable operation of the electric system; RULOF, emissions averaging and trading, and compliance extensions of up to 1 year for units installing control technology. As discussed in section X.C.2 of this preamble, states may use the RULOF provisions to address circumstances in which reliability or resource adequacy is a concern. Use of RULOF may be appropriate where reliability or resource adequacy considerations for a particular EGU are fundamentally different from those considered when developing these emission guidelines, which may make it unreasonable for an affected EGU to comply with a standard of performance by the prescribed date. Under these circumstances, the state may choose to particularize the compliance obligations for the affected EGU in order to address the reliability or resource adequacy concern. As explained in section X.C.2, the EPA believes any adjustments that are needed will take the form of different compliance timelines. RULOF is relevant at the stage of establishing standards of performance and compliance schedules to affected EGUs as a state plan is being developed or revised.

States have the ability to use emission averaging or trading, as well as unit-specific mass-based compliance, as described in section X.D of this preamble, which may also provide reliability-related benefits. The use of these alternative compliance flexibilities is not required, but states may employ these flexibilities, provided they demonstrate that their programs achieve an equivalent level of emission reduction with unit-specific application

[1022] DOE. DOE's Use of Federal Power Act Emergency Authority. *https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.*

[1023] See Resource Adequacy Analysis document for further analysis and exploration of these important elements.

[1025] ''In the current environment, grid operators are unsure about when resources may retire, increasing uncertainty and making planning harder. The proposed rules have long timelines for enactment, giving states, utilities, and grid operators plenty of time to plan for the transition.'' From ''Prepared Statement of Ric O'Connell Executive Director, GridLab,'' Testimony before FERC Annual Reliability Technical Conference on November 9, 2023.

[1026] ''Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants,'' Susan Tierney, November 7, 2023.

[1027] ''Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability,'' Susan Tierney, May 2014.

of rate-based standards of performance and apply requirements relevant to the particular flexibility, as specified in section X.D. These compliance flexibilities are voluntary, and states may choose whether to allow their use in state plans, subject to certain conditions. However, states may find that the reliability-specific adjustments discussed below provide sufficient flexibility in lieu of the mechanisms described in section X.D.

States may incorporate into their state plans a mechanism that allows compliance date extensions up to 1 year for an existing affected EGU that is in the process of installing a control technology to meet its standard of performance in the state plan, under specific circumstances, a detailed discussion can be found in section X.C.1.d of this document. As discussed in section VIII.N of this document, the Administrator may provide a similar extension for new combustion turbines. The state or Administrator may allow the extension of the compliance date if the source demonstrates a delay in the construction or implementation of the control technology resulting from causes that are entirely outside the owner or operator's control. These may include delays in obtaining a final construction permit, after a timely and complete application, or delays due to documented supply chain issues; for example, a backlog for step-up transformer equipment. This compliance date extension is not expressly offered for reliability purposes, but rather as a flexibility to account for unforeseen and uncontrollable lags in construction or implementation of control technology to meet the unit's standard of performance, in instances where a source can demonstrate efforts to comply by the required timeframes as part of these final actions, including evidence that it took the necessary steps to comply with sufficient lead time to meet the compliance schedule absent unusual problems, and that those problems are entirely outside the source's control and the source's actions or inactions did not contribute to the delay. This potential extension can help ensure that sufficient capacity is available by providing additional time for an affected EGU to operate for a specific amount of time while it resolves delays related to installation of pollution controls.

If the owner/operator of an affected EGU encounters a delay outside of the owner or operator's control, and which prevents the source from meeting its compliance obligations, the affected EGU must follow the procedures outlined in the state plan for documenting the basis for the extension.[1028] Any delay in implementation that will necessitate a compliance date extension of more than 1 year must be done through a state plan revision to adjust the compliance schedule using RULOF as a basis. See section X.C.2 of this preamble for information on RULOF.

A similar 1-year compliance date extension flexibility for units implementing control technologies that encounter a delay outside of the owner or operator's control which prevents the source from meeting compliance obligations is also available to certain new sources, which are directly regulated by the EPA. This is described in section VIII.N of this preamble.

3. Reliability Mechanisms

While the EPA believes the significant structural adjustments and compliance flexibilities that are discussed above are adequate to ensure that the implementation of these final rules does not interfere with systems operators' ability to ensure electric reliability, the EPA is also finalizing two reliability-related mechanisms as additional safeguards. These mechanisms include a short-term reliability mechanism for unexpected and short-duration emergency events, and a reliability assurance mechanism for units with retirement dates that are enforceable in the state plan, provided there is a documented and verified reliability concern. The EPA notes that these mechanisms must be included in the state plan to be utilized by the owners/operators of existing affected EGUs subject to requirements in the state plan. Sections XII.3.a, and XII.3.b of this preamble describe presumptively approvable methodologies for incorporating these mechanisms into a state plan.

a. Short-Term Reliability Mechanism

Comment: Multiple commenters requested an explicit short-term mechanism which could accommodate emergency situations and provide additional flexibility to affected sources. Commenters requested that the mechanism include additional rule flexibilities that could potentially be used during emergency conditions that would help reliability authorities avert a load shed event. A mechanism would function as an additional automated flexibility measure with a clearly articulated emergency provision for affected sources to respond to short-duration emergency grid situations. Some commenters requested a mechanism that is distinct from the process established by DOE's emergency authority under the Federal Power Act (section 202(c)), whereby DOE is required by the terms of section 202(c) to issue orders tailored to best meet particularized emergency circumstances.[1029] Other commenters highlighted the numerous rule flexibilities that were designed to accommodate reliability concerns and emergency conditions and indicated that the EPA's rule need not overly accommodate reliability and resource adequacy concerns since the primary burden for developing solutions falls to industry, grid operators, reliability coordinators, state planners, and other stakeholders. These commenters indicated that it is important to consider any trade-offs with additional flexibility measures, in particular any trade-offs with emissions implications.

Response: The EPA agrees with the latter commenters and expects that the broader adjustments in the final rules, in addition to the compliance flexibilities offered to states in section X.D of this document, along with DOE's pre-existing section 202(c) authority, are sufficient to enable an affected unit to respond to emergencies as needed and still comply with the annual requirements of these actions. As an additional safeguard measure, the EPA is finalizing a short-term reliability mechanism to assure that these final actions will not interfere with grid operators' ability to ensure electric reliability. More specifically, the EPA has determined that some accommodation during grid emergencies, which are rare, is warranted in order to provide some additional flexibility to help system planners, affected sources, state regulators, and reliability authorities meet demand and avert load shed when such emergencies occur. The EPA believes this additional flexibility is warranted, given the projected increase in extreme weather events exacerbated by climate change.

A short-term reliability mechanism for new sources is included in the final NSPS. Similarly, a short-term mechanism is offered to states to include in state plans for use with existing sources during specific and defined periods of time where the grid is under extreme strain. The short-term reliability mechanism is linked to specific conditions under which the system operators may not have

[1028] Assuming the affected EGU is in a state that has included the extension mechanism in its approved plan.

[1029] *https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.*

sufficient available generation to call upon to meet electric demand, and various reliability authorities have issued emergency alerts to rectify the situation. These emergency alerts are most often associated with extreme weather events where electric demand increases and there are often unexpected transmission and generation outages. Recent examples of short-term emergency alert conditions include Winter Storm Uri in 2021 and Winter Storm Elliot in 2022, both of which included unanticipated generator outages and triggered emergency grid operations. The EPA expects that the broader adjustments to the final rules, in combination with the compliance flexibilities described in section XII.F.2 of this document, are sufficient to enable an affected unit to respond to grid emergencies as needed and still comply with the annual requirements of these actions. Nonetheless, the EPA is finalizing this short-term reliability mechanism, available to states to include at their discretion, to provide an additional layer of assurance that these final actions will not interfere with the grid operator's ability to ensure electric reliability.

A short-term reliability mechanism is included for new sources in the final NSPS, and additionally offered to states to include in state plans for existing sources. The mechanism provides affected sources additional flexibility during rare and extreme emergency events, when all available generators are called upon to meet electric demand. For new sources, the mechanism allows sources to calculate applicability and compliance without using the emissions and operational data produced during these discrete events, with appropriate documentation.[1030] For existing sources, the mechanism allows sources to use the baseline emission rate during these discrete events, also with appropriate documentation.[1031]

The mechanism is only applicable during an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor, which requires plans and sets procedures for reliability entities to help avert disruptions in electric service during emergency conditions.[1032] The NERC reliability standard articulates roles and responsibilities, defines notification processes for reliability coordinators and operators, requires a plan for grid management practices, and specifies a compliance monitoring process. Notably, the standard defines three levels of Energy Emergency Alerts (EEA) that guide reliability coordinators during energy emergencies and assist with communicating information across the system and with the public to avert potential disruptions:

- *EEA–1:* All available generation resources in use—The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
- *EEA–2:* Load management procedures in effect—The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority. An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies. An energy deficient Balancing Authority is still able to maintain its minimum Contingency Reserve requirement.
- *EEA–3:* Firm Load interruption is imminent or in progress—The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

The alerts are typically issued in reaction to emergencies as they develop, are generally rare, and most often have been issued during extreme weather events, such as hurricanes, cold weather events, and heatwaves. The most concerning alert is EEA–3, where interruption of electric service through controlled load shed is imminent for some areas, although load shed does not necessarily occur under every EEA–3 declaration. According to NERC, 25 EEA–3s were declared in 2022, an increase of 15 EEA–3 declarations over 2021. Nine of the EEA–3 declarations in 2022 included shedding of firm load. While the number of declarations increased from 2021, the amount of load that was shed during the 2022 events was less than 10 percent of the previous year.[1033] All of the EEA–3 declarations in 2022 were related to extreme weather impacts, according to NERC.[1034]

Other emergency events (EEA–1 and EEA–2) are more frequent, although also relatively rare, based upon recent data. Data for the largest ISOs and RTOs indicate that EEA–1 and EEA–2 can occur several times over a year, for relatively brief periods in most instances, in response to developing reliability emergencies.[1035] Across the country, reliability coordinators (RCs) are charged by NERC to implement reliability standards and issue EEAs.[1036] The RCs monitor, track, and issue alerts according to the NERC alert protocol. This data is also generally supposed to be publicly available on each reliability coordinator's website, which documents the frequency and duration of emergency alerts. However, while there are requirements to report events where EEA–3 was declared to NERC[1037] and NERC publicly tracks use of EEA–3,[1038] EEA–1 events are the least likely to be documented consistently, for example, there is no similar publicly available tracking and reporting for use of EEA–1 alerts in a centralized and consistent manner.

Energy Emergency Alerts also have an important geographic and/or regional component, since most emergencies affect a particular geographic zone, and hence a smaller number of generators are subject to the alert in most instances.

[1030] The performance standard shall be the Phase I standard for the affected new source under the NSPS.

[1031] The baseline emission rate for existing sources is the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**.

[1032] NERC Reliability Standards, *https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx*, and NERC Emergency Preparedness and Operations (Reliability Standard EOP–011–2). *https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf.*

[1033] 2023 State of Reliability Technical Assessment, NERC. *https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf.*

[1034] Ibid.

[1035] Since 2021, ERCOT issued two EEA–1 events, two EEA–2 events, and one EEA–3 event (all for events occurring over an 8-hour period one day in 2021, and for 1 hour in 2023). In SPP, since 2021, there were eight EEA–1 events, five EEA–2 events, and two EEA–3 events (occurring over 5 days). The EEA–1 and EEA–2 events lasted between 1 and 19 hours. In MISO, there was a 2-day event in 2021 that resulted in an EEA magnitude 1, 2, or 3 alert through the day and into the next day. One EEA–1 event in 2022 lasted for a half hour and an EEA–2 event for 3 hours. In 2023, there was an EEA–2 event for 9.5 hours. In PJM, no alerts were issued in 2021. In 2022, roughly a dozen alerts were issued. Some lasted minutes, while others lasted half a day. One event stretched for 3 days. There were two alerts issued in 2023, lasting roughly 3 and 1 hours each. While this data is not comprehensive, it is indicative of the frequency and duration of emergency events that fall under the NERC reliability standard alert process. See: ERCOT Market Notices, SPP Historical Advisories and Alerts, *https://www.oasis.oati.com/SWPP/*; MISO Maximum Generation Emergency Declarations (2023), *https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf*; and MISO Maximum Generation Emergency Declarations (2023), *https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf.* See also PJM Emergency Procedures and Postings, *https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf.*

[1036] NERC Organization Certification (January 2024). *https://www.nerc.com/pa/comp/Pages/Registration.aspx.*

[1037] *https://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/M-11_Energy_Emergency_Alerts.pdf.*

[1038] *https://www.nerc.com/pa/RAPA/ri/Pages/EEA2andEEA3.aspx.*

During extreme and large-scale weather events, the alerts often cover a much broader geographic area, such as when Winter Storm Elliott impacted two-thirds of the lower 48 states and rapidly intensified into a bomb cyclone in December 2022. Many areas declared EEAs, and four states experienced operator-controlled load shed and 2.1 million customers experienced power outages.[1039] When these events occur, a much larger group of affected sources would be potentially covered.[1040] It should be noted that issuance of EEA's is not just dependent on a generator's availability, but also, generation deliverability, as transmission constraints due to operational conditions or planned maintenance activities can lead to issuance of EEA's that help ensure system stability and reliability.

The EPA's assessment is that these alerts generally occur infrequently, only rarely persist for as long as several days, and are indicative of a grid under strain. When the alerts are more prolonged, lasting for several days, they are generally dictated by persistent extreme weather with widespread impacts and a higher probability of load shed. The short-term reliability mechanism offers sources that come under a documented level 2 and or 3 EEA, combined with a documented request from the balancing authority to deviate from its scheduled operations, for example, by increasing output in response to the alert. In other words, only the specific units called upon, or otherwise instructed to increase output beyond the planned day-ahead or other near-term expected output during an EEA level 2 or 3 event are eligible for this flexibility, with proper documentation.

For new sources, the emissions and/or generation data will not be counted when determining applicability and the use of the sources' Phase 1 standard of performance may be used for compliance determinations through the duration of these events, as long as appropriate documentation is provided. For existing sources, states may choose to temporarily apply an alternative standard of performance, or a unit's baseline emission performance rate, when demonstrating compliance with the final standards, with appropriate documentation. It should be emphasized that these final emission guidelines require compliance with the standards of performance on an annual basis (or rolling annual average for new sources), as opposed to a shorter period such as hourly, daily, or monthly. This relatively long compliance period provides significant flexibility for sources that face circumstances whereby their emission performance may change temporarily due to various factors, including in response to grid emergency conditions. Nonetheless, this mechanism is included in these final rules to ensure that affected sources have the additional flexibility needed to meet demand during emergency conditions.[1041]

The short-term reliability mechanism references EEA–2 and EEA–3 for several reasons. First, balancing authorities and grid operators do not necessarily have to take action under EEA–1 conditions, such as calling on interruptible loads. As such, there is much less cost or inconvenience to declaring EEA–1, as a general matter, and EEA–2 and EEA–3 events are more aligned with events that are rare or truly represent emergency conditions. Second, EEA–1 events are a preparatory step in anticipation of potentially worsening conditions, as opposed to an indicator of imminent load-shed. Thus, under EEA–1, balancing authorities and grid operators do not generally take actions such as calling for voluntary demand reduction or calling on interruptible loads, and reliability coordinators are afforded more discretion for declaring an EEA–1. As such, there is much less cost or inconvenience to declaring EEA–1, as a general matter, and providing operational or cost relief under EEA–1 could create an incentive to deploy it more routinely. In addition, waiving significant regulatory requirements before taking actions such as calling for voluntary demand reductions or calling upon contractually arranged interruptible loads would not be commensurate to the significance of the various response actions. Third, reliability coordinators are afforded more discretion for declaring an EEA–1, and thus may have a potential incentive to deploy it more routinely if there is some operational or cost relief associated with it. And lastly, the reporting of EEA–1 is not consistent throughout the country, and there is some degree of opaqueness associated with the frequency and duration of EEA–1 events, thus making it a less robust mechanism threshold for purposes of aligning it with the requirements of this final action. For these reasons, the EPA believes that EEA–2 and EEA–3 are the appropriate threshold for inclusion in the short-term reliability mechanism and better represent rare or truly emergency conditions in which providing a limited exemption from a significant environmental requirement is justifiable.

Thus, the EPA believes that the selection of EEA–2 and EEA–3 are aligned with the conditions envisioned where an affected source might need temporarily relief, in order to offer reliability coordinators and balancing authorities the flexibility needed during emergency events to maintain reliability. In addition, as explained earlier, DOE's 202(c) authority is an additional mechanism that can be deployed under certain emergency conditions, which may occur outside any EEA–2 or EEA–3 event. These tools, either individually or in combination, help provide additional assurance that sources and reliability coordinators can continue to maintain a reliable system.

The mechanism is available to states to include in their state plans in an explicit manner, which will allow additional flexibility to sources in those states during short-term reliability emergencies. Inclusion of the reliability mechanism in a state plan must be part of the public comment process that each state must undertake. The comment process will afford full notice and the opportunity for the public comment, and the state plan will need to specify alternative performance standards for each specific affected source during these events (as defined in this section). The state plan must clearly indicate the specific parameters of emergency alerts cited as part of this mechanism, the relevant reliability coordinators that are authorized to issue the alerts in the state, and the compliance entities who are affected by this action (*i.e.,* affected sources). These sources must provide documentation of emergencies, as indicated in this section. The documentation must include evidence of the alert from the issuing entity, duration of the alert, and requests by reliability entities to sources to increase output in response to the emergency. The source must supply this

[1039] 2023 State of Reliability Technical Assessment, NERC. *https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf.*

[1040] For example, the entire footprint of SPP *currently* includes roughly 50 individual coal-steam units, reflecting roughly 19 GW of capacity.

[1040] For PJM, there are *currently* roughly 65 individual coal-steam units with total capacity of roughly 30 GW, which could potentially be covered by a regionwide alert. These estimates are considerably lower when known and committed coal-steam retirements are excluded. Within the PJM footprint, there are 27 control areas or transmission zones where emergency procedures are applied.

[1041] For example, units with installed CCS technology may be called upon to run at full capacity (*i.e.,* without the parasitic load of the carbon capture equipment). The EPA does not expect this to be a typical response as units are economically disincentivized to shut off or bypass control equipment given the tax credit incentives in IRC section 45Q.

information to the state regulatory entities and to the EPA when demonstrating compliance with the annual performance standards. This demonstration will indicate the discrete periods where the alternative standards or emission rates were in place, coinciding with the emergency alerts.

The calculation of the emission rate for an affected source in a state that adopts the short-term reliability mechanism must adhere to the following during potential emergency alerts:

• When demonstrating annual compliance with the standard of performance, the existing affected source may apply its baseline emission rate in lieu of its standard of performance for the hours of operation that correspond to the duration of the alert; and

• The existing affected EGU would demonstrate compliance based on application of its baseline emission performance rate standard of performance for the documented hours it operated under a revised schedule due to an EEA 2 or 3.

• For new sources, the EGU would demonstrate compliance based on application of its phase 1 performance standard for the documented hours it operated under a revised schedule due to an EEA 2 or 3. with the same documentation listed above.

Supplemental reporting, recordkeeping and documentation required:

• Documentation that the EEA was in effect from the entity issuing the alert, along with documentation of the exact duration of the event;[1042]

• Documentation from the entity issuing the alert that the EEA included the affected source/region where the unit was located; and

• Documentation that the source was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside of its scheduled dispatch during emergency conditions from a reliability coordinator, balancing authority, or ISO/RTO.

b. Reliability Assurance Mechanism

The EPA gave considerable attention and thought to comments from all stakeholders concerning potential reliability-related considerations. As noted earlier, the EPA engaged in extensive stakeholder outreach and provided additional opportunity for public comment as part of the supplemental notice for small businesses, since similar reliability-related concerns were raised. This section provides additional background, as well as approvable language, for a reliability assurance mechanism that states have the option to incorporate into their state plans.

Comment: Some commenters cautioned that EPA rules could exacerbate an ongoing concern that firm, dispatchable assets are exiting the grid at a faster pace than new capacity can be deployed and that most new electric generating capacity does not provide the equivalent reliability attributes as the capacity being retired. Several commenters provided examples where units with publicly announced retirement dates were delayed by reliability entities and coordinators due, in part, to the potential for energy shortfalls that might increase reliability risks in the ISO. Many commenters cited findings from NERC that highlighted the potential for capacity shortfalls, some of which are already in effect in some areas. Other commenters asserted that there is no need for a reliability assurance mechanism given the sufficient lead times in the proposal and the various flexibilities already provided. Some commenters included analysis that showed resource adequacy shortfalls over the forecasted time horizon were limited and manageable under the proposal.

Response: The EPA believes that the provisions in these final actions are sufficient to accommodate installation of pollution controls and reliability planning. The EPA has further articulated the use of RULOF, which can be deployed under the state planning and revision processes, for specific circumstances related to reliability. The EPA is also finalizing compliance flexibilities that can address delays to the installation or permitting of control technologies or associated infrastructure that are beyond the control of the EGU owner/operator. The EPA acknowledges that isolated issues could unfold over the course of the implementation timeline that could not have been foreseen during the planning process and that may require units to remain online beyond their planned cease operation dates to maintain reliability.

The EPA does not agree that the final rule will result in long-term adverse reliability impacts.[1043] [1044] Nevertheless, as an added safeguard, the EPA is finalizing a reliability assurance mechanism for existing affected sources that have committed to cease operation but, for unforeseen reasons, need to temporarily remain online to support reliability for a discrete amount of time beyond their planned date to cease operations. The primary mechanism to address reliability-related issues for units with cease operations dates is through the state plan revision process. This reliability assurance mechanism is designed to enable extensions for cease operation dates when there is insufficient time to complete a state plan revision. Under this reliability assurance mechanism, which can only be accessed if included in a state plan, units could obtain up to a 1-year extension of a cease operation date. If a state decides to include the mechanism in its state plan, then the mechanism must be disclosed during the public comment process that states must undertake. Under this reliability assurance mechanism, units may obtain extensions only for the amount of time substantiated through their applications and approved by the appropriate EPA Regional Administrator. For extension requests greater than 6 months, EPA will seek the advice of FERC in these cases and therefore applications must be submitted to FERC, as well as to the appropriate EPA Regional Administrator. The date from which an extension can be given is the enforceable date in the state plan, including any cease operation dates in state plans that are prior to January 1, 2032.

These provisions are similar in part to a reliability-related flexibility provided by the EPA for the MATS rule finalized in December 2011. On December 16, 2011, the EPA issued a memorandum[1045] outlining an Enforcement Response Policy whereby affected sources enter into a CAA section 113(a) administrative order for up to 1 year for narrow circumstances including when the deactivation of a unit or delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability. Under MATS, affected sources were required to come into compliance with standards within 3 years of the effective date. The EPA believed flexibility was warranted given potential constraints around the availability of control equipment and associated skilled workforce for all affected sources within the compliance window. While a 1-year extension as

[1042] *https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf.*

[1043] "Bulk System Reliability for Tomorrow's Grid" The Brattle Group, December 20, 2023.

[1044] "The Future of Resource Adequacy" The Department of Energy, April 2024.

[1045] *https://www.epa.gov/sites/default/files/documents/mats-erp.pdf.*

part of CAA section 112(i)(3)(B) was broadly available to affected sources, additional time through an administrative order was limited to units that were demonstrated to be critical for reliability purposes under the Enforcement Response Policy.[1046] FERC's role in this process, which was developed with extensive stakeholder input,[1047] was to assess the submitted request to ensure any application was adequately substantiated with respect to its reliability-related claims. While several affected EGUs requested and were granted a 1-year CAA section 112(i)(3)(B) compliance extension by their permitting authority, OECA only issued five administrative orders in connection to the Enforcement Response Policy.[1048] These orders relied upon a FERC review of the reliability risks associated with the loss of specific units, following the accompanying FERC policy memorandum guidance.[1049] The 2012 MATS Final Rule was ultimately implemented over the 2015–2016 timeframe without challenges to grid reliability.

Given the array of adjustments made to the rule explained above, and the ability of states to address unanticipated changes in circumstances through the state plan revision process, the EPA does not anticipate that this mechanism, if included by states in the planning process, will be heavily utilized. This mechanism provides an assurance to system planners and affected sources, which can provide additional time for the state to execute a state plan revision, if needed. For states choosing to include this option in their state plans, the reliability assurance mechanism can provide units up to a 1-year extension of the scheduled cease operation date without a state plan revision, provided the reliability need is adequately justified and the extension is limited to the time for which the reliability need is demonstrated. This mechanism can accommodate situations when, with little notice, the relevant reliability authority determines that an EGU scheduled to cease operations is needed beyond that date, in order to maintain reliability during the 12 months leading up to or after the EGU is scheduled to retire. For potential situations in which system planners, affected sources, and reliability authorities identify a reliability concern, including a potential resource adequacy shortfall and an associated demonstration of increased loss of load expectation, more than one year in advance, this approach allows for the time needed for states to undertake a state plan revision process. The EPA recognizes that successful reliability planning involves many stakeholders and is a complex long-term process. For this reason, the EPA is encouraging states to consult electric reliability authorities during the state plan process, as part of the requirements under Meaningful Engagement (see section X.E.1.b.i of this document). The EPA acknowledges that there may be isolated instances in which the deactivation or retirement of a unit could have impacts on the electric grid in the future that cannot be predicted or planned for with specificity during the state planning process, wherein all anticipated reliability-related issues would be analyzed and addressed. This mechanism is not intended for use with units encountering unforeseen delays in installation of control technologies, as such issues are addressed through compliance flexibilities discussed in section XII.F.2, or for units subject to an obligation to operate that is not based on the reliability criteria included here.

To ensure that reliability claims, following the specific requirements delineated below, submitted through this mechanism are sufficiently well documented, the EPA is requiring that the unit's relevant reliability Planning Authority(ies) certify that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested. Additionally, the EPA intends to seek the advice of FERC, the Federal agency with authority to oversee the reliability of the bulk-power system, to incorporate a review of applications for this mechanism that request more than 6 months of additional operating time beyond the existing date by which the unit is scheduled to cease operations to resolve a reliability issue. Additional operating time is available for up to 12 months from the unit's cease operation date through this mechanism. Any relief request exceeding 12 months would need to be addressed through the state plan revision process outlined in section X.E.3. In determining whether to grant a request under this mechanism, the EPA will assess whether the associated Planning Authority's reliability analysis identifies and supports, in a detailed and reasoned fashion, anticipated noncompliance with a Reliability Standard, substantiated by specific metrics described below, should a unit go offline per its established commitment. To assist in its determination, the EPA will seek FERC's advice regarding whether analysis of the reliability risk and the potential for violation of a mandatory Reliability Standard or increased loss of load expectation is adequately supported in the filed documentation.

This mechanism is for existing sources that have relied on a commitment to cease operating for purposes of these emission guidelines. Such reliance might occur in three circumstances: (1) units that plan to cease operation before January 1, 2032, and that are therefore exempt because they have elected to have enforceable cease operations dates in the state plan; (2) affected EGUs that choose to employ 40 percent natural gas co-firing by 2030 with a retirement date of no later than January 1, 2039; or (3) affected EGUs that have source-specific standards of performance based on remaining useful life, pursuant to the RULOF provisions outlined in section X.C.2 of this document. In each of these cases, units would have a commitment to cease operating by a date certain. This mechanism would allow for extensions of those dates to address unforeseen reliability or reserve margin concerns that arise due to changes in circumstances after the state plan has been finalized. Therefore, the date from which an extension can be given under this mechanism is the enforceable cease operations date in the state plan, including those prior to January 1, 2032. Only operators/owners of units that have satisfied all applicable milestones, metrics, and reporting obligations outlined in section X.C.3, and section X.C.4 for units with cease operation dates prior to January 1, 2032, would be eligible to use this mechanism.

This mechanism creates additional flexibility for specified narrow circumstances for existing sources and provides additional time and flexibility to allow a state, if necessary, to submit a plan revision should circumstances persist. In other words, this mechanism would be for use only when there is insufficient time to complete a state plan revision.

States can decide whether to include this extension mechanism in their state plans. If included in a state plan, the mechanism would be triggered when a unit submits an application to the EPA Regional Administrator where it faces an unforeseen situation that creates a

[1046] December 16, 2011, memorandum, ''The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercery and Air Toxics Standard'' from Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance.

[1047] See FERC Docket No. PL12–1–000.

[1048] *https://www.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.*

[1049] *https://www.ferc.gov/sites/default/files/2020-04/E-5_9.pdf.*

reliability issue should that unit go offline consistent with its commitment to cease operations—for example, if the reliability coordinator identifies an unexpected capacity shortfall and determines that a specific unit(s) in a state(s) is needed to remain operational to satisfy a specific and documented reliability concern related to a unit's planned retirement. This mechanism would allow extensions, if approved by the Regional EPA Administrator, for units to operate after committed retirement dates without a full state plan revision. Any existing standard of performance finalized in the state plan under RULOF or the natural gas co-firing subcategory would remain in place. States have the discretion to place additional requirements on units requesting extensions. The relevant EPA Regional Administrator would approve the reliability assurance application or reject it if it were found that that the reliability assertion was not adequately supported. Units would need to substantiate the claim that they must remain online for reliability purposes with documentation demonstrating a forecasted reliability failure should the unit be taken offline, and this justification would need to be submitted to the appropriate EPA Regional Administrator and, for extensions exceeding 6 months, also to FERC, as described below. Extensions would be granted only for the duration of time demonstrated through the documentation, not to exceed 12 months, inclusive of the 6-month extension that is available and the relevant Planning Authority(ies) must certify that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested. Any further extension would require a state plan revision.

The process and documentation required to demonstrate that a unit is required to stay online because it is reliability-critical is described in this section.

In order to use this mechanism for an extension, certain conditions must be met by the unit and substantiated in written electronic notification to the appropriate EPA Regional Administrator, with an identical copy submitted to FERC for extension requests exceeding 6 months. More specifically, those conditions are that, where appropriate, the EGU owner complied with all applicable reporting obligations and milestones as described in sections X.C.4 (for units in the medium-term subcategory and units relying on a cease operation date for a less stringent standard of performance pursuant to RULOF), and section X.E.1.b.ii (for units with cease operation dates before January 1, 2032). No less than 30 days prior to the compliance date for applications for extensions of less than 6 months, and no less than 45 days prior to the compliance date for applications for extensions exceeding 6 months, but no earlier than 12 months prior to the compliance date (any requests over 12 months prior to a compliance date should be addressed through state plan revisions), a written complete application to activate the reliability assurance mechanism must be submitted to the appropriate EPA Regional Administrator, with a copy submitted to the state, including information responding to each of the seven elements listed as follows.

A copy of an extension request exceeding 6 months must also be submitted to FERC through a process and at an office of FERC's designation, including any additional specific information identified by FERC and responding to each of the following elements:

(1) Analysis of the reliability risk if the unit were not in operation demonstrating that the continued operation of the unit after the applicable compliance date is critical to maintaining electric reliability, such that retirement of that unit would trigger one or more of the following: (A) would result in noncompliance with at least one of the mandatory reliability standards approved by FERC, or (B) would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, this requires a clear demonstration that each unit would be needed to maintain the targeted level of resource adequacy.[1050] In addition, a projection substantiating the duration of the requested extension must be included for the length of time that the unit is expected to extend its cease-operations date because it is reliability-critical with accompanying analysis supporting the timeframe, not to exceed 12 months. The demonstration must satisfactorily substantiate at least one of the two conditions outlined above. Any unit that has received a Reliability Must Run Designation or equivalent from a reliability coordinator or balancing authority would fit this description. The types of information that will be helpful, based on the prior reliability extension process developed for MATS between the EPA and FERC include, but are not limited to, system planning and operations studies, system restoration studies or plans, operating procedures, and mitigation plans required by applicable Reliability Standards as defined by FERC in its May 17, 2012, Policy Statement issued to clarify requirements for the reliability extensions available through MATS.[1051]

(2) Analysis submitted by the relevant Planning Authority that verifies the reliability related claims, or presents a separate and equivalent analysis, confirming the asserted reliability risk if the unit were not in operation, or an explanation of why such a concurrence or separate analysis cannot be provided, and where necessary, any related system wide or regional analysis. This analysis or concurrence must include a substantiation for the duration of the extension request.

(3) Copies of any written comments from third parties regarding the extension.

(4) Demonstration from the unit owner/operator, grid operator and other relevant entities that they have a plan that includes appropriate actions, including bringing on new capacity or transmission, to resolve the underlying reliability issue, including the steps and timeframes for implementing measures to rectify the underlying reliability issue.

(5) Retirement date extensions allowed through this mechanism will be granted for only the increment of time that is substantiated by the reliability need and supporting documentation and may not exceed 12 months, inclusive of the 6-month extensions available with RTO, ISO, and reliability coordinator certification.

(6) For units affected by these emissions guidelines, states may choose to require the application to identify the level of operation that is required to avoid the documented reliability risk, and consistent with that level propose alternative compliance requirements, such as alternative standards or consistent utilization constraints for the duration of the extension. The EPA Regional Office may, within 30 days of the submission, reject the application if the submission is incomplete with respect to the above requirements or if the reliability assertion is not adequately supported.

(7) Only owners/operators of units that have satisfied all applicable milestone and reporting requirements and obligations under section X.C.3., and section X.C.4 for units with cease

[1050] Probabilistic Assessment: Technical Guideline Document, NERC, August 2016.

[1051] "Policy Statement on the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards" FERC, Issued May 17, 2012, at PL12–1–000.

operation dates prior to January 1, 2032, may use this mechanism for an extension as those sources will have provided information enabling the state and the public to assess that the units have diligently taken all actions necessary to meet their enforceable cease operations dates and demonstrate the use of all available tools to meet reliability challenges. Units that have failed to meet these obligations may make extension requests through the state plan revision process.

The EPA intends to consult with FERC in a timely manner on reliability-critical claims given FERC's expertise on reliability issues. The EPA may also seek advice from other reliability experts, to inform the EPA's decision. The EPA intends to decide whether it will grant a compliance extension for a retiring unit based on a documented reliability need within 30 days of receiving the application for applications less than 6 months, and within 45 days for applications exceeding 6 months to account for time needed to consult with FERC. Whether to grant an extension to an owner/operator is solely the decision of the EPA Regional Administrator.

For units already subject to standards of performance through state plans including those co-firing until 2039, and for units with specific, tailored and differentiated compliance dates developed through RULOF that employ this mechanism, those standards would apply during the extension.

4. Considerations for Evaluating 111 Final Actions With Other EPA Rules

Consistent with the EPA's statutory obligations under a range of CAA programs, the Agency has recently initiated and/or finalized multiple rulemakings to reduce emissions of air pollutants, air toxics, and greenhouse gases from the power sector. The EPA has conducted an assessment of the potential impacts of these regulatory efforts on grid resource adequacy, which is examined and discussed in the final TSD, *Resource Adequacy Analysis.* This analysis is informed by regional reserve margin targets, regional transmission capability, and generator availability. Moreover, as described in this action, the EPA designs its programs, implementation compliance flexibilities, and backstop mechanisms to be robust to future uncertainties and various compliance pathways for the collective of market and regulatory drivers. Finally, the backstop reliability mechanisms discussed in this section are, by design, similar to mechanisms utilized in the EPA's proposed Effluent Limitations Guidelines (ELG) rulemaking. There, to ensure that units choosing to permanently cease the combustion of coal by a particular date in their permits are not restricted from operation in the event of an emergency related to load balancing, the permit conditions allow for grid emergency exemptions (88 FR 18900). Harmonizing the use of similar criteria for emergency related reliability concerns across the two rules further buttresses unit confidence that grid reliability and environmental responsibilities will not come into conflict. It also streamlines the demonstrations and evidence that a unit must provide in such events. This cross-regulatory harmonization ensures that the Agency can successfully meet its CWA and CAA responsibilities regarding public health in a manner consistent with grid stability as it has consistently done throughout its 54-year history.

The EPA has taken into consideration, to the extent possible, the alignment of compliance timeframes and other aspects of these policies for affected units. For each regulatory effort, there has been coordination and alignment of requirements and timelines, to the extent possible. The potential impact of these various regulatory efforts is further examined in the final TSD, *Resource Adequacy Analysis.* Additionally, the EPA considered the impact of this suite of power sector rules by performing a variety of sensitivity analyses described in XII.F.3. These considerations are discussed in the technical memoranda, *IPM Sensitivity* Runs and *Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS,* available in the rulemaking docket.

XIII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, EPA, submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Any changes made in response to recommendations received as part of Executive Order 12866 review have been documented in the docket.

The EPA prepared an analysis of the potential costs and benefits associated with these actions. This analysis, ''Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,'' is available in the docket and describes in detail the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates.

Table 6 presents the estimated present values (PV) and equivalent annualized values (EAV) of the projected climate benefits, health benefits, compliance costs, and net benefits of the final rules in 2019 dollars discounted to 2024. This analysis covers the impacts of the final standards for new combustion turbines and for existing steam generating EGUs. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the final rules.

Under E.O. 12866, the EPA is directed to consider the costs and benefits of its actions. Accordingly, in addition to the projected climate benefits of the final rules from anticipated reductions in CO_2 emissions, the projected monetized health benefits include those related to public health associated with projected reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3 and 7 percent. As shown in section 4.3.9 of the RIA, there are health benefits in the years 2028, 2030, 2035, and 2045 and health disbenefits in 2040. The projected climate benefits in this table are based on estimates of the social cost of carbon ($SC–CO_2$) at a 2 percent near-term Ramsey discount rate and are discounted using a 2 percent discount rate to obtain the PV and EAV estimates in the table. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and illustrative policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the final requirements.

These results present an incomplete overview of the potential effects of the final rules because important categories of benefits—including benefits from reducing HAP emissions—were not monetized and are therefore not reflected in the benefit-cost tables. The EPA anticipates that taking non-monetized effects into account would show the final rules to have a greater net benefit than this table reflects.

TABLE 6—PROJECTED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULES, 2024 THROUGH 2047

[Billions 2019$, discounted to 2024] [a]

	Present value (PV)		
	2% Discount rate	3% Discount rate	7% Discount rate
Climate Benefits [c]	270	270	270
Health Benefits [d]	120	100	59
Compliance Costs	19	15	7.5
Net Benefits [e]	370	360	320
Equivalent Annualized Value (EAV) [b]			
Climate Benefits [c]	14	14	14
Health Benefits [d]	6.3	6.1	5.2
Compliance Costs	0.98	0.91	0.65
Net Benefits [e]	20	19	19
Non-Monetized Benefits [e]	Benefits from reductions in HAP emissions Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP Reductions in exposure to ambient NO_2 and SO_2 Improved visibility (reduced haze) from $PM_{2.5}$ reductions		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The annualized present value of costs and benefits are calculated over the 24-year period from 2024 to 2047.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC–CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC–CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[d] The projected monetized air quality related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent. This table presents the net health benefit impact over the analytic timeframe of 2024 to 2047. As shown in section 4.3.9 of the RIA, there are health benefits in the years 2028, 2030, 2035, and 2045 and health disbenefits in 2040.

[e] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See section 4.2 of the RIA for a discussion of climate effects that are not yet reflected in the SC–CO_2 and thus remain unmonetized and section 4.4 of the RIA for a discussion of other non-monetized benefits.

As shown in table 6, the final rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent. The final rules are also projected to reduce emissions of NO_X, SO_2 and direct $PM_{2.5}$ leading to national health benefits from $PM_{2.5}$ and ozone in most years, producing a projected PV of monetized health benefits of about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Thus, these final rules are expected to generate a PV of monetized benefits of $390 billion, with an EAV of $21 billion discounted at a 2 percent rate. The PV of the projected compliance costs are $19 billion, with an EAV of about $0.98 billion discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $370 billion and EAV of about $20 billion.

At a 3 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at 3 percent. The PV of the projected compliance costs are about $15 billion, with an EAV of $0.91 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $360 billion and an EAV of about $19 billion.

At a 7 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at 7 percent. The PV of the projected compliance costs are about $7.5 billion, with an EAV of $0.65 billion discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $320 billion and an EAV of about $19 billion.

We also note that the RIA follows the EPA's historic practice of using a detailed technology-rich partial equilibrium model of the electricity and related fuel sectors to estimate the incremental costs of producing electricity under the requirements of proposed and final major EPA power sector rules. In section 5.2 of the RIA for these actions, the EPA has also included an economy-wide analysis that considers additional facets of the economic response to the final rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies. The social cost estimates in the economy-wide analysis and discussed in section 5.2 of the RIA are still far below the projected benefits of the final rules.

B. Paperwork Reduction Act (PRA)

1. 40 CFR Part 60, Subpart TTTT

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0685.

2. 40 CFR Part 60, Subpart TTTTa

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2771.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

Respondents/affected entities: Owners and operators of fossil-fuel fired EGUs.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 2.

Frequency of response: Annual.

Total estimated burden: 110 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $12,000 (per year), includes $0 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

3. 40 CFR Part 60, Subpart UUUUa

This action does not impose an information collection burden under the PRA.

4. 40 CFR Part 60, Subpart UUUUb

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2770.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This rule imposes specific requirements on state governments with existing fossil fuel-fired steam generating units. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit GHG emissions from these existing EGUs. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to be 89,000 hours at a total annual labor cost of $11.7 million. The annual burden for the Federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 24,000 hours at a total annual labor cost of $1.7 million. Burden is defined at 5 CFR 1320.3(b).

Respondents/affected entities: States with one or more designated facilities covered under subpart UUUUb.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 43.

Frequency of response: Once.

Total estimated burden: 89,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $11.7 million, includes $35,000 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

Pursuant to sections 603 and 609(b) of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. Summaries of the IRFA and Panel recommendations are presented in the supplemental proposed rule at 88 FR 80582 (November 20, 2023). The complete IRFA and Panel Report are available in the docket for this action.[1052]

As required by section 604 of the RFA, the EPA prepared a final regulatory flexibility analysis (FRFA) for this action. The FRFA provides a statement of the need for, and objectives of, the rule; addresses the issues raised by public comments on the IRFA for the proposed rule, including public comments filed by the Chief Counsel for Advocacy of the Small Business Administration; describes the small entities to which the rule will apply; describes the projected reporting, recordkeeping and other compliance requirements of the rule and their impacts; and describes the steps the agency has taken to minimize impacts on small entities consistent with the stated objectives of the Clean Air Act. The complete FRFA is available for review in the docket and is summarized here. The scope of the FRFA is limited to the NSPS. The impacts of the emission guidelines are not evaluated here because the emission guidelines do not place explicit requirements on the regulated industry. Those impacts will be evaluated pursuant to the development of a Federal plan.

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare. Since that time, the evidence of the harms posed by GHG emissions has only grown and Americans experience the destructive and worsening effects of climate change every day. Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021. At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development. Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under CAA section 111 to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and NSPS that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the BSER that,

[1052] See Document ID No. EPA–HQ–OAR–2023–0072–8109 and Document ID No. EPA–HQ–OAR–2023–0072–8108.

taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

These final actions ensure that EGUs reduce their GHG emissions in a manner that is cost-effective and improve the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

The significant issues raised in public comments specifically in response to the initial regulatory flexibility analysis came from the Office of Advocacy within the Small Business Administration (Advocacy). The EPA agreed that convening a SBAR Panel was warranted because the EPA solicited comment on a number of policy options that, if finalized, could affect the estimate of total compliance costs and therefore the impacts on small entities. The EPA issued an IRFA and solicited comment on regulatory flexibilities for small business in a supplemental proposed rule, published in November 2023.

Advocacy provided further substantive comments on the IRFA that accompanied the November 2023 supplemental proposed rule. The comments reiterated the concerns raised in its original comment letter on the proposed rule and further made the following claims: (1) the IRFA does not provide small entities an accurate description of the impacts of the proposed rule, (2) small entities remain concerned that the EPA has not taken reliability concerns seriously.

In response to these comments and feedback during the SBAR Panel, the EPA revised its small business assessment to incorporate the final SBA guidelines (effective March 17th 2023) when performing the screening analysis to identify small businesses that have built or have planned/committed builds of combustion turbines since 2017. The EPA also treated additional entities within this subset as small based on feedback received during the panel process. The net effect of these changes is to increase the total compliance cost attributed to small entities, and the number of small entities potentially affected. The EPA additionally increased the assumed delivered hydrogen price to $1.15/kg.

Further, the EPA is finalizing multiple adjustments to the proposed rule that ensure the requirements in the final actions can be implemented without compromising the ability of power companies, grid operators, and state and Federal energy regulators to maintain resource adequacy and grid reliability.

To estimate the number of small businesses potentially impacted by the NSPS, the EPA performed a small entity screening analysis for impacts on all affected EGUs by comparing compliance costs to historic revenues at the ultimate parent company level. The EPA reviewed historical data and planned builds since 2017 to determine the universe of NGCC and natural gas combustion turbine additions. Next, the EPA followed SBA size standards to determine which ultimate parent entities should be considered small entities in this analysis.

Once the costs of the rule were calculated, the costs attributed to small entities were calculated by multiplying the total costs to the share of the historical build attributed to small entities. These costs were then shared to individual entities using the ratio of their build to total small entity additions in the historical dataset.

The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 14 entities that own NGCC units considered in this analysis, three are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035 and none are projected to experience compliance costs greater than or equal to 3 percent of generation revenues in 2035.

Prior to the November 2023 supplemental proposed rule, the EPA convened a SBAR Panel to obtain recommendations from small entity representatives (SERs) on elements of the regulation. The Panel identified significant alternatives for consideration by the Administrator of the EPA, which were summarized in a final report. Based on the Panel recommendations, as well as comments received in response to both the May 2023 proposed rule and the November 2023 supplemental proposed rule, the EPA is finalizing several regulatory alternatives that could accomplish the stated objectives of the Clean Air Act while minimizing any significant economic impact of the final rule on small entities. Discussion of those alternatives is provided below.

Mechanisms for reliability relief: As described in section XII.F of this preamble, the EPA is finalizing several adjustments to provisions in the proposed rules that address reliability concerns and ensure that the final rules provide adequate flexibilities and assurance mechanisms that allow grid operators to continue to fulfill their responsibilities to maintain the reliability of the bulk-power system. The EPA is additionally finalizing additional reliability-related instruments to provide further certainty that implementation of these final rules will not intrude on grid operator's ability to ensure reliability. The short-term reliability emergency mechanism, which is available for both new and existing units, is designed to provide an alternative compliance strategy during acute system emergencies when reliability might be threatened. The reliability assurance mechanism will be available for existing units that intend to cease operating, but, for unforeseen reasons, need to temporarily remain online to support reliability beyond the planned cease operation date. This reliability assurance mechanism, which requires an adequate showing of reliability need, is intended to apply to circumstances where there is insufficient time to complete a state plan revision. Whether to grant an extension to an owner/operator is solely the decision of the EPA. Concurrence or approval of FERC is not a condition but may inform EPA's decision. These instruments will be presumptively approvable, provided they meet the requirements defined in these emission guidelines, if states choose to incorporate them into their plans.

Throughout the SBAR Panel outreach, SERs expressed concerns that the 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 Regional Transmission Organizations (RTOs) be involved to evaluate safety and reliability concerns.

SERs additionally stated that the proposed rule relies on the continued development of technologies not currently in wide use and large-scale investments in new infrastructure and that the proposed rule pushes these technologies significantly faster than the infrastructure will be ready and sooner than the SERs can justify investment to their stakeholders and ratepayers. SERs stated that 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 suite of comprehensive adjustments in the final rules, along with the two explicit reliability mechanisms are directly responsive to SER's statements and concerns about grid reliability and the impact of retiring generating on small businesses.

Subcategories: Throughout the SBAR Panel, SERs expressed concerns that control requirements on rural electric cooperatives may be an additional hardship on economically disadvantaged communities and small entities. SERs stated that the EPA should further evaluate increased energy costs, transmission upgrade costs, and infrastructure encroachment which are concrete effects on the disproportionately impacted communities. Additionally, SERs stated hydrogen and CCS cannot be BSER because they are not commercially available and viable in very rural areas.

The EPA solicited 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 EPA also solicited 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.

The EPA evaluated public comments received and determined that establishing a separate subcategory for rural electric cooperatives was not warranted. However, the EPA is not finalizing the low-GHG hydrogen BSER pathway. In response to concerns raised by small business and other commenters, the EPA conducted additional analysis of the BSER criteria and its proposed determination that low-GHG hydrogen co-firing qualified as the BSER. This additional analysis led the EPA to assess that the cost of low-GHG hydrogen in 2030 will likely be higher than proposed, and these higher cost estimates and associated uncertainties related to its nationwide availability were key factors in the EPA's decision to revise its 2030 cost estimate for delivered low-GHG hydrogen and are reflected in the increased price. For CCS, as discussed in sections VIII.F.4.c.iv and VII.C.1.a of this preamble, the EPA considered geographic availability of sequestration, as well as the timelines, materials, and workforce necessary for installing CCS, and determined they are sufficient. Moreover, while the BSER is premised on source-to-sink CO_2 pipelines and sequestration, the EPA notes that many EGUs in rural areas are primed to take advantage of synergy with the broader deployment of CCS in other industries. Capture, pipelines, and sequestration are already in place or in advanced stages of deployment for ethanol production from corn, an industry rooted in rural areas. The high purity CO_2 from ethanol production provides advantageous economics for CCS.

The EPA believes the decision to not finalize a low-GHG hydrogen BSER pathway is responsive to SER's statements and concerns regarding the availability of low-GHG hydrogen in very rural areas.

In addition, the EPA is preparing a Small Entity Compliance Guide to help small entities comply with this rule. The guide will be available 60 days after publication of the final rule at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

D. Unfunded Mandates Reform Act of 1995 (UMRA)

The NSPS contain a Federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for the private sector in any one year. The NSPS do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538 for state, local, and tribal governments, in the aggregate. Accordingly, the EPA prepared, under section 202 of UMRA, a written statement of the benefit-cost analysis, which is in section XIII.A of this preamble and in the RIA.

The repeal of the ACE Rule and emission guidelines do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and do not significantly or uniquely affect small governments. The emission guidelines do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop plans to implement the guidelines under CAA section 111(d) for designated EGUs. The burden for states to develop CAA section 111(d) plans in the 24-month period following promulgation of the emission guidelines was estimated and is listed in section XIII.B, but this burden is estimated to be below $100 million in any one year. As explained in section X.E.6, the emission guidelines do not impose specific requirements on tribal governments that have designated EGUs located in their area of Indian country.

These actions are not subject to the requirements of section 203 of UMRA because they contain no regulatory requirements that might significantly or uniquely affect small governments. In light of the interest in these actions among governmental entities, the EPA initiated consultation with governmental entities. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. For a summary of the UMRA consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary.*[1053]

E. Executive Order 13132: Federalism

These actions do not have federalism implications as that term is defined in E.O. 13132. Consistent with the cooperative federalism approach directed by the Clean Air Act, states will establish standards of performance for existing sources under the emission guidelines set out in this final rule. These actions will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

Although the direct compliance costs may not be substantial, the EPA nonetheless elected to consult with representatives of state and local governments in the process of

[1053] See Document ID No. EPA–HQ–OAR–2023–0072–0033.

developing these actions to permit them to have meaningful and timely input into their development. The EPA's consultation regarded planned actions for the NSPS and emission guidelines. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. For a summary of the Federalism consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary.*[1054]

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

These actions do not have tribal implications, as specified in Executive Order 13175. The NSPS imposes requirements on owners and operators of new or reconstructed stationary combustion turbines and the emission guidelines do not impose direct requirements on tribal governments. Tribes are not required to develop plans to implement the emission guidelines developed under CAA section 111(d) for designated EGUs. The EPA is aware of two fossil fuel-fired steam generating units located in Indian country, and one fossil fuel-fired steam generating units owned or operated by tribal entities. The EPA notes that the emission guidelines do not directly impose specific requirements on EGU sources, including those located in Indian country, but before developing any standards for sources on tribal land, the EPA would consult with leaders from affected tribes. Thus, Executive Order 13175 does not apply to these actions.

Because the EPA is aware of tribal interest in these rules and consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered government-to-government consultation with tribes and conducted outreach and engagement.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks Populations and Low-Income Populations

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is a significant regulatory action as defined by E.O. 12866(3)(f)(1), and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the Agency has evaluated the environmental health and welfare effects of climate change on children. GHGs contribute to climate change and are emitted in significant quantities by the power sector. The EPA believes that the GHG emission reductions resulting from implementation of these standards and guidelines will further improve children's health. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects (74 FR 66524, December 15, 2009). The assessment literature since 2016 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience. These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More detailed information on the impacts of climate change to human health and welfare is provided in section III of this preamble. Under these final actions, the EPA expects that CO_2 emissions reductions will improve air quality and mitigate climate impacts which will benefit the health and welfare of children.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

These actions, which are significant regulatory actions under Executive Order 12866, are likely to have to have a significant adverse effect on the supply, distribution or use of energy. The EPA has prepared a Statement of Energy Effects for these actions as follows. The EPA estimates a 1.4 percent increase in retail electricity prices on average, across the contiguous U.S. in 2035, and a 42 percent reduction in coal-fired electricity generation in 2035 as a result of these actions. The EPA projects that utility power sector delivered natural gas prices will increase 3 percent in 2035. As outlined in the Final TSD, *Resource Adequacy Analysis,* available in the docket for this rulemaking, the EPA demonstrates that compliance with the final rules can be achieved while maintaining resource adequacy, and that the rules include additional flexibility measures designed to address reliability-related concerns. For more information on the estimated energy effects, please refer section 3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking involves technical standards. Therefore, the EPA conducted searches for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Method 19 of 40 CFR part 60, appendix A. No applicable voluntary consensus standards (VCS) were identified for EPA Method 19. For additional information, please see the March 23, 2023, memorandum titled *Voluntary Consensus Standard Results for New Source Performance Standards for*

[1054] See Document ID No. EPA–HQ–OAR–2023–0072–0033.

Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.[1055]

In accordance with the requirements of 1 CFR part 51, the EPA is incorporating the following 10 voluntary consensus standards by reference in the final rule.

- ANSI C12.20–2010, American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010) is cited in the final rule to assure consistent monitoring of electric output. This standard establishes the physical aspects and acceptable performance criteria for 0.2 and 0.5 accuracy class electricity meters. These meters would be used to measure hourly electric output that would be used, in part, to calculate compliance with an emissions standard.
- ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), is cited in the final rule to provide directions and rules for conduct and reporting of results of thermal performance tests for open cycle simple cycle combustion turbines. The object is to determine the thermal performance of the combustion turbine when operating at test conditions and correcting these test results to specified reference conditions. PTC 22 provides explicit procedures for the determination of the following performance results: corrected power, corrected heat rate (efficiency), corrected exhaust flow, corrected exhaust energy, and corrected exhaust temperature. Tests may be designed to satisfy different goals, including absolute performance and comparative performance.
- ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), is cited in the final rule to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and combined heat and power units (PTC 46 is not applicable to simple cycle combustion turbines). Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions. PTC 46 provides explicit procedures for the determination of the following performance results: corrected net power, corrected heat rate, and corrected heat input.
- ASTM D388–99 (Reapproved 2004), Standard Classification of Coals by Rank, covers the classification of coals by rank, that is, according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite. It is used to define coal as a fuel type which is then referenced when defining coal-fired electric generating units, one of the subjects of this rule.
- ASTM D396–98, Standard Specification for Fuel Oils, covers grades of fuel oil intended for use in various types of fuel-oil-burning equipment under various climatic and operating conditions. These include Grades 1 and 2 (for use in domestic and small industrial burners), Grade 4 (heavy distillate fuels or distillate/residual fuel blends used in commercial/industrial burners equipped for this viscosity range), and Grades 5 and 6 (residual fuels of increasing viscosity and boiling range, used in industrial burners).
- ASTM D975–08a, Standard Specification for Diesel Fuel Oils, covers seven grades of diesel fuel oils based on grade, sulfur content, and volatility. These grades range from Grade No. 1–D S15 (a special-purpose, light middle distillate fuel for use in diesel engine applications requiring a fuel with 15 ppm sulfur (maximum) and higher volatility than that provided by Grade No. 2–D S15 fuel) to Grade No. 4–D (a heavy distillate fuel, or a blend of distillate and residual oil, for use in low- and medium-speed diesel engines in applications involving predominantly constant speed and load).
- ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008) covers two grades of kerosene suitable for use in critical kerosene burner applications: No. 1–K (a special low sulfur grade kerosene suitable for use in non-flue-connected kerosene burner appliances and for use in wick-fed illuminating lamps) and No. 2–K (a regular grade kerosene suitable for use in flue-connected burner appliances and for use in wick-fed illuminating lamps). It is used to define kerosene, which is a type of uniform fuel listed in this rule.
- ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011) covers biodiesel (B100) Grades S15 and S500 for use as a blend component with middle distillate fuels. It is used to define biodiesel, which is a type of uniform fuel listed in this rule.
- ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010) covers fuel blend grades of 6 to 20 volume percent biodiesel with the remainder being a light middle or middle distillate diesel fuel, collectively designated as B6 to B20. It is used to define biodiesel blends, which is a type of uniform fuel listed in this rule.
- ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009) is cited in the final rule for its guidance on determining performance characteristics of stationary combustion turbines. ISO 2314 specifies guidelines and procedures for preparing, conducting and reporting thermal acceptance tests in order to determine and/or verify electrical power output, mechanical power, thermal efficiency (heat rate), turbine exhaust gas energy and/or other performance characteristics of open-cycle simple cycle combustion turbines using combustion systems supplied with gaseous and/or liquid fuels as well as closed-cycle and semi closed-cycle simple cycle combustion turbines. It can also be applied to simple cycle combustion turbines in combined cycle power plants or in connection with other heat recovery systems. ISO 2314 includes procedures for the determination of the following performance parameters, corrected to the reference operating parameters: electrical or mechanical power output (gas power, if only gas is supplied), thermal efficiency or heat rate; and combustion turbine engine exhaust energy (optionally exhaust temperature and flow).

The EPA determined that the ANSI, ASME, ASTM, and ISO standards, notwithstanding the age of the standards, are reasonably available because they are available for purchase from the following addresses: American National Standards Institute (ANSI), 25 West 43rd Street, 4th Floor, New York, NY 10036–7422, +1.212.642.4900, *info@ansi.org*, *www.ansi.org*; American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990, +1.800.843.2763, *customercare@asme.org*, *www.asme.org*; ASTM International, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, +1.610.832.9500, *www.astm.org*; International Organization for Standardization (ISO), Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland, +41.22.749.01.11, *customerservice@iso.org*, *www.iso.org*.

[1055] See Document ID No. EPA–HQ–OAR–2023–0072–0032.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to these actions result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. Baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, and those without a high school diploma may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian populations, residents of Tribal Lands, populations with life expectancy data unavailable, children, and unemployed populations may also experience disproportionately higher ozone concentrations than the national average. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the national average.

For existing sources, the EPA believes that this action is not likely to change existing disproportionate and adverse disparities among communities with EJ concerns regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures for most demographic groups in the future years evaluated. However, in 2035, under the illustrative compliance scenarios analyzed, it is possible that Asian populations, Hispanic populations, and those linguistically isolated, and those living on Tribal land may experience a slight exacerbation of ozone exposure disparities at the national level (EJ question 3). Additionally at the national level, those living on Tribal land may experience a slight exacerbation of ozone exposure disparities in 2040 and a slight mitigation of ozone exposure disparities in 2028 and 2030. At the state level, ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups analyzed, also to a small degree. As discussed above, it is important to note that this analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

For new sources, the EPA believes that it is not practicable to assess whether this action is likely to result in new disproportionate and adverse effects on communities with environmental justice concerns, because the location and number of new sources is unknown. However, the EPA believes that the projected total cumulative power sector reduction of 1,365 million metric tons of CO_2 emissions between 2028 and 2047 will have a beneficial effect on populations at risk of climate change effects/impacts. Research indicates that racial, ethnic, and low socioeconomic status, vulnerable lifestages, and geographic locations may leave individuals uniquely vulnerable to climate change health impacts in the U.S.

The information supporting this Executive Order review is contained in section XII.E of this preamble and in section 6, Environmental Justice Impacts of the RIA, which is in the public docket.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

XIV. Statutory Authority

The statutory authority for the actions in this rulemaking is provided by sections 111, 302, and 307(d)(1) of the CAA as amended (42 U.S.C. 7411, 7602, 7607(d)(1)). These actions are subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons set forth in the preamble, the EPA amends 40 CFR part 60 as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Section 60.17 is amended by:
■ a. Revising paragraphs (d)(1), (g)(15) and (16), (h)(38), (43), (47), (145), (206), and (212), the introductory text of paragraph (i);
■ b. Removing note 1 to paragraph (k) and paragraph (l);
■ c. Redesignating paragraphs (j) through (u) as shown in the following table:

Old paragraph	New paragraph
(j)	(k).
(k)	(m).
(m) through (o)	(n) through (p).
(p) through (r)	(r) through (t).
(s)	(q).
(t)	(j).
(u)	(l).

■ d. Revising newly-redesignated paragraphs (j) and (l), the introductory text to newly-redesignated paragraph (m), newly-redesignated paragraph (n), and the introductory text to newly-redesignated paragraphs (o), (q), and (r).

The revisions read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) * * *

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010); IBR approved for §§ 60.5535(d); 60.5535a(d); 60.5860b(a).

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(g) * * *

(15) ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014); IBR approved for §§ 60.5580; 60.5580a.

(16) ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15,1997); IBR approved for §§ 60.5580; 60.5580a.

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(h) * * *

(38) ASTM D388–99 (Reapproved 2004) ε^1(ASTM D388–99R04), Standard Classification of Coals by Rank, (Approved June 1, 2004); IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251; 60.5580; 60.5580a.

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(43) ASTM D396–98, Standard Specification for Fuel Oils, (Approved April 10, 1998); IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b); 60.5580; 60.5580a.

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(47) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, (Approved October 1, 2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.

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(145) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1,

2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.

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(206) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

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(212) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

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(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209; phone: (301) 927–7077; website: *https://www.aoac.org/*.

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(j) CSA Group (CSA) (formerly Canadian Standards Association), 178 Rexdale Boulevard, Toronto, Ontario, Canada; phone: (800) 463–6727; website: *https://shop.csa.ca*.

(1) CSA B415.1–10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for §§ 60.534; 60.5476.

(2) [Reserved]

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(l) European Standards (EN), European Committee for Standardization, Management Centre, Avenue Marnix 17, B–1000 Brussels, Belgium; phone: + 32 2 550 08 11; website: *https://www.en-standard.eu*.

(1) DIN EN 303–5:2012E (EN 303–5), Heating boilers—Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW—Terminology, requirements, testing and marking, (October 2012), IBR approved for § 60.5476.

(2) [Reserved]

* * * * *

(m) GPA Midstream Association, 6060 American Plaza, Suite 700, Tulsa, OK 74135; phone: (918) 493–3872; website: *www.gpamidstream.org*.

* * * * *

(n) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland; phone: + 41 22 749 01 11; website: *www.iso.org*.

(1) ISO 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for §§ 60.5580; 60.5580a.

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 60.107a(d).

(4) ISO 10715:1997(E), Natural gas—Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a).

(o) National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161.

* * * * *

(q) Pacific Lumber Inspection Bureau (formerly West Coast Lumber Inspection Bureau), 1010 South 336th Street #210, Federal Way, WA 98003; phone: (253) 835.3344; website: *www.plib.org*.

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(r) Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092; phone (800) 332–8686; website: *www.tappi.org*.

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Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

■ 3. Section 60.5508 is revised to read as follows:

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit or an integrated gasification combined cycle (IGCC) facility that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014, but on or before May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014, but on or before May 23, 2023, or commences reconstruction after June 18, 2014, but on or before May 23, 2023. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

■ 4. Section 60.5509 is revised to read as follows:

§ 60.5509 What are my general requirements for complying with this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commenced construction after January 8, 2014, but on or before May 23, 2023, or commenced reconstruction after June 18, 2014, but on or before May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating

of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this paragraph (b)(7) continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline).

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(10) Your EGU is subject to subpart TTTTa of this part.

■ 5. Section 60.5520 is revised to read as follows:

§ 60.5520 What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 or 2 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 2 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 2 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

■ 6. Section 60.5525 is revised to read as follows:

§ 60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 or 2 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard = \frac{(50 \times HTIP_{ng}) + (69 \times HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 or 2 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced commercial operation (as defined in 40 CFR 72.2) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) has passed prior to October 23, 2015, emissions reporting shall begin according to § 60.5555(c)(3)(i) (for Acid Rain program units), or according to § 60.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(iii).

(4) Electric sales by your affected facility generated when it operated during a system emergency as defined in § 60.5580 are excluded for applicability with the base load standard if you can sufficiently provide the documentation listed in § 60.5560(i).

■ 7. Section 60.5535 is amended by revising paragraphs (a), (b), (c)(3), (d)(1), (e), and (f) to read as follows:

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ‘‘valid operating hours’’, as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from equation F–11 in appendix F to 40

CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) * * *

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

* * * * *

(d) * * *

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

* * * * *

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 or 2 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternative, or if the EGUs are subject to different emission standards in table 1 or 2 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

* * * * *

■ 8. Section 60.5540 is revised to read as follows:

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 or 2 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of 40 CFR 75 are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section.

Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 or 2 to this subpart, or the emissions standard calculated in accordance with § 60.5525(a)(2).

■ 9. Section 60.5555 is amended by revising paragraphs (a)(2)(iv) and (v), (f), and (g) to read as follows.

§ 60.5555 What reports must I submit and when?

(a) * * *

(2) * * *

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

* * * * *

(f) If your affected EGU captures CO_2 to meet the applicable emissions standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

■ 10. Section 60.5560 is amended by adding paragraphs (h) and (i) to read as follows:

§ 60.5560 What records must I maintain?

* * * * *

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert, and documentation of the exact duration of the event;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located, and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

■ 11. Section 60.5580 is amended by:

■ a. Revising the definitions for ''Annual capacity factor'', and ''Base load rating'';

■ b. Revising and republishing the definition for ''Coal''; and

■ c. Revising the definitions for ''Combined cycle unit'', ''Combined head and power unit or CHP unit'', ''Design efficiency'', ''Distillate oil'', ''ISO conditions'', ''Net electric sales'', and ''System emergency''.

The revisions and republications read as follows:

§ 60.5580 What definitions apply to this subpart?

* * * * *

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009(E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

* * * * *

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

* * * * *

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

* * * * *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

* * * * *

■ 12. Table 1 to subpart TTTT is revised to read as follows:

Table 1 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities That Commenced Construction After January 8, 2014, and Reconstruction or Modification After June 18, 2014

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: (1) 820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross) for units with a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h); or (2) 910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross) for units with a base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.

■ 13. Table 2 to subpart TTTT is revised to read as follows:

Table 2 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction After January 8, 2014, and Reconstruction After June 18, 2014 (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg CO_2/MWh (1,000 lb CO_2/MWh) of gross energy output; or 470 kg CO_2/MWh (1,030 lb CO_2/MWh) of net energy output.

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis].	50 kg CO_2/GJ (120 lb CO_2/MMBtu) of heat input.
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525.

■ 14. Table 3 to subpart TTTT is revised to read as follows:

Table 3 to Subpart TTTT of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§ 60.8(c)–(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

■ 15. Add subpart TTTTa to read as follows:

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard\ = \frac{\left(50 \text{ x } HTIP_{ng}\right) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen

(O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F–7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G–4 nomenclature.

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C–1 of 40 CFR part 98. If your fuel is not listed in table C–1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_A}{TDF} + [\ (Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\ ]\ \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}\ \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit

reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions) of this part.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/

h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.,* onsite photovoltaics), integrated energy storage (*e.g.,* onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

TABLE 1 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 23, 2023 (GROSS OR NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a. For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

TABLE 2 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS OR IGCC THAT COMMENCED MODIFICATION AFTER MAY 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit.	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

TABLE 3 TO SUBPART TTTTA OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTTA

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping.	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No..	
§ 60.8(b)	Performance test method alternatives.	Yes	Administrator can approve alternate methods.
§ 60.8(c)–(f)	Conducting performance tests.	No..	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No..	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)..	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No..	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements.	No..	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

Subpart UUUUa—[Reserved]

■ 16. Remove and reserve subpart UUUUa.

■ 17. Add subpart UUUUb to read as follows:

Sec.

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Introduction

§ 60.5700b What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish standards of performance limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. State plans under the emission guidelines in this subpart are also subject to the requirements of subpart Ba. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or Ba of this part, the requirements of this subpart shall apply.

§ 60.5705b Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases (GHG). The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from facilities regulated in the State plan, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the State plan, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from facilities regulated in the State plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to GHG emissions from facilities regulated in the State plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5710b Am I affected by this subpart?

(a) If you are the Governor of a State in the contiguous United States with one or more affected EGUs that must be addressed in your State plan as indicated in § 60.5845b, you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no affected EGUs, or if all EGUs in your State are excluded from being affected EGUs per § 60.5850b, you must submit a negative declaration letter in place of the State plan.

(b) If you are a coal-fired steam generating unit that has demonstrated that it plans to permanently cease operation prior to January 1, 2032, consistent with § 60.5740b(a)(9)(ii), and that would be an affected EGU under these emissions guidelines but for § 60.5850b(k), you must comply with § 60.5876b.

§ 60.5715b What is the review and approval process for my State plan?

(a) The EPA will determine the completeness of your State plan submission according to § 60.27a(g). The timeline for completeness determinations is provided in § 60.27a(g)(1).

(b) The EPA will act on your State plan submission according to § 60.27a. The Administrator will have 12 months after the date the final State plan or State plan revision (as allowed under § 60.5790b) is found to be complete to fully approve, partially approve, conditionally approve, partially disapprove, and/or fully disapprove such State plan or revision or each portion thereof.

§ 60.5720b What if I do not submit a State plan or my State plan is not approvable?

(a) If you do not submit an approvable State plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved State plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a State plan replacing the relevant portion(s) of the Federal plan.

§ 60.5725b In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan or a negative declaration letter (if applicable).

§ 60.5730b Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, consistent with the electronic submission requirements in § 60.5875b, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014, reconstruction on or before June 18, 2014, or modification on or before May 23, 2023, is found in your State, you will be found to have failed to submit a State plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5740b What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (13) of this section in your State plan submittal. The final State plan must meet the requirements and include the information required under § 60.5775b and must also meet any administrative and technical completeness criteria listed in § 60.27a(g)(2) and (3) that are not otherwise specifically enumerated here.

(1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by

your State plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845b. You must also identify the subcategory into which you have classified each affected EGU. States must subcategorize affected EGUs into one of the following subcategories:

(i) *Long-term coal-fired steam generating units,* consisting of coal-fired steam generating units that are not medium-term coal-fired steam generating units and do not plan to permanently cease operation before January 1, 2039.

(ii) *Medium-term coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2039.

(iii) *Base load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.

(iv) *Intermediate load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.

(v) *Low load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor less than 8 percent.

(vi) *Base load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.

(vii) *Intermediate load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.

(viii) *Low load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor less than 8 percent.

(2) *Inventory of Data from Affected EGUs.* You must include an inventory of the following data from the affected EGUs:

(i) The nameplate capacity of the affected EGU, as defined in § 60.5880b.

(ii) The base load rating of the affected EGU, as defined in § 60.5880b.

(iii) The data within the continuous 5-year period immediately prior to May 9, 2024 including:

(A) The sum of the CO_2 emissions during each quarter in the 5-year period.

(B) For affected EGUs in all subcategories except the low load natural gas- and oil-fired subcategories, the sum of the gross energy output during each quarter in the 5-year period; for affected EGUs in the low load natural gas- and oil-fired subcategories, the sum of the heat input during each quarter in the 5-year period.

(C) The heat input for each fuel type combusted during each quarter in the 5-year period.

(D) The start date and end date of the most representative continuous 8-quarter period used to determine the baseline of emission performance under § 60.5775b(d), the sum of the CO_2 mass emissions during that period, the sum of the gross energy output or, for affected EGUs in the low load natural gas-fired subcategory or low load oil-fired subcategory, the sum of the heat input during that period, and sum of the heat input for each fuel type combusted during that period.

(3) *Standards of Performance.* You must include all standards of performance for each affected EGU according to § 60.5775b. Standards of performance must be established at a level of performance that does not exceed the level calculated through the use of the methods described in § 60.5775b(b), unless a State establishes a standard of performance pursuant to § 60.5775b(e).

(4) *Requirements related to Subcategory Applicability.* (i) You must include the following enforceable requirements to establish an affected EGU's applicability for each of the following subcategories:

(A) For medium-term coal-fired steam generating units, you must include a requirement to permanently cease operations by a date after December 31, 2031, and before January 1, 2039.

(B) For steam generating units that meet the definition of natural gas- or oil-fired, and that either retain the capability to fire coal after May 9, 2024, that fired any coal during the 5-year period prior to that date, or that will fire any coal after that date and before January 1, 2030, you must include a requirement to remove the capability to fire coal before January 1, 2030.

(C) For each affected EGU, you must also estimate coal, oil, and natural gas usage by heat input for the first 3 calendar years after January 1, 2030.

(D) For affected EGUs that plan to permanently cease operation, you must include a requirement that each such affected EGU comply with applicable State and Federal requirements for permanently ceasing operation, including removal from its respective State's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU.

(5) *Increments of Progress.* You must include in your State plan legally enforceable increments of progress as required elements for affected EGUs in the long-term coal-fired steam generating unit and medium-term coal-fired steam generating unit subcategories.

(i) For affected EGUs in the long-term coal-fired steam generating unit subcategory using carbon capture to meet their applicable standard of performance and affected EGUs in the medium-term coal-fired steam generating unit subcategory using natural gas co-firing to meet their applicable standard of performance, State plans must assign calendar-date deadlines to each of the increments of progress described in subsection (a)(5)(i) and meet the website reporting obligations of subsection (a)(5)(iii):

(A) Submittal of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration for each affected EGU in the State plan.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or front-end engineering and design (FEED) study.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way.

(B) Completion of awarding of contracts. The owner or operator of an affected EGU can demonstrate compliance with this increment of progress by submitting sufficient evidence that the appropriate contracts have been awarded.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications.

(C) Initiation of on-site construction or installation of emission control equipment or process change.

(1) For each affected unit in the long-term coal-fired steam generating unit

subcategory, initiation of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, initiation of on-site construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(D) Completion of on-site construction or installation of emission control equipment or process change.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, completion of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, completion of on-site construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(E) Commencement of permitting actions related to pipeline construction. The owner or operator of an affected EGU must demonstrate that they have commenced permitting actions by a date specified in the State plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate each affected unit at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.

(1) For affected units in the long-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts CCS to meet the standard of performance and ensure timely completion of CCS-related pipeline infrastructure.

(2) For affected units in the medium-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts natural gas co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.

(F) For each affected unit in the long-term coal-fired steam generating unit subcategory, a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.

(G) Compliance with the standard of performance as follows:

(1) For each affected unit in the medium-term coal-fired subcategory, by January 1, 2030.

(2) For each affected unit in the long-term coal-fired steam generating subcategory, by January 1, 2032.

(ii) For any affected unit in the long-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than CCS or in the medium-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than natural gas co-firing:

(A) The State plan must include appropriate increments of progress consistent with 40 CFR 60.21a(h) specific to the affected unit's control strategy.

(1) The increment of progress corresponding to 40 CFR 60.21a(h)(1) must be assigned the earliest calendar date among the increments.

(2) The increment of progress corresponding to 40 CFR 60.21a(h)(5) must be assigned calendar dates as follows: for affected EGUs in the long-term coal-fired steam generating subcategory, no later than January 1, 2032; and for affected EGUs in the medium-term coal-fired steam generating subcategory, no later than January 1, 2030.

(iii) The owner or operator of the affected EGU must post within 30 business days of the State plan submittal a description of the activities or actions that constitute the increments of progress and the schedule for achieving the increments of progress on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10). As the calendar dates for each increment of progress occurs, the owner or operator of the affected EGU must post within 30 business days any documentation necessary to demonstrate that each increment of progress has been met on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10).

(iv) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan increment of progress within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable increment of progress on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10) within 30 business days.

(6) *Reporting Obligations and Milestones for Affected EGUs that Have Demonstrated They Plan to Permanently Cease Operations.* You must include in your State plan legally enforceable reporting obligations and milestones for affected EGUs in the medium-term coal-fired steam generating unit (§ 60.5740b(a)(1)(ii)) subcategory, and for affected EGUs that invoke RULOF based on a unit's remaining useful life according to paragraphs (a)(6)(i) through (v) of this section:

(i) Five years before the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life) or 60 days after State plan submission, whichever is later, the owner or operator of the affected EGU must submit an Initial Milestone Report to the applicable air pollution control agency that includes the information in paragraphs (a)(6)(i)(A) through (D) of this section:

(A) A summary of the process steps required for the affected EGU to permanently cease operations by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit.

(B) A list of key milestones that will be used to assess whether each process step has been met, and calendar day deadlines for each milestone. These milestones must include at least the initial notice to the relevant reliability authority or authorities of an EGU's deactivation date and submittal of an official retirement filing with the EGU's relevant reliability authority or authorities.

(C) An analysis of how the process steps, milestones, and associated timelines included in the Milestone

Report compare to the timelines of similar EGUs within the State that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines.

(D) Supporting regulatory documents, which include those listed in paragraphs (a)(6)(i)(D)(*1*) through (*3*) of this section:

(1) Any correspondence and official filings with the relevant Regional Transmission Organization (RTO), Independent System Operator, Balancing Authority, Public Utilities Commission (PUC), or other applicable authority;

(2) Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

(3) Any filings with the United States Securities and Exchange Commission or notices to investors, including but not limited to, those listed in paragraphs (a)(6)(i)(D)(*3*)(*i*) through (*v*) of this section.

(i) References in forms 10–K and 10–Q, in which the plans for the EGU are mentioned;

(ii) Any integrated resource plans and PUC orders approving the EGU's deactivation;

(iii) Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

(iv) Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

(v) Any notification to or from an RTO, Independent System Operator, or Balancing Authority altering the timing of deactivation for the EGU.

(ii) For each of the remaining years prior to the date by which an affected EGU has committed to permanently cease operations that is included in the State plan, the owner or operator of the affected EGU must submit an annual Milestone Status Report that includes the information in paragraphs (a)(6)(ii)(A) and (B) of this section:

(A) Progress toward meeting all milestones identified in the Initial Milestone Report, described in § 60.5740b(a)(6)(i); and

(B) Supporting regulatory documents and relevant SEC filings, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate compliance with or progress toward all milestones.

(iii) No later than six months from the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life), the owner or operator of the affected EGU must submit a Final Milestone Status Report. This report must document any actions that the EGU has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(iv) The owner or operator of the affected EGU must post their Initial Milestone Report, as described in paragraph (a)(6)(i) of this section; annual Milestone Status Reports, as described in paragraph (a)(6)(ii) of this section; and Final Milestone Status Report, as described in paragraph (a)(6)(iii) of this section; including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs website required by paragraph (a)(10) of this section within 30 business days of being filed.

(v) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan reporting milestone within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable reporting milestone on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10) within 30 business days.

(7) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your State plan all applicable monitoring, reporting and recordkeeping requirements, including initial and ongoing quality assurance and quality control procedures, for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860b.

(8) *State reporting.* You must include in your State plan a description of the process, contents, and schedule for State reporting to the EPA about State plan implementation and progress.

(9) *Specific requirements for existing coal-fired steam generating EGUs.* Your State plan must include the requirements in paragraphs (a)(9)(i) through (iii) of this section specifically for existing coal-fired steam generating EGUs:

(i) Your State plan must require that any existing coal-fired steam-generating EGU shall operate only subject to a standard of performance pursuant to § 60.5775b or under an exemption of applicability provided under § 60.5850b (including any extension of the date by which an EGU has committed to cease operating pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section).

(ii) You must include a list of the coal-fired steam generating EGUs that are existing sources at the time of State plan submission and that plan to permanently cease operation before January 1, 2032, and the calendar dates by which they have committed to cease operating.

(iii) The State plan must provide that an existing coal-fired steam generating EGU operating past the date listed in the State plan pursuant to paragraph (a)(9)(ii) of this section is in violation of that State plan, except to the extent the existing coal-fired steam generating EGU has received an extension of its date for ceasing operation pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section.

(10) *Carbon Pollution Standards for EGUs Websites.* You must require in your State plan that owners or operators of affected EGUs establish a publicly accessible ''Carbon Pollution Standards for EGUs Website'' and that they post relevant documents to this website. You must require in your State plan that owners or operators of affected EGUs post their subcategory designations and compliance schedules as well as any emissions data and other information needed to demonstrate compliance with a standard of performance to this website in a timely manner. This information includes, but is not limited to, emissions data and other information relevant to determining compliance with applicable standards of performance, information relevant to the designation and determination of compliance with increments of progress and reporting obligations including milestones for affected EGUs that plan to permanently cease operations, and any extension requests made and

granted pursuant to the compliance date extension mechanism or the reliability assurance mechanism. Data should be available in a readily downloadable format. In addition, you must establish a website that displays the links to these websites for all affected EGUs in your State plan.

(11) *Compliance Date Extension.* You may include in your State plan provisions allowing for a compliance date extension for owners or operators of affected EGU(s) that are installing add-on controls and that are unable to meet the applicable standard of performance by the compliance date specified in § 60.5740b(a)(4)(i) due to circumstances beyond the owner or operator's control. Such provisions may allow an owner or operator of an affected EGU to request an extension of no longer than one year from the specified compliance date and may only allow the owner or operator to receive an extension once. The optional State plan mechanism must provide that an extension request contains a demonstration of necessity that includes the following:

(i) A demonstration that the owner or operator of the affected EGU cannot meet its compliance date due to circumstances beyond the owner or operator's control and that the owner or operator has met all relevant increments of progress and otherwise taken all steps reasonably possible to install the controls necessary for compliance by the specified compliance date up to the point of the delay. The demonstration shall:

(A) Identify each affected unit for which the owner or operator is seeking the compliance extension;

(B) Identify and describe the controls to be installed at each affected unit to comply with the applicable standard of performance pursuant to § 60.5775b;

(C) Describe and demonstrate all progress towards installing the controls and that the owner or operator has itself acted consistent with achieving timely compliance, including:

(1) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; and

(2) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(D) Identify the circumstances that are entirely beyond the owner or operator's control and that necessitate additional time to install the identified controls. This may include:

(1) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in § 60.5740b(a)(4)(i);

(2) Documentation of any permit delays; or

(3) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(E) Identify a proposed compliance date no later than one year after the applicable compliance date listed in § 60.5740b(a)(4)(i) and, if necessary, updated calendar dates for the increments of progress that have not yet been met.

(ii) The State air pollution control agency is charged with approving or disapproving a compliance date extension request based on its written determination that the affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraphs (a)(11)(i)(A) through (E) of this section. The following provisions for approval must be included in the mechanism:

(A) All documentation required as part of this extension must be submitted by the owner or operator of the affected EGU to the State air pollution control agency no later than 6 months prior to the applicable compliance date for that affected EGU.

(B) The owner or operator of the affected EGU must notify the relevant EPA Regional Administrator of their compliance date extension request at the time of the submission of the request.

(C) The owner or operator of the affected EGU must post their application for the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), when they submit the request to the State air pollution control agency.

(D) The owner or operator of the affected EGU must post the State's determination on the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), upon receipt of the determination and, if the request is approved, update the information on the website related to the compliance date and increments of progress dates within 30 days of the receipt of the State's approval.

(12) *Short-Term Reliability Mechanism.* You may include in your State plan provisions for a short-term reliability mechanism for affected EGUs in your State that operate during a system emergency, as defined in § 60.5880b. Such a mechanism must include the components listed in paragraphs (a)(12)(i) through (vi) of this section.

(i) A requirement that the short-term reliability mechanism is available only during system emergencies as defined in § 60.5880b. The State plan must identify the entity or entities that are authorized to issue system emergencies for the State.

(ii) A provision that, for the duration of a documented system emergency, an impacted affected EGU may comply with an emission limitation corresponding to its baseline emission performance rate, as calculated under § 60.5775b(d), in lieu of its otherwise applicable standard of performance. The State plan must clearly identify the alternative emission limitation that corresponds to the affected EGU's baseline emission rate and include it as an enforceable emission limitation that may be applied only during periods of system emergency.

(iii) A requirement that an affected EGU impacted by the system emergency and complying with an alternative emission limitation must provide documentation, as part of its compliance demonstration, of the system emergency according to (a)(12)(iii)(A) through (D) of this section and that it was impacted by that system emergency.

(A) Documentation that the system emergency was in effect from the entity issuing the system emergency and documentation of the exact duration of the event;

(B) Documentation from the entity issuing the system emergency that the system emergency included the affected source/region where the unit was located;

(C) Documentation that the source was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside of its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/RTO; and

(D) Data collected during the event including the sum of the CO_2 emissions, the sum of the gross energy output, and the resulting CO_2 emissions performance rate.

(iv) A requirement to document the hours an affected EGU operated under a system emergency and the enforceable emission limitation, whether the applicable standard of performance or the alternative emission limitation, under which that affected EGU operated during those hours.

(v) A provision that, for the purpose of demonstrating compliance with the applicable standard of performance, the affected EGU would comply with its baseline emissions rate as calculated under § 60.5775b(d) in lieu of its otherwise applicable standard of performance for the hours of operation that correspond to the duration of the event.

(vi) The inclusion of provisions defining the short-term reliability mechanism must be part of the public comment process as part of the State plan's development.

(13) *Reliability Assurance Mechanism.* You may include provisions for a reliability assurance mechanism in your State plan. If included, such provisions would allow for one extension, not to exceed 12-months of the date by which an affected EGU has committed to permanently cease operations based on a demonstration consistent with this paragraph (a)(13) that operation of the affected EGU is necessary for electric grid reliability.

(i) The State plan must require that the reliability assurance mechanism would only be appliable to the following EGUs which, for the purpose of this paragraph (a)(13), are collectively referred to as ''eligible EGUs'':

(A) Coal-fired steam generating units that are exempt from these emission guidelines pursuant to § 60.5850b(k),

(B) Affected EGUs in the medium-term coal-fired steam-generating subcategory that have enforceable commitments to permanently cease operation before January 1, 2039, in the State plan, and

(C) Affected EGUs that have enforceable dates to permanently cease operation included in the State plan pursuant to § 60.24a(g).

(ii)The date from which an extension would run is the date included in the State plan by which an eligible EGU has committed to permanently cease operation.

(iii) The State plan must provide that an extension is only available to owners or operators of affected EGUs that have satisfied all applicable increments of progress and reporting obligations and milestones in paragraphs (a)(5) and (6) of this section. This includes requiring that the owner or operator of an affected EGU has posted all information relevant to such increments of progress and reporting obligations and milestones on the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10).

(iv) The State plan must provide that any applicable standard of performance for an affected EGU must remain in place during the duration of an extension provided under this mechanism.

(v) The State plan may provide for requests for an extension of up to 12 months without a State plan revision.

(A) For an extension of 6 months or less, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vi) to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(B) For an extension of more than 6 months and up to 12 months, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vii) to the Federal Energy Regulatory Commission (through a process and at an office of the Federal Energy Regulatory Commission's designation) and to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(vi) The State plan must require that to apply for an extension for 6 months or less, described in paragraph (a)(13)(v)(A) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in paragraphs (a)(13)(vi)(A) through (D) of this section no less than 30 days prior to the cease operation date, but no earlier than 12 months prior to the cease operation date.

(A) An analysis of the reliability risk that clearly demonstrates that the eligible EGU is critical to maintaining electric reliability. The analysis must include a projection of the length of time that the EGU is expected to be reliability-critical and the length of the requested extension must be no longer than this period or 6 months, whichever is shorter. In order to show an approvable reliability need, the analysis must clearly demonstrate that an eligible EGU ceasing operation by the date listed in the State plan would cause one or more of the conditions listed in paragraphs (a)(13)(vi)(A)(*1*) or (*2*) of this section. An eligible EGU that has received a Reliability Must Run designation, or equivalent from a Reliability Coordinator or Balancing Authority, would fulfill those conditions.

(1) Result in noncompliance with at least one of the mandatory reliability standards approved by FERC; or

(2) Would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, this requires a clear demonstration that the eligible EGU would be needed to maintain the targeted level of resource adequacy.

(B) Certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested. This certification must be accompanied by a written analysis by the relevant planning authority consistent with paragraph (a)(13)(vi)(A) of this section, confirming the asserted reliability risk if the eligible EGU was not in operation. The information from the relevant reliability planning authority must also include any related system-wide or regional analysis and a substantiation of the length of time that the eligible EGU is expected to be reliability critical.

(C) Copies of any written comments from third parties regarding the extension.

(D) Demonstration from the owner or operator of the eligible EGU, grid operator, and other relevant entities of a plan, including appropriate actions to bring on new capacity or transmission, to resolve the underlying reliability issue is leading to the need to employ this reliability assurance mechanism, including the steps and timeframes for implementing measures to rectify the underlying reliability issue.

(E) Any other information requested by the applicable EPA Regional Administrator or the Federal Energy Regulatory Commission.

(vii) The State plan must require that to apply for an extension longer than 6 months but up to 12 months, described in paragraph (a)(13)(v)(B) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in (a)(13)(vi)(A) through (E) of this section, except that the period of time under (a)(13)(vi)(A) would be 12 months. For requests for extensions longer than 6 months, this application must be submitted to the EPA Regional Administrator no less than 45 days prior to the date for ceasing operation listed in the State plan, but no earlier than 12 months prior to that date.

(viii) The State plan must provide that extensions will only be granted for the period of time that is substantiated by the reliability need and the submitted analysis and documentation, and shall not exceed 12 months in total.

(ix) The State plan must provide that the reliability assurance mechanism shall not be used more than once to extend an eligible EGU's planned cease operation date.

(x) The EPA Regional Administrator may reject the application if the submission is incomplete with respect to the requirements listed in paragraphs (a)(13)(vi)(A) through (E) of this section or if the submission does not adequately support the asserted reliability risk or the period of time for which the eligible EGU is anticipated to be reliability critical.

(b) [Reserved]

§ 60.5775b What standards of performance must I include in my State plan?

(a) For each affected EGU, your State plan must include the standard of performance that applies for the affected EGU. A standard of performance for an affected EGU may take the following forms:

(1) A rate-based standard of performance for an individual affected EGU that does not exceed the level calculated through the use of the methods described in § 60.5775b(c) and (d).

(2) A standard of performance in an alternate form, which may apply for affected EGUs in the long-term coal-fired steam generating unit subcategory or the medium-term coal-fired steam generating unit subcategory, as provided for in § 60.5775b(e).

(b) Standard(s) of performance for affected EGUs included under your State plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The State plan submittal must include the methods by which each standard of performance meets each of the following requirements:

(1) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.

(2) An affected EGU's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the standard of performance.

(3) An affected EGU's standard of performance is non-duplicative with respect to a State plan if it is not already incorporated as an standard of performance in the State plan.

(4) An affected EGU's standard of performance is permanent if the standard of performance must be met continuously unless it is replaced by another standard of performance in an approved State plan revision.

(5) An affected EGU's standard of performance is enforceable if:

(i) A technically accurate limitation or requirement, and the time period for the limitation or requirement, are specified;

(ii) Compliance requirements are clearly defined;

(iii) The affected EGUs are responsible for compliance and liable for violations identified;

(iv) Each compliance activity or measure is enforceable as a practical matter, as defined by 40 CFR 49.167; and

(v) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its standard of performance based on its emissions) and secure appropriate corrective actions: in the case of the Administrator, pursuant to CAA sections 113(a)–(h); in the case of a State, pursuant to its State plan, State law or CAA section 304, as applicable; and in the case of third parties, pursuant to CAA section 304.

(c) Methodology for establishing presumptively approvable standards of performance, for affected EGUs in each subcategory.

(1) Long-term coal-fired steam generating units

(i) BSER is CCS with 90 percent capture of CO_2.

(ii) Degree of emission limitation is 88.4 percent reduction in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an emission rate limit defined by an 88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.

(2) Medium-term coal-fired steam generating units

(i) BSER is natural gas co-firing at 40 percent of the heat input to the unit.

(ii) Degree of emission limitation is a 16 percent reduction in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an emission rate limit defined by a 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.

(iv) For units in this subcategory that have an amount of co-firing that is reflected in the baseline operation, States must account for such preexisting co-firing in adjusting the degree of emission limitation (*e.g.,* for an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 12 percent to reflect the preexisting level of natural gas co-firing).

(3) Base load oil-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb CO_2/MWh-gross.

(4) Intermediate load oil-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb CO_2/MWh-gross.

(5) Low load oil-fired steam generating units.

(i) BSER is uniform fuels.

(ii) Degree of emission limitation is 170 lb CO_2/MMBtu.

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 170 lb CO_2/MMBtu.

(6) Base load natural gas-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb CO_2/MWh-gross.

(7) Intermediate load natural gas-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb CO_2/MWh-gross.

(8) Low load natural gas-fired steam generating.

(i) BSER is uniform fuels.

(ii) Degree of emission limitation is 130 lb CO_2/MMBtu.

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 130 lb CO_2/MMBtu.

(d) Methodology for establishing the unit-specific baseline of emission performance.

(1) A State shall use the CO_2 mass emissions and corresponding electricity

generation or, for affected EGUs in the low load oil- or natural gas-fired subcategory, heat input data for a given affected EGU from the most representative continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to May 9, 2024.

(2) For the continuous 8 quarters of data, a State shall divide the total CO_2 emissions (in the form of pounds) over that continuous time period by either the total gross electricity generation (in the form of MWh) or, for affected EGUs in the low load oil- or natural gas-fired subcategory, total heat input (in the form of MMBtu) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh or lb CO_2 per MMBtu.

(e) Your State plan may include a standard of performance in an alternate form that differs from the presumptively approvable standard of performance specified in § 60.5775b(a)(1), as follows:

(1) An aggregate rate-based standard of performance (lb CO_2/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, provided the standard of performance meets the requirements of paragraph (f) of this section.

(2) A mass-based standard of performance in the form of an annual limit on allowable mass CO_2 emissions for an individual affected EGU, provided the standard of performance meets the requirements of paragraph (g) of this section.

(3) A rate-based standard of performance (lb CO_2/MWh-gross) implemented through a rate-based emission trading program, such that an affected EGU must meet the specified lb CO_2/MWh-gross rate that applies for the affected EGU, and where an affected EGU may surrender compliance instruments denoted in 1 short ton of CO_2 to adjust its reported lb CO_2/MWh-gross rate for the purpose of demonstrating compliance, provided the standard of performance meets the requirements of paragraph (h) of this section.

(4) A mass-based standard of performance in the form of an annual CO_2 budget implemented through a mass-based CO_2 emission trading program, where an affected EGU must surrender CO_2 allowances in an amount equal to its reported mass CO_2 emissions, provided the standard of performance meets the requirements of paragraph (i) of this section.

(f) Where your State plan includes a standard of performance in the form of an aggregate rate-based standard of performance (lb CO_2/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section, to each of the affected EGUs that form the group.

(2) Documentation of any assumptions underlying the calculation of the aggregate rate-based standard of performance (lb CO_2/MWh-gross).

(3) The process for calculating the aggregate gross generation weighted average emission rate (lb CO_2/MWh-gross) at the end of each compliance period, based on the reported emissions (lb CO_2) and utilization (MWh-gross) of each of the affected EGUs that form the group.

(4) Measures to implement and enforce the annual aggregate rate-based standard of performance, including the basis for determining owner or operator compliance with the aggregate standard of performance and provisions to address any changes to owners or operators in the course of implementation.

(5) A demonstration of how the application of the aggregate rate-based standard of performance will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(g) Where your State plan includes a standard of performance in the form of an annual limit on allowable mass CO_2 emissions for an individual affected EGU, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply to the affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The utilization level used to calculate the mass CO_2 limit, by multiplying the assumed utilization level (MWh-gross) by the presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual limit on mass CO_2 emissions, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the mass CO_2 limit for the affected EGU will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb CO_2/MWh-gross) that will also be applied to the affected EGU on an annual basis.

(6) For affected EGUs in the long-term coal-fired steam generating unit subcategory, in lieu of paragraphs (g)(2), (4), and (5) of this section, you may include a presumptively approvable mass CO_2 limit based on the product of the rate-based standard of performance (lb CO_2/MWh-gross) under paragraph (a)(1) of this section multiplied by a level of utilization (MWh-gross) corresponding to an annual capacity factor of 80 percent for the individual affected EGU with a backstop rate-based emission rate requirement equivalent to a reduction in baseline emission performance of 80 percent on an annual calendar-year basis.

(h) Where your State plan includes a standard of performance in the form of a rate-based standard of performance (lb CO_2/MWh-gross) implemented through a rate-based emission trading program, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that applies to each of the affected EGUs participating in the rate-based emission trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) Measures to implement and enforce the rate-based emission trading program, including the basis for awarding compliance instruments (denoted in 1 ton of CO_2) to an affected EGU that performs better on an annual basis than its rate-based standard of performance, and the process for demonstration of compliance that includes the surrender of such compliance instruments by an affected EGU that exceeds its rate-based standard of performance.

(3) A demonstration of how the use of the rate-based emission trading program will achieve equivalent or better emission reduction as would be achieved through the application of a

rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(i) Where your State plan includes a mass-based standard of performance implemented through a mass-based CO_2 emission trading program, where an affected EGU must surrender CO_2 allowances in an amount equal to its reported mass CO_2 emissions, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply to each affected EGU participating in the trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The calculation of the mass CO_2 budget contribution for each participating affected EGU, determined by multiplying the assumed utilization level (MWh-gross) of the affected EGU by its presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual budget of the mass-based CO_2 emission trading program, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the CO_2 emission budget for the group of participating affected EGUs will achieve equivalent or better emission performance as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply to each participating affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb CO_2/MWh-gross) that will also be applied to each participating affected EGU on an annual basis.

(j) In order to use the provisions of § 60.24a(e) through (h) to apply a less stringent standard of performance or longer compliance schedule to an affected EGU based on consideration of electric grid reliability, including resource adequacy, under these emission guidelines, a State must provide the following with its State plan submission:

(1) An analysis of the reliability risk clearly demonstrating that the particular affected EGU is critical to maintaining electric reliability such that requiring it to comply with the applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, a clear demonstration is required that the particular affected EGU would be needed to maintain the targeted level of resource adequacy. The analysis must also include a projection of the period of time for which the particular affected EGU is expected to be reliability critical and substantiate the basis for applying a less stringent standard of performance or longer compliance schedule consistent with 40 CFR 60.24a(e).

(2) An analysis by the relevant reliability planning authority that corroborates the asserted reliability risk identified in the analysis under paragraph (j)(1) of this section and confirms that requiring the particular affected EGU to comply with its applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region, and also confirms the period of time for which the EGU is projected to be reliability critical.

(3) A certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested.

§ 60.5780b What compliance dates and compliance periods must I include in my State plan?

(a) The State plan must include the following compliance dates:

(1) For affected EGUs in the long-term coal-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2032, unless the State has applied a later compliance date pursuant to § 60.24a(e) through (h).

(2) For affected EGUs in the medium-term coal-fired subcategory, the base load oil-fired subcategory, the intermediate load oil-fired steam generating subcategory, the low load oil-fired subcategory, the base load natural gas-fired subcategory, the intermediate load natural gas-fired subcategory, and the low load natural gas-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2030, unless State has applied a later compliance date pursuant to § 60.24a(e) through (h).

(b) The State plan must require affected EGUs to achieve compliance with their applicable standards of performance for each compliance period as defined in § 60.5880b.

§ 60.5785b What are the timing requirements for submitting my State plan?

(a) You must submit a State plan or a negative declaration letter with the information required under § 60.5740b by May 11, 2026.

(b) You must submit all information required under paragraph (a) of this section according to the electronic reporting requirements in § 60.5875b.

§ 60.5790b What is the procedure for revising my State plan?

EPA-approved State plans can be revised only with approval by the Administrator. The Administrator will approve a State plan revision if it is satisfactory with respect to the applicable requirements of this subpart and all applicable requirements of subpart Ba of this part. If one (or more) of State plan elements in § 60.5740b require revision, the State must submit a State plan revision pursuant to § 60.28a.

§ 60.5795b Commitment to review emission guidelines for coal-fired affected EGUs

EPA will review and, if appropriate, revise these emission guidelines as they apply to coal-fired steam generating affected EGUs by January 1, 2041. Notwithstanding this commitment, EPA need not review these emission guidelines if the Administrator determines that such review is not appropriate in light of readily available information on their continued appropriateness.

Applicability of State Plans to Affected EGUs

§ 60.5840b Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State, except as provided in § 60.5710b(b). However, affected EGU owners or operators must comply with the State plan that a State develops to implement the emission guidelines contained in this subpart.

(b) If a State does not submit a State plan to implement and enforce the standards of performance contained in this subpart by May 11, 2026, or the EPA disapproves State plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720b, applicable to each affected EGU within the State.

§ 60.5845b What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your State plan are:

(1) Any affected EGUs that were in operation or had commenced construction on or before January 8, 2014;

(2) Coal-fired steam generating units that commenced a modification on or before May 23, 2023.

(b) An affected EGU is a steam generating unit that meets the relevant applicability conditions specified in paragraphs (b)(1) through (2) of this section, as applicable, except as provided in § 60.5850b.

(1) Serves a generator capable of selling greater than 25 MW to a utility power distribution system; and

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

§ 60.5850b What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) New or reconstructed steam generating units that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(b) Modified natural gas- or oil-fired steam generating units that are subject to subpart TTTT of this part as a result of commencing modification after the subpart TTTT applicability date;

(c) Modified coal-fired steam generating units that are subject to subpart TTTTa of this part as a result of commencing modification after the subpart TTTTa applicability date;

(d) EGUs subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh;

(e) Non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(f) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(g) Units that serve a generator along with other EGUs, where the effective generation capacity (determined based on a prorated output of the base load rating of each EGU) is 25 MW or less;

(h) Municipal waste combustor units subject to 40 CFR part 60, subpart Eb;

(i) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or

(j) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(k) Existing coal-fired steam generating units that have demonstrated that they plan to permanently cease operations before January 1, 2032, pursuant to § 60.5740b(a)(9)(ii).

Recordkeeping and Reporting Requirements

§ 60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my State plan for affected EGUs?

(a) Your State plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (9) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet standards of performance must prepare a monitoring plan in accordance with the applicable provisions in 40 CFR 75.53(g) and (h), unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to 40 CFR part 75.

(2) For rate-based standards of performance, only ''valid operating hours,'', *i.e.,* full or partial unit (or stack) operating hours for which:

(i) ''Valid data'' (as defined in § 60.5880b) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; data obtained from flow monitoring bias adjustments are not considered to be valid data; and data provided or not provided from monitoring instruments that have not met the required frequency for relative accuracy audit testing are not considered to be valid data and

(ii) The corresponding hourly gross energy output value is also valid data (Note: For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based standards of performance, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage (CCS)), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(ii) For each ''valid operating hour'' (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2

concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6), if required by a State plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to 40 CFR part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D to 40 CFR part 75, as applicable.

(ii) For each measured hourly heat input rate, use Equation G–4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each ''valid operating hour'' (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6), if required by a State plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to 40 CFR part 75 and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(5) For rate-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis gross electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain, and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with gross electric output to determine gross energy output. The owner or operator must use the following procedures to calculate gross energy output, as appropriate for the type of affected EGU(s).

(i) Determine $P_{gross/net}$ the hourly gross or net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.,* full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate $P_{gross/net}$ for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output value reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(iv)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

$P_{GROSS/NET}$ = Gross or net energy output of your affected EGU for each valid operating hour (as defined in 60.5860b(a)(2)) in MWh.

$(PE)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(PE)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(PE)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected egu's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(PE)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(PT)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(V) of this section in MWh.

$(PT)_{HR}$ = Non-steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(PT)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric transmission and distribution factor of 0.95 for a combined heat and power affected egu where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consist of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Equation 2 to Paragraph (a)(5)(v)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

Q_M = Measured steam flow in kilograms (KG) (or pounds (LBS)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in joules per kilogram (J/KG) (or BTU/LB).

CF = Conversion factor of 3.6×10^9 J/MWH or 3.413×10^6 BTU/MWh.

(vi) For rate-based standards, sum all of the values of $P_{gross/net}$ for the valid operating hours (as defined in paragraph (a)(2) of this section). Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the $P_{gross/net}$ values for the valid operating hours to determine the CO_2 emissions rate (lb/gross or net MWh).

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly gross or net electric output for the common stack must be the sum of the hourly gross or net electric output of the individual affected EGUs and the operating time must be expressed as ''stack operating hours'' (as defined in 40 CFR 72.2).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in 40 CFR 72.2) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the gross or net energy output for the affected EGU.

(8) Consistent with § 60.5775b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(9) The owner or operator of an affected EGU must measure and report monthly fuel usage for each affected source subject to standards of performance with the information in paragraphs (a)(9)(i) through (iii) of this section:

(i) The calendar month during which the fuel was used;

(ii) Each type of fuel used during the calendar month of the compliance period; and

(iii) Quantity of each type of fuel combusted in each calendar month in the compliance period with units of measure.

(b) Your State plan must require the owner or operator of each affected EGU covered by your State plan to maintain the records, for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's standard of performance under § 60.5775b.

(ii) Copies of all reports submitted to the State under paragraph (b) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(c) Your State plan must require the owner or operator of an affected EGU covered by your State plan to include in a report submitted to you the information in paragraphs (c)(1) through (3) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour;

(ii) The gross or net electric output and the gross or net energy output ($P_{gross/net}$) values for each valid operating hour;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour;

(iv) The sum of the hourly gross or net energy output values and the sum of the hourly CO_2 mass emissions values, for all of the valid operating hours; and

(v) The calculated CO_2 mass emission rate (lbs/gross or net MWh).

(3) For each affected EGU the report must also include the applicable standard of performance and demonstration that it met the standard of performance. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate in units of the standard of performance.

(d) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a State plan that are required under § 60.5740b if applicable.

(e) If an affected EGU captures CO_2 to meet the applicable standard of performance, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from the EPA pursuant to paragraph (f) of this section.

(f) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5865b What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of State plan components, State plan requirements, supporting documentation, and the status of meeting the State plan requirements defined in the State plan.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that are used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860b.

(c) If your State has a requirement for all hourly CO_2 emissions and gross generation or heat input information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in 40 CFR part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records for a minimum of 10 years from the date the record is used to determine compliance with an emissions standard or State plan requirement. Each record must be in a form suitable and readily available for expeditious review.

(e) If your State plan includes provisions for the compliance date extension, described in § 60.5740b(a)(11), you must keep records of the information required in § 60.5740b(a)(11)(i) from affected EGUs that use the compliance date extension.

(f) If your State plan includes provisions for the short-term reliability mechanism, as described in § 60.5740b(a)(12), you must keep records of the information required in § 60.5740b(a)(12)(iii) from affected EGUs that use the short-term reliability mechanism.

(g) If your State plan includes provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13), you must keep records of the information required in § 60.5740b(a)(13)(vi) from affected EGUs that use the reliability assurance mechanism.

§ 60.5870b What are my reporting and notification requirements?

(a) In lieu of the annual report required under § 60.25(e) and (f), you must report the information in paragraph (b) of this section.

(b) You must submit an annual report to the EPA that must include the information in paragraphs (b)(1) through (10) of this section. For each calendar year reporting period the report must be submitted by March 1 of the following year.

(1) The report must include the emissions performance achieved by each affected EGU during the reporting period and identification of whether each affected EGU is in compliance with its standard of performance during the compliance period, as specified in the State plan.

(2) The report must include, for each affected EGU, a comparison of the CO_2 standard of performance in the State plan versus the actual CO_2 emission performance achieved.

(3) The report must include, for each affected EGU, the sum of the CO_2 emissions, the sum of the gross energy output, and the sum of the heat input for each fuel type.

(4) Enforcement actions initiated against affected EGUs during the reporting period, under any standard of performance or compliance schedule of the State plan.

(5) Identification of the achievement of any increment of progress required by the applicable State plan during the reporting period.

(6) Identification of designated facilities that have ceased operation during the reporting period.

(7) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of State plan development but began operation during the reporting period.

(8) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(9) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

(10) The report must include all other required information, as specified in your State plan according to § 60.5740b.

(c) If you include provisions for the compliance date extension, described in § 60.5740b(a)(11), in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(11)(i).

(d) If you include provisions for the short-term reliability mechanism, described in § 60.5740b(a)(12), in your State plan, you must report to the EPA the following information for each event, listed in § 60.5740b(a)(12)(iii).

(e) If you include provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13) in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(13)(vi).

§ 60.5875b How do I submit information required by these emission guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All State plan submittals, supporting materials that are part of a State plan submittal, any State plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through the EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States that claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539–01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the May 11, 2026, deadline for State plan submittal so that the official will have the ability to submit the initial or final State plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization, and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all State plan components designated as federally enforceable must also be submitted in an editable version. Following initial State plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable State plan components, including State plan backstop measures. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable State plan components. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

§ 60.5876b What are the recordkeeping and reporting requirements for EGUs that have committed to permanently cease operations by January 1, 2032?

(a) If you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must maintain records for and submit the reports listed in paragraphs (a)(1) through (3) of this section according to the electronic reporting requirements in paragraph (b) of this section.

(1) Five years before any planned date to permanently cease operations or by the date upon which the State plan is submitted, whichever is later, the owner or operator of the EGU must submit an initial report to the EPA that includes the information in paragraphs (a)(1)(i) and (ii) of this section.

(i) A summary of the process steps required for the EGU to permanently cease operation by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. These process steps may include, *e.g.,* initial notice to the relevant reliability authority of the deactivation date and submittal of an official retirement filing (or equivalent filing) made to the EGU's relevant reliability authority.

(ii) Supporting regulatory documents, which include those listed in paragraphs (a)(1)(ii)(A) through (G) of this section:

(A) Correspondence and official filings with the relevant regional RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority;

(B) Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

(C) Any filings pertaining to the affected EGU with the SEC or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which plans for the EGU are mentioned;

(D) Any integrated resource plans and PUC orders approving the EGU's deactivation;

(E) Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

(F) Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

(G) Any notification to or from an RTO, Independent System Operator, or relevant reliability authority altering the timing of deactivation of the EGU.

(2) For each of the remaining years prior to the date by which an EGU has committed to permanently cease operations, the owner or operator of the EGU must submit an annual status report to the EPA that includes the information listed in paragraphs (a)(2)(i) and (ii) of this section:

(i) Progress on each of the identified process steps identified in the initial report as described in paragraph (a)(1)(i) of this section; and

(ii) Supporting regulatory documents, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate progress toward all steps described in paragraph (a)(1)(i) of this section.

(3) The owner or operator must submit a final report to the EPA no later than 6 months following its committed closure date. This report must document any actions that the EGU has taken subsequent to ceasing operation to

ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(b) Beginning November 12, 2024, if you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must submit all the information required in paragraph (a) of this section in a Permanent Cessation of Operation report in PDF format following the procedures specified in paragraph (c) of this section.

(c) If you are required to submit notifications or reports following the procedure specified in this paragraph (c), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (c)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (c).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov*, and as described above, should include clear CBI markings and be flagged to the attention of the Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive P.O. Box 12055, RTP, NC 27711. All other files should also be sent to the attention of the Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(d) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(e) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (e)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(f) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs(f)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension

to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(g) Alternatives to any electronic reporting required by this subpart must be approved by the Administrator.

Definitions

§ 60.5880b What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A, Ba, TTTT, and TTTTa, of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit that meets the relevant applicability conditions in section § 60.5845b.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions, as defined below. For a stationary combustion turbine or IGCC, *base load rating* includes the heat input from duct burners.

Coal-fired steam generating unit means an electric utility steam generating unit or IGCC unit that meets the definition of ''fossil fuel-fired'' and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029, or that retains the capability to fire coal after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as ''cogeneration'') means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means an annual (calendar year) period for an affected EGU to comply with a standard of performance.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired,'' that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any calendar year after December 31, 2029.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to standard ambient temperature and pressure conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Oil-fired steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns oil for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

System Emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2, or its successor.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to 40 CFR part 75. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.4, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75 apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

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United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 24-1120 **September Term, 2023**

EPA-89FR39798

Filed On: July 19, 2024

State of West Virginia, et al.,

Petitioners

v.

Environmental Protection Agency and Michael S. Regan, Administrator, United States Environmental Protection Agency,

Respondents

Louisiana Public Service Commission, et al.,
Intervenors

Consolidated with 24-1121, 24-1122, 24-1124, 24-1126, 24-1128, 24-1142, 24-1143, 24-1144, 24-1146, 24-1152, 24-1153, 24-1155, 24-1222, 24-1226, 24-1227, 24-1233

BEFORE: Millett, Pillard, and Rao, Circuit Judges

O R D E R

Upon consideration of the motions for stay, the oppositions thereto, the replies, the Rule 28(j) letter, and the responses thereto; and the motions to participate as amici curiae and the lodged amicus briefs, it is

ORDERED that the motions of the Chamber of Commerce, the Sierra Club, the Environmental Defense Fund, and Professor Rachel Rothschild to participate as amici curiae be granted. The Clerk is directed to file the lodged amicus briefs. It is

United States Court of Appeals
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FURTHER ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending this court's review. *See Nken v. Holder*, 556 U.S. 418, 434 (2009); D.C. CIRCUIT HANDBOOK OF PRAC. AND INTERNAL PROCS. 33 (2021).

On the merits, petitioners dispute whether the Environmental Protection Agency ("EPA") acted arbitrarily or capriciously in determining that carbon capture and other emission control technologies are adequately demonstrated, or that specific degrees of emission mitigation are achievable with those technologies. But petitioners have not shown they are likely to succeed on those claims given the record in this case. Nor does this case implicate a major question under *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), because EPA has claimed only the power to "set emissions limits under Section 111 based on the application of measures that would reduce pollution by causing the regulated source to operate more cleanly[,]" a type of conduct that falls well within EPA's bailiwick, *id.* at 2610.

On irreparable harm, actual compliance deadlines do not commence until 2030 or 2032—years after this case will be resolved. Though the first deadline for States to submit state implementation plans is May 2026, the only consequence of failing to submit a state plan is the promulgation of a federal plan—which the States can replace with their own plans later. EPA Opp., Ex. 1, Goffman Decl. ¶ 100. To the extent petitioners claim harm due to the need for long-term planning, a stay will not help because the risk remains that the distant deadlines in EPA's rule will come back into force at the end of the case.

EPA has suggested that this case be expedited as an alternative means of protecting all parties' interests. Accordingly, to ensure this case can be argued and considered as early as possible in the court's 2024 term, it is

FURTHER ORDERED that the parties submit, within 14 days from the date of this order, proposed formats and schedules for the briefing of these cases. The parties are strongly urged to submit a joint proposal and are reminded that the court looks with extreme disfavor on repetitious submissions and will, where appropriate, require a joint brief of aligned parties with total words not to exceed the standard allotment for a single brief. Whether the parties are aligned or have disparate interests, they must provide detailed justifications for any request to file separate briefs or to exceed in the

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aggregate the standard word allotment. Requests to exceed the standard word allotment must specify the word allotment necessary for each issue.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Selena R. Gancasz
Deputy Clerk

APPENDIX B

- TECHNICAL SUPPORT DOCUMENT –

To: Docket EPA-HQ-OAR-2013-0495
Date: July 10, 2015
Subject: Literature Survey of Carbon Capture Technology

Introduction

On January 8, 2014, the Environmental Protection Agency (EPA) proposed New Source Performance Standards (NSPS) to limit carbon dioxide (CO_2) emissions from new fossil fuel-fired electricity generating units (EGUs) under Clean Air Act (CAA) §111(b).[1] Carbon capture and storage (CCS), also known as "carbon capture and sequestration," was evaluated as an option for new steam generating boilers and integrated gasification combined cycle (IGCC) units in developing the proposed and final NSPS. In determining the best system of emission reduction adequately demonstrated (BSER) to establish the standards, the EPA reviewed literature covering existing projects that implement CCS, existing projects that implement various components of CCS, planned CCS projects, and scientific and engineering studies of CCS. The final NSPS contains an emission limit of 1,400 pounds CO_2 per megawatt hour on a gross basis (lb CO_2/MWh-g) for new steam generating boilers and IGCC units based on partial CCS (i.e., CCS on a portion or "slip-stream" of the EGU exhaust). Among other compliance approaches,[2] partial CCS was determined to be adequately demonstrated based on the fact that post-combustion CCS is demonstrated in full-scale operation within the electricity generating industry, and full-scale pre-combustion CCS has been demonstrated in several chemical industry plants with results that are reasonably transferable to the electricity generating sector. It is important to note that the NSPS does not require near-term widespread use of full CCS for all electric utilities, but rather is based on partial CCS for only the subset of *new* fossil-fuel fired electric utility boilers or IGCC units.

The purpose of this technical support document (TSD) is to provide an overview of CCS technology and describes the status of sources implementing CCS projects to date. This TSD provides information on the technological feasibility of CCS (including partial CCS), but does not discuss costs. The EPA's conclusions regarding the costs and emission reductions associated with implementation of partial CCS are based on in-depth studies of costs by DOE/NETL reports and recent EIA AEO projections and are documented in a separate memorandum and the Regulatory Impact Analysis for the final NSPS. Similarly, a separate document discusses funding mechanisms associated with CCS projects.

This document is organized as follows:

[1] Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430.
[2] It is noted that a new utility boiler or IGCC unit can meet the final standard of performance of 1,400 lb CO2/MWh by co-firing natural gas should project developers choose to delay implementation of partial CCS.

I. Overview of CCS Technology for Fossil-fuel Fired EGUs

Use of fossil fuel to generate electricity commonly occurs in one of the following systems:

- A steam generating unit (also referred to simply as a "boiler") that feeds a steam turbine that spins an electric generator.
- A combustion turbine (or reciprocating internal combustion engine) that directly drives the generator. Some modern power plants use a "combined cycle" electric power generation process, in which a gaseous or liquid fuel is burned in a combustion turbine that both drives electrical generators and provides heat to produce steam in a heat recovery steam generator (HRSG) that drives a second electric generator to increase the overall efficiency of the electric power generation process.
- An integrated gasification combined cycle (IGCC) system that first gasifies solid fuel and burns the resulting syngas in a combined cycle stationary combustion turbine for electric generation.

The majority of new fossil-fuel fired electric generating units are projected to use natural-gas combined cycle technology which results in lower CO_2 emissions per MWh of electricity produced than steam generating units or IGCC systems burning solid fossil fuels such as coal. Use of CCS was analyzed as an option for reducing CO_2 emissions from new steam generating units and new IGCC systems for purposes of the NSPS.

Carbon capture and storage (CCS) involves the separation and capture of CO2 from flue gas, or syngas in the case of IGCC. CCS is a three-step process that includes:

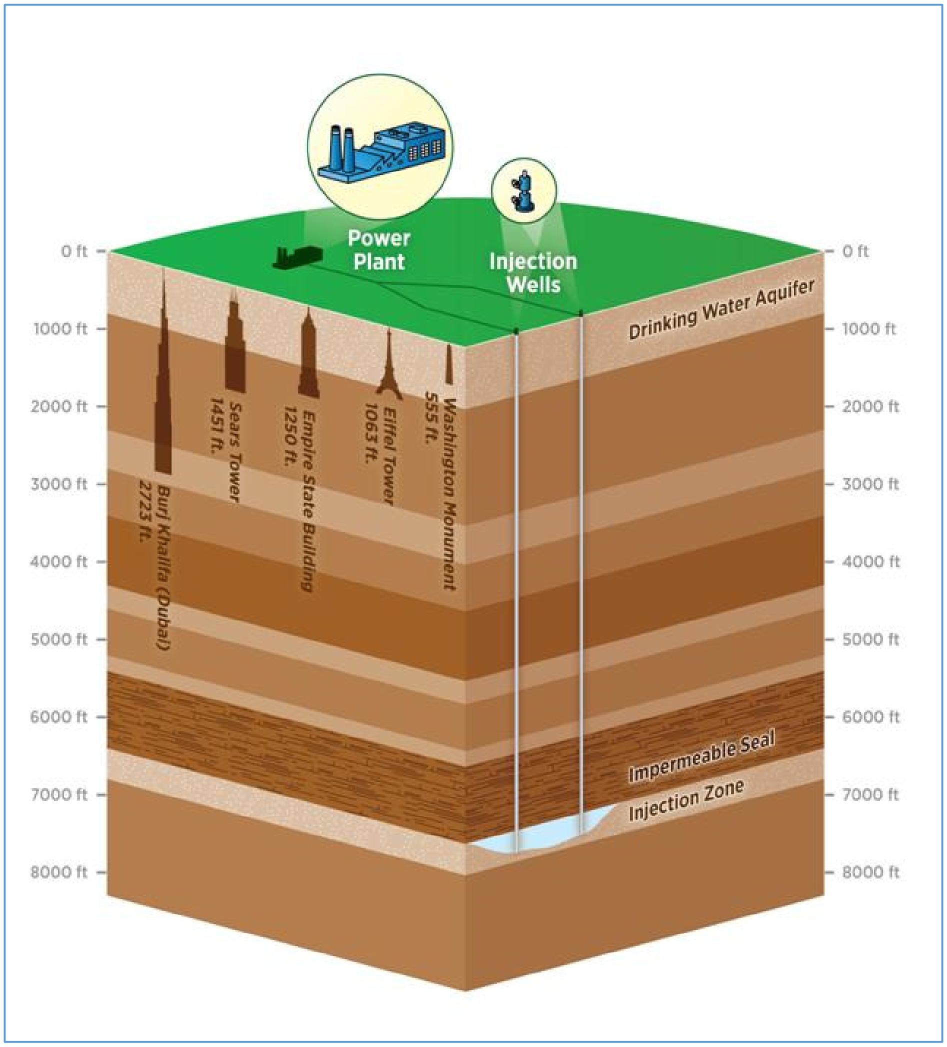
1. Capture of CO_2 from electric generating units (or other industrial processes);
2. Compression and transport of the captured CO_2 (usually in pipelines);
3. Underground injection and geologic sequestration (also referred to as storage) of the CO_2 into deep underground rock formations. These formations are often a mile or

more beneath the surface and consist of porous rock that holds the CO_2. Overlying these formations are impermeable, non-porous layers of rock that trap the CO_2 and prevent it from migrating upward.

Figure 1 illustrates the typical depth at which CO_2 would be injected.

Figure 1. CCS Schematic

(Subsurface depth to scale, 5,280 feet equals one mile) (EPA, 2013c)



Geologic sequestration is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO_2 increases oil production efficiency through a process referred to as enhanced oil recovery (EOR). CO_2 may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs such as unmineable coal seams also offer the potential for geologic storage.[3]

[3] Other types of opportunities include organic shales and basalt.

A study prepared for the U.S. DOE by the Pacific Northwest National Laboratory (Dooley, 2009) evaluated the development status of various CCS technologies. The study addressed the availability of capture processes; transportation options (CO2 pipelines); injection technologies; and measurement, verification, and monitoring technologies. The study concluded that, in general, CCS was technically viable at the time of the report (2009) although full-scale CCS systems had not yet been installed and fully integrated at an EGU at that time. The study also did not address the cost or energy requirements of implementing CCS technology.[4]

In 2010, an Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of CCS technologies (Interagency Task Force, 2010). The Task Force was specifically charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing commercial demonstration projects online by 2016. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical barriers to implementation.[5]

Much research and development has occurred in the 5 years since these DOE and interagency reports were written in the 2009-2010 timeframe. As described in more detail in Section II of this report, full-scale EGU CCS demonstration projects are underway. Research to reduce the energy requirements of CCS technologies and improve its cost-effectiveness continues, as described in section I.F of this document. A more recent report from the DOE/NETL provides a technology update and summarizes research continuing research sponsored by the DOE (NETL, 2013). The EPA's updated cost analysis for CCS systems based on DOE/NETL analyses (from 2010-2015), EIA AEO projections (from 2014), and other recent information is presented in the RIA for the NSPS.

The following subsections provide an overview of CO_2 capture technology, CO_2 compression, CO_2 pipeline infrastructure for transportation, geologic sequestration, and alternatives to geologic sequestration.

A. CO_2 Capture Technology

In general, CO_2 capture technologies applicable to fossil-fuel fired power generation can be categorized into three approaches:

- **Post-combustion systems** are designed to separate CO_2 from the flue gas produced by fossil-fuel combustion in air.

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[4] For up-to-date information on Department of Energy's National Energy Technology Laboratory's (NETL) Carbon Sequestration Program go to the NETL web site (NETL, 2015b) at: http://www.netl.doe.gov/research/coal/carbon-storage/research-and-development.
[5] For additional information on the Interagency Task Force and its findings on CCS, go to: http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

- **Pre-combustion systems** are designed to separate CO_2 and H_2 in the high-pressure syngas produced at IGCC power plants.

- **Oxy-combustion** uses high-purity oxygen (O_2), rather than air, to combust coal and therefore produces a highly concentrated CO_2 stream.

The post- and pre-combustion CO_2-capture processes typically use solvents, solid sorbents, and membrane-based technologies for separating and capturing CO2. Solvents chemically absorb the CO_2 which is separated from the solvent in a regeneration step. Solid sorbents capture CO2 through chemical adsorption, physical adsorption, or a combination of the two effects. Membrane-based capture uses permeable or semi-permeable materials to produce a highly concentrated CO2 stream that does not require a separation/capture step.

Each of the CO_2-capture approaches results in increased capital and operating costs and decreased electricity output (or energy penalty[6]), thereby increasing the cost of electricity.[7] The energy penalty occurs because the CO_2 capture process uses some of the energy produced from the plant (Interagency Task Force, 2010). Research is underway to reduce CO_2 capture costs and to improve performance. The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO_2 from fossil-fuel energy plants compared to currently available capture technologies. The large-scale CO_2 capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will continue to generate operational knowledge and enable continued commercialization and deployment of these technologies. The EPA is currently finalizing an NSPS limit based on partial CCS (as opposed to CCS of the full exhaust stream) to help mitigate the energy penalty and costs of CCS as the technology continues to emerge and be refined through further research.

Each of the CO_2-capture systems are described and discussed in more detail in the subsections below. Facility-specific applications of CO_2 capture systems are discussed in Section II.

1. Post-combustion CO_2 capture

Post-combustion CO_2 capture refers to removal of CO_2 from combustion flue gas prior to discharge to the atmosphere. It is referred to as "post-combustion capture" because the CO_2 is the

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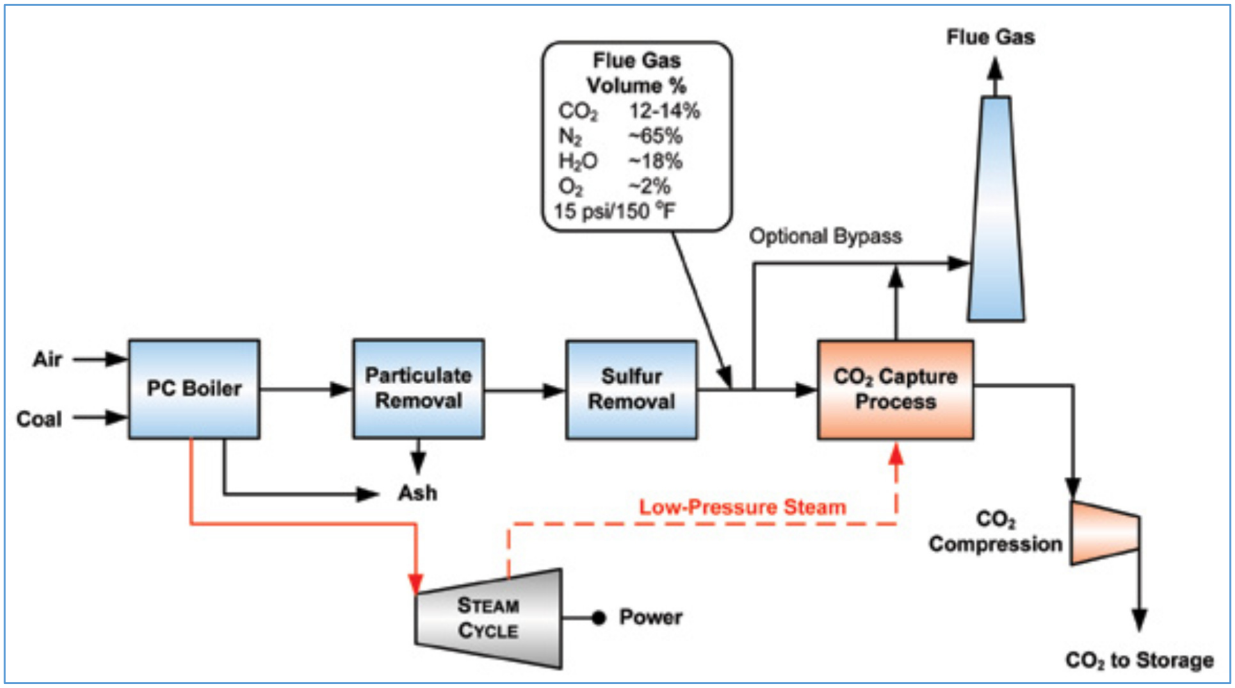
[6] The energy penalty represents the percentage reduction in the power plant operating efficiency. For example, a reduction in efficiency from 30 percent to 20 percent represents a 10 percentage point drop in efficiency, which is equivalent to a 33 percent energy penalty.

[7] There is on-going research sponsored by DOE/NETL and others to further reduce the energy requirements of the carbon capture systems. Progress is being made. For example, the heat duty (the energy required to regenerate the capture solvent) for the amine scrubbing process used at the Searles Valley facility in the mid-70's was about 12 MJ/mt CO_2 removed as compared to a heat duty of about 2.5 MJ/mt CO_2 removed for the amine processes used in 2014 at Boundary Dam and for the amine system that will be used at the WA Parish facility.

product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. A simplified process schematic of post-combustion CO_2 capture is shown in **Figure 2** (NETL, 2013).

Figure 2: Diagram Illustrating a Pulverized Coal Boiler with Post-Combustion CO_2 Capture



As noted previously, in a typical fossil fuel-fired steam generating unit, fuel is burned with air in a boiler to produce steam that drives a turbine/generator to produce electricity. Flue gas from the boiler consists primarily of N_2 and CO_2 with other components in trace amounts (e.g., particulate matter (PM), sulfur oxides (SOx), nitrogen oxides (NOx), hydrochloric acid (HCl) etc.) The CO_2 capture process is located downstream of the conventional pollutant controls for removal of PM and acid gases so these components will not interfere with CO_2 removal. In addition to the need to remove pollutants upstream of the CO_2 capture system, challenges to separating CO_2 from steam generating unit combustion flue gas include:

- the high volume of gas to be treated because the CO_2 is dilute (13–15 volume percent in coal-fired systems);
- the low pressure [15–25 pounds per square inch (psi)] of the flue gas;
- and the large auxiliary power load to compress captured CO_2 from near atmospheric pressure to pipeline pressure (about 2,200 psi).

The volume of flue gas to be treated (and the associated energy penalty) is reduced in partial CO_2 capture systems, where a slipstream of the flue gas is treated as opposed to the entire flue gas stream.

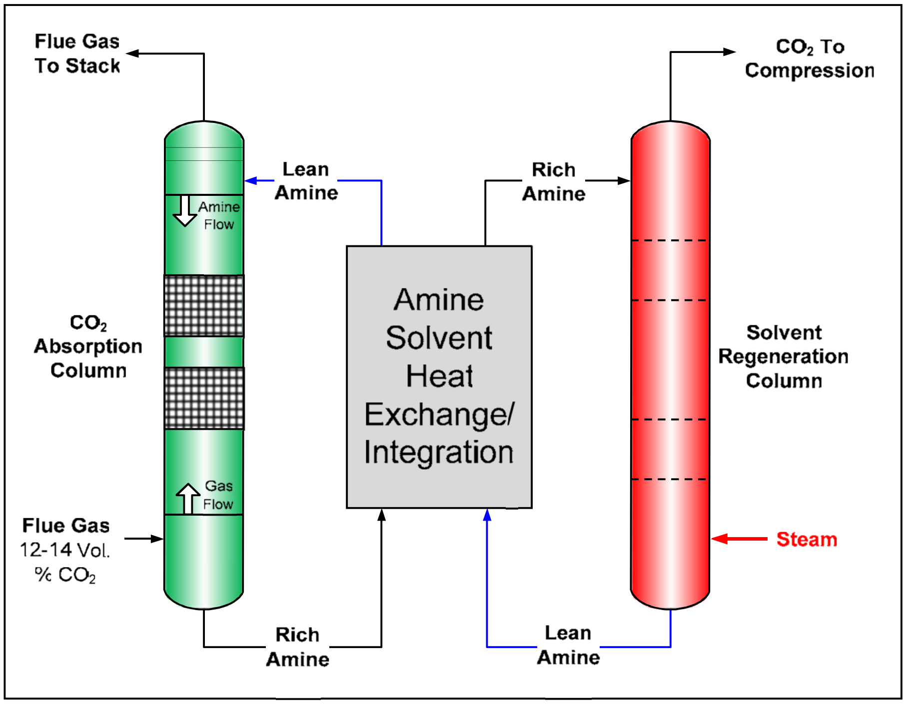
The CO_2 capture process involves use of a chemical solvent, solid sorbent, or membrane to separate CO_2 from the flue gas. Amine-based solvent systems are most commonly used for post-combustion capture systems. When contacted with the combustion flue gas, then solvent participates in a chemical absorption (chemisorption) separation process in which the CO_2 is absorbed by the liquid solvent. Solid sorbents can be used to capture CO_2 from flue gas through chemical adsorption, physical adsorption, or a combination of the two. Possible configurations for contacting the flue gas with solid sorbents include fixed, moving, and fluidized beds. Membrane-based capture uses permeable or semi-permeable materials that allow for the selective transport/separation of CO_2 from flue gas (NETL, 2015c).

Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry to produce food and chemical grade CO_2. Amine-based solvent systems are in commercial use for scrubbing CO_2 from industrial flue gases and process gases, and are available for use in CCS systems at electric utilities. Following absorption into the amine-based solvent, a high purity CO_2 stream is separated from the solvent in a steam stripping (solvent regeneration) process, where the solvent is heated with low pressure steam from the power plant's steam cycle. Solvent regeneration is responsible for much of the "energy penalty" of the CO_2 capture system because steam that could otherwise be used to generate electricity is instead used in the solvent regeneration process. Development of advanced solvents – those that are chemically stable, have high CO_2 absorption capacities, and have low regeneration energy requirements – continues to be an active area of research. The DOE/NETL's post-combustion CO_2 control technology R&D program includes projects directed at the use of solvents, solid sorbents, and membranes.

Amines chemically react with CO_2 via reversible reactions to form water-soluble compounds. Despite the low CO_2 partial pressure in combustion flue gas, amines are capable of achieving high levels of CO_2 capture due to fast kinetics and strong chemical reactions. However, the absorption capacity for commercially available amines is chemically limited, requiring two molecules of amine for each molecule of CO_2. In addition, usable amine solution concentrations are typically limited by viscosity and corrosion. Therefore, current amine systems are only between 20 and 30 percent amine with the remaining being water. Although the water present in the solution helps control the solvent temperature during absorption, which is an exothermic reaction, the water also requires significant amounts of sensible heating and stripping energy upon CO_2 regeneration. Not every amine system is the same, and various vendors offer different designs. In general, depending on the amount of heat integration, anywhere from 1,550 to greater than 3,000 British thermal units (Btu) per pound of CO_2 in the form of low pressure steam (approximately 45 psi) is required to regenerate the solvent to produce a concentrated CO_2 stream at a pressure of approximately 25 psi (Interagency Task Force, 2010).

An amine-based post-combustion capture process is depicted in **Figure 3**.

Figure 3. Schematic Diagram of Amine-based CO_2 Capture Process



After conventional air pollutant (SOx, NOx, PM) cleanup, the combustion flue gas enters an absorber reactor and flows counter-currently to a CO2-lean solvent where CO_2 is absorbed into, and chemically reacts with the amine solution. The treated flue gas (mostly N_2) is discharged to the atmosphere, and the CO_2-rich amine solution is pumped to a solvent regeneration column where the CO_2-rich solution is heated in order to reverse the chemical reactions between the CO_2 and amine solvent. Steam extracted from the turbine cycle provides the heat for regeneration of the amine solvent in the solvent regeneration column. Consequently, CO_2 is released, producing a concentrated stream that exits the regeneration column and is then cooled and dehumidified in preparation for compression, transport, and storage. From the solvent regeneration column, the CO_2-lean solution is cooled and returned to the absorber for reuse (Interagency Task Force, 2010).

Post-combustion CO_2 capture offers the greatest near-term potential for reducing power sector CO_2 emissions because it can be tuned for various levels of CO_2 capture (e.g., in partial capture systems as indicated by the optional bypass in **Figure 2**). Post-combustion capture technologies are available for application to conventional coal-fired power plants and the combustion flue gas from IGCC power plants (Interagency Task Force, 2010; NETL, 2013). Many projects are in the planning stages for demonstration scale-up including the Alstom chilled ammonia process and several amine-based processes (e.g., Fluor [Econamine], ABB/Lummus, Mitsubishi Heavy Industries [MHI], HTC Purenergy, Aker Clean Carbon, Cansolv, et al.) (Interagency Task Force, 2010).

The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO_2 capture. Most single component amine systems are not practical in a flue gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FG process uses a monoethanolamine (MEA) formulation specially designed to recover CO_2 and contains a corrosion inhibitor that allows the use of less expensive, conventional materials of construction. Other commercially available processes use sterically hindered amine formulations (for example, the Mitsubishi Heavy Industries KS–1 solvent) which are less susceptible to degradation and corrosion issues.

Several companies offering post-combustion CO_2 capture technologies have offered performance guarantees or made public statements regarding the technical feasibility of their systems for CO_2 capture from fossil-fuel fired power plants. For example:

- Linde and BASF offer performance guarantees for CCS technology. The two companies are jointly marketing new, advanced technology for capturing CO2 from low pressure gas streams in power or chemical plants. In product literature (BASF/Linde, undated) they note that Linde will provide a turn-key carbon capture plant using a scrubbing process and solvents developed by BASF, the world's leading technical supplier for gas treatment. They further note that:
    - The captured carbon dioxide can be used commercially for example for EOR (enhanced oil recovery) or for the production of urea. Alternatively it can be stored underground as a carbon abatement measure. […] The PCC (Post-Combustion Capture) technology is now commercially available for lignite and hard coal fired power plant […] applications.
    - The alliance between Linde, a world-leading gases and engineering company and BASF, the chemical company, offers great benefits […] Complete capture plants including CO_2 compression and drying … Proven and tested processes including guarantee … Synergies between process, engineering, construction and operation … Optimized total and operational costs for the owner.

- Fluor has developed patented CO_2 recovery technologies to help its clients reduce GHG emissions. The Fluor product literature (Fluor, 2015) specifically points to Econamine FG PlusSM process which uses an amine solvent to capture and produce food grade CO_2 from post-combustion sources. The literature further notes that Econamine FG Plus^{SM} (EFG+) is also used for carbon capture and sequestration projects, that the proprietary technology provides a proven, cost-effective process for the removal of CO_2 from power plant flue gas streams and that the process can be customized to meet a power plant's unique site requirements, flue gas conditions, and operating parameters.

- Fluor has also published an article titled "Commercially Available CO_2 Capture Technology" in which it describes the EFG+ technology (Johnson et. al, 2009). The article notes, "Technology for the removal of carbon dioxide (CO_2) from flue gas streams has been around for quite some time. The technology was developed not to address the GHG effect but to provide an economic source of CO_2 for use in enhanced oil recovery and industrial purposes, such as in the beverage industry."

- Mitshubishi Heavy Industries (MHI) offers a CO_2 capture system that uses a proprietary energy-efficient CO_2 absorbent called KS-1™. Compared with the conventional monoethanolamine (MEA)-based absorbent, KS-1™ solvent requires less solvent circulation to capture the CO2 and less energy to recover the captured CO_2.

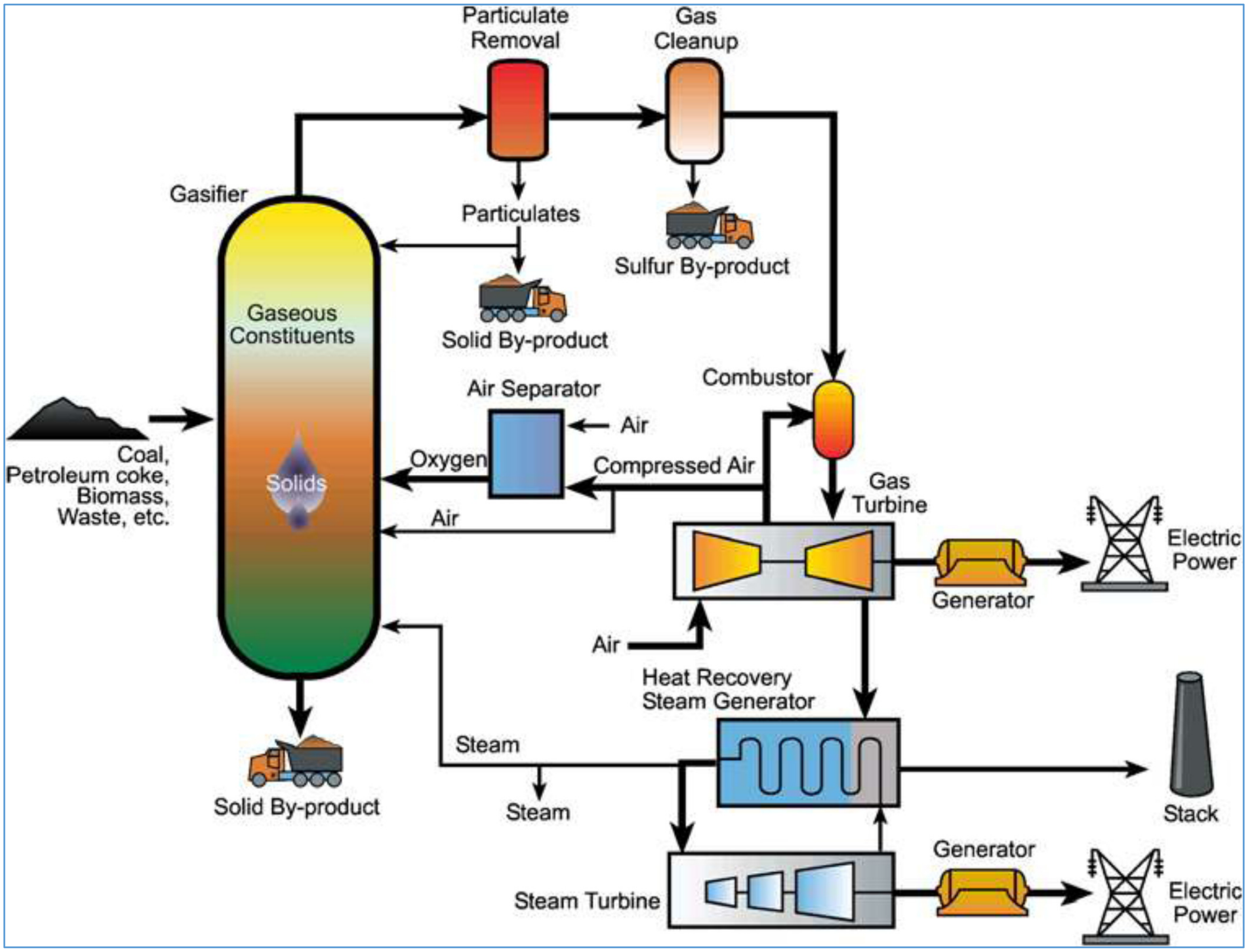
- Shell has developed the CANSOLV CO_2 Capture System, which Shell describes in its product literature as a world leading amine based CO_2 capture technology that is ideal for use in fossil fuel-fired power plants where enormous amounts of CO_2 are generated. The company also notes that the technology can help refiners, utilities and other industries lower their carbon intensity and meet stringent GHG abatement regulations by removing CO_2 from their exhaust streams, with the added benefit of simultaneously lowering SO_2 and NO_2 emissions.

The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO_2 capture performance and reduce costs.

2. Pre-combustion CO_2 capture

Pre-combustion CO_2 capture, as its name implies, takes place before the process gas is combusted to generate steam at a power plant. Pre-combustion capture is applicable mainly to IGCC processes where fuel is converted into gaseous components by applying heat under pressure in the presence of steam and limited O_2, as shown in **Figure 4.**

Figure 4. Schematic of an integrated gasification combined cycle (IGCC) power plant. (EPA, 2010)



In an IGCC system, the fuel (usually coal or petroleum coke at electric utilities) is heated with water and oxygen in an oxygen-lean environment. Unlike a boiler, a gasifier carefully controls the amount of air or oxygen available inside it so only a small portion of the fuel burns completely. This "partial oxidation" process provides heat to drive gasification reactions. Rather than burning, most of the fuel is chemically broken apart by the heat and pressure in the gasifier, setting into motion chemical reactions that produce syngas. The fuel (carbon), water and oxygen react to form primarily a mixture of hydrogen (H_2) and carbon monoxide (CO) known as synthesis gas or "syngas" according to the following high temperature reaction:

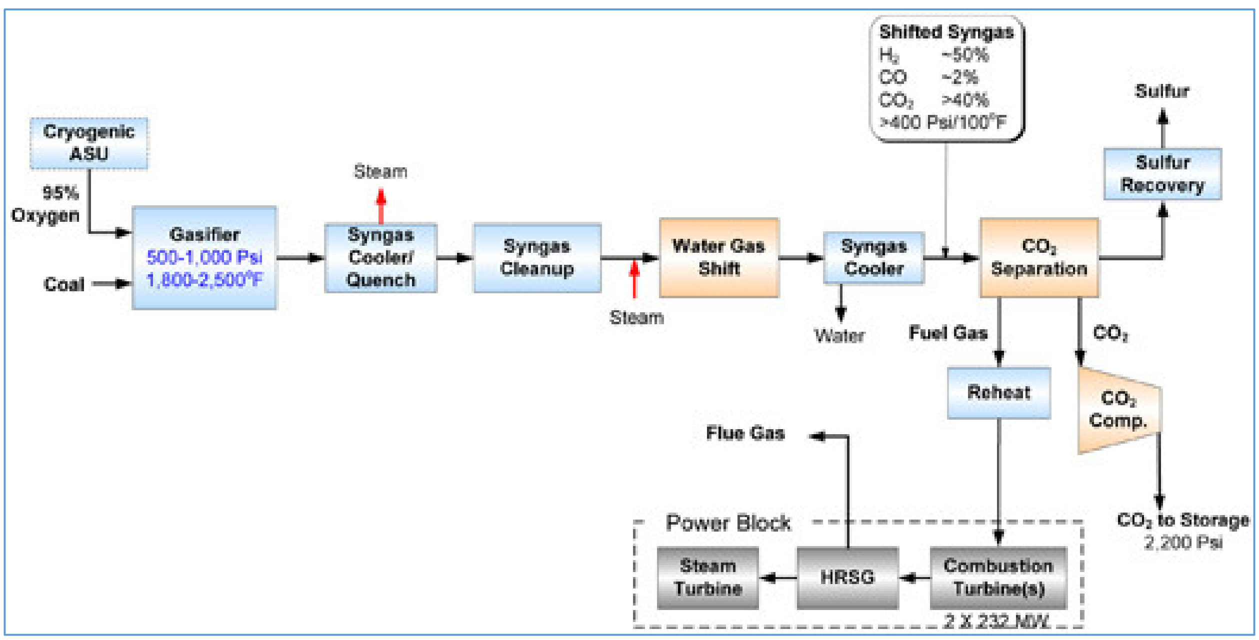
$$3C + H_2O + O_2 \rightarrow H_2 + 3CO$$

Although syngas is predominantly H_2 and CO, it can include other gaseous constituents (e.g., hydrogen sulfide (H_2S), carbonyl sulfide (COS), and CO_2) in varying compositions depending on fuel characteristics and the conditions in the gasifier. The amount of CO_2 in syngas depends upon the specific gasifier technology used, the operating conditions, and the fuel used; but is typically less than 20 volume percent. The gasification process also produces inorganic materials originating from the coal (e.g., minerals, ash). After removal of the impurities, the syngas is combusted using a conventional combustion turbine in a combined cycle configuration (i.e., a combustion turbine combined with a heat recovery steam generator and steam turbine).

Most syngas streams are at higher pressure and can contain higher concentrations of CO_2 than conventional steam generating units (especially if the syngas is shifted to enrich the CO_2 concentration as described below). As such, the pre-combustion CO_2 capture systems can utilize physical absorption (physisorption) solvents rather than the chemical absorption solvents described earlier for post-combustion processes. Physical absorption has the benefit of relying on weak intermolecular interactions and, as a result, the absorbed CO_2 can often be released (desorbed) by reducing the pressure rather than by adding heat. Pre-combustion capture systems have been used widely in industrial processes such as natural gas processing.

Figure 5 is a simplified process schematic for pre-combustion CO_2 capture. Components of the pre-combustion CO_2 capture system include a water-gas shift (WGS) reactor, syngas cooler (to achieve optimum temperature for the CO_2 separation step), CO_2 separation system, and compressor needed to raise the captured CO_2 to pipeline pressure.

Figure 5. Pre-Combustion CO_2 Capture for an IGCC Power Plant (NETL, 2015d)



In preparation for pre-combustion CO_2 capture, the amount of CO_2 in the syngas can be increased by "shifting" the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam ("water") with CO ("gas") to form H_2 and CO_2 according to the following catalytic reaction:

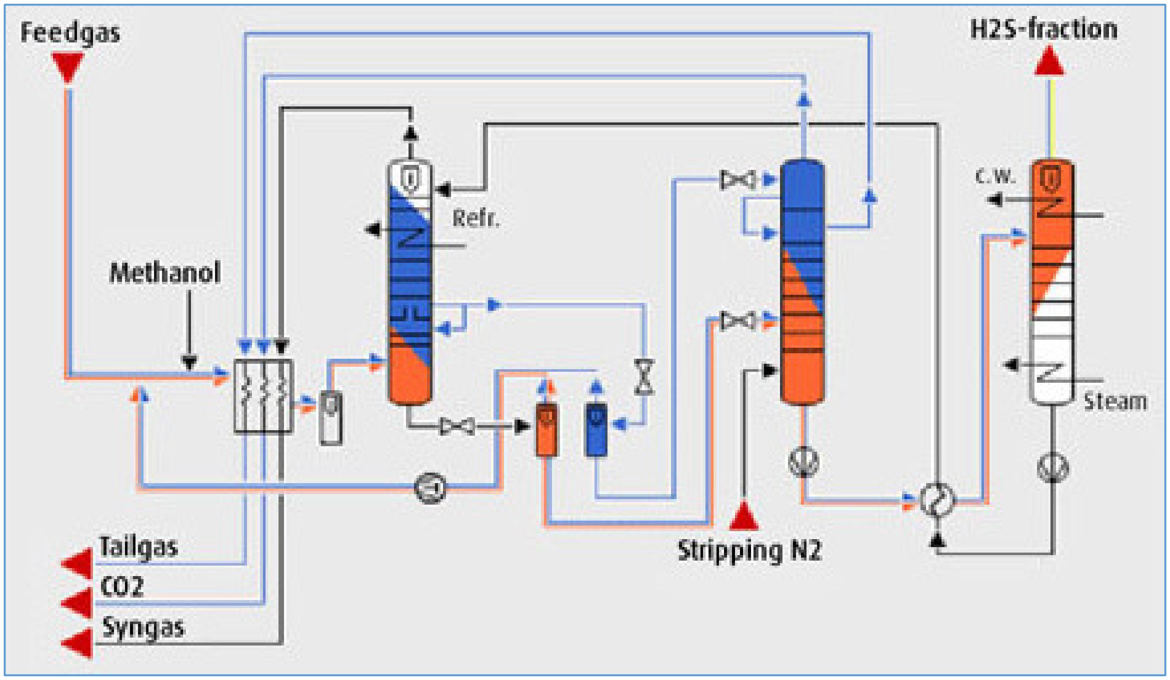
$$CO + H2O \rightarrow CO2 + H2$$

A WGS reactor is typically a fixed-bed reactor containing shift catalysts to convert CO and water into additional H_2 and CO_2. The resulting CO2 contained in the syngas is then separated from the H2-enriched syngas which is used for combustion in a combined-cycle turbine system for electricity generation. The CO2 separation process uses a physical solvent, solid sorbent, or membrane to separate the CO_2 from the syngas. Sulfur compounds and CO_2 can be removed either simultaneously or selectively (in a subsequent sulfur recovery step), depending on the shifted syngas composition and conditions, as well as the end fuel gas specifications. Contrary to the post-combustion capture flue gas, the IGCC syngas can contain a high concentration of CO_2 (at high partial pressure) and is pressurized. This allows the use of physical absorbents that require much less added energy to release the captured CO_2 and require less compression to get to pipeline standards. The lower volume of syngas to be handled results in smaller equipment sizes and lower capital costs. (Interagency Task Force, 2010); NETL 2013)

The current state-of-the-art pre-combustion CO_2 capture technologies that could be applied to IGCC systems (the glycol-based Selexol™ process and the methanol-based Rectisol® process) employ physical solvents that preferentially absorb CO_2 from the syngas mixture. Other CO2 separation processes that have yet to be built for full-scale IGCC power plants include the pyrolidone-based Purisol process and the polypropylene carbonate-based Fluor solvent (Interagency Task Force, 2010). Several Rectisol and Selexol systems are in use at commercial scale. For example, the Rectisol system is used for CO_2 capture at the Dakota Gasification Company's substitute natural gas (SNG) plant in North Dakota, which is designed to remove approximately 1.5 million tons of CO_2 per year from the syngas. The CO_2 is purified, transported via pipeline and injected into the Weyburn oilfield in Saskatchewan, Canada (NETL, 2015d).

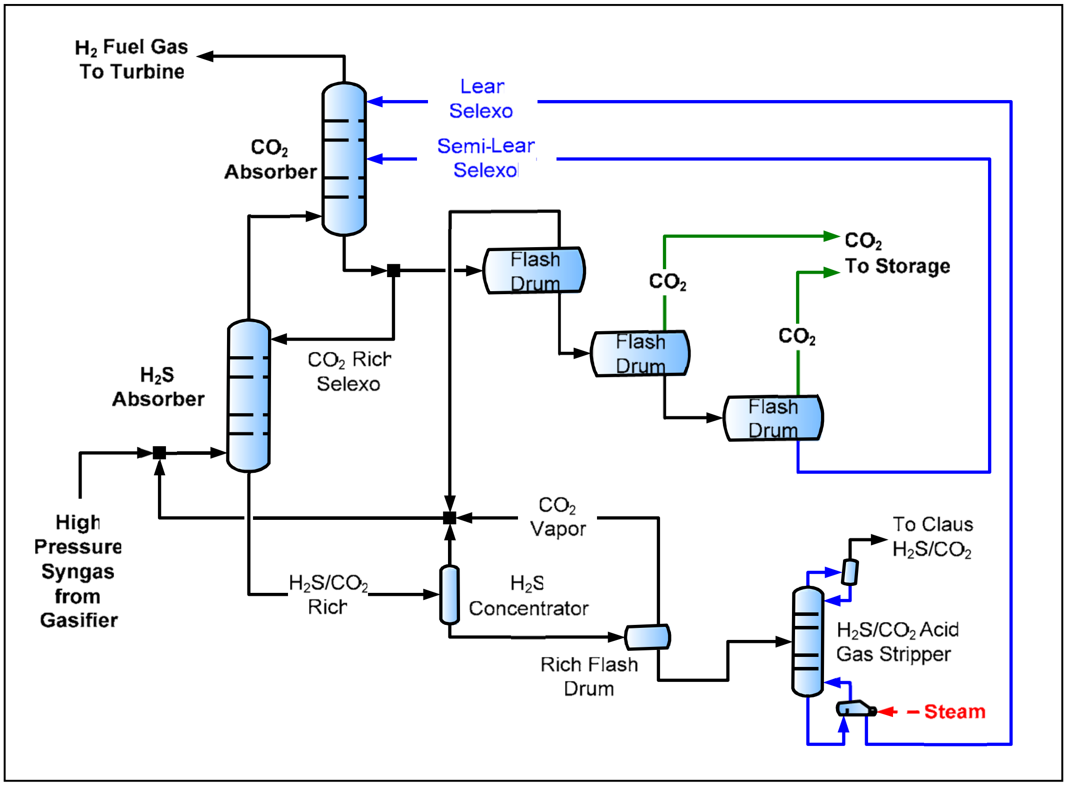
A simplified flow scheme of the Rectisol® process provided by technology vendor Linde is displayed in **Figure 6**. This is a configuration intended for dual removal of sulfur gases and CO_2 in separate fractions, resulting in a pure CO_2 product and an H_2S/COS enriched gas fraction (NETL, 2015h)

Figure 6: Rectisol Process Diagram (NETL, 2015h)



Using the two-stage Selexol™ process as an example (**Figure 7**), in the first stage, untreated syngas enters the first of two absorbers where H2S is preferentially removed using CO_2-rich solvent from the CO_2 absorber. The gas exiting the H2S absorber passes through the second absorber, where CO_2 is removed using both semi-lean and lean solvent streams. The treated syngas exits the absorber and is sent to the combustion turbine. The CO_2-rich solvent exits the CO_2 absorber, and a portion is sent to the H_2S absorber, while the remainder is sent to a series of flash drums for regeneration. The CO_2 product stream is obtained from the flash drums, and the semi-lean solvent is returned to the CO_2 absorber. The H_2S/CO_2-rich solvent exiting the H_2S absorber is sent to the acid gas stripper, where the absorbed gases are released using a steam heated reboiler. The acid gas from the stripper is sent to a Claus plant to produce elemental sulfur for commercial use, and the lean solvent exiting the stripper is returned to the CO_2 absorber. (Interagency Task Force, 2010)

Figure 7. Schematic Diagram of the Pre-Combustion Selexol™ CO_2 Capture Process



The Selexol™ process is being used at Southern Company's Kemper, Mississippi IGCC facility., Southern Company's Mississippi Power stated that, because the Selexol™ process has been used in industry for decades, the technical risk of its use at the Kemper IGCC facility are minimized.

For example:

> The carbon capture process being utilized for the Kemper County IGCC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over 40 years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable (Anderson, 2009).
>
> And …
>
> "The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk." (Mississippi Power Company, 2009).

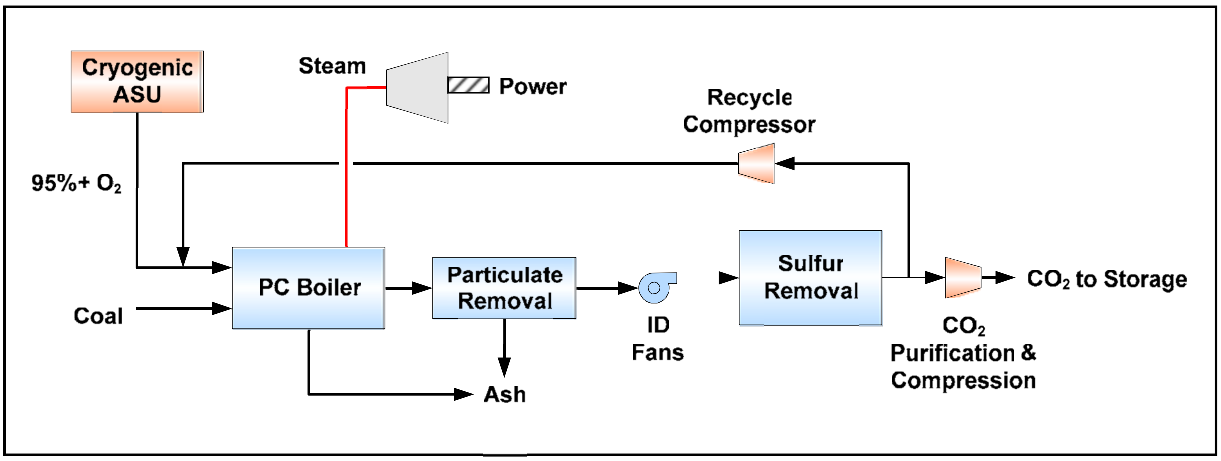
3. Oxy-combustion CO2 capture

Oxy-combustion (or oxy-fuel) refers to the replacement of air, either in the boiler or the gasifier, with pure oxygen (O_2). Using purified O2 helps eliminate unwanted byproducts present in air, and also increases the CO_2 purity of the resulting syngas or flue stream, making CCS more effective.

Oxy-combustion systems for CO_2 capture rely on combusting coal (or other fuel) with relatively pure O2 diluted with recycled CO_2 or CO_2/steam mixtures, as shown in **Figure 8**. The primary products of combustion are water and CO_2, with the CO_2 separated by condensing the water and removing any other gas constituents that infiltrated the combustion system (Interagency Task Force, 2010).

Figure 8. Pulverized Coal Power Plant with Oxy-Combustion CO_2 Capture

(Interagency Task Force, 2010); NETL 2013)



Oxy-combustion overcomes the technical challenge of low CO_2 partial pressure normally encountered in conventional coal combustion flue gas by producing a highly concentrated CO_2 stream (~60 percent), which is separated from water vapor by condensing the water through cooling and compression. An additional purification stage for the highly concentrated CO_2 flue gas may be necessary to produce a CO_2 stream that meets transportation and storage requirements. This purification step should have significantly less cost than a conventional post-combustion capture system, due to the high CO_2 concentration and reduced flue gas volume (Interagency Task Force, 2010).

The appeal of oxy-combustion is tempered by a few key challenges, including the capital cost and energy consumption for a cryogenic air separation unit (ASU), boiler air infiltration that dilutes the flue gas with N_2, and excess O_2 contained in the concentrated CO_2 stream. Flue gas recycle (~70 to 80 percent) is also necessary to approximate the combustion characteristics of air, since currently available boiler materials cannot withstand the high temperatures resulting from coal combustion in pure O_2. Consequently, the economic benefit of oxy-combustion compared to amine-based scrubbing systems is limited. (Interagency Task Force, 2010)

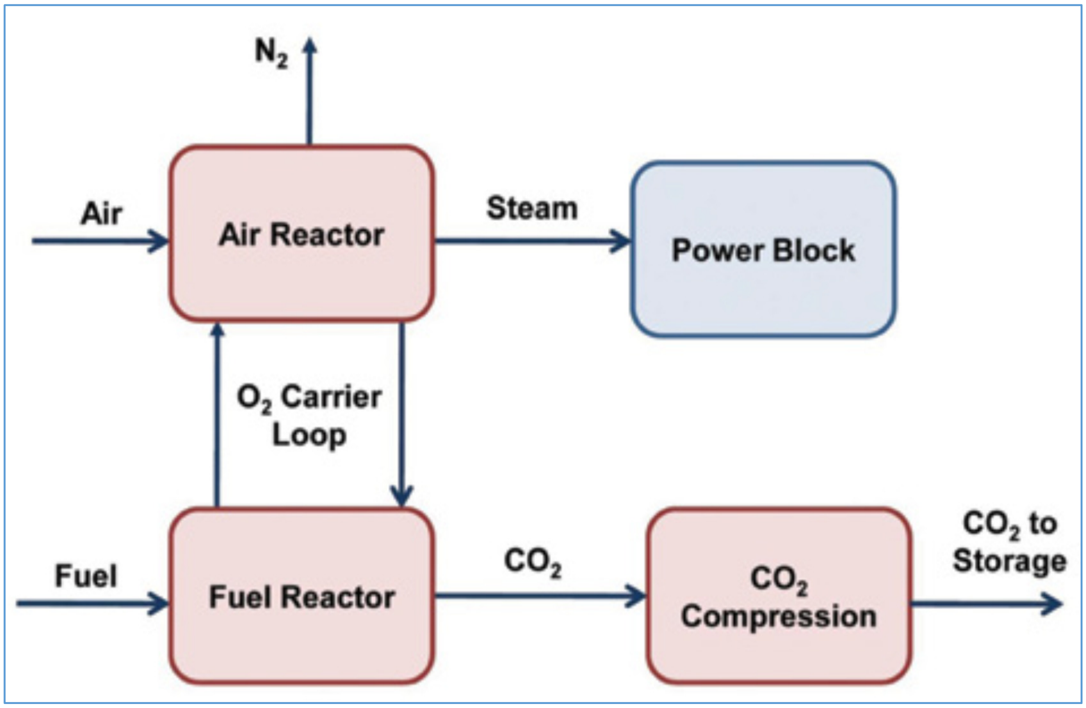
The conventional ASU is a cryogenic process that has a significant energy requirement. However, alternative oxygen separation methods are being researched for possible commercial scale development. These alternative methods include ion transport membranes (ITM), ceramic auto-thermal recovery, oxygen transport membranes, and chemical looping (EPA, 2010).

Several research institutes have investigated laboratory- and pilot-scale testing of oxy-fuel combustion, including (EPA, 2010):

- Pilot test programs for the European Enhanced Capture of CO2 (ENCAP) program and the Advanced Development of the Coal-Fired Oxy-fuel Process with CO2 Separation (ADECOS) program).
- A 30 MW oxy-firing pilot plant at the Schwarze Pumpe station in Spremberg, Germany.
- A 32 MW oxy-firing demonstration project in France retrofitting an existing boiler to natural gas oxy-combustion.
- A comprehensive test program using the 15 MW tangentially-fired Boiler Simulation Facility and 15 MW Industrial Scale Test Facility operated by Alstom Power, Inc., in Windsor, CT.

Chemical looping is an advanced technology similar to oxy-combustion in that it relies on combustion or gasification of coal in a N2-free environment. However, rather than using an ASU, chemical looping involves the use of a metal oxide or other compound as an oxygen carrier to transfer O_2 from air to the fuel. **Figure 9** presents a simplified process schematic for chemical looping. Chemical looping splits combustion into separate oxidation and reduction reactions. In the fuel reactor, the oxygen carrier releases the O_2 in a reducing atmosphere and the O_2 reacts with the fuel. The carrier is then recycled back to the oxidation chamber, or air reactor, where it is regenerated by contact with air. Because air is not introduced into the fuel (combustion) reactor, the products of combustion are primarily CO_2 and H_2O. Chemical looping can be applied in either coal combustion or coal gasification processes. (NETL, 2013)

Figure 9: Chemical Looping Process (NETL, 2013)



B. CO2 Compression

Regardless of how CO_2 is captured from a power plant, the CO_2 must be compressed to a pressure between 1,500 and 2,200 psi to be transported via pipeline and then injected into an underground storage site. As discussed in Section I.C below, compressed CO_2 is already being transported under these high pressures in a network of CO_2 pipelines used for EOR. Although compression of CO_2 to pipeline pressures is not new, research into more-advanced methods of CO_2 compression is ongoing because the compression of CO_2 requires mechanical energy and represents a potentially large auxiliary power load on the overall power plant system (NETL, 2015e).

Because CO_2 separation typically occurs at low pressure, compression is required to reduce the volume flow making transport more practical. Carbon dioxide storage sites for geological sequestration require high pressure as well. Given the high volume flows, centrifugal compressors are typically employed, especially when the captured CO_2 is produced near atmospheric pressure. The physics to compress CO_2 in a centrifugal compressor is the same as any other gas. However, CO_2 has unique characteristics compared to other gases that must be considered in the compressor design (e.g., the high volume reduction required, avoidance of water formation[8]). Its high molecular weight allows CO_2 to be liquefied at relatively high temperatures permitting hybrid compression and pumping options (NETL, 2013).
Compression of CO_2 generally occurs in multiple stages before an optimal pressure is achieved for transport of the CO_2. The gas temperature rises during each stage necessitating cooling

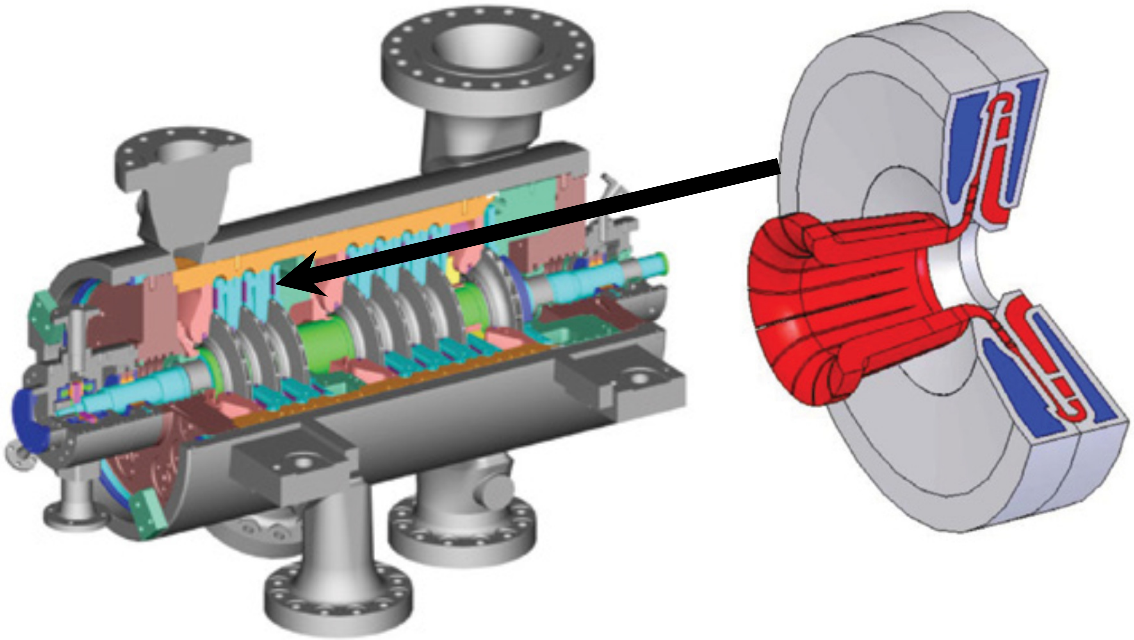
[8] Since CO2 dissolves in water and forms carbonic acid, which is corrosive, strict control of the water content in the CO2 stream is essential for safe and efficient operation of the compressor

between stages (Wong, 2006). A centrifugal compressor accommodates changes in volume flow several ways. First, the frame size of the compressor can be adjusted (smaller frame size for smaller volume flows and higher pressures) (NETL, 2013). For example, in an August 2007 study conducted for NETL, CO_2 compression was accomplished using a six-stage centrifugal compressor with inter-stage cooling that required an auxiliary load of approximately 7.5 percent of the gross power output of a subcritical pressure, coal-fired power plant (NETL, 2015e).

Two types of centrifugal compressors typically are used for CO_2 compression. The first is an integrally geared compressor. It is typically driven by an electric motor that drives a large bull-gear which, in turn, drives multiple pinion gears that contain centrifugal compressors on each end. The low pressure stages run at lower speeds, and the speed increases for the higher pressure stages. The integrally geared design has a separate inlet and exit flange for each stage, permitting intercooling between each stage, which can approach isothermal compression and minimize the power requirement. The drawback of this design is the sheer size and potential reliability issues with the many bearings, seals, and unshrouded impellers.

A second type of centrifugal compressor, a beam-style compressor, is commonly used in the petrochemical and natural gas industry. It can be configured in a straight-through or back-to-back configuration (as shown in **Figure 10**). The back-to-back design permits intercooling between the two sections and intercooling between multiple compressor bodies. The beam-style compressor contains only two bearings and seals and has demonstrated reliable service in many applications including large frame sizes in liquefied natural gas (LNG) applications (up to 78-inch impellers) and high pressure (up to 15,000 psi). While some intercooling is possible, the beam-style design will typically consume more power for a given application. New DOE/NETL-sponsored research in internally cooled diaphragms is working to close this gap. In the cooled diaphragm concept, the gas is continually cooled after each stage in the flow path through the compressor. A cooling jacket insert is used in the diaphragm of each stage to provide continuous cooling. Figure 1 shows a conceptual design for an internally cooled compressor. The flow of the CO_2 is shown in red, while the cooling liquid is shown in blue.

Figure 10: Multi-Stage Back-to-Back Centrifugal Compressor (left) and Design for an Internally Cooled Compressor (right) (NETL, 2013)



A technology evaluation for CO_2 compression was provided in a report for the American Electric Power Mountaineer CCS Project (Usher, 2011). The report explained options evaluated for compressing the full CO_2 product stream from the proposed nominal 235 MWe commercial scale application of Alstom's chilled ammonia process (CAP) at American Electric Power's Mountaineer generating station, in New Haven, West Virginia. The study focused on commercially available, integrally-geared, inter-cooled, gas compression systems. The scope of the study included all of the equipment required to compress and condition the captured CO_2 for sequestration. In the end, two arrangements were considered technically and economically feasible for implementation on the commercial scale system. Both utilize compression of the CO_2 to an intermediate condition, followed by variable-speed pumping to the final desired injection conditions. The compressor-pump arrangement allows for greater flexibility and higher operating efficiency throughout the life of the well, which is important based on the expected variability in injection pressure over the life of the injection wells.

Additional information on compressors and summaries of multiple advanced compression research projects (pilot studies) to continue improving the efficiency of CO_2 compression as part of CCS can be found in NETL 2013. Recent NETL-funded projects researching improvements to CO_2 compression relevant for CCS include the following:

- Southwest Research Institute is developing novel compression technology concepts to reduce CO_2 compression power requirements by 10 percent compared to conventional compressor designs. The basic concept is a semi-isothermal compression process where the CO_2 is continually cooled using an internal cooling jacket rather than using conventional interstage cooling. The project has completed thermodynamic (Phase I) and prototype testing (Phase II). A full-scale demonstration of a multi-stage, internally cooled diaphragm pilot test program (Phase III) was completed in 2014.

- Lehigh University set out to use systems analysis models to study the benefits of improved thermal integration for coal-fired power plants equipped with post- or oxy-combustion CO_2 capture systems.

- Ramgen Power Systems is designing and developing a unique compressor technology based upon aerospace shock wave compression theory for use as a CO_2 compressor. A shock wave-based gas turbine engine is also being developed. Ramgen's compressor design features a rotating disk that operates at high peripheral speeds to generate shock waves that compress the CO_2. Compared to conventional compressor technologies, shock compression offers several potential advantages: high compression efficiency; high single-stage compression ratios; opportunity for waste heat recovery; and low capital cost (NETL, 2015i).

C. CO_2 Transportation Pipeline Infrastructure

Pipelines are the most economical and efficient method of transporting CO_2 from commercial CCS facilities geologic storage sinks such as saline formations, coal seams, and oil and gas fields (Interagency Task Force, 2010). Technologies for the transport of CO_2 through a regionally extensive network of CO_2 pipelines are in use today. The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported that in 2013 there were 5,195 miles of CO_2 pipelines operating in the United States. (PHMSA, 2015)

The design, construction, operation, and safety requirements for CO_2 pipelines are proven. Design considerations for CO_2 pipelines include pipeline material selection and fracture control; pipeline diameter and depth; valve, seal, elastomer, and pumping material selection; valve spacing; and quality considerations, such as composition of the stream. Construction requirements and standards are in place to protect pipelines from damage and to maximize the integrity of the system over its operating lifespan. See Interagency Task Force, 2010.

Existing and new CO_2 pipelines are comprehensively regulated by the Department of Transportation's Pipeline Hazardous Material Safety Administration. The regulations govern pipeline design, construction, operation and maintenance, and emergency response planning. See generally 49 CFR 195.2. Additional regulations address pipeline integrity management by requiring heightened scrutiny to assure the quality of pipeline integrity in areas with a higher potential for adverse consequences. See 49 CFR 195.450 and 195.452.

In addition to the PHMSA Hazardous Liquid Pipeline Safety Regulations (49 CFR Part 195) requirements, industry design standards from the American Society of Mechanical Engineers (ASME) and the American Petroleum Institute (API), which are incorporated into 49 CFR Part 195 by reference, are in place to reduce pipeline risks from CO_2 pipeline systems. (Interagency Task Force, 2010)

On-site pipelines are not subject to the Department of Transportation standards, but rather adhere to the Pressure Piping standards of the American Society of Mechanical Engineers (ASME B31), which the EPA has found would ensure that piping and associated equipment meet certain quality and safety criteria sufficient to prevent releases of CO_2, such that certain additional requirements were not necessary (See 79 FR 358-59 (Jan. 3, 2014)). These existing controls over CO_2 pipelines assure protective management, guard against releases, and assure that captured CO_2 will be securely conveyed to a sequestration site.

D. Geologic Sequestration

Geologic sequestration (GS) – the long-term containment of a CO_2 stream in subsurface geologic formations – is based on a demonstrated understanding of the processes that affect CO_2 fate in the subsurface. Sequestration is already well proven. CO_2 has been retained underground for eons in geologic (natural) repositories and the mechanisms by which CO_2 is trapped underground are well understood. The physical and chemical trapping mechanisms, along with the regulatory requirements and safeguards of the Underground Injection Control (UIC) Program and complementary monitoring and reporting requirements of the Greenhouse Gas Reporting Program (GHGRP), together ensure that sequestered CO_2 will remain secure and provide the monitoring to identify and address potential leakage using Safe Drinking Water Act (SDWA) and Clean Air Act (CAA) authorities.

Subsurface formations suitable for GS of CO_2 captured from affected EGUs are geographically widespread throughout most parts of the United States. GS is technically feasible based on a demonstrated understanding of the processes that affect CO_2 fate in the subsurface; these processes can vary regionally as the subsurface geology changes. GS occurs through a combination of trapping mechanisms which are well understood and proven:

1. Structural and stratigraphic trapping is a physical trapping mechanism that occurs when the CO_2 reaches a stratigraphic zone with low permeability (i.e., geologic confining system) that prevents further upward migration.
2. Residual trapping is a physical trapping mechanism that occurs as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces.
3. Adsorption trapping is another physical trapping mechanism that occurs when CO_2 molecules attach to the surfaces of coal and certain organic rich shales, displacing other molecules such as methane.
4. Solubility trapping is a geochemical trapping mechanism where a portion of the CO_2 from the pure fluid phase dissolves into native ground water and hydrocarbons.
5. Mineral trapping is a geochemical trapping mechanism that occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals.

The effectiveness of long-term trapping of CO_2 has been demonstrated by natural analogs in a range of geologic settings where CO_2 has remained trapped for millions of years (Holloway et. al, 2007). For example, CO_2 has been trapped for more than 65 million years in the Jackson Dome, located near Jackson, Mississippi (IPCC, 2005). Other examples of natural CO_2 sources include Bravo Dome and McElmo Dome in Colorado and New Mexico, respectively. These natural storage sites are themselves capable of holding volumes of CO_2 that are larger than the volume of CO_2 expected to be captured from a fossil fuel-fired EGU. In 2010, the DOE estimated current CO_2 reserves of 594 million metric tons at Jackson Dome, 424 million metric tons at Bravo Dome, and 530 million metric tons at McElmo Dome (DiPietro, et. al, 2012).

GS is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO_2 increases oil production efficiency through a process referred to as enhanced oil recovery (EOR). Both deep saline and oil and gas formation types are widely available in the United States. Details on the geographic availability of geologic sequestration are provided in EPA, 2015.

Deep saline formations offer the greatest potential storage resource and capacity. These formations are sedimentary rock layers that are generally more than 800 meters deep and are saturated with waters or brines that have a high total dissolved solids (TDS) content (i.e., over 10,000 mg/L TDS) (Interagency Task Force, 2010). Deep saline formations are found throughout the United States, and many of these formations may be overlain by laterally extensive, impermeable formations that restrict upward movement of injected CO_2.

Eight Department of Energy Regional Carbon Sequestration Partnership (RCSP) “Development Phase” projects have been initiated and five of the eight projects are injecting or have completed CO_2 injection into deep saline formations. Three of these projects have already injected more than one million metric tons each, and one, the Cranfield Site, injected over eight million metric tons of CO_2 between 2009 and 2013 (NETL, 2013b). Various types of technologies for monitoring CO_2 in the subsurface and air have been employed at these projects, such as seismic methods (crosswell seismic, 3-D and 4-D seismic, and vertical seismic profiling), atmospheric CO_2 monitoring, soil gas sampling, well and formation pressure monitoring, and surface and ground water monitoring.[9] No CO_2 leakage has been reported from these sites, which further supports the availability of effective GS.

Enhanced oil recovery (EOR) is a technique that is used to increase the production of oil. Approaches used for EOR include steam injection, injection of specific fluids such as surfactants and polymers, and gas injection including nitrogen and CO_2. EOR using CO_2, sometimes referred to as “CO_2 flooding” or CO_2-EOR, involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil to make it more amenable for recovery. The crude oil and CO_2 mixture is then recovered and sent to a separator where the crude oil is separated from the gaseous hydrocarbons, native formation fluids, and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, purified to remove hydrocarbons, re-compressed, and re-injected into the reservoir to further enhance oil recovery. Not all of the CO_2 injected into the oil reservoir is recovered and re-injected. As the CO_2 moves from the injection point to the production well, some of the CO_2 becomes trapped in the small pores of the rock, or is dissolved in the oil and water that is not recovered. The CO_2 that remains in the reservoir is not mobile and becomes sequestered.

[9] A description of the types of monitoring technologies employed at RCSP projects can be found at DOE 2015a.

The amount of CO_2 used in an EOR project depends on the volume and injectivity of the reservoir that is being flooded and the length of time the EOR project has been in operation. Initially, all of the injected CO_2 is newly received. As the project matures, some CO_2 is recovered with the oil and the recovered CO_2 is separated from the oil and recycled so that it can be re-injected into the reservoir in addition to new CO_2 that is received. If an EOR operator will not require the full volume of CO_2 available from an EGU, the EGU has other options such as sending the CO_2 to other EOR operators, or sending it to deep saline formation GS facilities.

CO_2 used for EOR may come from anthropogenic or natural sources. The source of the CO_2 does not impact the effectiveness of the EOR operation. CO_2 capture, treatment and processing steps provide a concentrated stream of CO_2 in order to meet the needs of the intended end use. CO_2 pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO_2 and take into account CO_2 composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications related to the composition of the CO_2 stream. The regulatory requirements and company specifications ensure EOR operators receive a known and consistent CO_2 stream.

EOR has been successfully used at numerous production fields throughout the United States to increase oil recovery. The oil industry in the United States has over 40 years of experience with EOR. An oil industry study in 2014 identified more than 125 EOR projects in 98 fields in the United States (Koottungal, 2014). More than half of the projects evaluated in the study have been in operation for more than 10 years, and many have been in operation for more than 30 years. This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure GS that can be used for deployment of CCS across geographically diverse areas.

A DOE-sponsored study has analyzed the geographic availability of applying EOR in 11 major oil producing regions of the United States and found that there is an opportunity to significantly increase the application of EOR to areas outside of current operations (Kuuskraa, 2011). DOE-sponsored geologic and engineering analyses show that expanding EOR operations into areas additional to the capacity already identified and applying new methods and techniques over the next 20 years could utilize 18 billion metric tons of anthropogenic CO_2 and increase total oil production by 67 billion barrels (Kuuskraa, 2011). The study found that one of the limitations to expanding CO_2 use in EOR is the lack of availability of CO_2 in areas where reservoirs are most amenable to CO_2 flooding. DOE's Carbon Utilization and Storage Atlas identifies 29 states with oil reservoirs amenable to EOR, 12 of which currently have active EOR operations (NACAP, 2012). A comparison of the current states with EOR operations and the states with potential for EOR shows that an opportunity exists to expand the use of EOR to regions outside of current areas. The availability of anthropogenic CO_2 in areas outside of current sources could drive new EOR projects by making more CO_2 locally available.

Several EOR sites, which have been operated for years to decades, have been studied to evaluate the viability of safe and secure long-term sequestration of injected CO_2. Examples are identified below.

- CO_2 has been injected in the SACROC Unit in the Permian basin since 1972 for EOR purposes. One study evaluated a portion of this project, and estimated that the injection operations resulted in final sequestration of about 55 million tons of CO_2 (Han, 2010). This study used modeling and simulations, along with collection and analysis of seismic surveys, and well logging data, to evaluate the ongoing and potential CO_2 trapping occurring through various mechanisms. The monitoring at this site demonstrated that CO_2 can become trapped in geologic formations. In a separate study in the SACROC Unit, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO_2 leakage in the shallow freshwater aquifers (Romanak, 2010). No evidence of leakage was detected.

- The International Energy Agency Greenhouse Gas Programme conducted an extensive monitoring program at the Weyburn oil field in Saskatchewan between 2000 and 2010 (the site receiving CO_2 captured by the Dakota Gasification synfuel plant discussed later in this document). During that time over 16 million metric tons of CO_2 were safely sequestered as evidenced by soil gas surveys, shallow groundwater monitoring, seismic surveys and wellbore integrity testing. An extensive shallow groundwater monitoring program revealed no significant changes in water chemistry that could be attributed to CO_2 storage operations (Roston, 2010). The International Energy Agency Greenhouse Gas Programme developed a best practices manual for CO_2 monitoring at EOR sites based on the comprehensive analysis of surface and subsurface monitoring methods applied over the 10 years (Hitchon, 2012).

- The Texas Bureau of Economic Geology also has been testing a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi (Gulf Coast Carbon Center, 2015). As part of a DOE Southeast Regional Carbon Sequestration Partnership study, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year. Texas Bureau of Economic Geology is currently evaluating the results of several monitoring techniques employed at the Cranfield project and preliminary findings indicate no impact to groundwater (Gulf Coast Carbon Center, 2015). The project also demonstrates the availability and effectiveness of many different monitoring techniques for tracking CO_2 underground and detecting CO_2 leakage to ensure CO_2 remains safely sequestered.

CO_2 may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs such as unmineable coal seams also offer the potential for geologic storage.[10] Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable

[10] Other types of opportunities include organic shales and basalt.

coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively "locks" the CO_2 to the coal, where it remains stored.

In 2010, the EPA finalized an effective and coherent regulatory framework to ensure the long-term, secure and safe storage of large volumes of CO_2. The EPA developed these Underground Injection Control (UIC) Class VI well regulations under authority of the Safe Drinking Water Act (SDWA) to facilitate injection of CO_2 for GS, while protecting human health and the environment by ensuring the protection of underground sources of drinking water (USDWs). The Class VI regulations are built upon 35 years of federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The EPA and states have decades of UIC experience with the Class II program, which provides a regulatory framework for the protection of USDWs for CO_2 injected for purposes of EOR.
In addition, to complement both the Class VI and Class II rules, the EPA used CAA authority to develop air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration through the GHGRP. Information collected under the GHGRP provides a transparent means for the EPA and the public to continue to evaluate the effectiveness of GS.

Under SDWA, the EPA developed the UIC Program to regulate the underground injection of fluids in a manner that ensures protection of USDWs. UIC regulations establish six different well classes that manage a range of injectates (e.g., industrial and municipal wastes; fluids associated with oil and gas activities; solution mining fluids; and CO_2 for geologic sequestration) and which accommodate varying geologic, hydrogeological, and other conditions.

In 2010, the EPA established a new class of well, Class VI. Class VI wells are used to inject CO_2 into the subsurface for the purpose of long-term sequestration. See 75 FR 77230 (Dec. 10, 2010). This rule accounts for the unique nature of CO_2 injection for large-scale GS. Specifically, the EPA addressed the unique characteristics of CO_2 injection for GS including the large CO_2 injection volumes anticipated at GS projects, relative buoyancy of CO_2, its mobility within subsurface geologic formations, and its corrosivity in the presence of water. The UIC Class VI rule was developed to facilitate GS and ensure protection of USDWs from the particular risks that may be posed by large scale CO_2 injection for purposes of long-term GS. The Class VI rule establishes technical requirements for the permitting, geologic site characterization, area of review (i.e., the project area) and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, site closure, and financial responsibility for the purpose of protecting USDWs.

The EPA has issued Class VI permits for six wells under two projects.

- In September 2014, a UIC Class VI injection well permit (to construct) was issued by the EPA to Archer Daniels Midland for an ethanol facility in Decatur, Illinois. The goal of the project is to demonstrate the ability of the Mount Simon geologic formation, a deep saline formation, to accept and retain industrial scale volumes of

CO_2 for permanent GS. The permitted well has a projected operational period of five years, during which time 5.5 million metric tons of CO_2 will be injected into an area of review with a radius of approximately 2 miles.[11] Following the operational period, Archer Daniels Midland plans a post-injection site care period of ten years.[12]

- In September 2014, the EPA also issued four Class VI injection well permits (to construct) to the FutureGen Industrial Alliance project in Jacksonville, Illinois, which proposed to capture CO_2 emissions from a coal-fired power plant in Meredosia, Illinois and transport the CO_2 by pipeline approximately 30 miles to the deep saline GS site.[13] The Alliance proposed to inject a total of 22 million metric tons of CO_2 into an area of review with a radius of approximately 24 miles over the 20 year life of the project, with a post-injection site care period of fifty years.[14]

The CO_2 injection wells used for EOR are regulated through the UIC Class II program. 40 CFR §144.6(b). CO_2 storage associated with Class II wells is a common occurrence and CO_2 can be safely stored where injected through Class II-permitted wells for the purpose of enhanced oil or gas-related recovery. UIC Class II regulations issued under section 1421 of SDWA provide minimum federal requirements for site characterization, area of review, well construction (e.g., casing and cementing), well operation (e.g., injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational conditions that could lead to loss of injectate and migration into USDWs.

In addition, to complement the Class II and VI rules, the EPA used CAA authority to develop air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration through the Greenhouse Gas Reporting Program (GHGRP) found in 40 CFR Part 98. Information collected under the GHGRP provides a transparent means for the EPA and the public to continue to evaluate the effectiveness of GS.

Subpart PP of the GHGRP (40 CFR 98.420 - 98.428) provides requirements to account for CO_2 supplied to the economy. This subpart requires affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied to the economy. CO_2 suppliers are required to report the annual quantity of CO_2 transferred offsite and its end use, including GS.

Reporting under subpart RR (40 CFR 98.440 - 98.449) is required for all facilities that have received a Class VI UIC permit for injection of CO_2. Subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic

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[11] http://www.epa.gov/region5/water/uic/adm/. In addition, Archer Daniels Midland received a UIC Class VI injection well permit for a second well in December 2014. Archer Daniels Midland had been injecting CO_2 at this well since 2011 under a UIC Class I permit issued by the Illinois EPA.

[12] http://www.epa.gov/region5/water/uic/adm/.

[13] After permit issuance, and for reasons unrelated to the permitting proceeding, DOE initiated a structured closeout of federal support for the FutureGen project in February 2015. However, these are still active Class VI permits.

[14] http://www.epa.gov/r5water/uic/futuregen/.

information on the mass of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities. The subpart RR MRV plan includes five major components:

1. A delineation of monitoring areas based on the CO_2 plume location. Monitoring may be phased in over time.
2. An identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways. The monitoring program will be designed to address the risks identified.
3. A strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs. Multiple monitoring methods and accounting techniques can be used to address changes in plume size and risks over time.
4. An approach for establishing the expected baselines for monitoring CO_2 surface leakage. Baseline data represent pre-injection site conditions and are used to identify potential anomalies in monitoring data.
5. A summary of considerations made to calculate site-specific variables for the mass balance equation. Site-specific variables may include calculating CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment, and considerations for calculating CO_2 from produced fluids.

Monitoring programs conducted at international GS projects provide examples where large volumes of CO_2 have been safely injected and securely sequestered for long periods of time at volumes and rates consistent with those expected from CCS at EGUs. This experience has also demonstrated the value and efficacy of monitoring programs to determine the location of CO_2 in the subsurface and detect potential leakage through the presence of CO_2 in the shallow subsurface, near surface and air.

The Sleipner CO_2 Storage Project is located at an offshore gas field in the North Sea where CO_2 must be removed from the natural gas in order to meet customer requirements and reduce costs. The project began injecting CO_2 into the deep subsurface in 1996. The single offshore injection well injects approximately 1 million metric tons per year into a thick, permeable sandstone above the gas producing zone. Approximately 15 million metric tons of CO_2 have been injected since inception. Many U.S. and international organizations have conducted monitoring in conjunction with the Sleipner CO_2 Storage Project. The location and dimensions of the CO_2 plume have been measured numerous times using 3-dimensional seismic monitoring since the 1994 pre-injection survey. The monitoring data have demonstrated that although the plume is behaving differently than initially modeled due to thin layers of impermeable shale that were not initially identified in the reservoir model, the CO_2 remains trapped in the injection zone. Numerous other techniques have been successfully used to monitor CO_2 storage at Sleipner. The research and monitoring at Sleipner demonstrates the value of a comprehensive approach to site characterization, computational modeling and monitoring, as is required under UIC Class VI rules. The experience at Sleipner demonstrates that large volumes of CO_2, of the same order of magnitude expected for an EGU, can be safely injected and stored in saline reservoirs over an extended period.

Snøhvit is another large offshore CO_2 storage project, located at a gas field in the Barents Sea. Like Sleipner the natural gas must be treated to reduce high levels of CO_2 to meet processing standards and reduce costs. Gas is transported via pipeline 95 miles to a gas processing and liquefied natural gas plant and the CO_2 is piped back offshore for injection. Approximately 0.7 million metric tons per year CO_2 are injected into permeable sandstone below the gas reservoir. Between 2008 and 2011, the operator observed pressure increases in the injection formation (Tubaen Formation) greater than expected and conducted time lapse seismic surveys and studies of the injection zone and concluded that the pressure increase was mainly caused by a limited storage capacity in the formation (Grude et al., 2014). In 2011, the injection well was modified and injection was initiated in a second interval (Stø Formation) in the field to increase the storage capacity.

CO_2 from the Great Plains Synfuels plant in North Dakota has been injected into the Weyburn oil field in Saskatchewan Canada since 2000. The Great Plains Synfuels plant is discussed later in this document. It is anticipated that approximately 40 million metric tons of CO_2 will be permanently sequestered over the lifespan of the project. Extensive monitoring by U.S. and international partners has demonstrated that no leakage has occurred.

At the In Salah CO_2 storage project in Algeria, CO_2 is removed from natural gas produced at three nearby gas fields in order to meet export quality specification. The CO_2 is transported by pipeline approximately 3 miles to the injection site. Three horizontal wells are used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir approximately 6,200 feet deep. Between 2004 and 2011 over 3.8 million metric tons of CO_2 were stored. Injection rates in 2010 and 2011 were approximately 1 million metric tons per year. Storage integrity has been monitored by several US and international organizations and the monitoring program has employed a wide range of geophysical and geochemical methods, including time lapse seismic, microseismic, wellhead sampling, tracers, down-hole logging, core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite data. The data have been used to support periodic risk assessments during the operational phase of the project. In 2010 new data from seismic, satellite and geomechanical models were used to inform the risk assessment and led to the decision to reduce CO_2 injection pressures due to risk of vertical leakage into the lower caprock, and risk of loss of well integrity. The caprock at the site consisted of main caprock units, providing the primary seal, and lower caprock units, providing additional buffers. There was no leakage from the well or through the caprock, but the risk analysis identified an increased risk of leakage, therefore, the aforementioned precautions were taken. Additional analysis of the reservoir, seismic and geomechanical data led to the decision to suspend CO_2 injection in June 2011. No leakage has occurred and the injected CO_2 remains safely stored in the subsurface. The decision to proceed with safe shutdown of injection resulted from the analysis of seismic and geomechanical data to identify and respond to storage site risk. The Salah project demonstrates the value of developing an integrated and comprehensive set of baseline site data prior to the start of injection, and the importance of regular review of monitoring data.

Even though potentially adverse conditions were identified at some projects (In Salah and Snøhvit), there were no releases to air and the monitoring systems were effective in identifying the issues in a timely manner, and these issues were addressed effectively. In each case, the site-specific characteristics were evaluated on a case-by-case basis to select a site where the geologic conditions are suitable to ensure long-term, safe storage of CO_2. Each project was designed to address the site-specific characteristics and operated to successfully inject CO_2 for safe storage.

In summary, the different regulatory components, already in place, assure the safety and effectiveness of GS. The effective regulatory structure complements the analysis of the technical feasibility of GS, which together affirm that the technical feasibility of GS is adequately demonstrated.

E. Alternatives to Geologic Sequestration

Potential alternatives to storing CO_2 in geologic formations are emerging. Applications where captured anthropogenic CO_2 is converted to a useable product may offer the opportunity to offset the cost of CO_2 capture. Examples of CO_2 utilization include:

Carbonation/mineralization: Alkaline earth oxides react with CO_2 to create insoluble carbonates. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications such as for use in construction or cement manufacture. For example:

- Precipitated calcium carbonate (PCC) is produced through a chemical reaction process that uses calcium oxide (quicklime), water, and CO_2. Some pulp and paper manufacturers supply anthropogenic CO_2 from process exhausts to nearby PCC producers, which in turn supply PCC for use in paper manufacturing (40 CFR part 98, subpart PP).
- The combination of magnesium oxide and CO_2 results in a precipitation reaction where the CO_2 becomes mineralized.
- The Skyonics Skymine project, which opened its demonstration project in October 2014, captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products, including sodium carbonate, sodium bicarbonate, hydrochloric acid and bleach (Skymine, 2015).
- Other companies – including Calera and New Sky – also offer commercially available technology for the beneficial use of captured CO_2 (Calera, 2015; New Sky, 2015).

Bio-fuel production using algae: Plants convert CO_2 and water into starch using sunlight during the photosynthesis process. Although more advanced plants are not very effective in conversion of large quantities of CO_2, micro-algae can use high concentrations of CO_2 to create starch. The biomass product can be used to recycle CO_2 into valuable industrial fuel such as methane, methanol, hydrogen and bio-diesel.

Fuel production: Most carbon-based fuels are made up of carbon, hydrogen, and oxygen. CO_2 can be hydrogenated in the presence of a catalyst to create low-carbon-chain fuel such as methanol. Procuring hydrogen requires energy for hydrolysis of water or partial oxidation of natural gas.

Chemical synthesis: Ceramics, fertilizers, rubber, and many other small-scale industries require CO_2 at some stage of their manufacturing process. The largest use of CO_2 in this area is in fertilizer plants, where CO_2 is captured from the exhaust gases of NH_3 reformer units and used to manufacture urea.

CO_2 utilization is a promising research area. There are currently no plenary systems of regulatory control and GHG reporting for these approaches, as there are for geologic sequestration. Nonetheless, CO_2 utilization technologies not only show promise, but could potentially be demonstrated to show permanent storage of CO_2.

F. Continuing Research and Policy Development

Climate science and climate change mitigation options – including CCS - are the subject of great academic interest and a large body of academic literature on the subjects exits. In addition, other research organizations (e.g., U.S. national laboratories and others) have also published studies on these subjects.

The Thomson Reuters *Web of Science* database is a comprehensive source of academic publications from around the world. As a metric to gauge global interest and progress in CCS technologies, EPA conducted a search of the database using the keywords "carbon capture" and "carbon capture and sequestration" and searching by the title of the paper. After conducting the search, the data was sorted by year in order to create a timeline of CCS development. The results of this search are shown in **Figure 11** below. The number of publications regarding CCS has grown dramatically in the past decade, from only 7 papers in 2004 to 147 publication in 2014, with a peak of 205 publications in 2013.

In order to corroborate this trend, EPA also conducted a search using the U.S. patent database, using the keywords "Carbon Capture". The results of this search were segmented by year, and are shown in **Figure 12** below. As with the publications, the number of patents issued regarding CCS technology has increased rapidly over the past decade, beginning in 2007. The number of patents issued peaked in 2014, with 160 patents issued. Both The U.S. patent office and Thomson Reuters confirm that industry and academia are both working towards technological advancements in all stages of CCS.

Figure 11. Number of Publications Regarding CCS per Year

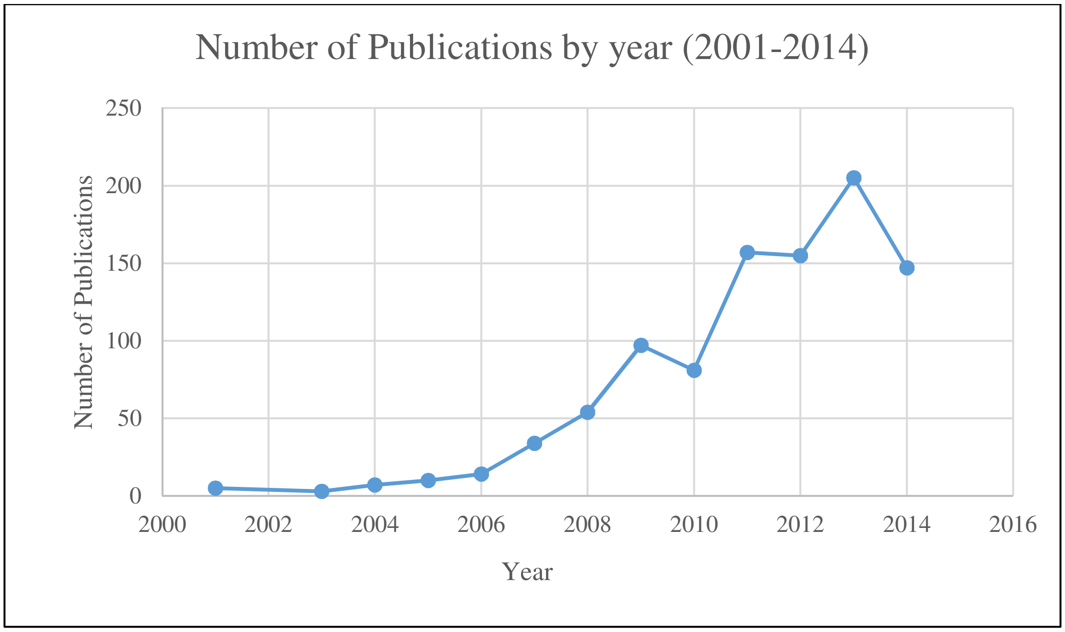
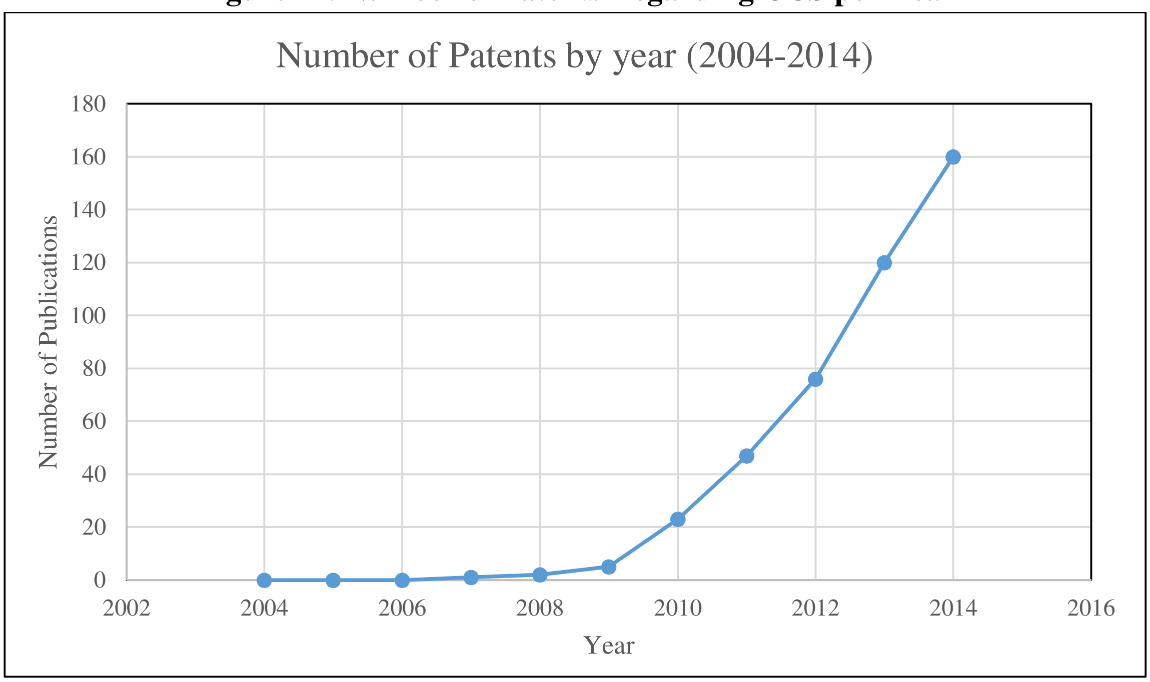


Figure 12. Number of Patents Regarding CCS per Year



Research is underway to reduce CO_2 capture costs and to improve performance. The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO_2 from fossil fuel energy plants compared to currently available capture technologies. The large-scale CO_2 capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will generate operational knowledge and enable continued commercialization and deployment of these technologies. The CCS Global Consortium and National Carbon Capture Center are examples of organizations dedicated to accelerating commercial CCS.

SaskPower created the CCS Global Consortium (http://www.saskpowerccs.com/consortium/) to share the knowledge and experience from the Boundary Dam Unit #3 facility with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology development through the creation of the Shand Carbon Capture Test Facility (CCTF) (SaskPower, 2015a). The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

The National Carbon Capture Center at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama is a consortium between DOE/NETL and electric power producers offering a world-class test facility and a highly specialized staff to accelerate the commercialization of advanced technologies and enable fossil-fuel based power plants to achieve near-zero emissions. The NCCC was established in 2009 to build on the experience, expertise, and infrastructure in place at the PSDF, which has been in operation since 1996. In undertaking its mission, the NCCC is involved in a range of activities to develop the most promising technologies for future commercial deployment, thereby maximizing the impact of project funds. A large portion of NCCC research is focused on development of post-combustion CO_2 capture for incorporation into pulverized coal power plants and pre-combustion CO_2 capture for integration into the new generation of coal gasification power plants. Post-combustion and pre-combustion CO_2 capture work has included multiple projects, such as testing of solvents, enzymes, gas separation membranes, sorbents, and catalysts, as well as other novel processes. The testing has supported technology developers from both industry and universities, and in many cases has yielded the bases for process improvements and scale-ups (Northington, et al., 2012).

In addition to research underway to accelerate commercial carbon capture, research is also underway to advance commercial use of geologic sequestration. The DOE has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to deploy large-scale field projects in different geologic settings across the country to demonstrate that GS can be achieved safely, permanently, and economically at large scales. Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-fired CO_2 emissions, 97 percent of industrial CO_2 emissions, 96 percent of the total land mass, and essentially all the geologic sequestration sites in the United States potentially available for GS (DOE, 2015a). The seven partnerships include more than 400 organizations spanning 43 states (and four Canadian provinces) (DOE, 2015a). RCSP project objectives are to inject at least one million metric tons of CO_2. In April 2015, DOE announced that CCS projects supported by the department have safely and permanently stored 10 million metric tons of CO_2 (DOE, 2015b).

In addition to Federal initiatives, multiple states have established emission performance standards or other measures to limit emissions of GHGs from new EGUs. The emission levels established by these standards would effectively require CCS. For example,

- In September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in base load generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing base load generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO2/MWh.
- In May 2007, Washington Governor Gregoire signed Substitute Senate Bill 6001, which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any base load electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Base load generation facilities must initially comply with an emission limit of 1,100 lb CO2/MWh.
- In July 2009, Oregon Governor Kulongoski signed Senate Bill 101, which mandated that facilities generating base load electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO2/MWh, and prohibited utilities from entering into long-term purchase agreements for base load electricity with out-of-state facilities that do not meet that standard.
- New York established emission standards of CO_2 at 925 lb CO2/MWh for new and expanded base load fossil fuel-fired plants.
- In May 2007, Montana Governor Schweitzer signed House Bill 25, adopting a CO_2 emissions performance standard for EGUs in the state. House Bill 25 prohibits the state Public Utility Commission from approving new EGUs primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and sequestered.
- On January 12, 2009, Illinois Governor Blagojevich signed Senate Bill 1987, the Clean Coal Portfolio Standard Law. The legislation establishes emission standards for new power plants that use coal as their primary feedstock. From 2009–2015, new coal-fueled power plants must capture and store 50 percent of the carbon emissions that the facility would otherwise emit; from 2016–2017, 70 percent must be captured and stored; and after 2017, 90 percent must be captured and stored.

II. Facilities Utilizing CCS

Many industries, including the power generation industry, are beginning to incorporate CCS into their plant designs. In the U.S. and abroad, multiple CCS projects are in various stages of development, from research and planning to currently operating pilot- and full-scale systems. Some of these projects are described in greater detail below. It should be noted that this section only highlights some of the major examples of CCS implementation, and should not be considered an exhaustive list of all CCS projects.

A. Post-combustion

Table 2 lists seven facilities that have experience with post-combustion CO_2 capture projects, including six EGUs and one soda ash production facility. Each project is briefly summarized in the following subsections.

Table 2. Summary of Post-combustion Carbon Capture and Storage Projects

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
AEP/Alstom - Mountaineer Project	Domestic	New Haven, West Virginia	EGU	Coal-fired power plant (30 MW slipstream)	Full (>90%) CCS	2009	100,000	Pipeline	GS	Mount Simon, 1.5 miles in depth
AES - Shady Point	Domestic	Panama, Oklahoma	EGU	Coal-fired power plant (320 MW)	Partial (<10%)	1991	66,000	Not transported	Purified and sold as food-grade CO2	Multiple Locations
AES - Warrior Run	Domestic	Cumberland, Maryland	EGU	Coal-fired power plant (180 MW)	Partial (<10%)	2000	110,000	Not transported	Purified and sold as food-grade CO2	Multiple Locations
Petra Nova - W.A. Parish	Domestic	Houston, Texas	EGU	Coal-fired power plant (240 MW slip steam)	Full (>90%) CCS	2017 (under construction)	1,600,000	Pipeline	EOR	Hilcorp's West Ranch Oil Field
SaskPower - Boundary Dam Unit #3	International	Estevan, Saskatchewan, Canada	EGU	IGCC power plant (110 MW)	Full (>90%) CCS	October, 2014	1,000,000	Pipeline	EOR	Weyburn EOR, 40 miles away

Searles Valley Minerals	Domestic	Trona, California	Soda Ash	Coal-fired power plant generating steam/power for onsite use	Post-combustion amine scrubbing	1978	264,898	NA: used onsite	Other use: carbonation of brine in soda ash process	Not specified
Fluor Corp. – Bellingham	Domestic	Bellingham, Massachusetts	EGU	Natural Gas-fired power plant (40 MW slipstream of a 320 MW plant)	Full (>90%) CCS	1991 (2005)	100,000	Not transported	Purified and sold as food-grade CO_2	Multiple Locations

1. AEP/Alstom - Mountaineer Project

AEP began a pilot CCS project at its Mountaineer Plant in New Haven, West Virginia in September, 2009. The project was a 20 MWe slipstream of the 1,300 MW plant, capturing 100,000 metric tons CO_2/year which was sequestered 1.5 miles underground in the neighboring Mount Simon Sandstone deposits. The project was initially planned to expand to 235 MW, with 150,000 metric tons CO_2/year, a 90% capture rate; however, uncertain federal climate regulation discouraged AEP from continuing the project (MIT, *Mountaineer Fact Sheet*, 2015).

2. AES – Shady Point/Warrior Run

The Shady Point (Panama, OK) and Warrior Run (Cumberland, MD) power plants use circulating fluidized bed reactors, and amine scrubbers developed by ABB/Lummus to capture CO2. Warrior Run began operations in 2000, and produces 180 MW of electricity along with steam for the CO_2 production unit. The plant captures about 10% of its CO_2 emissions, which are removed post-combustion via a slipstream (IEAGHG RD&D Database, 2013). Shady Point operates in a similar manner, except on a larger scale. The plant produces 320 MW, and has been operating since 1991. Shady Point extracts about 66,000 metric tons CO_2/day from the flue gas, which is purified to food grade levels in the CO_2 processing plant. The captured CO_2 from the Shady Point and Warrior Run plants is purified and used in food-processing and other industrial applications like fire extinguishers (NETL, *What Carbon Capture Technologies are in Use Today*).

3. Fluor Corp. – Bellingham

The Bellingham, Massachusetts CCS project, which incorporated the Fluor Ecomaine process described in section I, ran from 1991 to 2005 (Global CCS Institute, 2013). The project was a 40 MW slipstream of the 320 MW plant, capturing over 90% of CO_2 emissions totaling 100,000 metric tons of CO_2/day. This plant is unique in that it was an NGCC incorporating CCS into its operations. The CO_2 was sold for use in the beverage industry, as opposed to geologic sequestration (Bernton, 2014).

4. Petra Nova – W. A. Parish

The W.A. Parish CCS project near Houston, Texas will be the world's largest post-combustion CCS retrofit once it begins operation in 2017. The plant is a joint venture between NRG and JX Nippon Oil & Gas Exploration. Captured CO_2 will be used for EOR in the Gulf Coast region. The unit will collect 90% of the emitted CO_2 from a 240 MW slipstream of the 610 MW facility, for a total of 1.4 million metric tons CO_2/year. The CO_2 capture technology is provided by Kansai Mitsubishi, which has had CO_2 capture technology in commercial use since 1999, and currently is operating at 11 facilities across the globe (NRG Energy Inc., 2015). The plant will utilize a high-performance solvent, which was tested at a pilot-scale project at the Alabama

Power Barry plant, which is described below. The project began as a 60 MW slipstream demonstration and received DOE Clean Coal Power Initiative funding on that basis, however, the project was later expanded to the 240 MW slipstream due to the need to capture larger volumes of CO_2 for EOR operations.

5. SaskPower – Boundary Dam Unit #3

The Boundary Dam CCS project is the first commercial-scale post-combustion CCS plant in the world. Located in Saskatchewan, Canada, the Boundary Dam project incorporates EOR and Geological Sequestration into their operations, which began in October of 2014. Although initially only capturing 75% of CO_2, currently the unit produces 110 MW net (139 MW gross) of electricity, with 90% CO_2 capture totaling 1 million metric tons CO_2/year at a purity of over 99.999% (Monea, 2014). The plant uses a Shell Cansolv amine-based solvent to capture CO_2, which comes from local Saskatchewan lignite coal. In order to mitigate the cost of the retrofit, SaskPower sells the CO_2 to an oil drilling company for use in EOR and eventual sequestration, and to other industries for commercial use. The balance of unsaleable CO2 is sequestered. The plant also sells sulphuric acid and fly ash for added revenue (Hussain, 2014). CO_2 that is not used in EOR is immediately stored in deep brine-filled sandstone formations Additionally, initial indications are that the generation side is producing more power than estimated and that the energy penalty (parasitic load) is much lower than expected (Monea, 2015).

6. Searles Valley Minerals – Trona Soda Ash Plant

The Searles Valley Minerals soda ash plant in Trona, Ca, is the longest running carbon capture project in the U.S. The plant has been capturing CO_2 via post-combustion amine scrubbing since 1978. This CO_2 comes from the flue gas from a coal-fired power boiler generating steam and electricity for onsite use. The CO_2 is used to for carbonation reactions to produce soda ash. Since its inception, the soda ash plant has collected roughly 270,000 metric tons of CO_2 per year (EPA, 2014).

B. Pre-combustion

Table 3 contains 11 facilities that are in various stages of pre-combustion CO_2 capture projects, including nine EGUs, a fertilizer manufacturing plant, and a coal gasification facility. Each project is briefly summarized in the following subsections.

Table 3. Pre-combustion Carbon Capture and Storage Projects

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
2Co Energy - Don Valley Power Project	International	South Yorkshire, United Kingdom	EGU	920 MW (Gross), 650 MW (Net)	Full (>90%) CCS	2018/2019 (Planning Phase)	5,000,000	Pipeline	GS	The North Sea
CVR Energy/Chaparral Energy - Coffeyville Fertilizer Plant	Domestic	Coffeyville, Kansas	Fertilizer Plant	Not EGU		2013	1,000,000	Pipeline	EOR	112 km away
Dakota Gasification - Great Plains Synfuels Plant	Domestic	Beulah, North Dakota	Coal Gasification Plant	Coal Gasifier	Partial (50%)	1984 (began operation) 2000 (began CCS)	3,000,000	Pipeline	EOR	Weyburn EOR, 200 miles away
ELCOGAS, S.A. - Puertollano	International	Puertollano, Spain	EGU	IGCC (14 MW Slipstream)	Full (>90%) CCS	2010	365,000	Not transported	Hydrogen production	Spain
Emirates Steel Industries - Abu Dhabi	International	Abu Dhabi, United Arab Emirates	EGU	IGCC (~228 MW)	Full (>90%) CCS	2016 (under construction)	800,000	Pipeline	EOR	Rumaitha, 50 km away
Huaneng - GreenGen IGCC Project	International	Tianjin City, Bohai Rim, China	EGU	IGCC (400 MW)	Partial (>80%)	2020 (currently testing pilot)	2,000,000	Pipeline	EOR	51-100 km from the plant
Southern Company - Kemper County	Domestic	De Kalb, Mississippi	EGU	IGCC power plant (582 MW)	Partial (65%)	2016 (construction completed, currently testing)	3,500,000	Pipeline	EOR	60 miles away
Southern Compnay - Barry Plant	Domestic	Mobile, Alabama	EGU	Coal-fired power plant (25 MW slipstream)		June 2011 (capture) 2012 (storage)	150,000	Pipeline	GS	Citronelle oil field

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
Summit Power - Caledonia	International	Caledonia, Scotland, the United Kingdom	EGU	IGCC (570 MW)	Full (>90%) CCS	2022 (under construction)	3,800,000	Pipeline	GS	North Sea
Summit Power - Texas Clean Energy Project (TCEP)	Domestic	Odessa, Texas	EGU	IGCC (400 MW)	Full (>90%) CCS	2019	3,000,000	Pipeline	EOR	Permian Basin
Vattenfall/Nuon - Willem-Alexander Power Plant	International	Buggenum, the Netherlands	EGU	IGCC (20 MW Slipstrem)	Full (>90%) CCS	2011	Not provided	Not transported	Returned to the flue stream after compressed	Netherlands

1. CVR Energy/Chaparral Energy - Coffeyville Fertilizer Plant

Chaparral Energy and Coffey Resources Nitrogen Fertilizers, a subsidiary of CVR Energy, have joined to capture and sequester roughly 1 million metric tons CO_2/year using pre-combustion technology. Chaparral manages the compression, dehydration, and transportation facilities, while CVR owns the carbon and carbon capture sources. This retrofit, completed in 2013, allows the partnership to sell CO_2 for use in EOR operations 112 km (70 miles) away (MIT, *Coffeyville Fact Sheet,* 2015). The plant utilizes absorption physical solvent-based process using Selexol for CO2 separation. Similar to an IGCC, the plant gasifies petroleum coke to create a hydrogen-rich syngas from which the CO_2 is removed. The syngas is used to synthesize ammonia and urea ammonium nitrate fertilizers instead of being used for energy production (Chaparral Energy, 2015).

2. Dakota Gasification – Great Plains Synfuels Plant

Located in Beulah, ND, the Great Plains Synfuels Plant began operations in 1984 and later added CCS operations in the year 2000. The plant consumes roughly 18,000 tons of North Dakota lignite coal each day and captures about 3 million metric tons of CO_2 per year, which is the most CO_2 captured from conversion at any facility of the world (Dakota Gasification Company, *Great Plains Synfuels Plant,* 2015). Although not an EGU, the processes at a coal gasification plant are very similar to those at an IGCC. Dakota Gasification uses a Rectisol® system to capture CO_2 before the gasified coal is converted into synthetic natural gas (i.e., methane) via a methanation process (EPA, 2014). The CO_2 captured at the plant is sold to drilling companies for EOR and permanent sequestration in Saskatchewan, Canada as part of the Weyburn CO_2 Monitoring and Storage project, which is overseen by the International Energy Agency (IEA). The plant exports about 8,000 metric tons CO_2/day, which is about 50% of the CO_2 generated at the facility. As of December 31st, 2012, the facility had captured more than 24.5 million metric tons of CO_2, demonstrating how CCS can be used long term to reduce emissions (EPA, 2014).

3. ELCOGAS, S.A. – Puertollano

Another pilot-scale project, located at the ELCOGAS Puertollano plant in Spain, was one of the first pre-combustion IGCC CCS pilot plants in the world when it began operations in 2008. The plant uses a slip stream to test a small scale (14 MW) IGCC unit. The plant captured its first metric ton of CO_2 by 2010, and has since captured over 1,000 metric tons of CO_2. The project has also produced over 6 metric tons of H_2, as part of the project's stated goal to "obtain economic data enough to scale [the project] to the full Puertollano IGCC capacity in synthetic gas production." The Puertollano plant is part of a larger, Spanish national initiative to investigate advanced CCS technologies, including geological sequestration and oxy-fuel combustion (ELCOGAS, 2014).

4. Emirates Steel Industries – Abu Dhabi

The United Arab Emirates' first CCS project is an ambitious 800,000 metric tons CO_2/year facility operating adjacent to a steel mill in Abu Dhabi. Set to begin operations in 2016, this facility will process a 90% pure CO_2 stream from the steel plant before piping it to an oil field for EOR 50 kilometers away (Masdar, 2015). The Abu Dhabi Future Energy Company and the Abu Dhabi National Oil Company decided to continue with the project after completing a 2 year pilot plant study which ended in 2011 (Evans, 2008). The plant is expected to produce around 225 MW per year (Carvalho, 2011).

5. Huaneng – GreenGen IGCC Project

Scheduled to begin operations in 2020, Huaneng's GreenGen IGCC project is poised to be the largest EGU CCS project in Southeast Asia. The plant aims to capture 2 million metric tons CO_2/year, which will come from sub-bituminous coal coming primarily from China. The plant will provide 400 MW of electricity at this new plant, the largest of its kind in China and one of the largest in the world. However, first it will operate as a 250 MW IGCC while CO_2 capture technology is tested and developed. The facility will operate as a pre-combustion CCS plant, utilizing an amine chemical solvent-based process. (Global CCS Institute, 2011)

6. Southern Company/Mississippi Power – Kemper County

The Kemper County IGCC CCS project completed construction in late 2013 and is currently in the "startup and testing" phase, with plans to begin commercial operation in 2016. This facility, located in Kemper County, Mississippi, will provide 582 MW of lignite coal-based power while collecting 3.5 million metric tons CO_2/year. Kemper County uses Pre-combustion IGCC technology, with unique CCS technology designed by KBR to provide 65% capture. Additionally, KRG designed (TRIG™) gasification technology to more efficiently convert lignite coal into syngas for combustion. The TRIG™ is "an advanced pressurized circulating fluidized bed gasifier that operates at moderate temperatures (1,500-1950°F)" (Ariypadi, 2008). The TRIG™ can utilize both oxy-fuel and ambient air as combustion sources to mix with the lignite coal. The plant also utilizes Selexol™, a solvent that has also been used extensively for acid gas removal, including CO_2, for decades (Mississippi Power Company, 2009).

7. Southern Company/Mitsubishi Heavy Industries (MHI) – Barry Plant

The Southern Company partnered with MHI to create a pilot-scale CCS project at the Plant Barry Power station in Mobile, Alabama. The plant uses a 25 MW slip stream out of their 160 MW plant to capture 150,000 metric tons of CO_2/year. The plant uses an MHI amine based process called KM-CDR, and incorporates MHIA's KS-1 solvent. The plant has successfully captured CO_2 since June 2011, and began sequestering it in an underground saline formation in August, 2012. The plant was initially selected to be scaled up to a much larger size (100,000 metric tons of CO_2 capture/year) however Southern Company decided to opt out of the program in 2010 (MIT, *Plant Barry Fact Sheet*, 2015).

8. Summit Power – Caledonia

The Caledonia plant, in Scotland, the United Kingdom, is a large scale pre-combustion IGCC CSS project developed by Summit Power. The plant will produce 570 MW (net) from gasified bituminous coal, and will collect 3.8 million metric tons CO_2/year, or 90% of the total CO_2. This CO_2 is sent via pipeline to a saline formation in the North Sea for geologic sequestration (Summit Carbon Capture, 2015). The plant is scheduled to open in 2022, however it was granted funding from the UK and Scottish governments in March, 2015 to help conduct an industrial research and feasibility study to design, site, finance, and build the Caledonia Plant. The results of this study will be "shared across industry and academia, increasing understanding of how to develop and deploy CCS at commercial scale." (UK Dept. of Energy and Climate Change, 2015)

9. Summit Power - Texas Clean Energy Project (TCEP)

The TCEP will be a 400 MW IGCC facility located near Odessa, Texas. The plant will capture 90% of its CO_2, which will be around 3 million metric tons/year. The plant will sell the CO_2 for use in EOR, and will also sell urea, sulfuric acid, argon, and inert slag for use in various chemical processes (Gureghian, 2010). The plant plans to begin construction in 2015, and will utilize the Linde Rectisol® gas cleanup process to capture CO_2, the same process used at the Dakota Gasification plant. TCEP plans to begin construction in 2015 (Paul, 2015; MIT, *TCEP Fact Sheet*, 2015), and hopes to begin operations by 2019. Besides CO_2 capture, the plant will capture 99% of Sulphur dioxide, 90% of Nitrogen Oxide, and 99% of mercury.

10. Vattenfall/Nuon – Willem-Alexander Power Plant

The William-Alexander Power Plant, located in Buggenum, the Netherlands, is a coal-and-biomass-fired EGU that provides 253 MW of electricity. In 2011, the plant opened a pilot-scale CCS project testing IGCC technology with 90% CO_2 capture from pre-combustion technology. The plant used a slip stream of CO_2 equivalent to the amount produced by 20 MW of power, and then captured, compressed, and returned the CO_2 to the main stream instead of sequestering it. This process helped researchers determine feasibility and practicability of CCS for use in potential scale-ups to industrial size EGUs in the future. Due to the economic recession in the European Union, the project was discontinued in 2014, however valuable lessons were learned about CCS during the three years of operation (MIT, *Buggenum Fact Sheet,* 2015).

11. 2Co Energy - Don Valley Power Project

The Don Valley Power Project is the most ambitious pre-combustion CCS project to date. 2Co energy will produce 920 MW gross (650 MW net) of power in South Yorkshire, the United Kingdom. The plant will capture over 90% of emissions, totaling some 5 million metric tons of CO_2/year, which will be sequestered in the North Sea (2Co Energy, *Don Valley CCS Project*).

C. Oxy-combustion

Table 4 contains four EGU facilities that are implementing or planning oxy-fuel combustion CO_2 capture projects. Each project is briefly summarized in the following subsections.

Table 4. Oxy-combustion Carbon Capture and Storage Projects

Project Name	Domestic or International	Location	Facility type	Unit type	Capture details	Date began operation (Date ended operation if ended)	Amount of CO2 captured (metric tons/yr)	Transport details	Fate of captured CO2	Fate Location
Capture Power Ltd. - White Rose	International	North Yorkshire, United Kingdom	EGU	Coal-fired power plant (448 MW)	Full (>90%) CCS	planning/per-mitting phase	2,000,000	Pipeline	GS	The North Sea
CS Energy - Callide A Station	International	Biloela, Queensland, Australia	EGU	Coal-fired power plant (30 MW)	Full (>90%) CCS	2012	220,000(does not continuously run, captures 75 mt/day when operating	On Road	GS	Victoria, Australia
FutureGen 2.0 Alliance	Dommestic	Meredosia, Illinois	EGU	168 MW	Full (>90%) CCS	2017 (under construction)	1,100,000	Pipeline	GS	Various Locations
Total - Lacq	International	Lacq, France	EGU	Heavy oil-fired power plant (30 MW unit of larger facility)	Full (>90%) CCS of the unit's emissions, 15% of the plant's emissions	January, 2010	75,000	Pipeline	GS and natural gas recovery	Rousse, France (27 km away)

1. Capture Power Limited - White Rose CCS project

Capture Power Limited, which is a consortium of Alstom, BOC, and Drax Power, is currently planning an industrial scale oxy-fuel CCS facility in North Yorkshire, the United Kingdom. The plant will produce 448 MW of electricity from coal, capturing over 90% of the emitted CO_2, totaling 2 Million metric tons CO_2/year. The CO_2 will be piped to the North Sea, where it will be geologically sequestered (White Rose, 2015).

2. CS Energy – Callide A Station

Located in Queensland, Australia, the Callide A station is the first industrial-scale pilot plant in the country. The 30 MW coal-fired unit, part of the larger Callide plant, captures over 90% of its CO_2 emissions when running the capture technology, which is not done continuously because it's a pilot plant. The plant captures roughly 220,000 metric tons of CO_2/year. This CO_2 is pressurized and sent via trucks to Victoria, Australia, where it is sequestered underground. This pilot plant began operations in 2012. This project shows how old units (Callide A first began operations in 1965) can be retrofitted with CCS technology to cost-effectively reduce emissions (Callide, 2015).

3. FutureGen 2.0 Alliance

The FutureGen 2.0 project is a combined effort from industry and government to produce a full scale oxy-fuel combustion CCS plant in the United States. Located in Meredosia, Illinois, the 168 MW EGU will implement full CCS using purified oxygen as fuel, allowing the plant to capture over 1.1 Million metric tons of CO_2/year (FutureGen 2.0, *About FutureGen 2.0*). CO_2 captured from the plant will be sent via pipeline to various locations for use in EOR or simple geologic sequestration. Completion of the project is scheduled for 2017, making FutureGen the first full CCS plant using oxy-fuel combustion in the US (FutureGen 2.0, *About FutureGen 2.0*). The EPA has issued Class VI deepwell construction permits for the sequestration phase.

4. Total – Lacq Plant

Total, in combination with Air Liquide, the French Petroleum Institute, the French Bureau of Geological and Mining Reseach, and Alstom, worked to construct an oxy-fuel pilot plant at the Lacq facility in southern France. The 30 MW project runs on heavy oil, and captures over 90% of the unit's emissions, about 15% of the plant's total emissions. The Lacq oxfuel project began operations in January 2010, and has captured 75,000 metric tons of CO_2/year each year since (Total, *How CCS at the Lacq Pilot Works*). This CO_2 is transported via pipeline to Rousse, France, where it is used for natural gas recovery and geologic sequestration.

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1. PURPOSE / INTRODUCTION

Sargent and Lundy (S&L) was requested by the Environmental Protection Agency (EPA) Clean Air Markets Division (CAMD) to support their evaluation of post-combustion carbon dioxide (CO_2) capture technologies and their applicability to power applications. As EPA evaluates implementing carbon capture and sequestration on coal- and natural gas-fired units, for both existing and new facilities, two items are critical to their evaluation with respect to the development of these projects and their operation. This report discusses (1) the phases of project development and the overall timeline for these phases, as well as (2) the normal operation of a CO_2 Capture facility as well as design and operating considerations for how CO_2 Capture can operate in a constrained grid scenario.

2. CO_2 CAPTURE PROJECT DEVELOPMENT

2.1. PROJECT DEVELOPMENT PHASES

Figure 1 shows the typical steps for the development of a large construction project with considerations for special requirements associated with the development of a CO_2 Capture System (CCS). This report focuses on the development of the CCS project at the host site and does not consider the timeline or requirements associated with transporting and sequestering the CO_2 that is ultimately captured. However, these other infrastructure aspects of the CCS value chain are critical to the feasibility and timeline of implementing a CCS project. These phases are broken into two categories: Project Development (highlighted in light blue in Figure 1) and Project Implementation (highlighted in dark blue in Figure 1). Each of these phases, including their interconnectedness, are described in the following sections.

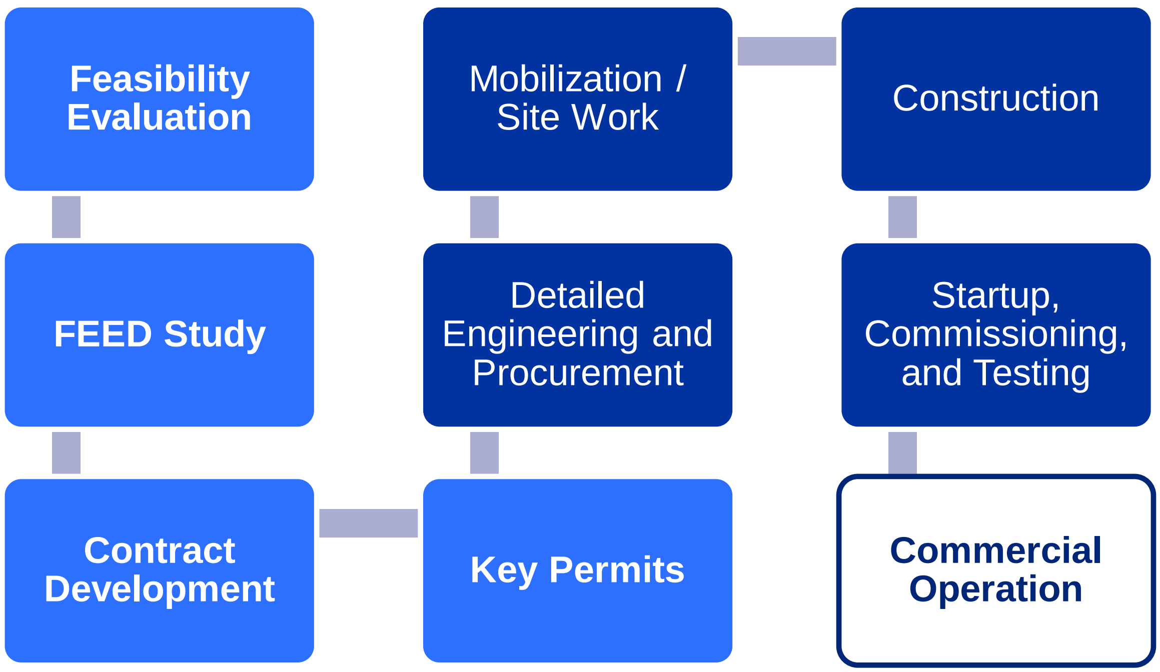

Figure 1: CCS Project Development Phases

2.1.1. Feasibility Evaluation

Feasibility evaluations are the first step in the project development of a CCS project. During this phase a preliminary evaluation of the facility and its suitability for applying a CCS is performed. This includes a preliminary technical review of the available utilities and footprint at the site to support implementation of a CCS, as well as the site's proximity and access to sequestration/offtake. This phase also includes a screening of the capture technologies and vendors that would be most suitable for the project and defines the expected balance of plant (BOP) scope for a selected technology/vendor. This phase includes a corresponding economic analysis to determine a high-level cost associated with a CCS and a summary of the findings of the technical review which help to guide the approach to the rest of the project development and implementation. This also includes identifying and onboarding project participants to support the front-end engineering and design (FEED) study.

Feasibility evaluations typically range from 6-9 months, but timeframes will vary by project.

2.1.2. FEED Study

A FEED study is a critical step in the project development of a CCS project to develop a preliminary design that has been sufficiently detailed to support the development of an executable project. CCS technology is typically fit for purpose, rather than a standardized design, due to the size and complexity of a CCS and the supporting BOP equipment. The FEED study includes development of a process design package for the selected technology, as well as a preliminary design for the CCS equipment, BOP equipment, and plant integration. The output of the FEED study is a design package and detailed cost estimate that will serve as the basis of the technical and commercial agreements. In addition, information developed during the FEED study will be used as preliminary input to develop the Title V Air Permit application that will be submitted to the applicable agency.

FEED studies typically range from 12-18 months, but timeframes will vary by project.

2.1.3. Technical and Commercial Agreements

In order to execute the project, a contract needs to be developed between the facility, the technology vendor and other contractors, as applicable, as well as securing project financing. The contract will include both technical and commercial documents which together form the basis of the executable contract for the project. This phase also includes development of the final price based on both the technical documents and final commercial agreements. This phase may also include competitive bidding of certain aspects of the project.

The development of these agreements including negotiations to reach final agreements typically require approximately 9 months, but timeframes will vary be project. In some cases, the development of these agreements may overlap somewhat with the FEED study, but final negotiations will not occur until the FEED study is complete.

2.1.4. Key Permits

For a CCS project, the longest duration permit is typically the Title V Air Permit (excluding permits associated with sequestration/offtake which are not considered in this report). In most states, this is also the primary permit that is required prior to commencing construction; however, this will vary depending on jurisdiction. Depending on the CCS technology, the expected type and quantity of emissions, and the location of the facility a project may trigger Prevention of Significant Deterioration (PSD) and be required to go through New Source Review (NSR) as part of the air permit application process. Other permits required for the project will be acquired during this period as well as during detailed engineering, as applicable and are generally not critical path schedule items.

Development of a Title V permit application typically requires approximately 6 months, but timeframes will vary by project. Review times by the agency will vary depending on the type of permit and other factors, a typical duration is 1-2 years from the time the permit application is submitted to the final permit being issued.

2.1.5. Detailed Engineering and Procurement

Detailed engineering begins with procurement of long-lead time items and subsequently all other equipment and components. After equipment is procured, and the engineering of that equipment is completed, final design information of those components are integrated into the preliminary design developed in the FEED study, allowing for detailed engineering to be completed around these components and interconnecting BOP systems. Detailed engineering includes the development of all necessary drawings to generate a complete set of Issue for Construction (IFC) drawings to be issued in packages to the construction contractor(s) to meet the expected construction schedule. Engineering and procurement will continue after construction begins and will overlap with the construction timeframe.

Detailed engineering and procurement typically requires approximately 24 months, but timeframes will vary depending on the scale and scope of the project. Presently the lead times of many of the major components required for a CCS system (one example is electrical transformers) have been extended and are unpredictable. If components are significantly delayed, this could result in corresponding increases in the overall timeframe for a CCS project.

2.1.6. Mobilization / Site Work

Mobilization involves the construction contractor(s) gathering and transporting their people, equipment, and infrastructure to site as well as setting this infrastructure up at the site. Initial site work includes the preliminary preparation of the site including clearing, grading, excavation, and in some cases demolition. Site work cannot begin until all of the necessary construction permits have been received, in most cases for power plants, this is the Title V Air Permit but depending on location may include other state and local permits.

Mobilization and initial site work typically requires approximately 6 months, but timeframes will vary depending on the scale of the project, project location, and seasonality.

2.1.7. Construction

Construction cannot begin until the necessary construction permits have been received as discussed above, and generally will not begin until the site work has been completed. Depending on the scope of the project, construction may be completed under one or more contracts and will include multiple contractors or construction crews working in different capacities and areas on the site.

Construction activities include, but not be limited to, the following major categories for CCS Projects:
- Foundations and Containment
- Underground Utilities
- CCS Vessel Erection
- Equipment Placement
- Structural Steel and Pipe Rack
- Piping and Interconnections
- Conduit and Cable Tray
- Electrical Wiring and Interconnections

Construction will vary depending on the scale and scope of the project, an expected timeframe for the construction activities is approximately 24 months; however, this timeframe is highly project and location specific and depends on the ability to attract the necessary labor to complete construction within this timeframe. This phase of work cannot begin until the site work is complete, and engineering has been advanced enough to produce construction ready (IFC) drawings. As discussed above the extended lead times of many of the major components required for a CCS system could increase construction timelines.

2.1.8. Startup, Commissioning, and Testing

As construction ramps down and systems are complete, pre-commissioning checks will begin. Once pre-commissioning checks are complete, commissioning begins. Commissioning may overlap with the end of construction as certain systems are completed. Commissioning activities includes both cold and hot activities, to ensure the system has been installed correctly, checked for leaks or other errors, and to make sure that individual systems operate as expected. When commissioning is complete, the CCS system will be started up. After the initial start-up the CCS system will go through a period of optimization and adjustment to ensure the complete system is operating as expected and is optimized for the operation. Once this period is completed, performance testing will occur. Performance testing typically is completed 30-90 days after the initial start-up to provide sufficient time for start-up and optimization.

Overall, startup, commissioning, and testing typically requires approximately 14 months, but timeframes will vary depending on the scale of the project. As discussed above, commissioning will overlap with the end of construction.

2.1.9. Commercial Operation

Once the system successfully passes performance testing, the system is ready for commercial operation.

2.2. PROJECT DEVELOPMENT TIMELINE

A typical high-level schedule for the development of a CCS project is included in Appendix A, showing both a baseline and extended duration schedule for these projects. Each project will have site specific considerations that could impact these durations as well as other factors that could result in potential schedule impacts or other roadblocks to the large scale deployment of CCS.

3. CO_2 CAPTURE SYSTEM OPERATION

3.1. CCS UNIT TIE-IN CONNECTIONS / INTEGRATION

An example process flow diagram (PFD) of an amine-based CO_2 Capture System (CCS) and the typical unit tie-ins is provided below for reference.

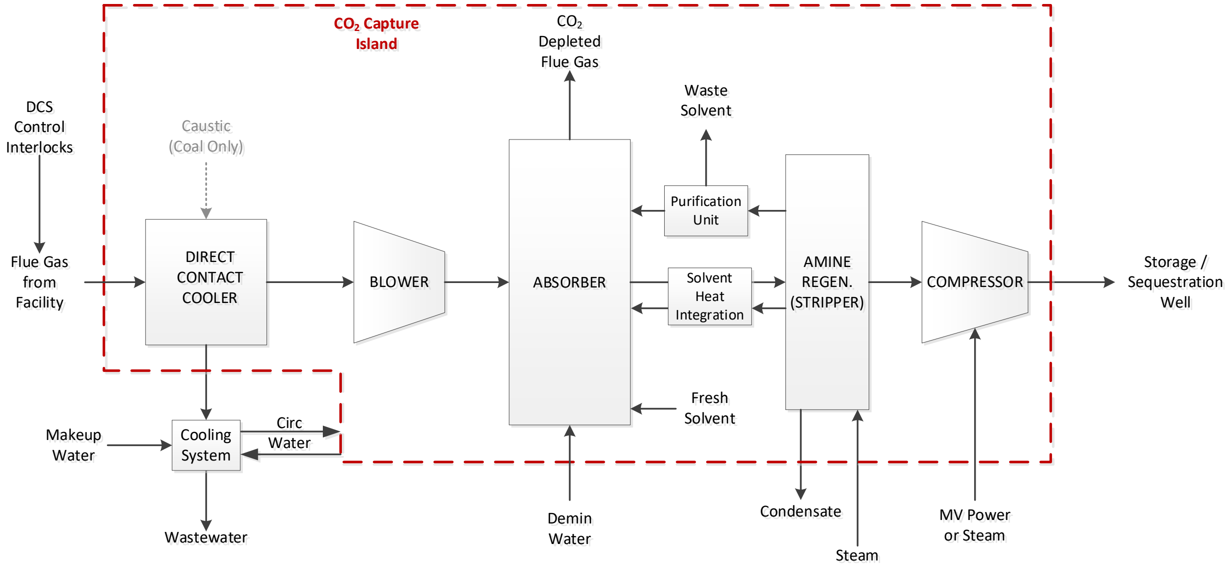

Figure 2: Typical Tie-Ins to CO_2 Capture System

Typical utilities for amine-solvent CCS systems include: steam for regenerating the solvent, power to run the pumps and other motors, demineralized water to maintain solvent water balance, raw water for cooling system makeup, and other support systems (e.g. fire water). The utilities that impact the host unit's output to the grid are steam and auxiliary power.

Steam for the CO_2 capture equipment is required for the stripper reboiler for thermal energy to release CO_2 from the solvent. Steam for the CO_2 capture equipment is expected to be extracted from the steam turbine from the low-pressure/intermediate-pressure crossover. Steam extraction from the steam turbine will reduce the overall gross capacity of the turbine. Extracted steam will be condensed in the CO_2 capture system reboilers and returned to the base unit as condensate. The condensate will be reintroduced to the host unit's steam cycle. While steam extraction is often used to supply the necessary steam, other options for stand-alone steam generation, such as auxiliary boilers, can be used instead. The use of these stand-alone options will impact the design and cost of the CCS but would not result in a unit derate. For the purposes of this evaluation, host unit steam extraction is assumed as the basis.

3.2. TYPICAL OPERATING PROCEDURES

3.2.1. CCS System Start-Up

The following is an example of a typical start-up procedure, official procedures are developed by the technology supplier and can vary from what is described below.

Typical Procedure:

1. Startup host unit and operate at the minimum load identified for CCS system startup.
2. Begin circulating water to the direct contact cooler and cooling water.
3. Begin circulating amine through system.
4. Begin sending flue gas to CO_2 island.
5. When sufficient CO_2 is built up in the circulating solvent, start sending steam to the reboilers and establish condensate return. The rate of steam extraction is site-specific and will be limited by steam turbine ramp rates. The steam turbine original equipment manufacturer (OEM) should be engaged in the initial design of the CCS system to establish the ramp rates and any other limitations.
6. When sufficient CO_2 is produced from the regenerator, begin ramping up the CO2 compressor.

Start-up is expected to be about 2-3 hours, after the host unit is online and stable, using a manual start-up sequence (this does not apply to the initial system startup and commissioning).

3.2.2. CCS System Shutdown

There are multiple types of system shut-downs, hot standby, cold standby, and emergency shut-downs.

Hot standby is typically implemented when the host unit and/or CCS system is expected to be offline for no more than 48 hours and could be implemented in a constrained grid scenario (see more discussion in Section 4). In hot standby, auxiliary power will still be necessary for the CCS, at a much smaller quantity, to run some pumps and other auxiliary equipment to maintain minimum circulation rates and temperatures within the system.

Cold standby is typically implemented when the host unit and/or CCS system is expected to be offline for more than 48 hours and is typically used to accommodate host unit outages and maintenance outages for the CCS. In cold standby scenarios, it is common that the major CCS vessels will be drained and the solvent will be stored in maintenance (or temporary) storage tanks. Other systems within the CCS process may also need to be drained for maintenance.

Emergency shut-downs occur in scenarios where equipment failure or other causes the host unit and/or CCS system to trip. Emergency shut-downs will have equipment impacts typically associated with loss of power to equipment (i.e. wear and tear). The impacts to solvent associated with an emergency shutdown are unknown at the time (i.e. overheating, etc.) and depends on the emergency systems and controls engineered into the specific CCS technology suppliers design.

The following is an example of a typical shut-down procedure, official procedures are developed by the technology supplier and can vary from what is described below.

Typical Procedure:

1. Close steam valve and stop sending steam to reboilers following steam turbine ramps rates (estimated 30 minutes or less). The steam turbine OEM should be engaged in the initial design to establish the ramp rates and any other limitations.
2. Close flue gas dampers and ramp down CO_2 island ID fans to stop sending flue gas to CO_2 island.
3. After flue gas dampers are closed, stop circulating DCC water.
4. Continue operating amine pumps in recirculation, minimum flow mode (hot standby) or empty amine to storage tank (cold shutdown).
5. As CO_2 production in the regenerator slows down, ramp down CO_2 compressor (estimated 30 minutes).
6. Stop cooling water circulation (estimated 30 minutes, or in conjunction with CO_2 compressor ramp down).

3.2.3. System Turndown

Most amine-based CCS systems are designed to accommodate a 50% turndown of the vessels without impact to the overall system performance. In many cases, and depending on the size of the host unit, multiple trains may be installed. In a multi-train system configuration, the overall system turndown is increased. For example, a unit with a 2 x 50% CCS train configuration could achieve a 25% turndown (with respect to the host unit load) by placing one train in standby and turning down the other train to 50%.

3.3. CONSTRAINED GRID OPERATIONS

As discussed above, hot standby could be implemented in a constrained grid scenario. In hot standby, steam extraction is halted and the majority of the CCS auxiliary power draw is removed. The time required to divert the majority of steam and power away from the CCS system is expected to be approximately 60 minutes, based on the shutdown procedure described in Section 3.2. There are not expected to be any adverse impacts associated with redirecting steam back to the host unit (if done in compliance with OEM specified steam turbine ramp rates), other than no longer being able to produce and sequester CO_2.

Figure 6 shows the expected derate curve during a shutdown to hot standby. The starting point is the full derate associated with steam extraction and CCS auxiliary power (normalized to 1.0). As the steam is redirected to the steam turbine, the derate is expected to decrease linearly and the output of the host unit begins to correspondingly increase. Similarly, as the ID fan and compressors ramp down, the auxiliary power draw decreases and the net output of the host unit to the grid increases.

During periods when the CCS is placed in hot standby to support a constrained grid scenario, the host unit will not be reducing their CO_2 emissions. Depending on the requirements of the Title V Air Permit, operation of the host unit without CCS in operation may not be allowed. To allow for the ability of units equipped with CCS to respond in a constrained grid scenario to maximize output to the grid, air permits will need to include wording to address this mode of operation, otherwise they may be subject to fines or other penalties.

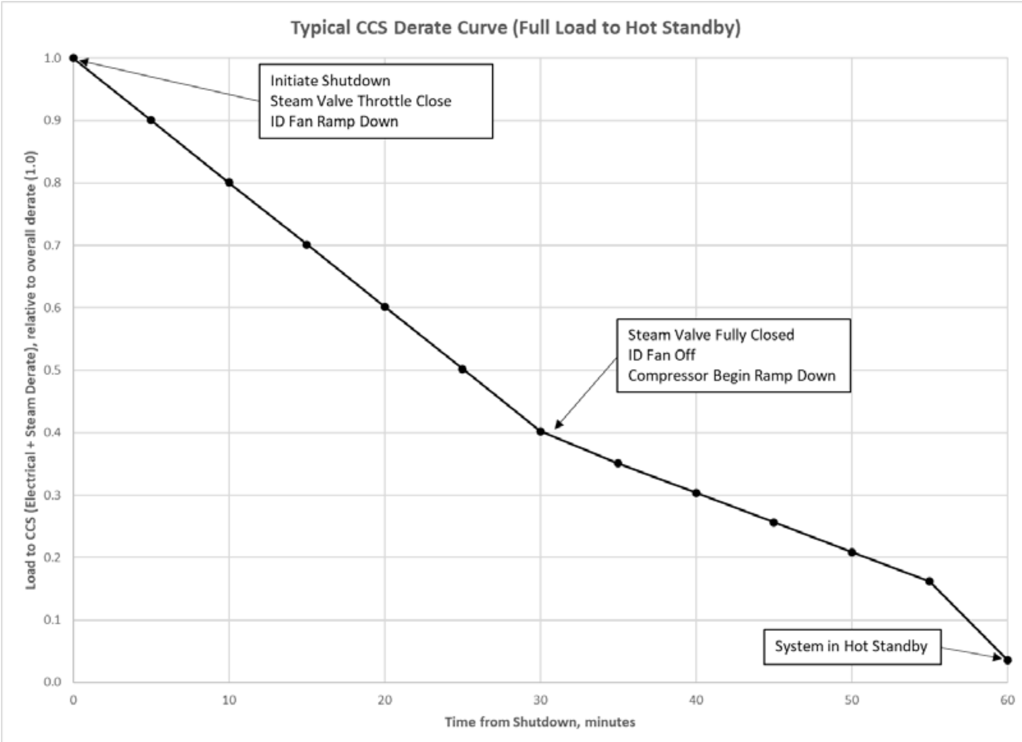

Figure 3: Typical CCS Derate Curve for Hot Standby

3.4. CONSIDERATIONS FOR NEW PLANTS WITH INTEGRATED DESIGN

There are cost benefits to including CCS integration considerations into new plant design rather than retrofitting it at a later time. The most significant benefit would be to design the steam turbine to be optimized for steam extraction to the CCS system. The steam turbine can be designed and optimized for expected steam extraction rates across operating loads, assuming that the CCS is always operating when the host unit is online (outside of startup and shut-down). Designing the steam turbine to always operate with steam being sent to the CCS system will have a different efficiency impact compared to designing the steam turbine to operate with the flexibility to toggle the CCS on or off. However, in a constrained grid scenario, units designed this way will not be able to be flexed to support grid stability and increase output to the grid.

4. SARGENT & LUNDY CO_2 CAPTURE EXPERIENCE

Sargent & Lundy is one of the longest-standing and most experienced full-service architect engineering firms in the world. Founded in 1891, the firm is a global leader in power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil-fueled power plants. S&L delivers comprehensive project services—from consulting, planning and design, permitting, and implementation to construction management, commissioning, and operations/maintenance—with an emphasis on quality and safety. The firm serves public- and private-sector clients in power and energy, oil & gas, government, industrial, mining, and other heavy industries.

S&L has extensive experience conducting technical evaluations for CO2 capture projects over the last decade, including feasibility, FEL, Pre-FEED, and FEED studies for clients which included preliminary system engineering, project layout, preliminary design, and cost estimates. Among the most notable FEED studies conducted by S&L was the Petra Nova Carbon Capture Project, which was awarded the Best Project of Merit award from Engineering News Record (ENR). S&L's work on the Petra Nova project included multiple FEED studies, Owner's Engineer services during project implementation, and detailed design of the 240 MW equivalent (MWe) slipstream carbon capture unit onto NRG's W.A. Parish Unit 8.

Figure 4: S&L CCS Experience Summary (as of 1/1/2024)

Of the numerous projects that S&L has completed or is currently supporting in the CCS space, a large portion have been feasibility studies for a range of industries, and more than 30 of these have been Pre-FEED or FEED studies. For all of these projects/studies S&L was the CCS system integrator, providing balance of plant engineering and integration into the existing facilities. For many of these projects, S&L also provided inside the boundary limit scope for the technology vendor. Our projects have also included pilot skid development and design, design of CO_2 pipelines, detailed design support, and miscellaneous project development support including permitting and Owner's Engineer support.

APPENDIX A. PROJECT DEVELOPMENT SCHEDULE

Typical CCS Schedule (Coal Boilers or NGCC)

The overall CCS schedule durations provided can be broken down into two phases, project development which includes feasibility evaluations, front-end engineering and design (FEED) studies, preparation of the technical/commercial agreements, permitting, and contract award, and project implementation which includes the detailed engineering, fabrication, construction, startup, commissioning, and testing. The overall CCS schedule provided shows both a baseline and extended duration for both phases to be 325 weeks (6.25 years) and 364 weeks (7 years), respectively. FEED Studies are critical to project development for CCS as this technology is an emerging technology with very limited full-scale / commercial installations. **This schedule is for the on-site CCS system only and does not include the scope associated with the development of the CO_2 off-take / storage (including transportation, sequestration, enhanced oil recovery utilization, and/or utilization).**

Project Development

No.	Description	Baseline Duration	Extended Duration	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Feasibility Evaluation (Technical and Economic Analysis)	24 weeks	36 weeks							
2	FEED Study (Pre-FEED and/or Full-FEED)	52 weeks	78 weeks							
3	Technical / Commercial Arrangements (Project Financing)	39 weeks	39 weeks							
4	Permits	52 weeks	52 weeks							

Project Implementation

No.	Description	Baseline Duration	Extended Duration	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
5	Detailed Engineering and Procurement	104 weeks	130 weeks							
6	Site Work/Mobilization	26 weeks	26 weeks							
7	Construction	104 weeks	130 weeks							
8	Startup, Commissioning, and Testing	60 weeks	60 weeks							
9	Commercial Operation	Milestone (325 weeks from project start)	Milestone (364 weeks from project start)							

Potential Impacts to Schedule

1. Delays in equipment fabrication and delivery due to high demand or customs issues.
2. Weather related delays in construction or deliveries, winter weather in cold-weather climates, high winds, storms, etc. Outage delays due to grid reliability/ demand.
3. Unknown undergrounds or other interferences resulting in re-work or construction delays.
4. More difficult retrofits, restricted site arrangements, may require more stick-built structures and less modular construction increasing overall construction time.
5. Contract negotiations may delay equipment/system award.
6. Public commenting periods (if required) could extend durations to received permits.
7. Project financing may be more challenging than traditional AQCS projects as CCS technology is still considered an emerging technology.

Potential Roadblocks / Bottlenecks for Large Scale Deployment

1. There are limited technology vendors who can provide this technology at commercial scale. In addition, there are limited constructors who still have the resources and knowledge to complete these types of large-scale retrofit projects. Fewer potential suppliers and constructors will limit the number of projects that can be implemented at once.
2. CCS projects require a large amount of structural steel, these projects will have to compete with other CCS projects and other infrastructure and clean energy projects for materials and equipment.
3. CCS projects require a large amount of heavy construction equipment as well as large construction crews to erect these large structures and the associated balance of plant equipment, these projects will have to compete with other CCS projects and other infrastructure and clean energy projects to attract skilled labor and have access to the necessary construction equipment.
4. Delays in engineering associated with high volume of projects associated with large scale deployment.
5. Labor availability and the cost to attract labor could become a challenge, especially with other large infrastructure projects also taking place domestically.

Office of Clean Energy Demonstrations

U.S. Department of Energy
Office of Clean Energy Demonstrations

Bipartisan Infrastructure Law
CARBON CAPTURE DEMONSTRATION PROJECTS PROGRAM

Funding Opportunity Announcement Number: DE-FOA-0002962

Type: Initial

Assistance Listing Number: **81.089, Fossil Energy Research and Development**
81.255, Clean Energy Demonstrations

Funding Opportunity Announcement Issue Date:	02/23/2023
Submission Deadline for Letters of Intent:	03/28/2023
Submission Deadline for Applications:	05/23/2023 – 5:00 PM ET
Expected Date for DOE Selection Notifications:	August 2023
Expected Date for Pre-Selection Interviews:	August 2023
Expected Timeframe for Award Negotiations:	Fall 2023

- Applicants must submit a Letter of Intent to be eligible to submit an Application.

Questions about this FOA? Email CCdemoprojectsprogram@hq.doe.gov
Problems with OCED eXCHANGE? Email OCED-ExchangeSupport@hq.doe.gov
Include FOA name and number in subject line.

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1.0 Funding Opportunity Description

1.1 Background and Context

The Department of Energy's (DOE) Office of Clean Energy Demonstrations (OCED) is issuing this Funding Opportunity Announcement (FOA), in collaboration with the Office of Fossil Energy and Carbon Management (FECM) and National Energy Technology Laboratory (NETL), for integrated carbon capture and storage (CCS) projects that demonstrate substantial improvements in the efficiency, effectiveness, cost, and environmental performance of carbon capture technologies for power, industrial, and other commercial applications. Awards made under this FOA will be funded with funds appropriated by the Infrastructure Investment and Jobs Act, more commonly known as the Bipartisan Infrastructure Law (BIL).

The BIL is a once-in-a-generation investment in infrastructure, designed to modernize and upgrade American infrastructure to enhance United States competitiveness, drive the creation of good-paying jobs with a free and fair choice to join a union, tackle the climate crisis, and ensure stronger access to economic, environmental, and other benefits for disadvantaged communities. The BIL appropriates more than $62 billion to DOE to invest in American manufacturing and workers; expand access to energy efficiency and clean energy; deliver reliable, clean, and affordable power to more Americans; and demonstrate and deploy clean energy technologies.

As part of and in addition to upgrading and modernizing infrastructure, DOE's BIL investments will support efforts to build a clean and equitable energy economy that achieves a zero-carbon electricity system by 2035, and to put the United States on a path to achieve net-zero emissions economy-wide by no later than 2050 and a fifty percent reduction from 2005 levels in economy-wide net greenhouse gas pollution by 2030 to benefit all Americans.

OCED's mission is to deliver clean energy technology demonstration projects at scale in partnership with the private sector to accelerate deployment, market adoption, and the equitable transition to a decarbonized energy system. OCED was established in December 2021 and was first authorized and funded through the BIL. The founding of OCED builds on DOE's expertise in clean energy research and development and expands DOE's scope to fill a critical gap on the path to net-zero emissions by 2050.

The BIL will invest up to $2.537 billion to fund domestic CCS demonstration and commercial-scale projects designed to further the development, deployment, and commercialization of technologies to capture and geologically store carbon dioxide (CO_2) emissions securely in the subsurface.

Many proven clean energy technologies poised for significant market share in a global clean energy economy exist today, including carbon capture and storage technologies. DOE seeks to fund projects that demonstrate substantial improvements in the efficiency, effectiveness, cost, and environmental performance of carbon capture technologies for power, industrial, and other commercial applications.

1.2 Program Purpose

To reach the President's ambitious domestic climate goal of net-zero emissions economy-wide by 2050, the United States will have to capture, transport, and permanently sequester significant quantities of carbon dioxide. There is growing scientific consensus that, while the first priority for addressing climate change must be to avoid emissions, CCS technologies and permanent sequestration are needed to minimizing the harm due to climate change.

While the technologies needed to decarbonize most of the U.S. economy exist, further innovation will create transformational pathways for meeting these decarbonization goals. Demonstration projects will support this innovation. Supported CCS demonstration projects will benefit entities intending to commercialize and deploy integrated CCS projects. Incentives are already driving CCS investments. Experience gained through successful execution that advance the state of this program can help to accelerate CCS deployment to achieve our climate goals while achieving other societal objectives.

DOE is aware of the concerns from environmental justice and climate organizations about how CCS projects could negatively affect communities, local environmental quality, and the overall climate mitigation effort if not developed with appropriate safeguards in alignment with Federal and state regulations to safeguard the environment, public health, and public safety. DOE has a history of investing in research and development to make carbon management technologies safer, more reliable, and more efficient. With this FOA we continue to support development of carbon management approaches that can enable responsible deployment as we progress towards our climate goals. CO_2 Carbon capture technology has the potential to reduce emissions of other kinds of pollutants in addition to CO_2, protect communities from increases in cumulative pollution, and maintain and create good, high-wage jobs across the country.[1]

Therefore, applications to this FOA will include a Community Benefits Plan (CBP) tailored to the scope of this FOA, discussing community and labor engagement; investing in the American workforce; Diversity, Equity, Inclusion and Accessibility (DEIA), and the Justice40 Initiative. These requirements will enable and inform future activities with the intent of developing community-informed carbon capture projects that serve the cost-effective, efficient, equitable, and environmentally responsible at-scale expansion of carbon capture operations that enable industry adoption and create quality jobs.

Successful CBP activities will be central to the implementation of all phases of the Carbon Capture Demonstration Projects Program. For example, DOE will require projects to track and report on outcomes and outputs related to community benefits such as but not limited to changes in non-CO_2 pollution.

[1] https://www.federalregister.gov/documents/2022/02/16/2022-03205/carbon-capture-utilization-and-sequestration-guidance

This FOA and any related activities will seek to encourage meaningful engagement and participation of workforce organizations, including labor unions, as well as underserved communities and underrepresented groups, including consultation with Tribal Nations consistent with Executive Orders 13985, 14025, 14052, and 13175, as well as the Memorandum on Tribal Consultation and Strengthening Nation-to-Nation Relationships[2]. Consistent with Executive Order 14008, this FOA is designed to help meet the goal that 40% of the overall benefits of certain federal investments in clean energy and climate solutions flow to disadvantaged communities, and to drive the creation of good-paying jobs with the free and fair chance for workers to join a union.

The funding for this FOA is authorized under section 41004(b) of the BIL and appropriated by Title III of Division J of the BIL. The programmatic authorizing statutes are:

- DOE Organization Act (Public Law 95-91), 42 U.S.C §§ 7101, et seq., as amended.
- Energy Policy Act of 2005 (Public Law 109-58) § 962(b), 42 U.S.C. § 16292(b), as amended.

Technology Space and Strategic Goals: This FOA seeks applications for transformational domestic, commercial-scale, integrated CCS, demonstration projects designed to further advance the development, deployment, and commercialization of technologies to capture, transport (if required), and store CO_2 emissions from:

- two projects at new or existing coal electric generation facilities
- two projects at new or existing natural gas electric generation facilities, and
- two projects at new or existing industrial facilities not purposed for electric generation.

CCS demonstration projects must be integrated with commercial facility operations and must be conducted in the United States.

Applicants must demonstrate significant improvements in the efficiency, effectiveness, cost, operational and environmental performance of existing carbon capture technologies.

This FOA makes available up to $1,700,000,000 for approximately 6 projects at up to a 50% federal cost share. Proposed projects must demonstrate as part of the application and during the award at least 90% CO_2 capture efficiency over baseline emissions and a path to achieve even greater CO_2 capture efficiencies for power and industrial operations. Note that if the carbon capture project includes a new, on-site auxiliary system to generate power or steam for its operation, it may need to include CO_2 capture, compression, and storage from the auxiliary system if needed to achieve the minimum unit-wide 90% CO_2 capture inclusive of the power industrial facility all new systems or processes associated with the CCS project.

This FOA focuses on CCS demonstration projects with existing sufficient technical detail to assess the readiness level of the proposed technologies and integrated systems to proceed into at-scale demonstrations and replication leading to commercialization.

[2] Memorandum on Tribal Consultation and Strengthening Nation-to-Nation Relationships - The White House

This will align to CCS technologies that have been validated to be at a minimum technology readiness level (TRL) of 7, to ensure that they are fully ready for demonstration. This means that the technologies funded can be readily replicated and deployed into commercial practice. Detailed technical descriptions of the specific Topic Areas (TAs) and associated TRL requirements are provided in the sections that follow. See Appendix N for a description of CCS Technology Readiness Levels.

Section 41004 of the BIL authorizes funding for both carbon capture large-scale pilot projects and carbon capture demonstration projects. DOE is issuing this carbon capture demonstration projects program FOA (FOA Number: DE-FOA-0002962) and a carbon capture large-scale pilot projects FOA (FOA Number: DE-FOA-0002963), available on OCED Exchange. DOE will not select the same project for both this FOA and the large-scale pilot projects FOA or projects that are interdependent between these two FOAs.

In general, technologies of interest for the carbon capture large-scale pilot projects FOA are less technologically mature (Technology Readiness Levels 5-7) than technologies of interest for the carbon capture demonstration projects FOA (Technology Readiness Levels 7-8). The large-scale pilot projects FOA focuses on technologies that have completed a small-pilot scale prototype at the time of application and will validate scaling factors to enable the large-scale pilot project to proceed to commercial-scale demonstration or commercial-scale application after the large-scale pilot project is complete. The carbon capture demonstration projects FOA focuses on commercial scale, integrated transformational[3] demonstration projects designed to further the development, deployment, and commercialization of technologies to capture, transport, and store emissions.

Organizations must decide which of these FOAs to apply to based on the TRL of the proposed project and other application requirements stated in the FOAs.

In September 2022, DOE issued FOA Number: DE-FOA-0002738 titled “BIL: CARBON CAPTURE DEMONSTRATION PROJECTS PROGRAM FRONT-END ENGINEERING DESIGN STUDIES FOR INTEGRATED CARBON CAPTURE, TRANSPORT, AND STORAGE SYSTEMS” to fund Front-End Engineering Design (FEED) studies associated with large CCS demonstration projects. Eligibility or awards made under that FOA do not impact eligibility for this FOA. Applicants need not have applied for or been awarded funding from that FOA to apply for this FOA.

DOE anticipates issuing a third carbon capture FOA in the future for projects that are still performing FEED studies and other early project work and will not be ready to apply to this FOA. Detailed technical descriptions of the specific Topic Areas are provided in the sections that follow.

[3] *See* the definition of transformational technology at 42 U.S.C. § 16292(a)(5).

1.3 Topic Areas

DOE anticipates selecting approximately 6 projects (two each for the Topic Areas discussed below) leading to the completion of facilities employing integrated CCS demonstration systems. Applicants will apply to one of the following Topic Areas (TA) depending on self-classification, based on the primary purpose of the facility, for the proposed CCS demonstration project.
For each Topic Area described below, Applicants must demonstrate significant improvements in the efficiency, effectiveness, cost, operational and environmental performance of existing carbon capture technologies.

1.3.1 Topic Area 1 – CCS Demonstration at a Coal Electric Generation Facility

The objective of each project awarded under **TA-1** is to demonstrate at commercial scale, in a domestic setting, advanced technologies that: (1) capture, transport (if required), and store CO_2 from new or existing, domestic coal electric generation-only or coal combined heat and power (CHP) facility for a minimum of three (3) years with ongoing monitoring and verification; and (2) achieve the minimum *unit-wide* 90% CO_2 capture efficiency (or greater) once stable operations are achieved. An example of a *unit* would be the entire exhaust stream, rather than a slipstream, associated with a single boiler or combustor. Capturing carbon from facility-wide, rather than unit-wide, emissions is permitted but not required.

Technical Requirements

Demonstrations may be conducted at a Coal Electric Generation-Only Facility, or a Coal Combined Heat and Power Facility; both will be referred to hereafter as "Coal electric generation units". Projects must be designed to process the output from at least an entire unit at the coal-based facility with 90% CO_2 capture efficiency (or greater). Based on these unit-scale findings, Applicants will develop a plan for achieving full facility-wide decarbonization and submit this as a project deliverable.

CCS systems planned to be located at existing coal electric generation facilities that are not currently in commercial operation or with an announced closure date earlier than 15 years from the time of this award will be considered not responsive for the current FOA.

To meet the prior scale development expectations for this Demonstration FOA, proposed projects should have completed:

1. TRL 7 for coal electric generation by completion of an integrated, continuous, pilot-scale test (≥ 10 MWe) using coal exhaust gas at 90% or higher carbon capture efficiency, or

2. TRL 8 for coal electric generation by completion of a 1st of a kind full-scale commercial demonstration. Projects proposing TRL 8 technologies should plan to demonstrate substantial improvement in the efficiency, effectiveness, cost, and environmental performance beyond the first of a kind demonstration.

1.3.2 Topic Area 2 – CCS Demonstration at a Natural Gas Electric Generation Facility

The objective of each project awarded under **TA-2**[4] is to demonstrate at commercial scale, in a domestic setting, advanced technologies that: (1) capture, transport (if required), and store CO_2 from a new or existing domestic simple cycle or combined cycle natural gas electric generation, natural gas CHP, or natural gas steam methane reformer (SMR) facility producing hydrogen for electricity generation, for a minimum of three (3) years with ongoing monitoring and verification; and (2) achieve the *unit-wide* 90% (or greater) CO_2 capture efficiency once stable operations are achieved.

Technical Requirements
Based on these unit-scale findings, Applicants will develop a plan for achieving full facility-wide decarbonization and submit this as a project deliverable.

The term "natural gas" means any fuel consisting in whole or in part of (i) natural gas; (ii) liquid petroleum gas; (iii) synthetic gas derived from petroleum or natural gas liquids; (iv) any mixture of natural gas and synthetic gas; or (v) biomethane.[5] Natural gas SMR facilities producing hydrogen for other than electricity generation are non-responsive to this FOA.

To meet the prior scale development expectations for this Demonstration FOA, proposed projects should have completed:

1. TRL 7 for NG electric generation by completion of an integrated, continuous, pilot-scale test with NG exhaust gas (≥ 10 Mwe) at 90% or higher carbon capture efficiency, or

2. TRL 8 for NG electric generation by completion of a 1st of a kind full-scale commercial demonstration. Projects proposing TRL 8 technologies should plan to demonstrate substantial improvement in the efficiency, effectiveness, cost and environmental performance beyond the first of a kind demonstration.

1.3.3. Topic Area 3 – CCS Demonstration at an Industrial Facility Not Purposed for Electric Generation

The objective of each project awarded under **TA-3** is to demonstrate at commercial scale, in a domestic setting, advanced technologies that capture, transport (if required), and store a minimum of 300,000 tonnes CO_2/yr from at least one *process slipstream* at a new or existing domestic industrial facility not purposed for electric generation for a minimum of three years with ongoing monitoring and verification. Note that coal or natural gas must be used to some extent in the process that produces the gas stream targeted for carbon capture. The proposed CCS technology must describe the potential to achieve the *unit-wide* 90% (or greater) CO_2 capture efficiency.

[4] *See* the definition of natural gas electric generation facility in 42 U.S.C. § 16292(a)(3).
[5] 42 U.S.C. § 16292(a)(2).

Based on these unit-scale findings, Applicants will develop a plan for achieving full facility-wide decarbonization and submit this as a project deliverable. The industrial sectors of interest include:

i. chemical production (e.g., ammonia, petrochemicals) *excluding ethanol and all hydrogen production*,
ii. mineral production (e.g., cement, lime, and glass),
iii. pulp and paper production, and
iv. iron and steel production,
v. oil refining unit offtake (e.g., catalytic cracker. Note that while steam methane reformers are not permitted alone in any TA, they are permitted in TA 3 if the project also proposes to capture carbon from another gas stream not associated with hydrogen production.)

CCS for natural gas processing is not of interest.

To meet the prior scale development expectations for this Demonstration FOA, proposed projects should have completed:

1. TRL 7 for industrial CO_2 capture by completion of an integrated, continuous, pilot-scale test at 90% or higher carbon capture efficiency using actual exhaust gas from the selected process (preferred) or a reasonably similar alternative gas source (must justify in application), or

2. TRL 8 for industrial CO_2 capture by completion of a 1st of a kind full-scale commercial demonstration. Projects proposing TRL 8 technologies should plan to demonstrate substantial improvement beyond the first of a kind demonstration.

Storage Requirements

For all TAs, captured CO_2 will be stored in a secure, domestic, geologic, subsurface formation that has sufficient capacity to store CO_2 from the proposed integrated CCS demonstration facility. Prior to construction, Applicants must have completed their feasibility and FEED studies, and engineering and design efforts as they relate to any emissions, any equipment, any necessary pipeline connections, and access from the proposed carbon capture facility to storage formation(s). Applicants will need to demonstrate the technical and regulatory readiness to complete all project elements, including any necessary agreements or commitments. Applicants must also provide commitment letters from any partners, subrecipients, or vendors who will be critical to completing the proposed scope.

Go/No-Go Reviews

DOE will use Go/No-Go reviews to manage each project to their specific, negotiated timeline and deliverables by evaluating progress of work toward required deliverables associated with each phase of the project prior to approving work in follow-on budget periods. DOE go/no go reviews will inform decisions to continue to advance or to terminate projects between (or potentially within) each phase of the award.

Additional Guidance for All Applicants

Projects must incorporate and integrate National Environmental Policy Act (NEPA) requirements into their proposed scope, schedule, and budget. Projects proposing work in states with state-level requirements similar to NEPA must specifically incorporate compliance with the state-level regulations into their plans (e.g., a site proposed in California must include compliance with the California Environmental Quality Act [CEQA] as applicable).

Applicants must discuss how they will identify and integrate applicable safety and compliance requirements with all relevant authorities into their proposed project. If at any point in the project, any reportable incidents, violations up to and including stop work orders, or other disciplinary measures are issued by any prevailing authority, this must be reported to DOE. Safety performance will also be reviewed at each Go/No-Go decision point. Multiple or severe violations may lead to project termination.

1.4 Award and Project Management Approach

Awards made under this FOA will utilize a four-phased approach for managing scope, schedule, deliverables, and budget; more information is included in Appendix K. Figure 1 shows an example of the requirements and deliverables for each phase. Activities and deliverables will be further defined during award negotiations and subsequent negotiations between phases. DOE's review and evaluation of deliverables reflecting activities in each phase will inform Go/No-Go decisions that occur between and within phases. Time periods for each phase are nominal and may be significantly accelerated if the applicant has completed all required work scope and documentation.

◇ Initial Application	Application	◇ Phase 1: Detailed Plan	☆ Phase 2: Site, Permit, Finance	☆ Phase 3: Build & Integrate	☆ Phase 4: Ramp-Up & Operations
☆ Go/No-Go Decisions	Pre - DOE funding	5% TPC, Funding, Up to 50% Cost Share, 12-18 Months	15% TPC, Funding, Up to 50% Cost Share, 2-3 Years	70% TPC Funding, Up to 50% Cost Share, 3-6 Years	10% TPC, Funding, Up to 50% Cost Share, 2-4 Years
Engineering, Procurement, Construction	• Separate FEEDs for Capture, Transport, and Storage • TRL/MRL/CRL descriptions, • Project L1 IPS, Phase 2 L2 IPS • Class 4/5 TPC Estimate	• Integrated FEED for Capture, Transport, and Storage • TRL/MRL/CRL Analysis, Uncertainties, Risk • Project L2 IPS, Phase 3 L3 IPS • Class 3 TPC Estimate	• Engineering & Design (~90%) • TRL/MRL/CRL Updates • Project L3 IPS, Phase 3 L4 IPS • Class 1 TPC Estimate • Standard PM Tool in use	• Tech Risk updates, tracking • Progress Execution Reports • Interim Go/No-Go reviews consistent with T/Cs	• Regular operations status reporting, • Tech Risk Updates, Tracking • Final TPC accounting
Business Development & Management	• Business Strategy • Team Description • Workforce Plan • Finance Plan • Market potential analysis	• Project Management Plan (PMP) • Risk Management Plan (RMP) • Financial Model • Updated workforce plans, • Market & off-take proposals • Site Selection	• Teaming Agreements • Site Access Secured • Integrated RMP Updated • Labor agreements • Financing in place • Phase 3 T/Cs Agreed/Approved,	• Regular progress/status reporting for all agreements • Regular financial status reports • Other reporting per T/Cs • Updated RMP covering phases 3 and 4	• Financial models updated with offtake and production data • Revised growth plans and projections • Updated RMP covering ramp and steady state operations
Permitting & Safety	• Safety Plan • Permitting Overview • Environmental Approval Overview (State & Federal)	• Site Safety Plans, Technology Safety Plans • Physical, Information, Cyber Security Plans • Environmental Data Package • Initial NEPA Documentation	• Updated SSP & TSP • Final Physical, Information & Cyber security plans • Permits for Construction • Environmental Authorizations	• Status reporting on required permits and environmental • Safety & security incident reporting & audits • Permits for Operations	• Ongoing permit, safety, and security reporting
Community Engagement & Benefits Plan	• Community Benefits Plan, including: • Community & Labor Engagement; Investing in American Workforce; DEIA; Justice40 Initiative	• Implement Phase 1 scope of CBP • Update CBP for Phases 2-4 based on Phase 1 activities	• Implement Phase 2 scope of CBP • Update CBP for Phases 3-4 based on Phase 2 activities	• Implement Phase 3 scope of CBP • Update CBP for Phase 4 based on Phase 3 activities	• Implement Phase 4 scope of CBP • Update CBP based on activities and findings from ramp-up and pilot-scale operations
Technical Data & Analysis	• LCA Analysis • TEA Analysis	• Performance Model • Updated LCA • Updated TEA	• Mature LCA, V&V plans • Mature TEA w/risk analysis • Technical V&V data and plans • Project completion testing	• Periodic TEA and LCA updates • V&V data collection & analysis • Project completion testing	• Validated performance model • LCA and TEA incorporating operational data • Ongoing data collection and dissemination • Performance ramp V&V

Figure 1. Summary of activities and outcomes in each phase of the projects awarded under this FOA.

Phase 1 – Detailed Project Planning

Phase 1 activities will focus on completing specific details about the overall project plan and analysis to refine projections submitted as part of the proposal. These activities must provide assurance to DOE that the overall plan is technologically, financially, and legally viable, with buy-in from relevant local and community stakeholders. This could include any plans to develop a skilled labor pool through Workforce and Community Agreements. Teams will integrate FEED studies associated with carbon capture, transport, and storage and complete preliminary engineering, construction, and commercial-scale designs. This will include finalization of a Project Management Plan (PMP), a Risk Management Plan (RMP), an Intellectual Property Management Plan (IPMP), the initial Safety Plan, and an initial financial plan for the entire 4-phase effort, and final site selection (pending NEPA review) for the various technologies to be included in the award.

The integrated FEED study must be complete at the end of Phase 1. Phase 1 should also include a continuation of analysis activities to refine and update Life Cycle Analysis (LCA) and techno-economic analysis (TEA) data provided in the application. Outreach and stakeholder engagement, which should be active prior to the application process, should continue in Phase 1 as the project site(s) are finalized and community economic and development impacts become clearer.

Teams should be fully engaged with the DOE's National Environmental Policy Act (NEPA) team as they develop environmental and regulatory plans to prepare for permitting and approval processes in Phase 2.

Applicants should plan approximately 12 months for Phase 1, depending on the extent of advanced planning and analysis each team has already completed, and how quickly the Recipient can move through the negotiated Go/No-Go requirements to move into Phase 2. DOE anticipates that some teams will have already performed extensive analysis, planning, design, and community engagement as required in Phase 1, and therefore some projects may advance to Phase 2 on a shorter timeline.

Phase 2 – Project Development, Permitting, and Financing

Phase 2 encompasses advanced planning activities and final design completion. Applicants will finalize their project development plans, commercial agreements, financial structure, and complete the necessary permitting and approval activities required to begin construction. By the end of Phase 2, engineering designs must be sufficiently mature to support completion and execution of relevant procurement or construction contracts and overall commencement of major project execution tasks. Long-lead procurement activities may be started in Phase 2 with prior DOE approval. Any agreements or commitments necessary to meet cost share requirements for the remainder of the project, including third-party financing agreements, must be completed. Risk management plans must be revised and updated to reflect progress made and risks mitigated as well as new or emerging risks and corresponding management plans.

By the completion of Phase 2, safety and security plans must be finalized and execution ready. All necessary permits and approvals must be in place to prepare for construction, including completion of required NEPA reviews Final pre-implementation LCA and TEA activities must be completed to DOE expectations and corresponding verification and validation (V&V) plans (for capture, transport, and storage) must be in place. They will be implemented in Phases 3 and 4. Community and labor engagement must have progressed towards a comprehensive Community Benefits Plan that reflects community input and implementation experience to date and sets the stage for ongoing engagement. Community impact targets must be finalized, and tracking plans must be in place to monitor economic and social impacts of the projects as they progress to implementation.

Evidence of a contingency reserve is required prior to beginning Phase 3 activities. More information on contingency reserve funding can be found in Section 2.0.

Phase 3 – Installation, Integration, and Construction

Phase 3 activities will focus on implementation. DOE expects this phase to be the longest in duration and the most cost intensive. Applicants will employ industry standard project management tools and will be required to provide regular status updates and reports. Plans developed in the preceding phases will be revised and updated as appropriate to reflect actual performance. Previously and newly identified risks will be tracked, actively managed, and regularly reported to DOE. Reporting frequencies and content requirements will be unique to each award and negotiated prior to Phase 3 commencement.

While Applicants will manage implementation, DOE will closely monitor progress and evaluate it against the plans developed through Phase 2. DOE and/or its third-party representatives will visit the site(s) regularly to verify progress and collect data, consistent with the established reporting requirements and substantial involvement.

Phase 3 may look significantly different for each award as there will be varying amounts of construction and retrofitting. Applicants must propose a funding level that is appropriate for the scale of the technologies and infrastructure being installed and constructed, within the limits outlined in Section 2.0 .

Phase 3 will conclude with a performance/startup test of the completed carbon capture, transport, and storage system running at full scale operation. This performance test must be completed before the Applicants can proceed to Phase 4.

DOE expects that Phase 3 activities may take approximately 3-6 years, but Applicants may propose shorter or longer lengths if the overall project length is no longer than 12 years.

Phase 4 – Ramp-Up and Sustained Operations

In Phase 4, Applicants will transition to operations. Phase 4 will commence with completion of award-specific criteria which will be negotiated in prior phases. Phase 4 activities will then focus on integrated system performance. By the end of Phase 4, each award will have demonstrated full commercial-scale design operations over an extended period. DOE expects that Phase 4 activities may take approximately 3 years but may extend longer depending on award-specific characteristics.

To meet a key OCED objective that DOE-funded commercial demonstration projects catalyze follow-on private sector investments as well as Justice40 goals, Phase 4 will also include substantial financial, socio-economic, environmental, and operational data collection and reporting to DOE. To the extent practicable while protecting sensitive and proprietary information, DOE will synthesize, anonymize, or otherwise incorporate site and operations data into quantitative and qualitative analyses that can be promulgated to external stakeholders for the purpose of informing future private sector investment decisions.

Applicants must propose a funding level that is appropriate for the scale of the project ramp-up and initial operation using DOE funding within the limits outlined in Section 2.0. Similar to Phase 3, contingency reserve will also be required for Phase 4. Applicants are also encouraged to review the regulations regarding Program Income and be aware of the ways in which Program Income can be treated during the award.

Transitions between Phases

Additional funding for subsequent phases will require successful completion of a Go/No-Go review at the end of each phase. Specific Go/No-Go criteria will be negotiated with each selected project for transitions between each phase. This may include a requirement to submit a standardized set of data to provide quantitative and qualitative insight on metrics spanning the technological, economic, market, workforce, Justice40 goals, and other components of the project's analysis activities.

DOE may also require the negotiation of additional Go/No-Go decision points within phases (i.e., phases may include one or more budget periods with Go/No-Go points at the end of each budget period). Applicants must propose quantitative Go/No-Go criteria for each budget period as part of the Workplan.

If DOE determines that an award is making insufficient progress, additional scrutiny and oversight by DOE or its representatives may be employed, and corrective measures negotiated. Awards may be discontinued at any of the Go/No-Go decision points if the Go/No-Go criteria, project, and/or program requirements are not met. Additional in phases Go/No-Go decisions may be utilized to ensure sufficient project progress.

Specific project structure details for each recipient will be negotiated on a project-by-project basis to produce the best possible balance between project outcomes and DOE risk exposure. Examples of factors that may be considered as part of such negotiations include project and risk management processes, team capabilities, cost share amounts, financial contingencies, and engagement of independent monitors such as an Independent Engineers and/or Community Benefits Plan consultants representing DOE interests.

DOE will require access to project performance and financial data necessary to track progress against a project baseline (or similar). As these projects are new demonstration-scale or commercial deployments, to the greatest extent possible, project progress and information will be shared with interested stakeholders.

Final Outcome

If funded through all four phases, DOE expects that the projects will reach technical and commercial viability under this FOA and will continue to operate beyond the financial assistance project period (well beyond DOE funding). Achieving DOE's broad end goals will necessitate review and evaluation of proposed project characteristics that include cost, schedule, and scope; technology; business; market; financial; management; community support or other factors throughout the project to validate assumptions made for determining commercial viability.

DOE will collect data during the project to ensure that the project can economically continue beyond the project period.

The phased approach is designed to guide projects through the project development process incrementally. Each subsequent phase is structured to ensure that each award meets a standard level of maturity, employs a robust execution approach, and that technical and non-technical project risks are adequately and appropriately managed throughout DOE's award.

As the projects are expected to continue as self-sustaining entities operating fully independent of federal funds, DOE may also request financial sustainability plans or long-term disposition and decommissioning plans as part of future Go/No-Go decision points. This may include proposed sources of funding/revenue and the business model which will support the projects beyond the DOE award. This may also include an estimate of profit and loss demonstrating how the projects will maintain financial self-sufficiency and strategies to grow beyond the initial award or retain sufficient funding for decommissioning and demolition, if appropriate.

2.0 Award Information

Anticipated Type of Award:	Cooperative Agreement
Application Type(s) Allowed:	New
Estimated Number of Awards:	Up to 6
Anticipated Funding Amount:	$1,700,000,000
Award Budget:	Maximum DOE funding for each award and each Topic Area are listed below. DOE funding will not exceed 50% of the total project cost.
Award Project Period:	The maximum project period is 12 years, and the scope of the proposed project would determine the specific project period within the maximum project period.

DOE may issue awards in one, multiple, or none of the following topic areas:

Table 1. Award Amounts by Topic Area

TA Number	TA Title	Anticipated Number of Awards	Maximum Award Size for Any One Individual Award (Fed Share*)	Approximate Total Federal Funding Available for All Awards	Anticipated Period of Performance
TA-1	CCS Demonstration at a Coal Electric Generation Facility	0 – 2	$350,000,000	$700,000,000	Up to 12 years
TA-2	CCS Demonstration at a Natural Gas Electric Generation Facility	0 – 2	$270,000,000	$540,000,000	Up to 12 years
TA-3	CCS Demonstration at an Industrial Facility Not Purposed for Electric Generation	0 – 2	$230,000,000	$460,000,000	Up to 12 years
Total		Up to 6	$850,000,000	$1,700,000,000	

*The DOE share listed under the anticipated individual award size is the maximum amount of DOE funding that can be proposed for each Topic Area.

Applications that propose a DOE share more than the maximum limits stated above will not be evaluated and will be considered nonresponsive to the FOA.

DOE has substantial involvement in work performed under Cooperative Agreements made as a result of this FOA. DOE is responsible for:

1. Reviewing in a timely manner project work performance and deliverables, and redirecting the work effort as needed to address critical programmatic issues;
2. Conducting program review meetings to ensure adequate progress and that the work accomplishes the program and project activities. At the Go/No-Go decision points, the recipient will provide a continuation application and present the detailed work plan and budget requirements for the following period. In addition to decision point, DOE may conduct unscheduled reviews, if necessary, on a non-interference basis, which may be used by DOE for assessments of whether to have continued performance of the award;
3. Redirecting work or shifting work emphasis, if needed; participating in recipient meetings and conference calls; this includes additional monitoring to permit specified kinds of direction or redirection of the work because of interrelationships with other projects;
4. Serving as scientific/technical liaison between the awardee and other program or industry staff;
5. Oversight of recipient progress to help ensure the project achieves intended results. This may include shifting work emphasis, within the various projects, if necessary to achieve project goals. If work scope changes are required, they will be negotiated between the parties; and
6. Coordinating the conduct of independent reviews of the project if needed.

There are limitations on recipient and DOE responsibilities and authorities in the performance of the project activities. Performance of the project activities must be within the scope of the Statement of Objectives, the terms and conditions of the Cooperative Agreement, and, if applicable, funding and schedule constraints.

The applicant will establish four phases for the proposed project. DOE will only fund up to one phase at a time.

A contingency reserve is required for Phases 3 and 4. The amount of contingency will be determined based on the quantitative risk analysis performed by the recipient. The required contingency may be adjusted based on the level of remaining project risks and other considerations as the project progresses.

Applicants must demonstrate that they can meet unexpected financial needs of the project. The full design package needed to advance to Phase 3 must also include documentation showing that the recipient has access to the required contingency reserve.

Typically, DOE expects contingency funds must be: (a) liquid, (b) immediately available, and (c) unrestricted funds dedicated exclusively to the project for the purpose of mitigating project performance baseline risk. Resources that have other requirements that must be met or subject to other constraints, such as performance guarantees, cannot count towards the contingency requirement.

The contingency reserve is in addition to total project costs and does not count towards the Recipient's minimum 50% cost share requirement. If expended, the contingency will not result in reimbursement by DOE above the total federal share approved in the award. DOE discourages Applicants from reducing scope to comply with the contingency reserve requirement.

DOE may establish more than one budget period for each award (and award phase) and fund only the initial budget period(s). Funding for all budget periods, including the initial budget period, is not guaranteed. Before the completion of each phase, DOE will conduct Go/No-Go reviews of all projects and may provide additional funding only to a subset of Applicants.

This FOA will be carried out in four phases with Go/No-Go decision points between each phase (and possibly within phases). Go/No-Go reviews will be conducted on individual projects as they complete the work in each phase.

Because proposed projects will be at differing maturity states, Phase durations will be negotiated with award Applicants.

Project continuation will be contingent upon several elements, including satisfactory performance and Go/No-Go Decision Point review. At the Go/No-Go Decision Points, DOE's evaluation will include project performance, project schedule adherence, the extent to which milestone objectives are met, compliance with reporting requirements, overall contribution to the program goals and objectives, and other factors as needed.

As a result of this evaluation, DOE may, at its discretion, authorize the following actions: (1) continue to fund the project, contingent upon the continued availability of funds appropriated by Congress for the purpose of this program and the availability of future-year budget authority; (2) recommend redirection of work under the project; (3) place a hold on federal funding for the project, pending further supporting data or funding; or (4) discontinue funding the project because of insufficient progress, change in strategic direction, or lack of funding.

DOE will accept only new applications under this FOA. DOE will not consider applications for renewals of existing DOE-funded awards through this FOA. This announcement and awards made under this announcement will fall under the purview of 2 C.F.R. Part 200 and 2 C.F.R. Part 910.

3.0 Eligibility Information

To be considered for substantive evaluation, an Applicant's submission must meet the criteria set forth below. If the application does not meet these eligibility requirements, it will be considered ineligible and removed from further evaluation.

DOE will not make eligibility determinations for potential Applicants prior to the date on which applications to this FOA must be submitted. The decision whether to submit an application in response to this FOA lies solely with the Applicant.

3.1 *Eligible Applicants*

Domestic Entities

The proposed prime recipient and subrecipient(s) must be domestic entities except as stated below. The following types of domestic entities are eligible to participate either as a prime recipient or subrecipient of this FOA:

1. Industry stakeholders, including any industry stakeholder operating in partnership with the National Laboratories;
2. Institutions of higher education;
3. Multi-institutional collaborations;
4. And other appropriate entities listed below:[6]
    a. For-profit entities;
    b. Non-profit entities;
    c. Tribal Nations
    d. State and local governmental entities;
    e. Incorporated Consortia; and
    f. Unincorporated Consortia

Federal agencies and instrumentalities (other than DOE), DOE/NNSA FFRDC, and Non-DOE/NNSA FFRDC, are eligible to participate only as a subrecipient, and are not eligible to apply as a prime recipient.

For non-DOE/NNSA FFRDCs, the Federal agency sponsoring the FFRDC must authorize in writing the use of the FFRDC on the proposed project and this authorization must be submitted with the application. The use of a FFRDC must be consistent with its authority under the award.

For DOE/NNSA FFRDCs, the cognizant Grants and Agreements Officer for the FFRDC must authorize in writing the use of the FFRDC on the proposed project and this authorization must be submitted with the application. The funding for the FFRDC will flow through the prime recipient. The following wording is acceptable for this authorization: Authorization is granted for the Laboratory to participate in the proposed project. The work proposed for the Laboratory is consistent with or complementary to the missions of the Laboratory and will not adversely impact execution of the DOE assigned programs at the Laboratory.

To qualify as a domestic entity, the entity must be organized, chartered, or incorporated (or otherwise formed) under the laws of a particular state or territory of the United States; have majority domestic ownership and control; and have a physical place of business in the United States.

[6] 42 U.S.C. § 16292(b)(4)(C).

Foreign Entities

In limited circumstances, DOE may approve a waiver to allow a foreign entity to participate as a prime recipient or subrecipient. A foreign entity may submit an Application to this FOA, but the Application must be accompanied by an explicit written waiver request. Likewise, if the Applicant seeks to include a foreign entity as a subrecipient, the applicant must submit a separate explicit written waiver request in the application for each proposed foreign subrecipient.

Appendix O lists the information that must be included in a foreign entity waiver request. The Applicant does not have the right to appeal DOE's decision concerning a waiver request.

Incorporated Consortia

Domestic incorporated consortia are eligible to participate as a prime recipient or subrecipient. For consortia incorporated (or otherwise formed) under the laws of a state or territory of the United States, please refer to "Domestic Entities" above. For consortia incorporated (or otherwise formed) in a foreign country, please refer to the requirements in "Foreign Entities" above. Each consortium must have an internal governance structure and a written set of internal rules. Upon request, the consortium must provide a written description of its internal governance structure and its internal rules to the DOE Grants and Agreements Officer.

If the consortium includes foreign members, the applicant must submit a separate explicit written waiver request in the application for each foreign member. See Appendix O.

Unincorporated Consortia

Unincorporated Consortia must designate one member of the consortium to serve as the prime recipient/consortium representative. The prime recipient/consortium representative must qualify as a domestic entity. Upon request, unincorporated consortia must provide the DOE Grants and Agreements Officer with a collaboration agreement, commonly referred to as the articles of collaboration, which sets out the rights and responsibilities of each consortium member. This agreement binds the individual consortium members together and should include the consortium's:

- Management structure;
- Method of making payments to consortium members;
- Means of ensuring and overseeing members' efforts on the project;
- Provisions for members' cost sharing contributions; and
- Provisions for ownership and rights in intellectual property developed previously or under the agreement.

If the consortium includes foreign members, the applicant must submit a separate explicit written waiver request in the Application for each foreign member. See Appendix O.

3.2 Cost Sharing

Applicants are bound by the cost share proposed in their applications if selected for award negotiations. The cost share must be at least 50% of the total project costs[7].[8] The cost share must come from non-federal sources unless otherwise allowed by law. Cost share may be provided in the form of cash or cash equivalents, or in-kind contributions. Cost share must come from non-federal sources (unless otherwise allowed by law) such as project participants, state or local governments, or third-party financing.

Federal financing, such as DOE Loan Guarantees, cannot be leveraged by applicants to provide the required cost share or otherwise cover the same scope that is proposed in the application. A contingency reserve will also be required for all Phase 3 and 4 activities. More information on contingency reserves can be found in Section 2.0. Neither contingency funds nor any program income should be included as cost share in the Applicant's budget.

DOE understands that projects selected under this FOA may require the use of existing data. For purposes of this FOA, DOE will consider data that is commercially available at an established market price to be an allowable cost under the project (either as DOE share or non-federal cost share) but DOE will not consider in-kind data (e.g., data, owned by an entity, that is not routinely sold commercially but is instead donated to the project and assigned a value) to be an allowable cost under the project, including as Recipient cost share.

Estimation methods used by the Recipient to assign a value to in-kind data cannot be objectively verified by DOE and therefore will not be accepted by DOE as an allowable cost under any project selected from this FOA. Consequently, DOE will not recognize in-kind data costs in any resulting approved DOE budget.

Each project team is free to determine how best to allocate the cost share requirement among the team members. The amount contributed by individual project team members may vary, as long as the cost share requirement for the project as a whole is met.

Although the cost share requirement applies to the project as a whole, including work performed by members of the project team other than the prime recipient, the prime recipient is legally responsible for paying the entire cost share. If the funding agreement is terminated prior to the end of the project period, the prime recipient is required to contribute at least the cost share percentage of total expenditures incurred through the date of termination.

[7] Total project costs are the sum of the government share, including FFRDC costs if applicable, and the recipient share of project costs.
[8] Section 988(c) of the Energy Policy Act of 2005 as amended (42 U.S.C. § 16352(c)). *See also* 2 C.F.R. § 200.306 and 2 C.F.R. § 910.130 for additional cost sharing requirements.

The prime recipient is solely responsible for managing cost share contributions by the project team and enforcing cost share obligation assumed by project team members in subawards or related agreements.

3.3 Applications Specifically Not of Interest and Responsiveness Criteria

The following types of Letters of Intent and Applications will be deemed nonresponsive and will not be reviewed or considered:

- Applications that do not specifically target one of the Topic Areas in Section 1.3.
- Applications that exceed the maximum DOE share as outlined in Section 2.0.
- Applications for proposed technologies that are not based on sound scientific principles (e.g., violates the laws of thermodynamics).
- Applications to advance the maturation of post-combustion and pre-combustion carbon capture technologies, apart from the required design of a CCS demonstration system;
- Applications to advance the maturation of CO_2 compression technologies, apart from the required design of a CCS demonstration system;
- Applications to advance the maturation of CO_2 storage technologies apart from the required design of a CCS demonstration system;
- Applications to advance the maturation of CO_2 conversion technologies;
- Applications that include costs for designing and constructing new electric generation and industrial facilities apart from the required design of a CCS demonstration system;
- Applications to advance the maturation of advanced power cycles (e.g., supercritical CO_2 cycle, and chemical looping configurations) apart from the required design of a CCS demonstration system;
- Applications on technologies to solely increase CO_2 concentration in the exhaust gas (e.g., exhaust gas recirculation (EGR)); Combining EGR with larger carbon capture and sequestration technologies is allowed.
- Applications that include algae-based carbon capture technologies;
- Applications that include materials screening (computational or experimental) of novel sorbents, solvents, membrane or electrochemical materials;
- Applications to advance the maturation of direct air capture;
- Applications that propose a host site that is not located in the United States;
- Applications proposing an existing host site that is not currently in commercial operation or with an announced closure date earlier than 15 years from the date of the award;
- Applications proposing CCS systems located at coal CHP facilities that are not generating electricity to the grid or district energy systems;
- Applications proposing CCS systems located at SMR facilities that: 1) are producing hydrogen from natural gas for other purposes than electricity generation to the grid or 2) are located in a refinery and the Applicant does not also propose to capture CO_2 from a different refinery process that does not produce hydrogen;
- Applications proposing CCS systems located at natural gas CHP facilities that are not generating electricity to the grid or district energy systems;
- In Topic Area 3: Industrial facilities that export the majority of electric power to the grid;

- Applications that propose to capture ethanol or hydrogen as a final product;
- Applications for basic research aimed solely at discovery and/or fundamental knowledge generation;
- Applications for bench- and pilot-scale testing;
- Applications that propose to demonstrate technologies that do not offer significant improvements in the efficiency, effectiveness, cost, and environmental performance of carbon capture and sequestration technology;
- Applications that propose to store CO_2 as biomass or its derivatives;
- Applications that include CO_2 pipelines for which the specific route has not been identified;
- Applications that do not use subsurface geologic formations for final storage/disposal
- Applications proposing a reservoir storage site that does not have a competent seal above it;
- Applications that do not have a designated storage/disposal site or have not completed detailed characterization of their storage/disposal site;
- Applications for which the process to acquire pore space rights / mineral rights has not been initiated;
- Applications that are seeking to use funds to characterize their storage site; and
- Applicants that have not completed FEED studies for carbon capture, transport, and storage.

3.4 Limitation on Number of Applications Eligible for Review

An entity may submit multiple Letters of Intent but must select only one to take forward as an Application to this FOA. The Letter of Intent and Application must address only one TA identified in Section 1.3. If an entity submits more than one Application, OCED will request a determination from the applicant's authorizing representative as to which application should be reviewed. Any other submissions received listing the same entity as the applicant will not be eligible for further consideration.

This limitation does not prohibit an applicant from collaborating on other applications (e.g., as a potential subrecipient or partner) so long as the entity is only listed as the Applicant on one Application submitted under this FOA.

4.0 Application and Submission Information

4.1 Application Package

All submissions must conform to the form and content requirements described below, including maximum page lengths.

- Each must be submitted in Adobe PDF format unless stated otherwise;
- Each must be written in English;
- All pages must be formatted to fit on 8.5 x 11 inch paper with margins not less than one inch on every side. Use Calibri typeface, a black font color, and a font size of 12 point or larger (except in figures or tables, which may be 10 point font). A symbol font may be used to insert Greek letters or special characters, but the font size requirement still applies. References must be included as footnotes or endnotes in a font size of 10 or larger. Footnotes and endnotes are counted toward the maximum page requirement;
- A **control number** will be issued when an Applicant begins the OCED eXCHANGE application process. The control number must be included with all application documents. Specifically, the control number must be prominently displayed on the upper right corner of the header of every page and included in the file name (i.e., *Control Number_Applicant Name_Application*);
- Page numbers must be included in the footer of every page; and
- Each submission must not exceed the specified maximum page limit, including cover page, charts, graphs, maps, and photographs when printed using the formatting requirements set forth above and single spaced. If Applicants exceed the maximum page lengths indicated below, DOE will review only the authorized number of pages and disregard any additional pages.

Note: The maximum file size that can be uploaded to the OCED eXCHANGE website is 50MB. Files in excess of 50MB cannot be uploaded, and hence cannot be submitted for review. If a file exceeds 50MB but is still within the maximum page limit specified in the FOA it must be broken into parts and denoted to that effect. For example:

ProposalContent_Part_1
ProposalContent_Part_2

DOE will not accept late submissions that resulted from technical difficulties due to uploading files that exceed 50MB.

4.2 Application Submission

There are several one-time actions before submitting an application in response to this FOA, and it is vital that Applicants address these items as soon as possible. Some may take several weeks, and failure to complete them could interfere with an Applicant's ability to apply to this FOA, or to meet the negotiation deadlines and receive an award if the application is selected. These requirements are as follows:

4.2.1 OCED eXCHANGE

To apply to this FOA, Applicants must register with and submit application materials through OCED's online application portal, OCED eXCHANGE, at https://oced-exchange.energy.gov. See detailed instructions at Financial Opportunities: Manuals (energy.gov). OCED eXCHANGE is designed to enforce the deadlines specified in this FOA. The "Apply" and "Submit" buttons will automatically disable at the defined submission deadlines. If an Applicant experiences technical difficulties with a submission, the Applicant should contact the OCED eXCHANGE helpdesk for assistance (OCED-exchangeSupport@hq.doe.gov).

4.2.2. Unique Entity Identifier (UEI) and System for Award Management

Each Applicant (unless the Applicant is excepted from those requirements under 2 C.F.R. § 25.110) is required to: (1) Be registered in the SAM at https://www.sam.gov before submitting its application; (2) provide a valid UEI number in its application; and (3) continue to maintain an active SAM registration with current information at all times during which it has an active federal award or an application or plan under consideration by a federal awarding agency. DOE may not make a federal award to an Applicant until the Applicant has complied with all applicable UEI and SAM requirements and, if an Applicant has not fully complied with the requirements by the time DOE is ready to make a federal award, the DOE will determine that the Applicant is not qualified to receive a federal award and use that determination as a basis for making a federal award to another Applicant. Designating an Electronic Business Point of Contact and obtaining a special password called a Marketing Partner ID Number are important steps in SAM registration.

NOTE: Due to the high demand of UEI requests and SAM registrations, entity legal business name and address validations are taking longer than expected to process. Entities should start the UEI and SAM registration process as soon as possible. If entities have technical difficulties with the UEI validation or SAM registration process, they should utilize the HELP feature on SAM.gov. Additional entity validation resources can be found here: GSAFSD Tier 0 Knowledge Base - Validating your Entity**.**

4.2.3. FedConnect

Register in FedConnect at https://www.fedconnect.net. To create an organization account, your organization's SAM MPIN is required. For more information about the SAM MPIN or other registration requirements, review the FedConnect Ready, Set, Go! Guide at https://www.fedconnect.net/FedConnect/Marketing/Documents/FedConnect_Ready_Set_Go.pdf.

4.2.4. Grants.gov

Register in Grants.gov (http://www.grants.gov) to receive automatic updates when Modifications to this FOA are posted. However, please note that Letters of Intent, Concept Papers, and Applications will not be accepted through Grants.gov. As applicable, modifications to this FOA will be posted on the OCED eXCHANGE website and the Grants.gov system. However, you will only receive an email when a modification is posted if you register for email notifications for this FOA in Grants.gov. OCED recommends that you register as soon after the release of the FOA as possible to ensure you receive timely notice of any amendments or other FOAs.

4.2.5. Electronic Authorization of Applications and Award Documents

Submission of an application and supplemental information under this FOA through electronic systems used by the DOE, including OCED eXCHANGE and FedConnect.net, constitutes the authorized representative's approval and electronic signature.

4.3. Application Forms

The application forms and instructions are available on OCED Exchange. To access these materials, go to https://oced-exchange.energy.gov/ and select the appropriate FOA number.

4.4. Submission Dates and Times

All required submissions must be submitted in OCED eXCHANGE no later than 5 p.m. ET on the dates provided on the cover page of this FOA.

4.5. Requirement for Full and Complete Disclosure

Applicants are required to make a full and complete disclosure of all information requested. Any failure to make a full and complete disclosure of the requested information may result in:

- The termination of award negotiations;
- The modification, suspension, and/or termination of a funding agreement;
- The initiation of debarment proceedings, debarment, and/or a declaration of ineligibility for receipt of federal contracts, subcontracts, and financial assistance and benefits; and
- Civil and/or criminal penalties.

4.6. Proposal Content

This application process includes multiples phases: Letter of Intent and Application.

4.6.1. Letter of Intent

Applicants must submit a Letter of Intent by the specified due date and time to be eligible to submit an Application. Letters of Intent will be used by OCED to plan for the merit review process. The letters should not contain any proprietary or sensitive business information. The letters will not be used for down-selection purposes, and do not commit an Applicant to submit an application.

Applicants are not bound to the statements made in the Letter of Intent; it is reasonable for project partners, locations, or other factors to change during the application development process. DOE will not provide feedback on the Letters of Intent. OCED will not review or consider nonresponsive Letters of Intent (Section 3.3).

Each Applicant must provide all the following information as part of the Letter of Intent:

- Lead organization (Applicant);
- Project title;
- Major project subcontractors;
- Major project vendors;
- Key individuals;
- Zip Code(s) to be impacted by the project;
- Topic Area of Interest;
- Expected duration of each phase of the project; and
- Abstract – The abstract provided should be not more than 200 words in length and should provide a truncated explanation of the proposed project.

4.6.2. Application

All Application documents must be marked with the control number issued to the Applicant. Each Application must be limited to a single proposal. Applications must conform to the content and form requirements listed below and must not exceed the stated page limits. Applicants must provide sufficient citations and references to justify the claims and approaches made to DOE. However, DOE and reviewers are under no obligation to review cited sources.

4.6.2.1. Application for Federal Assistance (SF-424)

(PDF, 3 pages maximum)	**File Naming Convention:** ControlNumber_LeadOrganization_App424

The Standard Form (SF-424) represents the government-wide standard form for grant application packages, and requires basic information about the Applicant (name, address, telephone number, type of Applicant, etc.), including a list of sources of proposed funding and a description of the proposed project. Complete all required fields in accordance with the instructions on the form.

In Field 21 of the SF-424, the authorized representative must certify and agree with the Certification and Assurances found at Certifications and Assurances for Use with SF-424 | Department of Energy

Note: The dates and dollar amounts on the SF-424 are for the complete project.

4.6.2.2. Technical Volume

An application must include a Technical Volume, which includes the following components that are further detailed below: a) Cover Page; b) Project Overview; c) Technical Description, Innovation, and Impact, d) Technical Approach and Project Management Plan, e) Technical Qualifications and Resources. The Technical Volume may not be more than 55 pages, including the table of contents, and all citations, charts, graphs, maps, photos, or other graphics, and must include all of the components listed above. The Applicant should consider the weighting of each of the technical review criterion (Section 5.2.2) when preparing the Technical Volume.

a) Cover Page	
(PDF, 2 pages maximum)	**File Naming Convention:** ControlNumber_LeadOrganization_Cover_Page

The cover page must include the project title, the specific FOA Topic Area being addressed , both the technical and business points of contact, names of all team member organizations, senior/key personnel, and their organizations (including collaborating organizations), the project location(s) by the city, state, and zip code + 4 and State for each location where project work will be performed by the prime recipient or subrecipient(s), and any statements regarding confidentiality as described in section 8.1. For each proposed prime recipient and subrecipient(s) that meets the criteria for domestic entity as stated in section 3.1, the applicant must state and certify that entity's domestic entity status. For each proposed prime recipient and subrecipient(s) that does not meet the criteria for domestic entity stated in section 3.1, the applicant must state the entity's status as a foreign entity and submit a foreign entity waiver request as specified in Appendix O.

b) Project Overview (Approximately 15% of the Technical Volume)	
(PDF, 8 page maximum)	**File Naming Convention:** ControlNumber_LeadOrganization_Project_Overview

The Project Overview should contain, at a minimum, the following information:

- **Background:** The Applicant should discuss the background of their organization, including the history, successes, and current development status (i.e., the technical baseline) relevant to the technical topic being addressed in the Application. Applicants should also explain why they are championing the proposed project and the driving force behind their commitment to its successful completion.
- **Project Goal:** The Applicant should explicitly identify the targeted improvements to the baseline technology and the critical success factors in achieving that goal, including the ways in which the proposed project will lead to industry adoption. It should also include the ways in which the proposed project location and related infrastructure, skilled workforce, community benefits, etc. will contribute to the success of the overall project.
- **Carbon Capture Host Site, Transportation, and Storage Site Description and Integration**. Applicants are required to describe the new or existing proposed host site, transport method, and storage site facilities, including, but not limited to, process diagrams, emissions profiles, P&IDs, geologic characterizations, and availability and quality of land, water, steam and/or waste heat (as applicable). A corresponding narrative is required to provide application reviewers a clear understanding of the proposed capture and sequestration process and project from technical, cost effectiveness, and integrated systems perspectives. At a minimum, the description shall include the following:
    - *Anticipated feed conditions* (e.g., pressure, temperature, flow rate, gas composition, and contaminant levels),
    - *Electrical, water and waste management*. Applicants should describe how electricity consumption, heat, water, and waste will be managed in the proposed CCS demonstration project and tied into the existing host facility.
    - *Contaminants Controls*. Applicants should describe how contaminants in the gas stream targeted for carbon capture (e.g., NO_x, SO_x, PM_s) and chemical contaminants associated with the carbon capture technology (e.g., amines, nitrosamines) will be managed and their potential effects on the carbon capture system, host site, and/or environment.
    - *Long term impacts of solvent, sorbents, membranes, etc.* Applicants should describe the plans for recharging/regenerating the solvent, sorbent beds, membranes, etc. to maintain adherence to 90% carbon capture target as well as long term impacts on the process equipment, infrastructure, and the environment.
    - CO_2 *product disposition*. Applicants must demonstrate that the proposed CO_2 capture technology will produce a CO_2 stream of required temperature and quality suitable for cost-effective compression and transport/disposition of the stream, without adversely affecting existing operations, compressors, pipelines, or geologic-storage formations.
    - *Description of the* CO_2 *capture equipment design concept* (e.g., membrane module architecture, absorber/desorber design, etc.).

- *Description of the economic and performance testing plan.* Applicants must identify the key cost and performance metrics that must be validated to successfully demonstrate the CCS technology and reduce uncertainties and risks to facilitate private-sector investments in follow-on deployments. Applicants must describe the activities to be performed and data to be collected to validate the cost and performance of the integrated CCS demonstration system.
- Description of how the capture system will be integrated with the host plant (including any gas preconditioning steps and any integration challenges), and how the integration will differ (or not) from the relevant referenced pilot demonstrations

- **DOE Impact:** The Applicant should discuss the impact that DOE funding would have on the proposed project. Applicants should specifically explain how DOE funding, relative to prior, current, or anticipated funding from other public and private sources, is necessary to achieve the project objectives.
- Identify any potential long-term constraints the project will have on the impacted communities' access to natural resources (e.g., water) and tribal cultural resources. If applicable, describe a long-term cleanup strategy that ensures communities and neighborhoods remain healthy and safe and not burdened with cleanup costs and waste.
- The Applicant should outline a climate resilience strategy that accounts for climate impacts and extreme weather patterns such as high winds (tornadoes and hurricanes), heat and freezing temperatures, drought, wildfire, and floods.

c) Technical Description, Innovation, and Impact (Approximately 35% of the Technical Volume)	
(PDF, 20 page maximum)	**File Naming Convention:** ControlNumber_LeadOrganization_Technical_Description

The Technical Description should contain, at a minimum, the following information:

- **Relevance and Outcomes.** The Applicant should provide a detailed description of the proposed demonstration project, including the objectives that will be pursued during the project. This section should describe the relevance of the proposed project to the goals and objectives of the FOA including meeting DOE project performance objectives. The Applicant should clearly specify the expected outcomes of the project.
- **Readiness.** The Applicant should provide a discussion of the proposed CCS demonstration project from technical, environmental, cost effectiveness, and integrated systems perspectives. This will include evaluation of supplied mass and energy balances, estimates of heating and cooling duties and electric power requirements covering the carbon capture system and balance-of-plant, cost of capture, and levelized cost of electricity (if applicable), as well as the adequacy and completeness of information provided in the State Point Data Table (see Appendix F) and Block Flow Diagram and Supplemental Data (Appendix L).

The Applicant should provide justification that the proposed CCS technology has attained the required TRL and is capable of meeting specific TA performance targets to support readiness for the proposed CCS demonstration. Scientific, engineering, and technical information and performance data obtained from prior tests of the proposed technology should be provided to support evidence of the readiness of the proposed technology for demonstration at the scale proposed. The Applicant is asked to provide copies of the table in Appendix P for all prior demonstrations (pilot and industrial) as well as the proposed project in this application. Note that failure to provide at least two tables (one for the current demonstration, and one for the most relevant pilot demonstration) will be considered noncompliant.

- **Feasibility.** The Applicant should demonstrate the technical feasibility of the proposed technology and capability of achieving the anticipated performance targets, including a description of previous work done and prior results. This section should also address the project's access to necessary infrastructure (e.g., transportation, water, electricity transmission) including any use of existing infrastructure, as well as to a skilled workforce.
- **CO_2 Capture Host Site Selection***.* Applicants are required to identify the location for conducting the integrated CCS demonstration project. Applicants must discuss the adequacy of the proposed CO_2 capture host site for the CCS demonstration project. Applicants must also discuss the fit of the site from a community benefits standpoint (including social characterization of nearby communities, community support for the project, and workforce availability), with reference to the CBP as appropriate. Applicants must provide plans for execution of the host site agreement, including key criteria and any conditions. The specific facility must be located **exclusively in the United States.**
- **CO_2 Storage Site Selection.** Applicants are required to provide supporting information showing that the UIC Class VI injection well permits and all relevant permits to construct the proposed storage facility have been granted or that the applications to obtain such permits have been submitted to EPA, the corresponding state agency(s), or any other applicable regulatory entities. If the permits are not granted at the time of the application, the Applicants should discuss the timing when the permits are expected to be granted and any potential obstacles to obtaining those permits. Permits must be granted before construction/drilling begins (Phase 3). The specific facility must be located **exclusively in the United States.**
- **Summary of the CO_2 Capture FEED***.* Applicants are required to submit summary results of a FEED study for the proposed CO_2 capture technology integrated with the proposed host site and designed for a minimum CO_2 capture efficiency of 90%. Format and content guidance are in Appendix C. Please include a summary of the Techno-Economic Analysis with the FEED Summary. Although the full FEED study is not required to be submitted, DOE may request submittal of the full FEED study and underlying documentation at any point during application review or project execution.
- **CO_2 Pipeline FEED Study.** Applicants are required to submit summary results of a FEED study for the proposed CO_2 pipeline and associated infrastructure required to connect the selected CO_2 capture host and storage sites. Please include a summary of the Techno-Economic Analysis with the FEED Summary.

Format and content guidance are in Appendix D. Although the full FEED study is not required to be submitted, DOE may request submittal of the full FEED study and underlying documentation at any point during application review or project execution.

- **CO_2 Storage FEED Study.** Applicants are required to submit summary results of a FEED study for the proposed CO_2 storage site. Included with this summary should be a detailed characterization of the storage site, current mineral rights (or a summary of ongoing discussions), and geologic and reservoir modeling studies to justify CO_2 injectivity and long-term storage plans. Please include a summary of the Techno-Economic Analysis with the FEED Summary. Format and content guidance are in Appendix E. Although the full FEED study is not required to be submitted, DOE may request submittal of the full FEED study and underlying documentation at any point during application review or project execution.
- **Carbon Capture Technology Description.** The Applicants are required to describe the advanced carbon capture technology, including but not limited to, the following:
  - Preliminary process flow diagrams;
  - Mass and energy balances;
  - Steam and power requirements;
  - As applicable, a discussion of the absorption/desorption chemistry and operating cycle for solvent and sorbent systems; and
  - As applicable, a description of relevant membrane chemistry, including transport mechanism.
- **Innovation and Impacts**: The Applicant should describe the current state-of-the-art in the applicable field, the specific innovation of the proposed CCS technology, how the proposed technology would demonstrate significant improvements in the efficiency, effectiveness, cost, and environmental performance of CCS systems for power, industrial, or other commercial applications over current and emerging technologies, and the overall impact on advancing the state-of-the-art/technical baseline if the project is successful.

d) Technical Approach and Project Management (Approximately 20% of the Technical Volume)	
(PDF, 10 page maximum)	**File Naming Convention:** ControlNumber_LeadOrganization_Technical_Approach

The Technical Approach should include a summary of the Project Objectives, Technical Scope, and Work Breakdown Structure (WBS), Milestones, Go/No-Go decision points, and Project Schedule. A Project Management Plan is separately requested. The Technical Approach should contain, at a minimum, the following information:

- **Project Objectives:** The Applicant should provide a clear and concise (high-level) statement of the goals and objectives of the project as well as the expected outcomes.
- **Technical Scope Summary:** The Applicant should provide a summary description of the overall work scope and approach to achieve the objective(s). The overall work scope is to be divided by performance periods that are separated by discrete decision points (see below for more information on Go/No-Go decision points).

The Applicant should describe the specific expected end result of each performance period, including milestones detailed in the Community Benefits Plan.

- **Work Breakdown Structure (WBS) and Task Description Summary:** The WBS/Workplan should describe the work to be accomplished and how the Applicant will achieve the milestones, will accomplish the final project goal(s), and will produce all deliverables. The Workplan is to be structured with a hierarchy of performance period, task and subtasks, which is typical of a standard WBS for any project. The Workplan shall contain a concise description of the specific activities to be conducted over the life of the project. The description shall be a full explanation and disclosure of the project being proposed (i.e., a statement such as "we will then complete a proprietary process" is unacceptable).

  It is the Applicant's responsibility to prepare an adequately detailed task plan to describe the proposed project and the plan for addressing the objectives of this FOA. The summary provided should be consistent with the PMP. The PMP will contain a more detailed description of the WBS and tasks.

- **Milestone Summary:** The Applicant should provide a summary of appropriate milestones throughout the project to track overall project progress. The Applicant should also provide the means by which the milestone will be verified. The summary provided should be consistent with the milestones listed in the PMP.
- **Go/No-Go Decision Points**: Provide a summary of project-wide Go/No-Go decision points at appropriate points in the Workplan. At a minimum, each project must have at least one project-wide Go/No-Go decision point at the end of each Phase of the project. Interim Go/No-Go decision points may also be used. The Applicant should also provide the specific technical and Community Benefits criteria to be used to evaluate the project at the Go/No-Go decision point. The summary provided should be consistent with the description in the PMP.
- **End of Project Goal:** The Applicant should provide a summary of the end of project goal(s). The summary provided should be consistent across all documents in application.
- **Requirements for Infrastructure Projects:** Within the first 2 pages of the Workplan, include a description of how the project complies with Buy America (see Section 4.8.3.) and Davis-Bacon Requirements (see Section 4.8.4.) as applicable.
- **Project Management:** The Applicant should provide a summary of the team's proposed management strategy, including the following:
  - The overall approach to and organization for managing the work;
  - The roles of each project team member;
  - Any critical handoffs/interdependencies among project team members;
  - The technical and management aspects of the management plan, including systems and practices, such as financial and project management practices;
  - The approach to project risk management, including a plan for securing a qualified workforce and mitigating risks to project performance including but not limited to community or labor disputes;
  - A description of how project changes will be handled;

- If applicable, the approach to Quality Assurance/Control; and
- How communications will be maintained among project team members.

The summary provided within the Technical Volume should be consistent with the PMP (see Appendix K). The PMP will contain more detailed information.

- **Market Transformation Plan:** The Applicant should describe how the project will advance market transformation, including the following:
  - Identification of target market, competitors, and distribution channels for proposed technology along with known or perceived barriers to market penetration, including a mitigation plan.
  - Identification of a product development and/or service plan, commercialization timeline, financing, product marketing, legal/regulatory considerations including intellectual property, infrastructure requirements, data dissemination, and product distribution.

e) Technical Qualifications and Resources (Approximately 30% of the Technical Volume)	
(PDF, 15 page maximum)	**File Naming Convention:** ControlNumber_LeadOrganization_Technical_Qualifications

The Technical Qualifications and Resources should contain, at a minimum, the following information:

- Describe the project team's unique qualifications and expertise, including those of key subrecipients. The project team should include the following members or skill sets, at a minimum: CO_2 capture technology developer or licensor, CO_2 pipeline operator (if applicable), CO_2 capture storage site owner or operator, EPC company(s), financial partner(s), NEPA compliance consultant, LCA consultant, and CBP consultant.
- Describe the project team's existing equipment and facilities, or equipment or facilities already in place on the proposed project site, that will facilitate the successful completion of the proposed project; include a justification of any new equipment or facilities requested as part of the project.
- This section should also include relevant, previous work efforts (of similar size, scope, and complexity), demonstrated innovations, and how these enable the Applicant to achieve the project objectives.
- Describe a brief summary of the relevant experiences of key personnel leading and supporting the project
- Describe the time commitment of the key team members to support the project.
- Describe the technical services to be provided by DOE/NNSA FFRDCs, if applicable.

- Describe the skills, certifications, or other credentials of the construction and ongoing operations workforce.
- For multi-organizational projects, describe succinctly:
    - The roles and the work to be performed by each organization;
    - How the various efforts will be integrated and managed;
    - Process for making project management decisions;
    - Intellectual Property issues; and
    - Communication plans.

4.6.2.3. Community Benefits Plan: Job Quality and Equity

(PDF, 25 pages maximum)	**File Naming Convention:** ControlNumber_LeadOrganization_Comm_Benefits

Deployment of new technology will likely be more successful if equity and justice, community and labor engagement, and quality jobs are integrated into technology development from the beginning. For example, failing to meaningfully engage with community stakeholders, Tribes, and labor unions has been a contributing factor to delays or cancellations of energy and carbon management projects in the past. Related to CCS specifically, DOE has received many questions and concerns related to potential benefits or negative impacts such as changes to air pollution, water pollution, energy prices, and jobs, among other topics. With thorough assessment of potential technology impacts and meaningful engagement, impacted groups can be project partners whose questions and concerns can improve overall project outcomes as well as pathways for future deployment. This is clear from feedback obtained from DOE stakeholders, requests for information, published research, and information obtained from DOE project work.

Therefore, applications must include a Community Benefits Plan (CBP) that describes how the proposed project would: (1) support meaningful community and labor engagement; (2) invest in America's workforce; (3) advance diversity, equity, inclusion, and accessibility; and (4) contribute to the President's goal that 40% of overall benefits of certain federal investments flow to disadvantaged communities (the Justice40 Initiative). CBP activities should also be incorporated into the project schedule, workplan, budget, and other key documents.

The sections below outline the requirements for each goal. Requirements are intentionally flexible to generate the best approaches from project teams that are responsive to communities, workers, and impacted groups. If there is content overlap between a specific CBP section and other parts of the CBP or the overall application, Applicants should point reviewers to more comprehensive efforts addressed elsewhere in the application. In cases where information is incomplete, Applicants should clearly explain the reason for missing information and provide plans to address those gaps during the project.

For this FOA, the CBP sections must specifically address localized impacts related to changes in air pollution (including criteria air pollutants and other hazardous pollutants such as NO_X, SO_X, and PM, as well as potential pollution from solvents, sorbents, or other materials used in the CCS

technology), water use, water pollution, impacts to consumer energy prices, safety related to CO_2 transport via pipeline, and job retention or creation.

Within the CBP, the Applicant is encouraged to provide specific detail on how to ensure accountability and the delivery of measurable community and jobs benefits, ideally through the use of negotiated agreements between the Applicant and the community, and/or the Applicant and labor unions referred to collectively here as "Workforce and Community Agreements."[9] Such agreements facilitate community and labor input and social buy-in, identify how concerns will be mitigated, and specify the distribution of community and economic benefits, including job quality, access to jobs and business opportunities for local residents, and mitigate community harms, thus reducing or eliminating these types of risks.

Plans should be specific, actionable, and measurable: the idea is to move beyond vision or assessment to concrete goals, outcomes, and implementation plans. Each CBP section should therefore propose specific milestones and metrics to measure progress. Applicants are encouraged to use SMART (Specific, Measurable, Achievable, Relevant and Timely) milestones whenever possible. Major milestones and work descriptions relevant to the plan should be included within the project schedule, workplan, budget, and other key documents. Each section should also include information about the resources intended to implement the specified activities.

The Community Benefits Plan should provide the most details regarding actions the Applicant would take during Phase 1 but should also describe in a higher-level summary what goals, deliverables, outcomes, and implementation strategies the Applicant would pursue in Phases 2 – 4. If DOE selects a project, DOE will provide feedback to award Applicants and require that they update their Community Benefits Plan during award negotiations.

Public transparency around community benefit activities can support project success and buy-in, and DOE will work to develop publicly available summaries of CBPs with project performers after awards are made as appropriate. Applicants and may share details of their CBP with stakeholders and other parties at their own discretion.

Awardees must implement their CBP as part of carrying out the project; the CBP is expected to deepen and evolve during each phase for awarded projects. During the life of the award DOE or its representative(s) will independently evaluate the recipient's implementation status and effectiveness, including as part of the Go/No-Go review process. Adequate progress made in implementing the community benefits plan will be required for projects to advance through phases.

[9] Workforce and Community Agreements include good neighbor agreements, community benefits agreements, community workforce agreements, project labor agreements, and other collective bargaining agreements.

Applicants are also encouraged to provide Community and Labor Partnership Documentation from representative organizations reflecting substantive engagement and feedback on Applicant's approach to community benefits. These letters of support should be submitted under the Community Partnership Documentation (see Section 4.6.3.4) and do not count toward the Community Benefits Plan page limit.

Detailed guidance and examples on creating each section of the CBP will be provided under the application documents section on the OCED Exchange website at https://oced-Exchange.energy.gov. Applicants are encouraged to read these resources prior to writing their Community Benefits Plan. Applicants are also encouraged to leverage information generated in other portions of this FOA to support Community Benefits Plan development, including the Environmental Considerations Summary and LCA.

Community and Labor Engagement

The Community and Labor Engagement section should describe the Applicant's plans and actions to engage with Tribal governments and local stakeholders such as community-based organizations representing local residents and businesses, labor unions and other worker organizations, workforce development organizations, local government, emergency responders, communities with environmental justice concerns, disadvantaged communities, and community-based organizations that support or work with disadvantaged communities. By facilitating labor and community input, social buy-in, and accountability, such engagement can substantially reduce or eliminate stalls or slowdowns, litigation, and other risks associated with project implementation.

Community and labor engagement should be responsive to the priorities of impacted groups, ensure community and labor input can impact project decisions, and support transparency and accountability. Ideally, engagement can lay groundwork for eventual negotiation of Workforce and Community Agreements, which could take the form of one or more kinds of negotiated agreements with communities, labor unions, or, ideally, both.

If awarded and in conjunction with DOE, recipients will also identify to DOE any federally recognized Indian Tribes, which include Alaska native village or regional or village corporations (who are not project partners) for whom the proposed project may have implications. The recipient will provide information to support DOE's development of a Tribal engagement plan that acknowledges each Tribe's consultation policies, traditions, and expectations, and adheres to DOE Order 144.1 on Tribal consultation. Appropriate mitigation will be identified through government-to-government consultation to offset any such potentially adverse implications. DOE is and remains responsible for government-to-government consultation with any federally recognized Indian Tribes, which include Alaska native village or regional or village corporations about the proposed project.

The Community and Labor Engagement section should include the following elements:

- **Background and Experience.** A description of prior and ongoing efforts by the project team to engage community stakeholders, Tribes, and workforce organizations including labor unions.

- **Community History and Dynamics**. A description of the current and historical social, cultural, economic, labor, and environmental landscape, decision-making structures, and other relevant information about the project's affected areas and groups.
  This is a first step of "getting to know the area" that should be completed before conducting a more structured stakeholder analysis and can identify sources of influence and conflicts to establish a foundation for proactive engagement around major projects.
- **Stakeholder Analysis.** A description of key stakeholder groups (sectors, labor unions, communities, organizations, etc.); how they were identified; and anticipated level of engagement (e.g., advisory committee, working group member, active public participant).
- **Statement on existing community and labor support.** A statement discussing the extent to which the surrounding community or communities, Tribes, and labor unions have indicated support for or concerns with the ongoing operations of the host site(s) and/or the proposed project.
- **Engagement Implementation Strategies, Methods, and Timeline.** An engagement plan which includes objectives for the engagement and when and how project teams will engage stakeholders, workforce organizations including labor unions, and communities This should include a description of specific engagement methods (e.g., listening sessions, town halls, open houses, mediated discussions) matched to project phases and goals. Applicants should describe how they will extend these methods to include traditionally excluded stakeholders. **I**f awarded, Applicants will work in conjunction with the Department of Energy to develop a Tribal engagement plan as appropriate. <u>This section should demonstrate how engagement will explicitly address topics related to changes in Non-CO_2 air pollution, emissions, or discharges, including criteria air pollutants and materials used in the capture unit such as solvents; Waste streams including wastewater, spent solvent, or solvent degradation products; water use; impacts to consumer energy prices; safety related to CO_2 transport via pipeline; job retention or creation; and any other process or construction inputs or outputs that could cause positive or negative environmental, health, economic, or other impacts.</u>
- **Two-way Engagement Statement.** A statement discussing how the project will incorporate community input. The statement should describe elements of the project where engagement can impact project decisions or characteristics—and specifically identify whether project site(s) could be changed based on social considerations and what opportunities exist for community participation in and access to project data.
- **Workforce and Community Agreements Statement.** A description of any plans to negotiate a Community Benefits Agreement, Good Neighbor Agreement, Project Labor Agreement, Community Workforce Agreement, and/or other collective bargaining agreements. Given project complexity and sensitivities, Applicants should consider pursuing multiple agreements.
- **Engagement Evaluation Strategy.** A description how stakeholder engagement success will be evaluated, including by evaluating stakeholder perceptions of the progress.
- **Resource Summary.** A summary of the resources dedicated to implementing the plan including staff with relevant expertise and budget.

Investing in the American Workforce

A well-qualified, skilled, and trained workforce is necessary to ensure project stability, continuity, and success, and to meet program goals. High-quality jobs are critical to attracting and retaining the qualified workforce required. Applicants should describe their approach to ensuring jobs are of sufficient quality during construction and operation to attract and retain the skilled workforce needed for project success, mitigate health and safety issues, and invest in workforce development.

The Investing in the American Workforce section should include the following elements:

- **Background and Experience.** A summary of the project team's previous or ongoing efforts to provide above average pay and benefits to properly classified employees in both the construction and ongoing operations; support the rights of workers to a free and fair chance to join a union; attend to workplace health and safety in partnership with workers, and invest in workforce development.
- **Quality Jobs.** A description of plans to attract, train, and retain a skilled, qualified, local, and diverse workforce for construction, ongoing operations/production/maintenance, and scale-up activities, including the anticipated quality of jobs the project will create (i.e., wages– beyond compliance with Davis-Bacon prevailing wages and benefits, opportunities for wage progression, classification as employees, jobs for in-state workers, etc.). Describe how these jobs will be sufficiently attractive to skilled and trained workers under competitive labor market conditions.
- **Workforce Development.** A description of plans for workforce development, including:
  - Investing in workforce education and training (e.g., labor-management training programs, registered apprenticeships, partnerships with community colleges, sector-based approaches to workforce development);
  - Supporting workers' skill acquisition and opportunities for advancement; and
  - Utilizing an appropriately credentialed workforce (e.g., requirements for appropriate and relevant professional and safety training, certification, and licensure, including where appropriate utilization of graduates from registered apprenticeship programs).
- **Worker Rights.** Employees' ability to organize, bargain collectively, and participate, through labor organizations of their choosing, in decisions that affect them contributes to the effective conduct of business and facilitates amicable settlements of any potential disputes between employees and employers, providing assurances of project efficiency, continuity, and multiple public benefits. Provide information including:
  - How the applicant will ensure workers can form and join unions of their choosing, and how they will have the opportunity to organize within the workplace during construction and ongoing operations. An affirmative commitment could be an intention or willingness to permit union recognition through card check (as opposed to requiring union elections); intention or willingness to enter into binding arbitration to bargain first contracts with the union; a pledge to allow union organizers access to appropriate onsite non-workplaces (e.g., lunchrooms), and/or other supportive commitments or pledges.
  - Plans to ensure project success and continuity by mitigating labor disputes or strikes (e.g., neutrality with respect to union organizing and good faith negotiations);

- Activities and policies to ensure worker engagement in the design and execution of workplace safety and health plans;
- Plans to ensure workplace health and safety and worksites are free from harassment and discrimination;
- Descriptions of how Project Labor Agreements or Community Workforce Agreements will be utilized in construction activity (e.g., collective bargaining agreements between unions and contractors that govern terms and conditions of employment for all workers on a construction project);
- Plans to track retention rates and address areas of worker or workplace concern.

- **Milestones and Timelines.** A list of milestones and timelines for the proposed activities.
- **Resource Summary.** A description of project resources dedicated to implementing activities including staff with relevant expertise and budget.

Diversity, Equity, Inclusion, and Accessibility

The Community Benefits Plan must include a section describing how Diversity, Equity, Inclusion, and Accessibility (DEIA) objectives will be incorporated into the project. The section should detail how the Applicant will partner with underrepresented businesses, educational institutions, and training organizations that serve workers who face barriers to accessing quality jobs, and/or other project partners to help address DEIA.

Historically Black Colleges and Universities, other Minority Serving Institutions, Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses, Veteran Owned Businesses, Tribal Colleges and Universities, community-based groups, faith-based organizations, or entities located in an underserved community that meet the eligibility requirements are encouraged to participate on the application team. The Selection Official may consider the inclusion of these types of entities as part of the selection decision.

DEIA plans should describe steps taken to ensure an inclusive workplace environment committed to equal opportunity and free of harassment. This should include compliance with civil rights obligations and nondiscrimination laws, including Title VI of the Civil Rights Act of 1964 and implementing regulations, the Americans with Disabilities Act of 1990 (ADA), and Section 504 of the Rehabilitation Act, all other civil rights requirements, and accompanying regulations.

The DEIA section should include the following elements:

- **Background and Experience.** A description of prior and ongoing efforts by the project team relevant to DEIA.
- **Strategies, Milestones, and Timelines.** A description of targeted DEIA outcomes and implementation strategies, including milestones and timelines. For example, Applicants can discuss any commitments to partner with Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses, and Veteran Owned Businesses for contractor support needs; plans to partner with workforce training organizations serving under-represented communities and those facing systemic barriers to quality employment such as those with disabilities, returning citizens, opportunity youth, women, and veterans; and/or plans to provide comprehensive supportive services (such as childcare and transportation assistance) to increase representation and access in project's construction and operations jobs.
- **Resource Summary.** A description of project resources dedicated to implementing DEIA activities including staff with relevant expertise and budget.

Justice40 Initiative

Applicants should submit a Justice40 Initiative section that describes plans to advance energy and environmental justice (EEJ) through their project. The Justice40 Initiative section should include an assessment of project impacts and where they flow, and an implementation strategy that explains what actions the Applicants will take to maximize benefits and minimize negative impacts and measure, track, and report project impacts. Meaningful engagement with impacted communities is a key component of EEJ and is covered in detail as part of the Community and Labor Engagement section. Applicants should address how their plans will be transparent and accountable to impacted disadvantaged communities.

Project impacts and community assessments should be quantifiable, measurable, and trackable to the greatest extent possible. If no project sites or related activities are located within or near a disadvantaged community, Applicants should provide a detailed explanation to support this conclusion.

The Justice40 Initiative section should include the following elements:

- **Background and Experience**. A description of any prior or ongoing efforts by the project team relevant to energy and environmental justice and local community impacts of CCS.
- **Assessment of impacted communities and groups.** A description of all applicable communities or groups which could experience impacts from the proposed project at both early and late phases. Applicants should identify which of these are considered disadvantaged communities.[10]

[10] Pursuant to E.O. 14008 and the Office of Management and Budget's Interim Justice40 Implementation Guidance M-21-28, DOE has developed a definition and tools to locate and identify disadvantaged communities. These resources can be located at https://energyjustice.egs.anl.gov/. Pursuant to Office of Management and Budget's Memorandum M-23-09, DOE recognizes disadvantaged communities as defined and identified by the White House Council of Environmental Quality's

For each disadvantaged community, Applicants should characterize the existing burdens they are facing using EJSCREEN, disadvantaged community definition tools, or other analytic tools. Applicants should include which tool was used in their analysis. Impacts to communities and Tribes/ANCs should be considered for all inputs and outputs along all four phases of the project, in addition to impacts at the project site(s) or work location(s).

- **Assessment of project benefits and where they flow.** Applicants should describe in detail all anticipated project benefits. This description should clearly enumerate:

  a) specific project benefits and metrics that will be used to track each benefit;
  b) where/to whom project benefits are expected to flow and the extent to which these benefits flow to disadvantaged communities; and
  c) how well the anticipated benefits align with community priorities ascertained through community engagement.

  Benefits could include measurable direct or indirect investments or positive project outcomes that contribute to the eight DOE Justice40 policy priorities in disadvantaged communities: (1) a decrease in energy burden; (2) a decrease in environmental exposure and burdens; (3) an increase in access to low-cost capital; (4) an increase in job creation, the clean energy job pipeline, and job training for individuals; (5) increases in clean energy enterprise creation and contracting (e.g., minority-owned or disadvantaged business enterprises); (6) increases in energy democracy, including community ownership; (7) increased parity in clean energy technology access and adoption; and (8) an increase in energy resilience.

  If this project could result in reductions in air or water pollution, or reduction in water use, Applicants should describe clearly the expected magnitude of those benefits and under what conditions they could occur.

- **An assessment of project negative impacts and where they flow**. Applicants should describe all anticipated project negative impacts. This description should clearly enumerate:

  a) specific project negative impacts and metrics that will be used to track each impact;
  b) where/to whom impacts are expected to flow and the extent to which these benefits flow to disadvantaged communities;
  c) how additional project negative impacts will interact with existing cumulative burdens.

Climate and Economic Justice Screening Tool (CEJST) Version 1.0, which can be located at https://screeningtool.geoplatform.gov/. DOE's Justice40 Implementation Guidance is located at https://www.energy.gov/sites/default/files/2022-07/Final%20DOE%20Justice40%20General%20Guidance%20072522.pdf.

Negative impacts could include ecological (such as the effects on natural resources and on the components, structures, and functioning of affected ecosystems), aesthetic, historic, cultural, economic, social, or health impacts. Consider direct impacts, indirect impacts, and cumulative impacts. This section may refer to the impacts identified in the NEPA Environmental Considerations Summary.

<u>In this section, Applicants must specifically discuss any anticipated increases in: Non-CO_2 air pollution, emissions, or discharges, including criteria air pollutants and materials used in the capture unit such as solvents; waste streams, including wastewater, spent solvent, or solvent degradation products; water use; and consumer energy prices. Applicants must also specifically address safety risks from CO_2 transport and storage</u>.

- **Assessment of information gaps.** Describe where additional work is needed to fully assess or measure potential project impacts or impacted communities. Applicants should outline research, engagement and analytical goals to clarify the unknowns as part of their implementation plan.
- **Implementation Plan, Milestones and Timelines**. An Implementation plan which includes strategies, methods, and milestones to maximize benefits, minimize negative impacts and measure, track, and report impacts. This should specifically discuss minimizing and mitigating any increases in air pollution, water pollution and use, and how Applicants will mitigate safety risks from CO_2 transport and storage. Applicants should clearly describe how the plan includes accountability, feedback, and transparency mechanisms with impacted groups and disadvantaged communities, such as community agreements and access to/participation in collecting project data.
- **Addressing barriers to realizing benefits and minimizing negative impacts**. A discussion of potential barriers to realizing benefits and minimizing negative impacts, and plans for mitigating those barriers.
- **Resource Summary**. Describe resources dedicated to implementing the plan including staff with relevant expertise and budget.

4.6.2.4. Community Partnership Documentation

(PDF, each letter may not exceed 3 pages)	**File Naming Convention:** ControlNumber_LeadOrganization_PartnerDoc

In support of the Community Benefits Plan, Applicants may submit documentation to demonstrate existing or planned partnerships with potentially affected Tribes, labor unions, and community entities, such as, organizations that represent and serve disadvantaged or overburdened communities or workers and/or local businesses. The Partnership Documentation could be in the form of a letter on the partner's letterhead outlining the planned partnership signed by an officer of the entity, a Memorandum of Understanding, or other similar agreement. Such letters must state the specific nature of the partnership and must not be general letters of support. If the Applicant intends to enter into a Workforce and Community Agreement as part of the Community Benefits Plan, please include letters from proposed partners as appropriate.

4.6.2.5. Resumes

(PDF, 2 pages each)	**File Naming Convention:** ControlNumber_LeadOrganization_Resumes

Applicants are required to submit two-page resumes for senior and key senior personnel that demonstrate their experience and ability to lead the proposed project.

4.6.2.6. Letters of Commitment

(PDF, 1 page each)	**File Naming Convention:** ControlNumber_LeadOrganization_LOCs

Submit letters of commitment from 1) all subrecipients and 2) all third-party cost share providers. If applicable, the letter must state that the third party is committed to providing a specific minimum dollar amount or value of in-kind contributions allocated to cost sharing.

The following information for each third party contributing to cost sharing should be identified: (1) the name of the organization; (2) the proposed dollar amount to be provided; and (3) the proposed cost sharing type – (cash-or in-kind contributions). Letters of support or endorsement for the project from entities that do not have a substantive role in the project are not accepted.

4.6.2.7. Project Management Plan

(PDF, 50 pages)	**File Naming Convention:** ControlNumber_LeadOrganization_PMP

Applicants are required to submit a Project Management Plan (PMP). A PMP template is available as Appendix K.

4.6.2.8. Initial Environmental, Health, & Safety Assessment

(PDF, 10 pages each)	**File Naming Convention:** ControlNumber_LeadOrganization_EHSA

Applicants are required to submit an initial summary of the plan to perform EH&S assessment of the proposed project in accordance with the format provided in Appendix G.

4.6.2.9. Life Cycle Analysis

(PDF, N/A pages each)	**File Naming Convention:** ControlNumber_LeadOrganization_LCA

Applicants are required to submit an initial Life Cycle Analysis (LCA) of the proposed CCS demonstration project in accordance with the guidance provided in Appendix J.
The LCA will be updated as a Phase 2 deliverable.

4.6.2.10. Business Case Analysis

(PDF, 30 pages each)	**File Naming Convention:** ControlNumber_LeadOrganization_BCA

Applicants are required to submit a Business Case Analysis in the format provided in Appendix H. If the plan includes the utilization of 45Q (or other federal or state) tax credits, the Business Case Analysis shall include, at a minimum, details on the anticipated revenue and duration of the credits. The plan must also include a preliminary discussion of plans to deploy the technology beyond the proposed project.

4.6.2.11. Project Financing Plan

(PDF, 20 pages each, plus excel spreadsheets)	**File Naming Convention:** ControlNumber_LeadOrganization_PFP

Applicants are required to submit a Project Financing Plan in the format provided in Appendix I. The Applicant shall provide sufficient evidence to demonstrate the Applicant's financial capability to fund, or obtain funding, for the non-DOE share of the proposed project costs, including contingency. The Project Financing Plan must be based on the economic and business assumptions developed in the application and should demonstrate that the project has adequate funding, including contingency, to complete the proposed scope of work. The Project Financing Plan should address all financing aspects of the project.

4.6.2.12. Budget Justification Workbook

(MS Excel)	**File Naming Convention:** ControlNumber_LeadOrganization_Budget_Justification **File Naming Convention:** ControlNumber_LeadOrganization_Subrecipient_Budget_Justification

The Budget Justification must include the Budget Justification Workbook, Subrecipient budget justification (if applicable), Contract budget justification (if applicable), and Budget for DOE/NNSA FFRDC (if applicable) as necessary elements.

Budget Justification Workbook

Applicants must complete the Budget Justification Workbook which is available on OCED eXCHANGE at https://oced-Exchange.energy.gov/. Applicants must complete each tab of the Budget Justification Workbook for the project as a whole, including all work to be performed by the prime recipient and its subrecipients and contractors. Applicants must include costs associated with implementing the various requirements (e.g., Buy America requirements for infrastructure projects, Davis-Bacon Act, Community Benefits Plan, reporting, oversight) and with required annual audits and incurred cost proposals in their proposed budget documents. Such costs may be reimbursed as a direct or indirect cost.

The “Instructions and Summary” included with the Budget Justification Workbook will auto-populate as the Applicant enters information into the Workbook. Applicants must carefully read the “Instructions and Summary” tab provided within the Budget Justification Workbook. Save the Budget Justification Workbook in a single Microsoft Excel file using the above file naming convention for the title.

Subrecipient Budget Justification

Applicants must provide a separate budget justification for each subrecipient that is expected to perform work. The budget justification must include the same justification information described in the “Budget Justification Workbook” section above. Save each subrecipient budget justification in a Microsoft Excel file using the above File Naming Convention for the title.

Funding, Cost Share and Subaward with FFRDC

DOE will NOT fund DOE/NNSA FFRDCs participating as a subrecipient through the DOE field work authorization process. DOE will NOT fund non-DOE/NNSA FFRDCs through an interagency agreement with the sponsoring agency. Therefore, the prime recipient and FFRDC are responsible for entering into an appropriate subagreement that will govern, among other things, the funding of the FFRDC portion of the work from the prime recipient under its DOE award. Such an agreement must be entered into before any project work begins.

The Applicant must prepare the budgets utilizing rates appropriate for funding the FFRDCs through subawards. The Applicant’s cost share requirement will be based on the total cost of the project, including the Applicant’s, the subrecipient’s, and the FFRDC’s portions of the project. Note that the FFRDC effort, in aggregate, may not exceed 5% of the total estimated cost of the project, including the Applicant’s and the FFRDC’s portions of the effort.

4.6.2.13. Summary for Public Release

(PDF, 1 page)	**File Naming Convention:** ControlNumber_LeadOrganization_PublicRelease

Applicants must submit a one-page summary of their project that is suitable for dissemination to the public. It should be a self-contained document that identifies the name of the Applicant, the lead project manager, the project title, the objectives of the project, a description of the project (including the proposed capture technology, the proposed CO_2 capture rate (tonnes per year), the carbon capture host site and the location of the carbon storage site) , the potential impact of the project (e.g., benefits, outcomes), and major participants, and the project’s commitments and goals described in the Community Benefits Plan. This document must not include any proprietary or sensitive business information as DOE may make it available to the public after selections are made.

4.6.2.14. Summary Slides

(MS PowerPoint, 5 slides)	**File Naming Convention:** ControlNumber_LeadOrganization_Slide

Applicants must provide a up to a 5-slide deck summarizing the proposed project.

The Summary Slide deck must include the following information:

- The project title;
- The proposed project cost and schedule
- The location of the major project work sites
- A description of the project
- The proposed carbon capture technology
- The proposed storage site(s)
- The proposed capture rate (tonnes per year)
- The impact of the project on industry;
- Any key graphics (illustrations, charts and/or tables);
- The project's key idea/takeaway;
- Topline community benefits;
- Requested DOE funds and proposed Applicant cost share.

4.6.2.15. Environmental Considerations Summary

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_Environmental_Considerations

DOE's decision whether and how to distribute federal funds under this FOA is subject to the National Environmental Policy Act (NEPA) (42 U.S.C. § 4321, et seq.). Your responses will assist DOE in determining the appropriate level of NEPA review (if your proposal is selected) and in preparing an environmental assessment (EA) or environmental impact statement (EIS), if necessary. While not all information may be available at the proposal stage, please provide as much detail and information as is currently available. Consultation with experts or advisors in your organization to assist with your responses is highly recommended.

1. **Please provide a brief summary of the proposed project.** Describe proposed activities (not goals and objectives) and specify if this project is part of a larger project or connected to another project.

2. **Is there ongoing or anticipated federal government involvement in any aspect of this project (e.g., funding, permitting, technical assistance, project located on federally administered land)?** *If "yes," please list the agency and describe the nature of the involvement.*

3. **Is the project fully defined (i.e., all sites and activities are known)?** *If "no", please describe the sites and/or activities/tasks that are yet to be defined.*

4. **Add a table as seen below for each location where proposed project activities would take place:**

Proposed location (physical address or coordinates)	Setting of the proposed location (e.g., urban, industrial, suburban, agricultural, university campus, manufacturing facility, etc.) and the current condition or use of the site	General description of the proposed activities	Land administration (e.g., federal [specify BLM, USFS, etc.], Tribal, state, local, private)

5. **Attach a map showing the location(s) of the proposed project, and a site layout map showing the proposed facilities and associated infrastructure.** *(A GIS shapefile is preferrable, if available.)* The map showing the location(s) of the proposed project and site layout map requested with the Environmental Considerations Summary may be submitted as separate files and may be in larger engineering formats. While the maps may be created as a GIS shapefile or other engineering formats, the maps must be saved and submitted as a PDF file.

6. **Describe new facilities to be constructed, any modifications of existing facilities, and any new infrastructure or facilities necessary for the construction or operation of the proposed project.** *(e.g., access roads, laydown areas, off-site parking areas, railroad links, docks, water outfalls and intakes, pipelines, electrical transmission, waste treatment facilities, etc.)*

7. **Identify and describe any existing, modifications to, or new permits, licenses, or authorizations that would be required to perform project activities.** *(e.g., environmental permits, operating permits, or drilling permits)*

8. **Provide a brief description of the existing environmental burdens at the proposed project location(s) and surrounding areas, including those contributed to or exacerbated by existing facilities the project will leverage or modify.** *Existing environmental burdens can be identified using available tools, such as DOE's Energy Justice Dashboard (beta) (https://www.energy.gov/diversity/energy-justicedashboard-beta) or the U.S. Environmental Protection Agency's EJSCREEN (https://www.epa.gov/ejscreen).*

9. **Would any of the following have the potential to be impacted (directly or indirectly) by the proposed project?** *If "yes", provide a detailed description of: (1) the resources that could be affected, and (2) how project activities may affect those resources (including potential direct and indirect [visual, noise, etc.] impacts).*
   a. Tribal lands or resources of Tribal interest and/or sensitivity
   b. Environmental Justice (EJ) Populations (EJ populations include minority, low income, and Tribal populations)
   c. Historic, archeological, or cultural resources (includes listed and eligible resources over 50 years old or of cultural significance)

- d. Areas having a special designation (e.g., federal and state designated wilderness areas, national parks, national natural landmarks, wild and scenic rivers, state and federal wildlife refuges, and marine sanctuaries)
- e. Threatened or endangered species (whether proposed or listed by state or Federal governments), including their habitat
- f. Land resources (e.g., prime farmland, unique farmland, or other farmland of statewide or local importance, tundra, rainforests)
- g. Floodplains
- h. Wetlands
- i. Air quality (indoor and/or outdoor)
- j. Greenhouse gas emissions
- k. Water quality (surface and/or ground water and/or special sources of water including sole source aquifers)
- l. Ocean resources (e.g., coral reefs) Coastal zones
- m. Marine mammals or essential fish habitat Land use
- n. Socioeconomic conditions
- o. Sensitive receptors (e.g., hospitals, schools, daycare facilities, elderly housing)
- p. Navigable Airspace
- q. Transportation infrastructure

10. **Please describe:**
    - a. any coordination or discussions that have been initiated or the plan to coordinate with state and/or federal agencies (e.g., State Historic Preservation Office, U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, Nuclear Regulatory Commission, etc.)
    - b. any coordination or discussions that have been initiated with any Tribal governments
    - c. any issues that would generate public controversy regarding proposed project
    - d. any studies, reviews, and/or plans that have been completed for the proposed project (e.g., environmental site assessments, waste management plans, health and safety plans, cultural resource surveys, identification of prime or unique farmland, wildlife surveys, etc.)
    - e. any environmental considerations and/or mitigation strategies that have been incorporated into the proposed project (e.g., measures to reduce and/or avoid greenhouse gas emissions, and/or impacts to cultural resources, historic properties, state or federally protected species, wetlands, floodplains, traffic, ambient noise, etc.)
    - f. any discussions with affected communities

4.6.2.16. Current and Pending Support Disclosures

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_Current_Support

Current and pending support is intended to allow the identification of potential duplication, overcommitment, potential conflicts of interest or commitment, and all other sources of support.

As part of the application, the lead project manager and all senior/key personnel at the applicant and subrecipient level must provide a list of all sponsored activities, awards, and appointments, whether paid or unpaid; provided as a gift with terms or conditions or provided as a gift without terms or conditions; full-time, part-time, or voluntary; faculty, visiting, adjunct, or honorary; cash or in-kind; foreign or domestic; governmental or private-sector; directly supporting the individual's research or indirectly supporting the individual by supporting students, research staff, space, equipment, or other research expenses. All connections with foreign government-sponsored talent recruitment programs must be identified in current and pending support.

For every activity, list the following items:

- The sponsor of the activity or the source of funding;
- The award or other identifying number;
- The title of the award or activity. If the title of the award or activity is not descriptive, add a brief description of the research being performed that would identify any overlaps or synergies with the proposed research;
- The total cost or value of the award or activity, including direct and indirect costs and cost share. For pending proposals, provide the total amount of requested funding;
- The award period (start date – end date); and
- The person-months of effort per year being dedicated to the award or activity.

To identify overlap, duplication of effort, or synergistic efforts with the project proposed under the application, append a description of the other award or activity to the current and pending support.

Details of any obligations, contractual or otherwise, to any program, entity, or organization sponsored by a foreign government must be provided on request to either the applicant institution or DOE. Supporting documents of any identified source of support must be provided to DOE on request, including certified translations of any document.

Principal Investigators and senior/key personnel must provide a separate disclosure statement listing the required information above regarding current and pending support. Each individual must sign and date their respective disclosure statement and include the following certification statement:

> I, [Full Name and Title], certify to the best of my knowledge and belief that the information contained in this Current and Pending Support Disclosure Statement is true, complete, and accurate. I understand that any false, fictitious, or fraudulent information, misrepresentations, half-truths, or omissions of any material fact, may subject me to criminal, civil or administrative penalties for fraud, false statements, false claims or otherwise. (18 U.S.C. §§ 1001 and 287, and 31 U.S.C. §§ 3729-3733 and 3801-3812). I further understand and agree that (1) the statements and representations made herein are material to DOE's funding decision, and (2) I have a responsibility to update the disclosures during the period of performance of the award should circumstances change which impact the responses provided above.

The information may be provided in the format approved by the National Science Foundation (NSF), which may be generated by the Science Experts Network Curriculum Vita (SciENcv), a cooperative venture maintained at https://www.ncbi.nlm.nih.gov/sciencv/, and is also available at https://www.nsf.gov/bfa/dias/policy/nsfapprovedformats/cps.pdf. The use of a format required by another agency is intended to reduce the administrative burden to researchers by promoting the use of common formats. If the NSF format is used, the individual must still include a signature, date, and a certification statement using the language included in the paragraph above.

Definitions:

Current and pending support

(a) All resources made available, or expected to be made available, to an individual in support of the individual's RD&D efforts, regardless of

- (i) whether the source is foreign or domestic;
- (ii) (ii) whether the resource is made available through the entity applying for an award or directly to the individual; or
- (iii) (iii) whether the resource has monetary value; and

(b) includes in-kind contributions requiring a commitment of time and directly supporting the individual's RD&D efforts, such as the provision of office or laboratory space, equipment, supplies, employees, or students. This term has the same meaning as the term Other Support as applied to researchers in NSPM-33:

For researchers, Other Support includes all resources made available to a researcher in support of and/or related to all of their professional RD&D efforts, including resources provided directly to the individual or through the organization, and regardless of whether or not they have monetary value (e.g., even if the support received is only in-kind, such as office/laboratory space, equipment, supplies, or employees).

This includes resource and/or financial support from all foreign and domestic entities, including but not limited to, gifts provided with terms or conditions, financial support for laboratory personnel, and participation of student and visiting researchers supported by other sources of funding.

Senior/key personnel – an individual who contributes in a substantive, meaningful way to the scientific development or execution of a research, development and demonstration (RD&D) project proposed to be carried out with DOE award.[11]

[11] Typically, these individuals have doctoral or other professional degrees, although individuals at the masters or baccalaureate level may be considered senior/key personnel if their involvement meets this definition. Consultants, graduate students, and those with a postdoctoral role also may be considered senior/key personnel if they meet this definition.

4.6.2.17. Potentially Duplicate Funding Notice

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_DuplicateFunding

If the applicant or project team member has other active awards of federal funds, the applicant must determine whether the activities of those awards potentially overlap with the activities set forth in its application to this FOA. If there is a potential overlap, the applicant must notify DOE in writing of the potential overlap and state how it will ensure any project funds (i.e., recipient cost share and federal funds) will not be used for identical cost items under multiple awards.

Likewise, for projects that receive funding under this FOA, if a recipient or project team member receives any other award of federal funds for activities that potentially overlap with the activities funded under the DOE award, the recipient must promptly notify DOE in writing of the potential overlap and state whether project funds from any of those other federal awards have been, are being, or are to be used (in whole or in part) for one or more of the identical cost items under the DOE award.

If there are identical cost items, the recipient must promptly notify the DOE Grants and Agreements Officer in writing of the potential duplication and eliminate any inappropriate duplication of funding.

4.6.2.18. Transparency of Foreign Connections

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_ForeignConnections

Applicants must identify the following as they relate to the proposed recipient and subrecipients:

1. the identity of all owners and covered individuals who are a party to any Foreign Government-Sponsored Talent Recruitment Program of a foreign country of risk (i.e., China, Iran, North Korea, and Russia);

2. The existence of any joint venture or subsidiary that is based in, funded by, or has a foreign affiliation with any foreign country of risk;

3. Any current or pending contractual or financial obligation or other agreement specific to a business arrangement, or joint venture-like arrangement with an enterprise owned by a foreign state or any foreign entity;

4. Percentage, if any, that the proposed recipient or subrecipient is wholly or partially owned by an entity in a foreign country of risk;

5. The percentage, if any, of venture capital or institutional investment by an entity that has a general partner or individual holding a leadership role in such entity who has a foreign affiliation with any foreign country of risk;

6. any technology licensing or intellectual property sales to a foreign country of risk, during the 5-year period preceding submission of the proposal; and

7. Any foreign business entity, offshore entity, or entity outside the United States related to the proposed recipient or subrecipient.

4.6.2.19. CO_2 Capture FEED Study

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_CC_FEED

See Appendix C. Please include Techno-Economic Analysis within the FEED. Note that the complete FEED study is initially an optional input, although DOE may request it with the application.

4.6.2.20. CO_2 Pipeline FEED Study

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_PIPE_FEED

See Appendix D. Please include Techno-Economic Analysis within the FEED. Note that the complete FEED study is initially an optional input, although DOE may request it with the application.

4.6.2.21. Sequestration FEED Study

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_STORAGE_FEED

See Appendix E. Please include Techno-Economic Analysis within the FEED. Note that the complete FEED study is initially an optional input, although DOE may request it with the application.

4.6.2.22. Storage Permits

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_PERMITS

Include PDF copies of the Class VI AND Storage Site permits. If you do not have either permit, then submit a copy of the application(s) and a description of where you are in the process of obtaining the permits.

4.6.2.23. Key Performance Parameter Tables

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_KPP_Tables

A table of parameters necessary to compare current Capture demonstrations with previous demonstrations. See Appendix P for more info.

4.6.2.24. *Disclosure of Lobbying Activities*

(PDF)	**File Naming Convention:** ControlNumber_LeadOrganization_LLL

Prime recipients and subrecipients may not use any federal funds to influence or attempt to influence, directly or indirectly, congressional action on any legislative or appropriation matters. Recipients and subrecipients are required to complete and submit SF-LLL, "Disclosure of Lobbying Activities" (https://www.grants.gov/web/grants/forms/sf-424-individual-family.html) to ensure that non-federal funds have not been paid and will not be paid to any person for influencing or attempting to influence any of the following in connection with the application:

- An officer or employee of any federal agency;
- A Member of Congress;
- An officer or employee of Congress; or
- An employee of a Member of Congress.

4.7. Intergovernmental Review

This FOA is not subject to Executive Order 12372 – Intergovernmental Review of Federal Programs.

4.8. Funding Restrictions

4.8.1. Allowable Costs

All expenditures must be allowable, allocable, and reasonable in accordance with the applicable federal cost principles. Pursuant to 2 C.F.R. § 910.352, the cost principles in the Federal Acquisition Regulations (48 C.F.R. Part 31 Subpart 31.2) apply to for-profit entities. The cost principles contained in 2 C.F.R. Part 200 Subpart E apply to all entities other than for-profits.

4.8.2. Pre-Award Costs

Applicants selected for award negotiations must request prior written approval to charge pre-award costs. Pre-award costs are those incurred prior to the effective date of the federal award directly pursuant to the negotiation and in anticipation of the federal award where such costs are necessary for efficient and timely performance of the scope of work. Such costs are allowable only to the extent that they would have been allowable if incurred after the date of the federal award and **only** with the written approval of the federal awarding agency, through the DOE Grants and Agreements Officer. Pre-award costs cannot be incurred prior to the Selection Official signing the Selection Statement and Analysis. Pre-award expenditures are made at the Applicant's risk. OCED is not obligated to reimburse costs: (1) in the absence of appropriations; (2) if an award is not made; or (3) if an award is made for a lesser amount than the Applicant anticipated. This includes any action related to the proposed project that would have an adverse effect on the environment or limit the choice of reasonable alternatives prior to DOE completing the NEPA review process.

4.8.3. Buy America Requirements for Infrastructure Projects

Pursuant to the Build America, Buy America Act (referred to here as "Buy America") in Title IX of Division G of the BIL, federally assisted projects that involve infrastructure work, undertaken by applicable recipient types, require that:

- All iron, steel, and manufactured products used in the infrastructure work are produced in the United States; and
- All construction materials used in the infrastructure work are manufactured in the United States.

Whether a given project must apply this requirement is project-specific and dependent on several factors, such as the recipient's entity type, whether the work involves "infrastructure" as that term is defined in Section 70912 of the BIL, and whether the infrastructure in question is publicly owned or serves a public function.

Applicants are strongly encouraged to assess whether their project may have to apply this requirement, both to make an early determination as to the need of a waiver, as well as to determine what impact, if any, this requirement may have on the proposed project's budget.

For additional information on Buy America requirements, visit DOE's Build America, Buy America webpage.

4.8.4. Davis-Bacon Act Requirements

Projects awarded under this FOA will be funded under Division D of the BIL. Accordingly, per Section 41101 of the BIL, all laborers and mechanics employed by the recipient, subrecipients, contractors or subcontractors in the performance of construction, alteration, or repair work funded in whole or in part under this FOA shall be paid wages at rates not less than those prevailing on similar projects in the locality, as determined by the Secretary of Labor in accordance with subchapter IV of chapter 31 of title 40, United States Code commonly referred to as the "Davis-Bacon Act" (DBA). There are also weekly reporting requirements.

Recipients of funding under this FOA will also be required to undergo DBA compliance training and to maintain competency in DBA compliance. The Grants and Agreements Officer will notify the recipient of any DOE sponsored DBA compliance trainings. The Department of Labor offers free Prevailing Wage Seminars several times a year that meet this requirement, at https://www.dol.gov/agencies/whd/government-contracts/construction/seminars/events.

For additional guidance on how to comply with the DBA provisions and clauses, see https://www.dol.gov/agencies/whd/government-contracts/construction and https://www.dol.gov/agencies/whd/government-contracts/protections-for-workers-in-construction,.

4.8.5. Risk Assessment

Pursuant to 2 C.F.R. § 200.206, DOE will conduct an additional review of the risk posed by applications submitted under this FOA.

Such risk assessment will consider:

1. Financial stability;
2. Quality of management systems and ability to meet the management standards prescribed in 2 C.F.R. Part 200 as amended and adopted by 2 C.F.R. Part 910;
3. History of performance;
4. Audit reports and findings; and
5. The applicant's ability to effectively implement statutory, regulatory, or other requirements imposed on non-federal entities.

In addition, the risk assessment should include assessment of community opposition, potential labor disputes, availability of a skilled workforce, and public and worker health and safety considerations.

DOE may make use of other publicly available information. DOE may also make use of the history of an applicant's performance under DOE or other federal agency awards. DOE reserves the right to ask for information pertaining to prior practices or violations at facilities included in the proposal. Depending on the severity of the findings and whether the findings were resolved, DOE may elect not to fund the applicant.

In addition to this review, DOE must comply with the guidelines on government-wide suspension and debarment in 2 C.F.R. Part 180 and must require non-federal entities to comply with these provisions. These provisions restrict federal awards, subawards and contracts with certain parties that are debarred, suspended or otherwise excluded from or ineligible for participation in federal programs or activities.

The applicant should consider that for large construction projects, DOE may require a Project Labor Agreement (PLA), an agreement between a private entity (or entities) and a labor organization (or organizations) representing individuals who will be working on a construction project. Assessment of applicability will be conducted on a case-by-case basis.
Further, as DOE invests in critical infrastructure and funds critical and emerging technology areas, DOE also considers possible vectors of undue foreign influence in evaluating risk. If high risks are identified and cannot be sufficiently mitigated, DOE may elect to not fund the award.

4.8.6. Human Subjects Research

No funding will be provided under this FOA for any activities involving human subjects.

4.8.7. Performance of Work in the United States (Foreign Work Waiver)

a. Requirement
All work performed under awards issued under this FOA must be performed in the United States. The recipient must flow down this requirement to its subrecipients.

b. Failure to Comply
If the recipient fails to comply with the Performance of Work in the United States requirement, DOE may deny reimbursement for the work conducted outside the United States and such costs may not be recognized as allowable recipient cost share.
The recipient is responsible should any work be performed outside the United States, absent a waiver, regardless of whether the work is performed by the recipient, subrecipients, contractors or other project partners.

c. Waiver
To seek a foreign work waiver, the applicant must submit a written waiver request to DOE. Appendix O lists the information that must be included in a request for a foreign work waiver.

4.8.8. Prohibition related to Foreign Government-Sponsored Talent Recruitment Programs

a. Prohibition
Persons participating in a Foreign Government-Sponsored Talent Recruitment Program of a Foreign Country of Risk are prohibited from participating in projects selected for federal funding under this FOA. Should an award result from this FOA, the recipient must exercise ongoing due diligence to reasonably ensure that no individuals participating on the DOE-funded project are participating in a Foreign Government-Sponsored Talent Recruitment Program of a Foreign Country of Risk. Consequences for violations of this prohibition will be determined according to applicable law, regulations, and policy.

Further, the recipient must notify DOE within five (5) business days upon learning that an individual on the project team is or is believed to be participating in a foreign government talent recruitment program of a foreign country of risk. DOE may modify and add requirements related to this prohibition to the extent required by law.

b. Definitions
1. **Foreign Government-Sponsored Talent Recruitment Program.** An effort directly or indirectly organized, managed, or funded by a foreign government, or a foreign government instrumentality or entity, to recruit science and technology professionals or students (regardless of citizenship or national origin, or whether having a full-time or part-time position).

Some foreign government-sponsored talent recruitment programs operate with the intent to import or otherwise acquire from abroad, sometimes through illicit means, proprietary technology or software, unpublished data and methods, and intellectual property to further the military modernization goals and/or economic goals of a foreign government.

Many, but not all, programs aim to incentivize the targeted individual to relocate physically to the foreign state for the above purpose. Some programs allow for or encourage continued employment at U.S. research facilities or receipt of federal research funds while concurrently working at and/or receiving compensation from a foreign institution, and some direct participants not to disclose their participation to U.S. entities. Compensation could take many forms including cash, research funding, complimentary foreign travel, honorific titles, career advancement opportunities, promised future compensation, or other types of remuneration or consideration, including in-kind compensation.

2. Foreign Country of Risk. DOE has designated the following countries as foreign countries of risk: Iran, North Korea, Russia, and China. This list is subject to change.

4.8.9. Affirmative Action and Pay Transparency Requirements

All federally assisted construction contracts exceeding $10,000 annually will be subject to the requirements of Executive Order 11246, as amended, Equal Employment Opportunity.

1. Recipients, subrecipients, contractors and subcontractors are prohibited from discriminating in employment decisions on the basis of race, color, religion, sex, sexual orientation, gender identity or national origin.
2. Recipients and Contractors are required to take affirmative action to ensure that equal opportunity is provided in all aspects of their employment. This includes flowing down the appropriate language to all subrecipients, contractors and subcontractors.
3. Recipients, subrecipients, contractors and subcontractors are prohibited from taking adverse employment actions against applicants and employees for asking about, discussing, or sharing information about their pay or, under certain circumstances, the pay of their co-workers.

The Department of Labor's ("DOL") Office of Federal Contractor Compliance Programs ("OFCCP") uses a neutral process to schedule contractors for compliance evaluations. OFCCP's Technical Assistance Guide should be consulted to gain an understanding of the requirements and possible actions the recipients, subrecipients, contractors and subcontractors must take https://www.dol.gov/sites/dolgov/files/ofccp/Construction/files/ConstructionTAG.pdf?msclkid=9e397d68c4b111ec9d8e6fecb6c710ec. Additional guidance may also be found in the National Policy Assurances, produced by DOE.

Additionally, for construction projects valued at $35 million or more and lasting more than one year, the recipients, subrecipients, contractors and subcontractors may be selected by OFCCP to participate in the *Mega Construction Project Program*.

DOE, under relevant legal authorities including Sections 205 and 303(a) of Executive Order (EO) 11246, will require participation as a condition of the award. This program offers extensive compliance assistance with EO 11246. For more information regarding this program, see https://www.dol.gov/agencies/ofccp/construction/mega-program.

4.9. Other Submission Requirements

4.9.1. Post Submission Materials and Just-In-Time Documents

Some materials will be required as post submission materials that are due after the merit review is complete. The applicant will be notified on what documents and materials to submit, the format required, and where and when to submit the materials.

4.10. Administrative and National Policy Requirements

To receive a Federal award under this FOA, all applicants must follow applicable cross-cutting administrative and national policy requirements. The policies are requirements based on social, economic, or other objectives or considerations that may be attached to the expenditure of federal funds by award recipients, consortium participants, and contractors, in general, or may relate to the expenditure of federal funds for other specified activities.
These administrative and national policy requirements include, but are not limited, to the following:

- Clean Air Act (42 U.S.C. § 7401 *et seq.*)
- Clean Water Act (33 U.S.C. § 1251 *et seq.*)
- National Flood Insurance Act of 1968 and Flood Disaster Prevention Act of 1973 (42 U.S.C. § 4001 *et seq.*), DOE regulations at 10 C.F.R. Part 1022, and Executive Order 13690 – establishing a Federal Flood Risk Management Standard and a Process for Further Soliciting and Considering Stakeholder Input
- Title VI of the Civil Rights Act of 1964 (42 U.S.C. § 2000d *et seq.*) and DOE regulations at 10 C.F.R. Part 1040 Subpart B
- Section 504 of the Rehabilitation Act of 1973 as amended (29 U.S.C. § 794) and DOE regulations at 10 C.F.R. Part 1040 Subpart D
- Age Discrimination Act of 1975 as amended (42 U.S.C. § 6101 *et seq.*) and DOE regulations at 10 C.F.R. Part 1040 Subpart E
- Title IX of the Education Amendments of 1972 (20 U.S.C. § 1681 *et seq.*) and DOE regulations at 10 C.F.R. Part 1042
- Federal Funding and Transparency Act of 2006; 2 C.F.R. Part 170

5. Application Review Information

5.1. Compliance Criteria

Letters of Intent

Letters of Intent are deemed compliant if:

- The Applicant entered all required information and clicked the “Submit” button in OCED eXCHANGE by the deadline stated in the FOA.

Applications

To be determined compliant, all Applicant submissions must:

- comply with the applicable content and form requirements listed in Section 4.0;
- include all required documents;
- be successfully uploaded in OCED eXCHANGE https://OCED-exchange.energy.gov, including clicking the “Submit” button; and
- be submitted by the deadline stated in the FOA.

DOE will not review or consider submissions submitted through means other than OCED eXCHANGE, submissions submitted after the applicable deadline, or incomplete submissions.

5.2. Technical Review Criteria

5.2.1. Letters of Intent

Feedback will not be provided on Letters of Intent; they will only be used for DOE planning purposes.

5.2.2. Applications

Applications will be evaluated against the technical review criteria shown below. All sub-criteria are of equal weight.

Criterion 1: Technology Merit and Site Suitability (25%)

This criterion involves consideration of the following factors:

a) Adequacy of the Applicant’s description of the proposed CCS demonstration project from the technical, environmental, cost effectiveness, and integrated systems perspectives and degree to which the proposed project meets the stated objectives and success metrics of the FOA.

b) Degree to which the proposed carbon capture technology is ready for demonstration on the proposed commercial process and at the scale proposed. Degree to which the Applicant provides data from prior testing on an integrated, continuous, pilot-scale or demonstration-scale system using actual exhaust gas from the same type of commercial process as that proposed (preferred) or from a reasonably similar alternative and supporting analysis that the proposed carbon capture technology has attained a TRL of 7 and can achieve at least 90% carbon capture efficiency to support readiness for the proposed CCS demonstration. (Footnotes and the bibliography are only to be utilized to validate the information requested in the narrative.)

c) Thoroughness of the description of the proposed domestic carbon capture host site, and how the carbon capture technology will be integrated within the host site, including, but not limited to: process diagrams; emissions profiles; availability and quality of steam and/or waste heat (as applicable); anticipated feed conditions for the stream targeted for capture; electrical, water and waste management; contaminants controls; and NEPA and permitting activities conducted to date. Adequacy of plans for execution of the host site agreement, including key criteria and any conditions. Adequacy of the proposed domestic carbon capture host site to meet FOA objectives and adequacy and completeness of information provided to justify the selection for the specific carbon capture host site.

d) Thoroughness of the description of the CO_2 pipeline, including the transportation route, specifications, requirements, challenges, maps, rights-of-way, and current status of permitting activities. Adequacy of the CO_2 pipeline to meet FOA objectives and the extent to which the Applicant submitted evidence that provides confidence that the Applicant will be able to secure access to the proposed CO_2 transportation route for the proposed project as well any rights of way or permits necessary for ~~the~~ pipeline infrastructure.

e) Thoroughness of the description of the proposed carbon storage site, including level of commitment, characterization, and NEPA and permitting activities conducted to date. Adequacy of the proposed carbon storage site to meet FOA objectives and adequacy and completeness of information provided to characterize the pore space and injectivity behavior of the specific carbon storage site. Quality of supporting information showing that the UIC Class VI injection well permits and any required permit(s) to prepare ~~for~~ the proposed storage site for injection and storage have been granted or the applications to obtain such permits have been submitted

f) Thoroughness of the description of the proposed carbon capture technology, including but not limited to the following: equipment design concept, preliminary process flow diagrams, mass and energy balances, steam and power requirements, management and impact of emissions originating in the carbon capture system (e.g., amines, nitrosamines), a discussion of the absorption/desorption chemistry and operating cycle for solvent and sorbent systems including recharging/regenerating (as applicable); and a description of relevant membrane chemistry for membrane systems, including transport mechanism (as applicable). Thoroughness of the description of remaining technical challenges for the proposed carbon capture technology. Adequacy of the proposed carbon capture system to meet FOA objectives.

g) Degree to which the proposed project would demonstrate significant improvements in the efficiency, effectiveness, cost, and environmental performance of carbon capture technologies for power, industrial, or other commercial applications when compared to the technology in existence on December 27th 2020. Degree to which the projected performance of the proposed carbon capture technology was substantiated by experimental evidence from prior testing on exhaust gas from the same type of commercial process as that proposed (preferred) or from a reasonably similar alternative.
h) Evidence that the project is proposed at an appropriate scale and that the proposed demonstration will facilitate subsequent deployments of the carbon capture technology at similar scales. Note that a reasonable scale-up is roughly 10x.
i) Thoroughness of the description of the testing plan and its adequacy to validate key cost and performance metrics and reduce uncertainties and risks to facilitate private-sector investments in follow-on deployments.
j) Adequacy and completeness of information provided in the State Point Data Table, Block Flow Diagram and Supplemental Data, and key performance parameter table.
k) Adequacy of the Initial Environmental, Health & Safety Risk Assessment, including identification of risks and evaluation of increases or decreases of criteria pollutants and noise impacts.
l) Adequacy of the preliminary LCA to meet FOA objectives and degree to which a complete description of the preliminary LCA was provided.
m) Thoroughness of the summary of the CO_2 capture FEED study and the extent to which the information provides evidence that the FOA objectives are likely to be achieved.
n) Thoroughness of the summary of the CO_2 pipeline FEED study and the extent to which the information provides evidence that the FOA objectives are likely to be achieved.
o) Thoroughness of the summary of the CO_2 storage FEED study or and the extent to which the information provides evidence that the FOA objectives are likely to be achieved.

Criterion 2: Technical Approach and Project Management Plan (15%)

This criterion involves consideration of the following factors:

a) Adequacy and feasibility of the Applicant's approach to achieving the objectives of the FOA and the overarching goal of readiness for Phases 3–4 by the end of Phase 2.
b) Thoroughness of the project description and plans necessary for the design, installation/modification, permitting, and operation of equipment for required scale of design.
c) The adequacy and completeness of the Data Management Plan (DMP) in conveying a clear explanation of data collection methodologies, file types, data analytics considerations, machine learning applications (if applicable), and data storage. Thoroughness and significance of the details concerning how project data will be shared with DOE and the public.

d) The following aspects of the PMP shall be evaluated:
   i. Adequacy and completeness of the PMP in: establishing integrated baselines (technical scope, budget, schedule) and performance metrics that will be assessed during the proposed CCS demonstration project and in managing project performance relative to those baselines; defining the actions that will be taken when these baselines must be revised; and identifying project risks and strategies for mitigation.
   ii. Soundness and completeness of the project schedule; including all tasks necessary for successful completion of the project; incorporating and showing relationships among all technical, business, financial, NEPA, permitting and other appropriate factors; including important milestones and decision points; and allocating sufficient and appropriate time to complete the project deliverables and success criteria.
   iii. Adequacy of the Baseline Cost Plan for establishing the baseline cost (including supporting documentation for the cost estimate) for the project and incorporating costs for all tasks necessary for performing the proposed project.
   iv. Adequacy of the project management system to monitor and control project scope, cost, and schedule.
   v. Adequacy of the Project Communication Protocol for ensuring effective communication between the Recipient and DOE.

   vi. Adequacy of the Risk Management Plan for assessing, identifying, tracking, and managing project risk; completeness of the identification of potential risk elements, quality and adequacy of the approach to assessing and managing risk, conformance of risk management approach with industry standards, and adequacy of the approaches to risk mitigation.
   vii. Adequacy of the Environmental Management Plan for assessing, monitoring, and reporting the potential environmental impacts to air, land and water resources, and potential impacts of waste production.

Criterion 3: Applicant/Team Capabilities and Commitments (20%)

This criterion involves consideration of the following factors:

a) Demonstrated experience of the Applicant and partnering organizations in the technology areas addressed in the application and in managing projects of similar size, scope, and complexity.
b) Adequacy of the credentials, capabilities, and experience of senior and key personnel and partnering organizations.
c) Clarity and likely effectiveness of the project organization, including sub-recipients or partners, to successfully complete the project.
d) Adequacy and availability of proposed personnel, facilities, and equipment to perform project tasks.

e) Completeness of proposed team structure that includes these team members or skill sets, if applicable: CO_2 capture technology developer or licensor, CO_2 capture host site owner(s) or operator(s), CO_2 pipeline operator, CO_2 storage site owner, EPC(s), financial partner(s), NEPA compliance consultant, LCA consultant, CBP consultant, or others as appropriate. Adequacy of the letters of commitment from proposed team members.
f) Strength of the commitment(s) for use and availability of the proposed carbon capture host site to support the proposed project, including strength of the evidence showing the Applicant's right to capture CO_2 at the proposed carbon capture host site.
g) Strength of the commitment(s) for use and availability of the proposed CO_2 pipeline to support the proposed project, including strength of the evidence showing the Applicant's right of way (ROW) to transport CO_2 from the host site to the storage site.
h) Strength of the commitment(s) for use and availability of the proposed carbon storage site (if different than the carbon capture host site) to support the proposed project, including strength of the evidence showing the Applicant's right to store CO_2 at the proposed carbon storage site.

Criterion 4: Financial and Market Viability (20%):

This criterion involves consideration of the following factors:

a) Degree to which future similar projects would be financially viable independent of DOE cost share.

b) The adequacy and justification of the proposed project budget and spend plan covering both DOE funding and non-federal cost share. This includes the Applicant's ability to provide contingency to meet unknown project cost overruns often seen with large demonstration projects.
c) Adequacy, completeness, and viability of the proposed Project Financing Plan.
d) Reasonableness and completeness of the plan, including a financing schedule, demonstrating the potential for the Applicant to successfully implement the project.
e) Completeness of financial information and consistency with the funding and financial business plans and with other application materials.
f) Viability of financial projections in the financial model to attract investors and lenders.
g) Degree of financial commitment to the project evidenced by the Applicant and other project parties.
h) The availability, credibility, and risk/terms of non-federal cost share sources and funds necessary to meet ongoing cost share needs. This includes the ability to leverage DOE financial assistance funding from this FOA including state and local incentives and private financing.
i) The adequacy of the business plan for developing key project agreements such as financing, acquisition strategies, power purchase agreements, feedstock supply, offtake (sales) agreements, transport and storage services, and other relevant project documents.

j) The adequacy and clarity of the financial risk management discussion and a demonstrated understanding of financial and market risks involved in the proposed work, as well as the quality of the mitigation strategies to address them.
k) The potential of this project to have a catalytic impact on further deployment of CCS for similar applications.

Criterion 5: Community Benefits Plan (20%)

Overall Approach

a) The extent to which the plan specifically and convincingly demonstrates how the proposed project will provide societal benefits and mitigate/minimize negative impacts to workers and communities—including impacts related to air pollution, water use, water pollution, consumer energy prices, safety related to CO_2 transport via pipeline, and job retention or creation.
b) The extent to which the actions outlined in the Community Benefits Plan (CBP) are supported by enforceable, negotiated Workforce and Community Agreements (e.g., good neighbor agreements, workforce agreements, project labor agreements, collective bargaining agreements, and similar agreements).
c) The extent to which the team and resources—including staff, facilities, capabilities, and budget—are capable of implementing plans outlined in the CBP.
d) Extent to which the Community Benefits Plan is integrated into the project management schedule and other key documents and provides mechanisms, supported by measurable actions, to impact project direction in a timely manner.

Community and Labor Engagement

e) The extent to which the project demonstrates a clear and appropriately robust plan to meaningfully engage affected local stakeholders including community-based organizations that support or work with disadvantaged communities; labor unions; and/or Tribes, in a manner that can impact project decisions.
f) The extent to which impacted communities and labor unions~~,~~ are appropriately included as core partners in the project and/or affirm support.

Investing in the American Workforce

g) The extent to which the CBP demonstrates that the jobs supported by the proposed project will be quality jobs and provides robust and credible plan to attract, train, and retain skilled workers (e.g., through a workforce and community agreement and commitment to workers' free and fair choice to join a union or labor organization of their choosing; and/or commitments to wages above prevailing wage requirements, benefits, or other worker support).
h) The extent to which the Community Benefits Plan demonstrates plans to invest in workers by supporting workers' skill acquisition and opportunities for advancement, including through registered apprenticeship; utilizing an appropriately credentialed workforce; and commitments to wages above prevailing wage requirements benefits.

Diversity, Equity, Inclusion, and Accessibility

i) The extent to which the CBP includes specific and high-quality actions to meet DEIA goals, which may include DEIA recruitment procedures; partnerships with workforce training or support organizations serving workers facing systematic barriers to employment; the provision of supportive services to help train, place, and retain individuals from underrepresented communities in good-paying jobs, registered apprenticeships, or other career-track training opportunities.

j) The extent to which the proposed project partners or contracts with Minority-Serving Institutions (MSIs), Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses, Veteran Owned Businesses, and/or Tribal Nations.

Justice40 Initiative

k) The extent to which the CBP identifies specific and measurable benefits, how the benefits will flow, and how negative impacts would be mitigated—and specifically describes these impacts on disadvantaged communities.

l) The extent to which the project illustrates the ability to support the overall goal of the Justice40 Initiative that 40% of the overall benefits of certain federal investments flow to disadvantaged communities.

5.3. Standards for Application Evaluation

Applications that are determined to be eligible will be evaluated in accordance with this FOA and the guidance provided in the "DOE Merit Review Guide for Financial Assistance and Unsolicited Proposals" available at https://www.energy.gov/management/articles/merit-review-guide-financial-assistance-and-unsolicited-proposals-current

5.4. Evaluation and Administration by Non-Federal Personnel

In conducting the merit review evaluation, the Go/No-Go Reviews and Peer Reviews, the government may seek the advice of qualified non-federal personnel as reviewers. The government may also use non-federal personnel to conduct routine, nondiscretionary administrative activities, including DOE contractors.

The Applicant, by submitting its application, consents to the use of non-federal reviewers/administrators. Non-federal reviewers must sign conflict of interest and non-disclosure acknowledgements (NDA) prior to reviewing an application. Non-federal personnel conducting administrative activities must sign an NDA.

5.5. Other Selection Factors

5.5.1. Program Policy Factors

In addition to the above criteria, the Selection Official may consider the following program policy factors in determining which Applications to select for award negotiations:

- It may be desirable to select for award a project, or group of projects, that represent a diversity of technologies under this FOA;
- It may be desirable to select for award a project, or group of projects, with a broad or specific geographic distribution under this FOA;
- It may be desirable to select for award a project, or group of projects, that leverage existing public-private partnerships and/or Federal resources;
- It may be desirable to select for award a project, or group of projects, that can demonstrate greater than the minimum required CO_2 capture efficiency;
- It may be desirable to select a project, or group of projects, if such a selection will optimize use of available funds; and
- It may be desirable to select a project, or group of projects, if such a selection will have an outsized catalytic impact on overall CCS deployment; and
- It may be desirable to select a project, or group of projects, if such a selection presents lesser schedule risk, lesser budget risk, lesser technical risk, lesser community negative impact risk, and/or lesser environmental risks. Environmental risk includes, but is not limited to, an adverse impact to air (including non-CO_2 gasses such as SOx and NOx), soil, water, or increase in overall cradle-to-grave greenhouse gas footprint (carbon dioxide equivalent, CO_2e).
- It may be desirable to select a project or group of projects based on the degree to which the proposed project will employ procurement of U.S. iron, steel, manufactured products, and construction materials.
- It may be desirable to select a project, or group of projects which incorporate Applicant or team members from Minority Serving Institutions (e.g., Historically Black Colleges and Universities (HBCUs)/Other Minority Serving Institutions); and partnerships with Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses, Veteran Owned Businesses, or Tribal Nations.
- It may be desirable to select a project or group of projects, when compared to the existing DOE project portfolio and other projects to be selected from the subject FOA, contributes to the total portfolio meeting Justice40 goals.

5.6. *Evaluation and Selection Process*

5.6.1. Overview

The evaluation process consists of multiple phases; each includes an initial eligibility review and a thorough technical review. Rigorous technical reviews of eligible submissions are conducted by reviewers that are experts in the subject matter of the FOA. Ultimately, the Selection Official considers the recommendations of the reviewers, along with other considerations such as program policy factors, in determining which applications to select.

5.6.2. Recipient Integrity and Performance Matters

DOE, prior to making a federal award with a total amount of federal share greater than the simplified acquisition threshold, is required to review and consider any information about the applicant that is in the designated integrity and performance system accessible through SAM (currently the Federal Awardee Performance and Integrity Information System (FAPIIS)) (see 41 U.S.C. § 2313).

The applicant, at its option, may review information in the designated integrity and performance systems accessible through SAM and comment on any information about itself that a federal awarding agency previously entered and is currently in the designated integrity and performance system accessible through SAM.

DOE will consider any written comments by the applicant, in addition to the other information in the designated integrity and performance system, in making a judgment about the applicant's integrity, business ethics, and record of performance under federal awards when completing the review of risk posed by applicants as described in 2 C.F.R. § 200.206.

5.6.3. Pre-Selection Interviews and Site Visits

As part of the evaluation and selection process, DOE may invite one or more Applicants to participate in pre-selection interviews. The invited Applicant(s) will meet with DOE representatives to provide clarification on the contents of the Full Applications and to provide DOE an opportunity to ask questions regarding the proposed project. The information provided by Applicants to DOE through pre-selection interviews contributes to DOE's selection decisions.

DOE will arrange to meet with the invited Applicants in person at DOE's offices or a mutually agreed upon location. DOE may also arrange site visits at certain Applicants' facilities and at its discretion, may meet with community stakeholders concerning the project. In the alternative, DOE may invite certain Applicants to participate in a one-on-one conference with DOE via webinar, videoconference, or conference call.

The pre-selection interviews and site visits may also include discussions with affected stakeholders or communities potentially impacted to understand their concerns/risks. In the alternative, DOE may invite certain applicants to participate a one-on-one meeting with DOE virtually.

DOE will not reimburse Applicants for travel and other expenses relating to the pre-selection interviews or site visits, nor will these costs be eligible for reimbursement as pre-award costs.

Participation in pre-selection interviews or site visits with DOE does not signify that Applicants have been selected for award negotiations.

5.6.4. Selection

The Selection Official may consider the technical merit, the Federal Consensus Board's recommendations, program policy factors, and the amount of funds available in arriving at selections for this FOA.

5.7. Anticipated Notice of Selection and Award Negotiation Dates

OCED anticipates notifying Applicants selected for negotiation of award and negotiating awards by the dates provided on the cover page of this FOA.

6. Award Administration Information

6.1. Award Notices

6.1.1. Ineligible Submissions

Ineligible Applications will not be further reviewed or considered for award. The Grants and Agreements Officer will send a notification letter by email to the technical and administrative points of contact designated by the Applicant in OCED eXCHANGE. The notification letter will state the basis upon which the Application is ineligible and not considered for further review.

6.1.2. Application Notifications

DOE will notify Applicants of its determination by email to the technical and administrative points of contact designated by the Applicant in OCED eXCHANGE. The notification letter will inform the Applicant whether or not its Application was selected for award negotiations. Alternatively, DOE may notify one or more Applicants that a final selection determination will be made at a later date, subject to the availability of funds or other factors.

6.1.3. Successful Applicants

Receipt of a notification letter selecting an Application for award negotiations does not authorize the Applicant to commence the project. If an application is selected for award negotiations, it is not a commitment by DOE to issue an award. Applicants do not receive an award until award negotiations are complete and the Grants and Agreements Officer executes the funding agreement, accessible by the prime recipient in FedConnect.

Applicants must designate a primary and a backup point-of-contact in OCED eXCHANGE with whom DOE will communicate to conduct award negotiations. The Applicant must be responsive during award negotiations by providing requested documentation, including just-in-time documentation and meet the negotiation deadlines.
If the Applicant fails to do so or if award negotiations are otherwise unsuccessful, DOE will cancel the award negotiations and rescind the Selection. DOE reserves the right to terminate award negotiations at any time for any reason.

6.1.4. Alternate Selection Determinations

In some instances, an Applicant may receive a notification that its application was not selected for award and DOE designated the application to be an alternate. As an alternate, DOE may consider the Application for federal funding in the future. A notification letter stating the Application is designated as an alternate does not authorize the Applicant to commence the project. DOE may ultimately determine to select or not select the Application for award negotiations.

6.1.5. Unsuccessful Applicants

DOE shall promptly notify in writing each Applicant whose application has not been selected for award or whose application cannot be funded because of the unavailability of appropriated funds.

6.2. Award Conditions and Reporting

Applicants of an award made under this FOA must comply with requirements of all applicable federal, state, and local laws, regulations, DOE policy and guidance, instructions in this FOA, and the award terms and conditions. Applicants must require subrecipients' compliance with all applicable requirements. Reporting requirements are identified on the Federal Assistance Reporting Checklist, attached to the award agreement.

7. Questions/Agency Contacts

Upon the issuance of a FOA, DOE personnel are prohibited from communicating (in writing or otherwise) with Applicants regarding the FOA except through the established question and answer process as described below. Specifically, questions regarding this FOA must be submitted to: CCdemoprojectsprogram@hq.doe.gov. Questions must be submitted not later than 3 business days prior to the application due date and time. Please note, feedback on individual concepts will not be provided through Q&A.

All questions and answers related to this FOA will be posted on OCED eXCHANGE at: https://OCED-exchange.energy.gov. **You must first select this specific FOA Number to view the questions and answers specific to this FOA**. OCED will attempt to respond to a question within 3 business days unless a similar question and answer has already been posted on the website. Questions related to the registration process and use of the OCED eXCHANGE website should be submitted to: OCED-ExchangeSupport@hq.doe.gov. Include FOA name and number in subject line.

8. Other Information

8.1. Treatment of Application Information

DOE takes very seriously the confidentiality of all applicants and will treat information submitted in applications, as well as the identity of applicants, as confidential to the fullest extent permissible under Federal law. In order for DOE to protect confidential information, the applicant must also treat the information as confidential and properly mark it as described below. DOE will not be able to protect information that the applicant has released publicly or is in the public domain. For additional information on DOE's Freedom of Information Act (FOIA) regulations, see 10 C.F.R. Part 1004.

Applicants should not include business sensitive (e.g., commercial or financial information that is privileged or confidential), trade secrets, proprietary, or otherwise confidential information in their application unless such information is necessary to convey an understanding of the proposed project or to comply with a requirement in the FOA. Applicants are advised to not include any critically sensitive proprietary detail.

If an application includes business sensitive, trade secrets, proprietary, or otherwise confidential information, it is furnished to the federal government (government) in confidence with the understanding that the information shall be used or disclosed only for evaluation of the application. Such information will be withheld from public disclosure to the extent permitted by law, including FOIA. Without assuming any liability for inadvertent disclosure, DOE will seek to limit disclosure of such information to its employees and to outside reviewers when necessary for merit review of the application or as otherwise authorized by law. This restriction does not limit the government's right to use the information if it is obtained from another source.

Applications and other submissions containing confidential, proprietary, or privileged information must be marked as described below. Failure to comply with these marking requirements may result in the disclosure of the unmarked information under FOIA or otherwise. The U.S. Government is not liable for the disclosure or use of unmarked information and may use or disclose such information for any purpose.

The cover sheet of the Application and other submissions must be marked as follows and identify the specific pages containing trade secrets, confidential, proprietary, or privileged information:

Notice of Restriction on Disclosure and Use of Data:
Pages [list applicable pages] of this document may contain trade secrets, confidential, proprietary, or privileged information that is exempt from public disclosure. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance or loan agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source. [End of Notice]

The header and footer of every page that contains confidential, proprietary, or privileged information must be marked as follows: "Contains Trade Secrets, Confidential, Proprietary, or Privileged Information Exempt from Public Disclosure." In addition, each line or paragraph containing proprietary, privileged, or trade secret information must be clearly marked with double brackets or highlighting.

8.2. Retention of Submissions

DOE expects to retain copies of all Applications and other submissions. No submissions will be returned. By applying to DOE for funding, Applicants consent to DOE's retention of their submissions.

8.3. Personally Identifiable Information

All information provided by the Applicant must to the greatest extent possible exclude Personally Identifiable Information (PII), which is information which can be used to distinguish or trace an individual's identity, such as their name, social security number, biometric records, alone, or when combined with other personal or identifying information which is linked or linkable to a specific individual, such as date and place of birth, mother's maiden name. (See OMB Memorandum M-07-16 dated May 22, 2007, found at:
https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/memoranda/2007/m07-16.pdf

By way of example, Applicants must screen resumes to ensure that they do not contain PII such as personal addresses, personal landline/cell phone numbers, and personal emails. **Under no circumstances should Social Security Numbers (SSNs) be included in the application**. Federal agencies are prohibited from collecting, using, and displaying unnecessary SSNs. (See, the Federal Information Security Modernization Act of 2014 (Pub. L. No. 113-283, Dec 18, 2014; 44 U.S.C. § 3551).

8.4. Uniform Commercial Code Financing Statements

Per 2 C.F.R. § 910.360 (Real Property and Equipment) when a piece of equipment is purchased by a for-profit recipient or subrecipient with federal funds, and when the federal share of the financial assistance agreement is more than $1,000,000, the recipient or subrecipient must:

Properly record, and consent to the Department's ability to properly record if the recipient fails to do so, UCC financing statement(s) for all equipment in excess of $5,000 purchased with project funds. These financing statement(s) must be approved in writing by the Grants and Agreements Officer prior to the recording, and they shall provide notice that the recipient's title to all equipment (not real property) purchased with federal funds under the financial assistance agreement is conditional pursuant to the terms of this section, and that the government retains an undivided reversionary interest in the equipment.

The UCC financing statement(s) must be filed before the Grants and Agreements Officer may reimburse the recipient for the federal share of the equipment unless otherwise provided for in the relevant financial assistance agreement. The recipient shall further make any amendments to the financing statements or additional recordings, including appropriate continuation statements, as necessary or as the Grants and Agreements Officer may direct.

8.5. Prohibition on Certain Telecommunications and Video Surveillance Services or Equipment

As set forth in 2 C.F.R. § 200.216, Applicants and subrecipients are prohibited from obligating or expending project funds (federal funds and recipient cost share) to procure or obtain; extend or renew a contract to procure or obtain; or enter into a contract (or extend or renew a contract) to procure or obtain equipment, services, or systems that uses covered telecommunications equipment or services as a substantial or essential component of any system, or as critical technology as part of any system. As described in Section 889 of Public Law 115-232, covered telecommunications equipment is telecommunications equipment produced by Huawei Technologies Company or ZTE Corporation (or any subsidiary or affiliate of such entities).

See Public Law 115-232, Section 889, 2 C.F.R. § 200.216, and 2 C.F.R. § 200.471 for additional information.

8.6. Title to Subject Inventions

Ownership of subject inventions is governed pursuant to the authorities listed below:

- Domestic Small Businesses, Educational Institutions, and Nonprofits: Under the Bayh-Dole Act (35 U.S.C. § 200 et seq.), domestic small businesses, educational institutions, and nonprofits may elect to retain title to their subject inventions;
- All other parties: The Federal Non-Nuclear Energy Act of 1974, 42. U.S.C. § 5908, provides that the government obtains title to new inventions unless a waiver is granted (see below);
- Class Patent Waiver;

DOE may issue a class waiver that applies to this FOA. Under this class waiver, domestic large businesses may elect title to their subject inventions similar to the right provided to the domestic small businesses, educational institutions, and nonprofits by law. In order to avail itself of the class waiver, a domestic large business must agree that any products embodying or produced through the use of a subject invention first created or reduced to practice under this program will be substantially manufactured in the United States.

Advance and Identified Waivers: For an applicant not covered by a Class Patent Waiver or the Bayh-Dole Act, the applicant may request a patent waiver that will cover subject inventions that may be invented under the award, in advance of or within 30 days after the effective date of the award. Even if an advance waiver is not requested or the request is denied, the recipient will have a continuing right under the award to request a waiver for identified inventions, i.e., individual subject inventions that are disclosed to DOE within the timeframes set forth in the award's intellectual property data terms and conditions. Any patent waiver that may be granted is subject to certain terms and conditions in 10 C.F.R. Part 784.

DEC: On June 07, 2021, DOE approved a DETERMINATION OF EXCEPTIONAL CIRCUMSTANCES (DEC) UNDER THE BAYH-DOLE ACT TO FURTHER PROMOTE DOMESTIC MANUFACTURE OF DOE SCIENCE AND ENERGY TECHNOLOGIES. In accordance with this DEC, all awards, including sub-awards, under this FOA shall include the U.S. Competitiveness Provision in accordance with the U.S. Manufacturing Commitments section further below.

A copy of the DEC can be found at https://www.energy.gov/gc/determination-exceptional-circumstances-decs. Pursuant to 37 C.F.R. § 401.4, any nonprofit organization or small business firm as defined by 35 U.S.C. § 201 affected by any DEC has the right to appeal it by providing written notice to DOE within 30 working days from the time it receives a copy of the determination.

DOE may issue and publish on the website above further DECs prior to the issuance of awards under this FOA. DOE may require additional submissions or requirements as authorized by any applicable DEC.

8.7. Government Rights in Subject Inventions

Where Applicants retain title to subject inventions, the United States government retains certain rights.

Government Use License

The United States government retains a nonexclusive, nontransferable, irrevocable, paid-up license to practice or have practiced for or on behalf of the United States any subject invention throughout the world. This license extends to contractors doing work on behalf of the government.

March-In Rights

The United States government retains march-in rights with respect to all subject inventions. Through "march-in rights," the government may require a prime recipient or subrecipient who has elected to retain title to a subject invention (or their assignees or exclusive licensees), to grant a license for use of the invention to a third party. In addition, the government may grant licenses for use of the subject invention when a prime recipient, subrecipient, or their assignees and exclusive licensees refuse to do so.

DOE may exercise its march-in rights only if it determines that such action is necessary under any of the four following conditions:

- The owner or licensee has not taken or is not expected to take effective steps to achieve practical application of the invention within a reasonable time;
- The owner or licensee has not taken action to alleviate health or safety needs in a reasonably satisfied manner;
- The owner has not met public use requirements specified by federal statutes in a reasonably satisfied manner; or
- The United States manufacturing requirement has not been met.

Any determination that march-in rights are warranted must follow a fact-finding process in which the recipient has certain rights to present evidence and witnesses, confront witnesses and appear with counsel and appeal any adverse decision. To date, DOE has never exercised its march-in rights to any subject inventions.

8.8. Rights in Technical Data

Data rights differ based on whether data is first produced under an award or instead was developed at private expense outside the award.

"Limited Rights Data": The United States government will not normally require delivery of confidential or trade secret-type technical data developed solely at private expense prior to issuance of an award, except as necessary to monitor technical progress and evaluate the potential of proposed technologies to reach specific technical and cost metrics.

Government Rights in Technical Data Produced Under Awards: The United States government normally retains unlimited rights in technical data produced under government financial assistance awards, including the right to distribute to the public. However, pursuant to special statutory authority, certain categories of data generated under DOE awards may be protected from public disclosure for up to five years after the data is generated ("Protected Data").

For awards permitting Protected Data, the protected data must be marked as set forth in the award's intellectual property terms and conditions and a listing of unlimited rights data (i.e., non-protected data) must be inserted into the data clause in the award. In addition, invention disclosures may be protected from public disclosure for a reasonable time in order to allow for filing a patent application.

8.9 Copyright

The prime recipient and subrecipients may assert copyright in copyrightable works, such as software, first produced under the award without DOE approval. When copyright is asserted, the government retains a paid-up nonexclusive, irrevocable worldwide license to reproduce, prepare derivative works, distribute copies to the public, and to perform publicly and display publicly the copyrighted work. This license extends to contractors and others doing work on behalf of the government.

8.10 Fraud, Waste, and Abuse

The mission of the DOE Office of Inspector General (OIG) is to strengthen the integrity, economy and efficiency of the Department's programs and operations including deterring and detecting fraud, waste, abuse and mismanagement.

The OIG accomplishes this mission primarily through investigations, audits, and inspections of DOE activities to include grants, cooperative agreements, loans, and contracts. The OIG maintains a Hotline for reporting allegations of fraud, waste, abuse, or mismanagement. To report such allegations, please visit https://www.energy.gov/ig/ig-hotline.

Additionally, recipients of DOE awards must be cognizant of the requirements of 2 C.F.R. § 200.113. Applicants and subrecipients (if applicable) are encouraged to allocate sufficient costs in the project budget to cover the costs associated for personnel and data infrastructure needs to support performance management and program evaluation needs including but not limited to independent program and project audits to mitigate risks for fraud, waste, and abuse.

8.11 U.S. Manufacturing Commitments

A primary objective of DOE's multi-billion-dollar research, development, and demonstration investments is to cultivate new research and development ecosystems, manufacturing capabilities, and supply chains for and by United States industry and labor. Therefore, in exchange for receiving taxpayer dollars to support an applicant's project, the applicant must agree to a U.S. Competitiveness provision requiring that any products embodying any subject invention or produced through the use of any subject invention will be manufactured substantially in the United States unless the Recipient can show to the satisfaction of DOE that it is not commercially feasible.

Award terms, including the specific U.S. Competitiveness Provision applicable to the various types of recipients and projects, are available here.

Please note that a subject invention is any invention conceived or first actually reduced to practice in performance of work under an award. An invention is any invention or discovery which is or may be patentable. The recipient includes any awardee, recipient, sub-awardee, or sub-recipient.

As noted in the U.S. Competitiveness Provision, if an entity cannot meet the requirements of the U.S. Competitiveness Provision, the entity may request a modification or waiver of the U.S. Competitiveness Provision. For example, the entity may propose modifying the language of the U.S. Competitiveness Provision in order to change the scope of the requirements or to provide more specifics on the application of the requirements for a particular technology.

As another example, the entity may request that the U.S. Competitiveness Provision be waived in lieu of a net benefits statement or United States manufacturing plan.
The statement or plan would contain specific and enforceable commitments that would be beneficial to the United States economy and competitiveness.

Examples of such commitments could include manufacturing specific products in the United States, making a specific investment in a new or existing United States manufacturing facility, keeping certain activities based in the United States or supporting a certain number of jobs in the United States related to the technology. DOE may, in its sole discretion, determine that the proposed modification or waiver promotes commercialization and provides substantial United States economic benefits, and grant the request. If granted, DOE will modify the award terms and conditions for the requesting entity accordingly.

More information and guidance on the waiver and modification request process can be found in the DOE Financial Assistance Letter on this topic. Additional information on DOE's Commitment to Domestic Manufacturing for DOE-funded R&D is available here.

The U.S. Competitiveness Provision is implemented by DOE pursuant to a Determination of Exceptional Circumstances (DEC) under the Bayh-Dole Act and DOE Patent Waivers. See Section 8.8 Title to Subject Inventions for more information on the DEC and DOE Patent Waivers.

8.12 Government Right to Reject or Negotiate

DOE reserves the right, without qualification, to reject any or all applications in response to this FOA and to select any application, in whole or in part, as a basis for negotiation and/or award.

8.13 Export Control

The United States government regulates the transfer of information, commodities, technology, and software considered to be strategically important to the United States to protect national security, foreign policy, and economic interests without imposing undue regulatory burdens on legitimate international trade. There is a network of federal agencies and regulations that govern exports that are collectively referred to as "Export Controls".

All recipients and subrecipients are responsible for ensuring compliance with all applicable United States Export Control laws and regulations relating to any work performed under a resulting award.

The recipient must immediately report to DOE any export control violations related to the project funded under the DOE award, at the recipient or subrecipient level, and provide the corrective action(s) to prevent future violations.

8.14 Interim Conflict of Interest Requirements for Financial Assistance

The DOE Interim Conflict of Interest Policy for Financial Assistance (COI Policy) can be found here. The interim COI policy is applicable to all non-Federal entities that receive DOE funding by means of a financial assistance award (e.g., a grant, cooperative agreement, or technology investment agreement) and, through the implementation of the interim COI policy by the entity, to each investigator who is planning to participate in, or is participating in, the project funded wholly or in part under the DOE financial assistance award. The interim COI policy establishes standards that provide a reasonable expectation that the design, conduct, and reporting of projects funded wholly or in part under DOE financial assistance awards will be free from bias resulting from financial conflicts of interest or organizational conflicts of interest. The Recipient is subject to the requirements of the interim COI policy, and the recipient must certify that it is compliant with all the requirements in the interim COI policy. The Recipient must flow down the requirements of the interim COI policy to any subrecipient non-Federal entities.

APPENDIX A: APPLICATION REQUIREMENTS CHECKLIST

Component	File Format	Page Limit	File Name
SF-424 Application for Federal Assistance	PDF	N/A	ControlNumber_LeadOrganization_App424
Cover Page	PDF	2 pages	ControlNumber_LeadOrganization_Cover_Page
Project Overview	PDF	8	ControlNumber_LeadOrganization_Project_Overview
Technical Description, Innovation, and Impact	PDF	20	ControlNumber_LeadOrganization_Technical_Description
Technical Approach and Project Management Plan	PDF	10	ControlNumber_LeadOrganization_Technical_Approach
Technical Qualifications and Resources	PDF	15	ControlNumber_LeadOrganization_Technical_Qualifications
Community Benefits Plan: Job Quality and Equity	PDF	25	ControlNumber_LeadOrganization_Comm_Benefits
Community Partnership Documentation	PDF	3 pages per letter	ControlNumber_LeadOrganization_PartnerDoc
Resumes	PDF	2 pages each	ControlNumber_LeadOrganization_Resumes
Letters of Commitment	PDF	1 page each	ControlNumber_LeadOrganization_LOCs
Project Management Plan	PDF	50	ControlNumber_LeadOrganization_PMP
Initial Environmental, Health, & Safety Assessment	PDF	10	ControlNumber_LeadOrganization_EHSA
Life Cycle Analysis	PDF	N/A	ControlNumber_LeadOrganization_LCA

Business Case Analysis	PDF	30	ControlNumber_LeadOrganization_BCA
Project Financing Plan	PDF	20	ControlNumber_LeadOrganization_PFP
Budget Justification Workbook	MS Excel	N/A	ControlNumber_LeadOrganization_Budget_Justification
Subrecipient Budget Justification	MS Excel	N/A	ControlNumber_LeadOrganization_Subrecipient_Budget_Justification
Summary of Public Releasee	PDF	1	ControlNumber_LeadOrganization_Public_Release
Summary Slides	MS PowerPoint	5	ControlNumber_LeadOrganization_Slide
Environmental Considerations Summary	PDF	N/A	ControlNumber_LeadOrganization_Environmental_Considerations
Current and Pending Support Disclosures	PDF	N/A	ControlNumber_LeadOrganization_Current_Support
Potentially Duplicate Funding Notice	PDF	N/A	ControlNumber_LeadOrganization_DuplicateFunding
Transparency of Foreign Connections	PDF	N/A	ControlNumber_LeadOrganization_ForeignConnections
CO_2 Capture FEED Study (optional)	PDF	N/A	ControlNumber_LeadOrganization_CC_FEED
CO_2 Pipeline FEED Study (optional)	PDF	N/A	ControlNumber_LeadOrganization_PIPE_FEED
CO_2 Storage FEED Study (optional)	PDF	N/A	ControlNumber_LeadOrganization_STORAGE_FEED
Storage Permits	PDF	N/A	ControlNumber_LeadOrganization_PERMITS
Key Performance Parameters Tables	PDF	N/A	ControlNumber_LeadOrganization_KPP_TABLES
Disclosure of Lobbying Activities	PDF	N/A	ControlNumber_LeadOrganization_LLL

APPENDIX B: LIST OF ACRONYMS

DEIA	Diversity, Equity, Inclusion, and Accessibility
DMP	Data Management Plan
DOE	Department of Energy
OCED	Office of Clean Energy Demonstrations
FFATA	Federal Funding and Transparency Act of 2006
FOA	Funding Opportunity Announcement
FOIA	Freedom of Information Act
FFRDC	Federally Funded Research and Development Center
GAAP	Generally Accepted Accounting Principles
G/AO	Grants and Agreements Officer
IPMP	Intellectual Property Management Plan
M&O	Management and Operating
MPIN	Marketing Partner ID Number
MSI	Minority-Serving institution
MYPP	Multi-Year Program Plan
NDA	Non-Disclosure Acknowledgement
NEPA	National Environmental Policy Act
NNSA	National Nuclear Security Administration
OMB	Office of Management and Budget
OSTI	Office of Scientific and Technical Information
PII	Personal Identifiable Information
RFI	Request for Information
RFP	Request for Proposal
SAM	System for Award Management
SOPO	Statement of Project Objectives
SPOC	Single Point of Contact
TA	Topic Area
TIA	Technology Investment Agreement
TRL	Technology Readiness Level
UCC	Uniform Commercial Code
UEI	Unique Entity Identifier
WBS	Work Breakdown Structure
WP	Work Proposal

APPENDIX C: CO_2 CAPTURE FEED STUDY GUIDANCE

CO_2 Applicants are required to submit summary results of a FEED study for the proposed CO_2 capture technology integrated with the proposed host site. Although the full FEED study is not required to be submitted, DOE may request submittal of the full FEED study and underlying documentation at any point during application review or project execution. Activities include, but are not limited to, those listed below:

1. **Project Scope and Design** that includes research / business objectives and the summary of the proposed project.

2. **Project Design Basis** including, but not limited to site characteristics and ambient conditions, fuel feedstock and exhaust gas characteristics, and host site environmental requirements. The design basis shall clearly identify all permits and environmental reviews necessary to initiate construction. All internal or corporate approvals required by the host site to initiate construction shall be identified.

3. **Engineering Design Package**. Design of the carbon capture system shall result in equipment sizing fully substantiated with kinetic, heat and mass transfer data, as well as justification for choice of materials of construction. The cost estimate shall include preparation of a capital cost estimate, including the cost of capture in $/tonne CO_2 captured, levelized cost of electricity (LCOE) for **TA-1 and TA-2** and levelized cost of product for **TA-3**.

   The FEED shall include, at a minimum: process flow diagrams; carbon capture process model scaled-up for the proposed industrial facility; utility flow diagrams; piping and instrumentation diagrams; heat and material balances; ; final layout drawings; complete engineered process and utility equipment lists; single line diagrams for electrical; electrical equipment and motor schedules; vendor quotations; detailed project execution plans; resourcing and work force plans; a hazard and operability study (HAZOP) review; and a constructability review. The FEED shall incorporate all engineering disciplines necessary to perform the final design and construction, which include, but are not limited: to process, civil, architectural, structural, mechanical, piping, electrical, and control systems engineering.

   Engineering design shall cover both the carbon capture system and balance-of-plant. Balance-of-plant includes, but is not limited to, utilities such as compression, cooling water, water treatment, waste treatment, and the sources of energy, electricity, and/or steam, necessary to power the carbon capture system.

   The latter may include integration of an external energy source (e.g., natural gas-fueled, solar, wind, geothermal) or integration of the carbon capture system into the existing plant. If the carbon capture system is designed to purchase renewable electricity or to generate it on site, then the plant must include a method of energy storage or back-up power generation to supply electricity when renewable electricity is not available.

If the carbon capture system requires co-generation of power or steam for its operation, it must include CO_2 capture, compression, and storage from both the base facility and co-generation plant.

The engineering design package should also cover the integration of the carbon capture process within the industrial facility, including but not limited to the following: novel approaches to recover waste heat from the facility and integrate it with the carbon capture system; and design of pollution control systems upstream of the carbon capture system. If multiple major emission sources exist at the facility, the Applicant should describe whether aggregation of the sources into one stream, upstream of the carbon capture facility, is proposed.

FEED Study – Requirements

It is understood that the content to be included in a Front-End Engineering and Design (FEED) study package is tailored by the type of project and the needs of the owner. Often Engineering and Construction (E&C) firms practicing in a given industry (e.g., power generation or industrial sectors) will have an in-house standard in the absence or lack of owner definition. The goal of any FEED study is for the owner and E&C firm to collaboratively define as much of the project's scope as possible to reduce risk and uncertainty prior to executing the project. Often, Items 1 – 3 of the lists below are provided by the owner to the E&C firm.

The following is a list of content to be included in the FEED study package. Applicants are encouraged to include additional materials outside this list that resulted from the uniqueness of their respective project or the needs of the owner. Applicants are also encouraged to integrate FEED study activities with CBP requirements and activities as appropriate for the project.

1.) Project Background
    a. Discusses Project need or Research/Business Objective
2.) Project Scope
    a. Provides a summary of the proposed project and how it will meet the objective
    b. Provides the system boundaries of the proposed project
3.) Project Design Basis
    a. Site Characteristics
        i. Location, topography, available land, transportation access, available utilities, …
        ii. Community Benefits, including regional analysis of communities and disadvantaged communities, and whether those communities rely on limited resources (e.g., water) that could be impacted by the project. This information should be consistent with the Engagement Plan, EEJ Assessment, and J40 plan.
    b. Site Ambient Conditions
        i. Elevation, atmospheric pressure, temperature averages/extremes, prevailing wind, seismic data, air composition, ….
    c. Fuel Feedstock and Exhaust Gas Characteristics
        i. Design compositional analyses of the fuel (coal, natural gas, etc.)
        ii. Design compositional analyses of the exhaust gas (flow rate, composition, etc.)

d. Environmental and Permit Requirements - as dictated by the authority(s) having jurisdiction (e.g., State DEP, EPA, etc.)
    i. Air emission permitting limitations and required control technologies
    ii. Water discharge permitting limitations and required control technologies
    iii. Waste disposal (e.g., coal ash, spent absorbents, etc.) permitting limitations and required control technologies
e. Site Specific Design Considerations
    i. Flood plain, soil conditions, rainfall/snowfall criteria, building/enclosure permitting, noise regulations, local community requirements (plumes visibility)
f. Modularization Design Requirements

4.) Basic contracting and purchasing strategy

5.) Engineering Design Packages
a. Process Engineering
    i. Process area descriptions
    ii. Block Flow Diagram (BFD), Process Flow Diagram (PFD), and Process & Instrumentation Diagram (P&ID)
    iii. Process simulation output and heat and material balances (H&MB)
    iv. HAZOP/PHA documentation
    v. Major Process Equipment specifications/data sheets
    vi. Equipment and instrumentation lists
        1. Key parameters and their value for equipment costing (i.e., height, diameter, heat duty, delta Temperature, power, materials of construction, etc.)
    vii. Cause and Effect diagrams
    viii. Overpressure Relief/Flare Study
b. Civil Engineering
    i. Soil Load Analysis
    ii. Storm water runoff plan
    iii. Geologic assessment
    iv. Spill containment assessment
c. Structural Engineering
    i. Foundation design drawings (e.g., concrete sonotubes & slabs, helical pillars)
    ii. Structural and Architectural drawings (e.g., process equipment/piping structural supports, access gangways/ladders, building enclosures, etc.)
    iii. Material take-offs
d. Mechanical Engineering
    i. General site plan view(s)
    ii. 3-D model and/or equipment elevation sections & plan drawings
    iii. Piping/tracing/insulation line list and material specification
    iv. Piping isometrics

v. Piping layout/routing drawings

e. Electrical Engineering
   i. Electrical load lists
   ii. One-line diagram(s)
   iii. Electrical equipment (e.g., substation, motor control centers, switchgear) specifications
   iv. Cable/cable tray routing drawings
   v. Lighting drawings
f. Instrumentation & Controls Engineering (System Integration)
   i. Control system architecture specification
   ii. Instrument/equipment lists and specifications
   iii. Loop drawings
   iv. Communications infrastructure (e.g., remote SCADA ability, telephone, internet) specifications
g. Fire Protection Engineering
   i. Fire protection system (e.g., sprinkler, foam, water cannons, etc.) design specifications and drawings
h. Facilities Engineering
   i. Building/Security Infrastructure Plans
      1. Front Office/Administration
      2. Control Room(s)
      3. Maintenance/Shop Area
   ii. HVAC
i. Site Security
j. Logistics
k. Constructability
   i. Construction access
   ii. Lay-down areas
   iii. Sequencing of construction work
l. Project Cost Estimate (~ +/- 15%, AACE Class 3 or similar)
   i. Individual component capital cost (i.e., absorber, regenerator, etc.)
   ii. Breakdown of operating costs
   iii. Overall cost of capture (\$/tonne of CO_2 product)
m. Estimated Project Schedule

APPENDIX D: CO_2 PIPELINE FEED STUDIES

$CO_2$$CO_2$ Applicants are required to submit summary results of a FEED study for the proposed CO_2 Pipeline connecting the CO_2 capture and storage site(s). Although the full FEED study is not required to be submitted, DOE may request submittal of the full FEED study and underlying documentation at any point during application review or project execution.

1. **Project Parameters including, but not limited to:**
   a. Site characteristics and ambient conditions,
   b. Product gas compositions,
   c. Permit list, review agencies, and environmental requirements,
   d. Land use, right-of-way, property boundaries, and title research,
   e. Roads, railroads, utility corridors research,
   f. Project environment, safety and health (ES&H) criteria including pipeline construction and operational impacts to communities and the environment, potential impacts to disadvantaged communities, as well as pipeline failure risk analysis and risk acceptance criteria for pipeline operations.
   g. Unsteady state / downtime / flow assurance / maintenance
   h. Project management plan and an updated risk register.
   i. Overall project schedule in Gantt chart.

2. **Engineering Design Package including, but not limited to:**
   a. A Route Report and Maps, complete with:
      i. A GIS database to house all route and survey information,
      ii. Pipeline route map incorporating aerial photography, property boundaries, right-of-way and workspace, environmental features, elevation profile, hydrological data, pipeline materials, foreign crossings, and others,
      iii. Topographic and crossing investigation/survey including elevation, environmental or population impact, crossing methods, constructability issues, and proposed mitigation and other relevant information at key locations,
      iv. Right-of-way, workspace, land, and access investigation/survey including property ownership, land use types, damage assessment, utility corridors, access points, workspace configurations, and other relevant information at key locations,
      v. Geotechnical and hydrotechnical investigations (desktop or field),
      vi. Wetland and environmental survey/investigation information,
      vii. Cultural and archeological survey/investigation information,
      viii. Population density study and preliminary High Consequence Area (HCA) determination,
      ix. Disadvantaged community designations,
      x. Site selection for aboveground facilities including booster stations, meter stations, launchers and receivers, and mainline block valves,
      xi. Routing critical path.

b. A Design Basis document that covers:
    i. Operating philosophy,
    ii. Codes, standards, specifications, and procedures,
    iii. Design criteria including metallurgical requirements to address ductile fracture propagation,
    iv. Route selection process,
    v. Hydraulic analysis,
    vi. Material selection and pressure design,
    vii. Crossing design,
    viii. Corrosion control,
    ix. Integrity management.
c. Key Design Calculations and Drawings that cover:
    i. Pressure design,
    ii. Maximum Operating Pressure (MOP) determination,
    iii. Hydraulic analysis,
    iv. Pipeline and equipment sizing,
    v. Material take-off,
    vi. Process flow diagram (PFD),
    vii. Preliminary piping and instrumentation diagram (P&ID),
    viii. Power requirements, sources, costs, and timing.
d. Technical Specifications for major materials and activities, including but not limited to pipe, valves, launcher/receiver, facility piping, rotating equipment, static equipment, construction, survey, welding, and others.
e. Preliminary Hazard and Operability Analysis (HAZOP).
f. If converting a pipeline to CO_2 service, a conversion-to-service plan for PHMSA regulatory compliance that includes an integrity assessment plan to demonstrate fitness for service.
g. Additional safety risk assessment
    i. Air dispersion and atmospheric modeling study
    ii. Emergency Response Plan (ERP)
    iii. Use of crack arrestors
    iv. Current state-of-the-art of odorant additives for CO_2

3. **Project cost estimate.** Design of the pipeline system shall support an itemized capital cost estimate consistent with AACE (Association of the Advancement of Cost Engineering) Class 3, or similar, with an expected accuracy range of -10% to -20% on the low side and +10% to +30% on the high side. The cost estimate should include a basis of estimate for each item. Provide a benchmark study for the overall cost estimate if available. Each Recipient is required to submit a pipeline buildout plan with a P-10, P-50 and P-90 project cost analysis based on the acquisition and installation of carbon transport pipeline networks that fulfill the Build America, Buy America Act provisions in the BIL.

APPENDIX E: CO_2 STORAGE FEED AND STORAGE FIELD DEVELOPMENT PLAN

Applicants are required to submit summary results of a FEED study for the proposed CO_2 storage site. Although the full FEED study is not required to be submitted, DOE may request submittal of the full FEED study and underlying documentation at any point during application review or project execution.

The storage complex should have appropriate subsurface characteristics to meet objective, such as large volumes of accessible pore space in laterally extensive storage reservoirs overlain by regionally extensive seals to protect against adverse environmental impacts.

The Storage Field Development Plan should: (1) explain the strategy for developing the storage field to maximize its potential utility; (2) describe all elements of the proposed storage field facilities and establish a logical order and timing for the development of all anticipated facilities, accounting for changing needs for monitoring and use of pore space and changing CO_2 delivery rates over time; and (3) present a cost plan over the proposed life of the project. It is expected that the facilities description within the Storage Field Development Plan would be based on information associated with the relevant permits (e.g., UIC or OCS permit application and associated permit terms and conditions, NPDES permit, monitoring well permits, site access road permit), along with regulatory rules and guidance. The Plan should include, if relevant, the assessment and repurposing or plugging of legacy wells and other existing infrastructure. It is understood that this Plan will be only a draft or preliminary until after relevant permits are received, financing is arranged, and other considerations are settled.

There are several major cost categories related to the development of a CO_2 storage site, including wells, infrastructure, compression, and monitoring deployment. Each of these will bring their own cost uncertainty due to outside influences such as oilfield contractor demand, steel price, supply chain disruptions, and inflation. To set the correct expectations, each Plan is required to include a project cost breakdown with a P-10, P-50 and P-90 project cost analysis. Project risks and their effect on cost should be clearly explained. In addition, each proposed well should have a full Authorization for Expenditures (AFEs) with cost uncertainty ranges defined for each line item.

The Storage Field Development Plan should additionally report the progression of the storage resource status through Prospective, Contingent, and Capacity based on the SRMS guidelines described at SPE CO_2 Storage Resource Management System (SRMS). Projects should follow the SRMS process to classify the status of the storage resource(s). The estimated classification of the resource(s) and capacity(ies) will be used by DOE to demonstrate how IIJA-funded projects are increasing storage capabilities in the U.S.

Suggested contents of the Storage Field Development Plan are described below. Please note however that DOE will accept the Plan in whatever format is company standard for the Applicant/Recipient, assuming that the Plan has all needed information to understand the build-out, operations and costs for the planned storage of CO_2.

Suggested contents of the Field Development Plan:

1. **Executive Summary**
2. **Legal Considerations and Rights**
    - Pore/Surface Rights
    - Rights of Way and Easement
    - Liability Relief
    - Procurement Plan (as needed)
3. **Storage Development Description and Rationale for Development Plan**
    - Field Characterization Results
    - Seismic Interpretation and Structural Configuration
    - Geological Interpretation and Reservoir Description, including:
        - Stratigraphy
        - Structure and Dip
        - Porosity
        - Permeability
        - Minerology
        - Saturations
        - In-Situ Stress State
        - Geochemistry
        - Fault Zone Presence and Characteristics
        - Cap Rock Characteristics
    - Petrophysics
    - Well logs
    - Coring and Core analysis plans
    - Special Core Analysis (SCAL)
    - Volumetrics by segment
    - Aquifer strength
    - Reservoir Pressure, Temperature, and Reservoir Fluids
    - Reservoir Units and Modelling Approach
    - Injection Rate and Mass Over Time
    - Area of Review Calculation
    - Legacy Well Evaluation
    - Well test (DST) plans / Injectivity testing
    - Reservoir fluid characterization plans
    - Geomechanics testing
4. **Development and Management Plan**
    - Development Plan / Well layout
    - Well Construction and Legacy Well Mitigation Plans
    - Completion design
    - Rig scheduling / drill well timing
    - Injection Facilities
    - Monitoring Plan (Seismic, Pressure, Temperature, etc.)
    - Injection Operations

- Flow Assurance Operations
- Decommissioning & PISC Plan
- Costs (AACE Class 3 or other as appropriate)
    - Pre-Project Costs (Seismic, Exploration Drilling, Appraisal Drilling, Studies)
    - Drilling and completion of wells (including future recompletes)
    - Assessment and repurposing or plugging of legacy wells, pipelines and other existing infrastructure
    - Facilities
    - Flow Assurance
    - Field OpEx, excluding tariffs
    - Decommissioning & PISC costs
- Project Risks & Mitigations (e.g., faults and potential for induced seismicity or leakage as well as the natural seismicity)
- Storage Management Plan

APPENDIX F: STATE-POINT DATA TABLES

***Instructions for completing data tables*:** The tables that follow in this attachment shall be populated with data provided by the Applicant. Applicants proposing projects shall complete the appropriate combinations of Tables 1, 2 and 3 that relate to their proposed process concept. *Merit scoring of application will correspond to the completeness of the data table and supporting information.*
Key data or estimates provided in the table(s) shall be supported with short narratives in bullet form within the Scientific and Technical Merit section. These bullets shall describe the sources for the individual data provided. This may be measurements made directly by the Applicant and shall identify the apparatus and methodology used in the measurement(s). Due to page limitations, citations may be utilized to describe the sources for the individual data provided by the Applicant or others, or by example calculations for noncritical data. Other acceptable sources of data are the open literature (with citation and description), or estimated or extrapolated data (with description of method/model used for the estimate, or the procedure used for extrapolation). Arguments supported by theory/mechanisms shall be provided for projected performance for new, advanced solvent, sorbent, or membrane materials.

For **TA-1,** Applicants are required to provide the demonstrated performance data for their solvent, sorbent, or membrane technology. Applicants shall prepare the State Point Data Table for coal-based relevant exhaust gas conditions. Applicants should substantiate performance of the proposed technology by providing pilot-scale validation (i.e., total system) with coal relevant exhaust gas conditions.

For **TA-2**, Applicants are required to provide the demonstrated performance data for their solvent, sorbent, or membrane technology. Applicants shall prepare the State Point Data Table for natural gas relevant exhaust gas conditionsCO_2. Applicants should substantiate performance of the proposed technology by providing pilot-scale validation (i.e., total system) with NG relevant exhaust gas conditions.

For **TA-3**, Applicants are required to provide the demonstrated performance data for their solvent, sorbent, or membrane technology. Applicants shall prepare the State Point Data Table for exhaust gas conditions similar to the ones in the selected industrial application. Applicants should substantiate performance of the proposed capture technology by providing pilot-scale validation (i.e., total system) with actual exhaust gas having a similar CO_2 concentration as to the one in the selected industrial application.

Table F1. State-Point Data for Solvent Based Systems

	Units	Measured/ Estimated Performance	Projected Performance
Pure Solvent			
Molecular Weight	mol^{-1}		
Standard Boiling Point	°C		
Standard Freezing Point	°C		
Vapor Pressure @ 15°C	bar		
Working Solution			
Concentration	kg/kg		
Specific Gravity (15 °C/15 °C)	-		
Specific Heat Capacity @ STP	kJ/kg·K		
Viscosity @ STP	cP		
Surface Tension @ STP	dyn/cm		
CO_2 Mass Transfer Rate [K_L]	m/s		
CO_2 Reaction Rate	-		
Thermal Conductivity	W/(m·K)		
Absorption			
Pressure	bar		
Temperature	°C		
Equilibrium CO_2 Loading	gmol CO_2/kg		
Heat of Absorption	kJ/kg CO_2		
Solution Viscosity	cP		
Desorption			
Pressure	bar		
Temperature	°C		
Equilibrium CO_2 Loading	gmol CO_2/kg		
Heat of Desorption	kJ/kg CO_2		
Pilot Scale Data			
Location			
The following information should be provided for the longest steady-state duration test performed at pilot scale			
Scale	tCO_2/year		
Duration of Long-Term Test (consecutive hours)	hr		

CO_2 concentration in the feed stream (e.g., flue gas, process stream)	Mol %		
Carbon Capture Efficiency	%		
Solvent Make-up rate	%/yr		
Reboiler Duty	KJ/Kg CO_2		
Details on solvent reclamation or refreshing			
CO_2 Product Purity	Mol % dry		
CO_2 Product Oxygen Concentration	Mol% (or ppm)		

***Definitions for Table 1*:**

- *STP* – Standard Temperature and Pressure (15 °C, 1 atm)
- *Pure Solvent* – Agent(s), working alone or as a component of a working solution, responsible for enhanced CO_2 absorption. For example: the amine monoethanolamine (MEA) in an aqueous solution.
- *Working Solution* – The solute-free (*i.e.,* CO_2-free) liquid solution used as the working solvent in the absorption/desorption process. For example: the liquid mixture of MEA and water.
- *Absorption* – The conditions of interest for absorption are those that prevail at maximum solvent loading, which typically occurs at the bottom of the absorption column. Measured data are preferable to estimated data.
- *Desorption* – The conditions of interest for desorption are those that prevail at minimum solvent loading, which typically occurs at the top of the desorption column. Operating pressure and temperature for the desorber/stripper are process dependent. Measured data are preferable to estimated data.
- *Pressure* – The pressure of CO_2 in equilibrium with the solution. If the vapor phase is pure CO_2, this is the total pressure, and if it is a mixture of gases, this is the partial pressure of CO_2.
- *Concentration* – Mass fraction of pure solvent in working solution.
- *Loading* – The basis for CO_2 loading is moles of pure solvent.
- *Mass Transfer Rate* – Overall liquid phase mass transfer coefficient.
- CO_2 *Reaction Rate* – A characterization of the CO_2 absorption trend with respect to time, as complete in the range of time as possible.
- Details on solvent reclamation or refreshing – Include information about reclamation rates or solvent replacement/refreshing during the long-term test.
- CO_2 Product Purity – Average purity of the CO_2 product from the capture system during the long-term testing.
- CO_2 Product Oxygen Concentration – Oxygen content of the CO_2 produced during the long-term testing.

Table F2. State-Point Data for Sorbent Based Systems

	Units	Measured Performance (Powder form)	Projected or Measured Performance (structured material system)
Sorbent			
True Density @ STP	kg/m^3		
Bulk Density	kg/m^3		
Average Particle Diameter	mm		
Particle Void Fraction	m^3/m^3		
Packing Density	m^2/m^3		
Solid Heat Capacity @ STP	kJ/kg·K		
Crush Strength	kg_f		
Attrition Index	-		
Thermal Conductivity	W/(m·K)		
Adsorption			
Pressure	bar		
Temperature	°C		
Equilibrium Loading	gmol CO_2/kg		
Heat of Adsorption	kJ/gmol CO_2		
CO_2 Adsorption Kinetics	gmol/time		
Desorption			
Pressure	bar		
Temperature	°C		
Equilibrium Loading	gmol CO_2/kg		
Heat of Desorption	kJ/gmol CO_2		
CO_2 Desorption Kinetics	gmol/time		
Pilot Scale Information			
Location			
The following information should be provided for the longest steady-state duration test performed at pilot scale			
Scale	tCO_2/year		
Duration of Long-Term Test (consecutive hours)	hrs		
CO_2 concentration in feed stream (e.g., flue gas, process stream)	%		
Carbon Capture Efficiency	%		

Cycle Time	Hr		
Sorbent Make-up rate	%/yr		
Details on sorbent reactivation or refreshing			
Heat Duty	KJ/Kg CO_2		
CO_2 Product Purity	Mol % dry		
CO_2 Product Oxygen Concentration	Mol% (or ppm)		

***Definitions for Table 2*:**

- *STP* – Standard Temperature and Pressure (15 °C, 1 atm)
- *Sorbent* – Adsorbate-free (*i.e.,* CO_2-free) and dry material as used in adsorption/desorption cycle.
- *Adsorption* – The conditions of interest for adsorption are those that prevail at maximum sorbent loading. Measured data are preferable to estimated data.
- *Desorption* – The conditions of interest for desorption are those that prevail at minimum sorbent loading. Operating pressure and temperature for the desorber/stripper are process dependent. Measured data are preferable to estimated data.
- *Pressure* – The pressure of CO_2 in equilibrium with the sorbent. If the vapor phase is pure CO_2, this is the total pressure, and if it is a mixture of gases, this is the partial pressure of CO_2.
- *Packing Density* – Ratio of the active sorbent area to the bulk sorbent volume.
- *Loading* – The basis for CO_2 loading is mass of dry sorbent.
- *Kinetics* – A characterization of the CO_2 adsorption/desorption trend with respect to time, as complete in the range of time as possible.
- Cycle Time – time for entire absorption and regeneration cycle utilized during long term testing
- Details on sorbent reactivation or refreshing – Include information about reactivation process and rates or sorbent replacement during the long-term test
- CO_2 Product Purity – Average purity of the CO_2 product from the capture system during the long-term testing
- CO_2 Product Oxygen Concentration – Oxygen content of the CO_2 produced during the long-term testing

Table F3. State-Point Data for Membrane Based Systems

	Units	Measured/ Estimated Performance	Projected Performance
Materials Properties			
Materials of Fabrication for Selective Layer			
Materials of Fabrication for Support Layer (if applicable)			
Nominal Thickness of Selective Layer (μm)			
Membrane Geometry			
Max Trans-Membrane Pressure	bar		
Hours tested without significant degradation			
Membrane Performance			
Temperature	°C		
Pressure Standardized Flux for Permeate (CO_2)	GPU or equivalent		
CO_2/H_2O Selectivity	-		
CO_2/N_2 Selectivity	-		
Type of Measurement (Ideal or mixed gas)	-		
Proposed Module Design			
Flow Arrangement	-		
Packing Density	m^2/m^3		
Shell-Side Fluid	-		
Pilot Scale Information			
Location			
The following information should be provided for the longest steady-state duration test performed at pilot scale			
Scale	tCO_2/yr.		
CO_2 concentration in feed stream (e.g., flue gas, process stream)	%		
Duration of Long-Term Test (consecutive hours)	hrs		
Average CO_2 capture Efficiency	%		
Starting CO_2 Capture Efficiency	%		

***Definitions for Table 3*:**

- *Membrane Geometry* – Flat discs or sheets, hollow fibers, tubes, etc.
- *Pressure Standardized Flux* – For materials that display a linear dependence of flux on partial pressure differential, this is equivalent to the membrane's permeance.
- *GPU* – Gas Permeation Unit, which is equivalent to 10^{-6} $cm^3/(cm^2 \cdot s \cdot cmHg)$ at 1 atm and 0 °C. For non-linear materials, the dimensional units reported shall be based on flux measured in $cm^3/(cm^2 \cdot s)$ (at 1 atm and 0 °C) with pressures measured in cm Hg. Note: 1 GPU = 3.3464×10^{-6} $kgmol/(m^2 \cdot s \cdot kPa)$ [SI units]
- *Type of Measurement* – Either mixed or pure gas measurements; projected permeance and selectivities shall be for mixture of gases found in de-sulfurized exhaust gas.
- *Flow Arrangement* – Typical gas-separation module designs include spiral-wound sheets, hollow-fiber bundles, shell-and-tube, and plate-and-frame, which result in either co-current, counter-current, crossflow arrangements, or some complex combination of these.
- *Packing Density* – Ratio of the active surface area of the membrane to the volume of the module.
- *Shell-Side Fluid* – Either the permeate or retentate stream.
- Details on membrane reactivation or replacement – Include information about reactivation process and rates or membrane replacement during the long-term test
- Starting CO_2 Capture Efficiency – Capture efficiency achieved in the first hour of long-term testing
- Ending CO_2 Capture Efficiency – Capture efficiency achieved in the last hour of long-term testing
- CO_2 Product Purity – Average purity of the CO_2 product from the capture system during the long-term testing
- CO_2 Product Oxygen Concentration – Oxygen content of the CO_2 produced during the long-term testing
- Membrane Feed Pressure – Pressure of gas fed to the membrane for separation during the long-term test. *Repeat this parameter for each stage of membrane used during the long-term test
- Permeate Pressure – Pressure of the corresponding permeate of the membrane that accounts for the trans membrane pressure drop and any vacuum used. * Repeat this parameter for each stage of membrane used during the long-term test

APPENDIX G: BASIS FOR CCS TECHNOLOGY EH&S ASSESSMENT

An assessment of EH&S risks is required with the application and as part of the deliverables for each Go/No-Go review. Unanticipated or uncontrolled EH&S risks will impede commercialization of CCS technologies, and the EH&S assessment is a critical element of the demonstration projectCO_2 An updated EH&S assessment at the of end of Phase 1, shall be coordinated with the FEEDs for capture, pipeline, storage system. Final EH&S assessment at the end of Phase 4 needs to be updated with data collected during the operation phase of the project. The EH&S risk assessment shall be conducted by qualified and experienced organizations and professionals (*e.g.,* environmental scientists, industrial hygienists, safety engineers).

Required elements for the EH&S Assessment are:

1) All potential ancillary or incidental air and water emissions, and solid wastes produced from the proposed technology shall be identified and their magnitude estimated. In addition to solvents or sorbents used, researchers shall consider possible by-products of side reactions that might also occur in the system, accumulated waste products, and the fate of contaminants from the feed gas stream. Environmental degradation products shall be addressed. Accumulation, soil mobility, and degradability shall be considered. Conditions at the point of discharge shall be examined.

2) If possible, a concise but complete and comprehensible description of the various toxicological effects of the substances identified in (1) above shall be provided. A thorough literature search shall be conducted to examine potential human health effects and ecotoxicity. Where information is lacking for a particular material, it shall be compared to similar substances or classes of substances.

3) Properties related to volatility, flammability, explosivity, other chemical reactivity, and corrosivity shall also be collected from existing databases or if necessary, through direct measurement in cases where the substance is not in common use.

4) The compliance and regulatory implications of the proposed CCS technology shall be addressed with reference to applicable U.S. EH&S laws and associated standards including the Comprehensive Environmental Response and Liability Act of 1980, Toxic Substances Control Act, Clean Water Act, Clean Air Act, Superfund Amendments and Reauthorization Act Title III, and the Occupational Safety and Health Act.

5) An engineering analysis shall be conducted for any potentially hazardous materials identified to look for ways their use can be eliminated or minimized. Less hazardous materials should be substituted where possible. For any new materials being proposed, synthetic options shall be examined that may lead to similar, less-hazardous compounds with the required functionality. Possible engineering controls and other mitigation strategies shall be described as appropriate.

6) Precautions for safe handling and conditions for safe storage shall be identified, including any incompatibilities with other materials that may be used in the process. Waste treatment and offsite disposal options shall be examined. Accidental release measures shall also be discussed.

APPENDIX H: BUSINESS CASE ANALYSIS

The business case analysis demonstrates an understanding of the current and projected landscapes of this CCS demonstration project, any future deployment projects, and the potential utilization of tax credits including their projected revenue and duration.

The first section of the business case analysis should identify the potential market size of a technology option proposed by the Applicant. The analysis will contain a business case analysis, technical overview; market analysis; future deployment projection; and quantification of potential benefits of the technology.

An outline of each of the five major pieces of the analysis are as follows:

Business Case Analysis

a. A *pro forma* which quantifies the projected financial parameters such as operating costs, operating revenues, financing cash flows, EBITDA, tax credits/liabilities, ROI, and IRR over the project lifespan. The Business Case Analysis should also include a list of key economic/financial assumptions.

Technical Overview

a. Description of the technology and potential applicability across the coal, natural gas, and industrial point source sector area.

Market Analysis

a. Survey of relevant carbon emission point sources
b. Applicability of technology to these sources
c. Financial analysis of application of the technology to these sources
d. Discussion of potential financing structures and partnerships for deployment of the technology
e. Discussion of the potential utilization of tax credits and other incentives, including projected revenue and duration

Future Deployment Projection

a. Provide the potential deployment scale of the technology across the current and future coal, natural gas, and industrial point source sector
b. Identify and compare competing technology options
c. Discussion of potential barriers to large scale deployment
d. Discuss steps that will be taken during the proposed project to enable future deployment of the technology.

Quantify Potential Benefits of the technology

a. Provide estimates of the potential benefits of large-scale deployment in terms of metrics such as manufacturing jobs, revenue, emissions reductions, etc.

APPENDIX I: PROJECT FINANCING PLAN

Applicants must present a viable plan to obtain funding for the entire non-DOE share of the total project cost in the form of a **Project Financing Plan** that identifies all sources of project funds.

For non-federal cost share commitments that are in the form of cash, each provider must present audited financial statements for the prior year and all unaudited interim financial statements for the current year. If audited financial statements are not available, the financial statements presented must be certified by the Chief Financial Officer of the organization that the statements were prepared on the basis of U.S. Generally Accepted Accounting Principles (US GAAP). Each provider must describe how the financial statements evidence the capacity of the provider to supply their committed cost share.

For non-federal cost share commitments that are not in cash, provide a full description of the commitment and justification for the qualification of such commitment as non-federal cost share. Provide supporting evidence regarding the value of the non-cash commitment.

Applicant must certify in writing that all non-federal cost share will come from qualified sources.

The **Project Financing Plan** shall be based on a business plan for the development, construction, and operation of the project. Describe the strategies and tactics to be deployed to secure funding for the project. DOE notes that not all funding needs to be available at the start of the project, but the plan should clearly show when all funding will be available to meet project needs. The Plan must be based on assumptions that are consistent with other materials in the application.

If project finances are expected to include benefits from Section 45Q federal income tax credits (or other Federal or State tax credits), describe the way the value from the credits will be derived. State whether the credits will be used by the Applicant or an affiliate or if tax equity will be engaged to monetize the tax benefits for the benefit of the project. State whether any 45Q tax credits are planned to be allocated to the CO_2 storage site operator. Ensure the financial model appropriately shows the projected financial impacts of 45Q tax credits and other tax benefits through at least the end of the 45Q tax credit earning period, or the life of the project, whichever is longer.

Project Parties. A description of the main parties (developers, owners, investors) to the project, including background, ownership and experience, proposed financial contribution to project, and expected financial benefit to each party of the project.

Project Assumptions. A description and explanation for each of the financial, economic, and operating assumptions for the project. The assumptions should be consistent with and supported by other documents in the application materials.

Contracts and Agreements. A description of all contracts, agreements, permits, licenses, etc., that will need to be established or obtained to finance the project. Also describe agreements to be entered into regarding the operation of the project and any related responsibilities of the Project Parties.

Financial Projections. Financial projections should be presented on an annual basis, commence with the initial project Phase, and extend to the end of the life of the facility. Projections should include a statement of revenues and expenses (income statement), balance sheet, and cash flow statement (sources and uses of funds). In addition, a cashflow waterfall schedule should be included as well as projections of annual net cash flows (for purposes of calculating NPV and IRR). The projections should be adequately supported. The statements and schedules should be prepared using Excel software and the Excel-based model should be provided in electronic format including cell formulas so that review of the model assumptions and calculations may be facilitated. The financial model should be included in the application as an attachment named “PFP.pdf”.

Financial Commitments. The Applicant must discuss the priority placed by their teams’ respective management on financing the project. This should include a discussion of management’s decision to: (1) allocate internal resources, (2) obtain recourse financing, or (3) obtain limited or non-recourse project financing. The degree of commitment to the project will be measured in part by the level of financial commitment assumed by project team members. The project team can also demonstrate its commitment by: (A) sharing in project costs above the Government’s minimum requirements and (B) agreeing to cover potential project cost increases.

Limited Recourse Project Financing. For projects employing non-recourse or limited recourse debt financing, provide a description of the Applicant’s approach to, and the status of, such financing. Include copies of available funding commitments, draft Term Sheets, or expressions of interest from funding sources an attachment named “PFP.pdf”.

Equity: If tax credit equity is part of the financing plan, provide a description of the structure of the legal arrangements either in place or contemplated. Project when tax equity contributions to pay project costs will be made. List prospects for other equity investors and include progress to date in gaining interest in the project by such investors.

The Applicant should include commitment letters to provide funds in accordance with the terms of this funding opportunity announcement. Commitment letters must be issued by each organization that is slated to provide funding. The funds must be committed in accordance with the terms of this funding opportunity announcement and consistent with the application. The commitments should state the amount of funds to be provided, the fact that the funds are non-federal cost share, the relationship of the funding source to the Applicant, the timing of funding, and any caveats, restrictions, limitations or the like. Commitments to provide funds shall be submitted in a letter signed by an officer of the corporation or other entity that is qualified to commit the funding to the proposed project.

Commitment letters must identify the type of proposed cost sharing (e.g., cash, services, and/or property) to be contributed. If property or services are proposed, the Applicant should provide support for their valuation and explain how valuation was determined. If a property appraisal is used, the Applicant should provide a copy and an explanation of whether the property values used are acquisition, book, or replacement costs.

Commitment letters from the Applicant and third parties should be provided in an attachment named "CSCL.pdf". Save this information in a single file named "CSCL.pdf" and click on "Add Optional Other Attachment" to attach with OCED eXCHANGE.

Contract Bonding Practices. For proposed construction contracts or subcontracts, the Applicant must explain its contract bonding and/or surety/guarantor practices and how they will be applied if their application is accepted for Federal funding.

Financing Schedule. A tentative schedule of dates and events that comprise the financing efforts must be provided. The schedule shall include, to the extent possible, key project dates such as signing of the EPC contract, negotiating Purchase and Sale agreements, finalizing the Operations and Maintenance Agreement, and the target date for financial closing for construction.

Applicants are required to provide sufficient contingency reserve to support the project. The amount of contingency will be determined based on the quantitative risk analysis. Applicants must demonstrate that they can meet unexpected financial needs of the project. The full design package needed by the end of Phase 2 in order to advance to Phase 3 must also include documentation showing that the recipient has access to the required contingency. Typically, DOE expects contingency funds must be: (a) liquid, (b) immediately available, and (c) unrestricted funds dedicated exclusively to the project for the purpose of mitigating project performance baseline risk. Resources that have other requirements that must be met or subject to other constraints, such as performance guarantees, cannot count towards the contingency requirement. The contingency reserve is in addition to total project costs and cannot count towards cost share, until expended and with DOE's consent. If expended, the contingency will not result in reimbursement by DOE above the total federal share approved in the award. DOE discourages Applicants from reducing scope to comply with the contingency reserve requirement.

APPENDIX J: LIFE CYCLE ANALYSIS

Applicants will submit an initial Life Cycle Analysis (LCA) with their application. An updated LCA is required at the end of Phase 2.

The Life Cycle Analysis (LCA) shall be conducted to demonstrate the potential environmental impacts of capturing a minimum of 90% of unit-wide carbon dioxide (CO_2) emissions and storing the captured CO_2 in secure subsurface geologic formations. The scope of the LCAs for areas TA-1 and TA-2 is cradle-to-delivered electricity, inclusive of transmission of the electricity to the final customer. For combined heat and power (CHP) facilities, the scope will also include the exported heat.

Under TA-3, the scope of LCA is cradle-to-gate, where the gate is defined as the production of industrial products ready for transport from the industrial facility.

Initial LCA Guidance

1. Applicants shall provide a screening-level, greenhouse-gas only analysis with scopes and functional units as defined above for TAs 1, 2, and 3 and a contribution analysis showing at a minimum the impacts from fuel extraction and delivery, plant direct emissions, and CO_2 transport and storage.
2. The documentation and report do not necessarily need to follow the NETL CO2U LCA Guidance Document, but all sources of life cycle inventory should be clearly documented in the application.
3. Applicants must use NETL data where possible. Any alternative sources of life cycle inventory will need to be justified. The following is a list of NETL life cycle inventory data sources:
    a. Upstream dashboard version 3
    b. Grid Mix Explorer 4.2
    c. NETL CO2U openLCA LCI Database Version 2.1 (or latest)
    d. NETL CO2U Documentation Spreadsheet

LCA Guidance

1. TA-1 and TA-2
    a. Required life cycle inventory data:
        i. Energy inputs to the facility including fuels and electricity
        ii. Combustion emissions at the facility
        iii. Chemical inputs to the facility

iv. Construction of the facility and manufacturing impacts for the required materials/equipment (e.g., structural steel, concrete, etc.)

v. Carbon dioxide transport and saline aquifer storage life cycle inventory values (gate-to-grave emissions data to be used for all projects using saline storage) are available in the NETL CO2U openLCA LCI Database [Version 2.1 (or latest)] and the NETL CO2U Documentation Spreadsheet as "Saline aquifer transport and storage"

vi. Electricity transmission and distribution life cycle inventory values (gate-to-gate emissions data to be used for TA-1 and TA-2 life cycle modeling projects):

1. Sulfur Hexafluoride 7.87E-05 kg/kg CO_2 stored

2. Electricity transmission and distribution electricity loss rate to be used for TA-1 and TA-2 life cycle modeling projects are determined by state from the table below (derived from EIA State Electricity Profiles):

State	T&D Loss Rate	State	T&D Loss Rate	State	T&D Loss Rate
AL	3.5%	LA	5.3%	OH	5.3%
AK	5.5%	ME	5.2%	OK	4.3%
AZ	4.2%	MD	5.3%	OR	4.5%
AR	4.7%	MA	5.3%	PA	3.5%
CA	5.3%	MI	4.9%	RI	4.7%
CO	5.3%	MN	5.3%	SC	4.4%
CT	3.7%	MS	4.0%	SD	5.0%
DE	5.3%	MO	5.3%	TN	5.3%
FL	5.3%	MT	3.5%	TX	5.2%
GA	5.3%	NE	4.8%	UT	4.8%
HI	5.6%	NV	5.3%	VT	1.8%
ID	5.3%	NH	3.7%	VA	5.3%
IL	4.4%	NJ	5.3%	WA	4.0%
IN	5.3%	NM	4.1%	WV	3.2%
IA	4.9%	NY	5.2%	WI	5.3%
KS	4.0%	NC	5.3%	WY	2.1%
KY	5.3%	ND	2.4%		

b. LCA results:

i. TAs 1 and 2 shall be normalized to 1 MWh of electricity.

ii. A contribution analysis shall be provided so that impacts can be differentiated by major operation/input.

iii. A sensitivity analysis shall be provided for key model inputs with known technical variability and/or expected variability from different site-specific commercialization scenarios.

c. Emissions scope:

i. The scope of environmental impacts shall include all the additional impact categories listed in Section 2.1.8.2 of the NETL CO2U LCA Guidance Document. To accomplish this the environmental inventory will need to include data beyond greenhouse gas emissions, as discussed in Section 2.2.2.2 of the NETL CO2U LCA Guidance Document.

ii. For GHG emissions, the global warming potential shall be reported using the 100-year global warming potential (GWP) characterization factors as the default values from the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) and the Fifth Assessment Report (AR5), sensitivity cases using the 20-year GWP values is encouraged:

Table J.1. GWP Characterization Factors

GHG	AR4 (IPCC 2007)[12]		AR6 (IPCC 2013)[13]	
	100-year (Default)	20-year	100-year (Default)	20-year
CO_2	1	1	1	1
CH_4	25	72	36	85
N_2O	298	289	298	264
SF_6	22,800	16,300	23,500	17,500

Note: These GWP characterization factors may be updated by NETL to reflect the latest science.

d. Resources – NETL has tools that may be helpful in completing the LCA requirement. These tools are not exhaustive but can be used to provide some life cycle inventory data for some energy and material inputs. The following resources are recommended:

i. General LCA guidance – NETL CO2U LCA Guidance Document

ii. NETL Life Cycle Inventory Data – NETL CO2U openLCA LCI Database

iii. Electricity Consumption LCI Data – NETL Grid Mix Explorer

[12] IPCC (2007). Climate Change 2007: The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 16, 2020, from https://www.ipcc.ch/report/ar4/wg1/

[13] IPCC. (2013). *Climate Change 2013 The Physical Science Basis*. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

e. LCA Submission Requirements for Final Project Deliverables

i. LCA Report – see NETL CO2U LCA Guidance Document, Chapter 6 "Completing the NETL CO_2U LCA Report Template"

ii. LCA Model with Life Cycle Inventory Data – see NETL CO2U LCA Guidance Document, for modeling guidance (no specific LCA software type is required)

f. List of all licensed LCA data used within the model with external reviewer limited-license access for DOE review

2. TA-3 for Industrial Facilities

a. System Boundary: cradle-to-gate where the gate is defined as the production of industrial products ready for transport from the industrial facility. The transport and geologic storage of captured carbon dioxide is included within the system boundary of TA-3. The transportation, use, and end-of-life management of the industrial products is excluded from the life cycle system boundary for TA-3.

b. Reporting Metric: kg of CO_2e/unit of industrial product produced.

i. "unit of industrial product produced" shall be replaced with quantity of products produced from the industrial operation referenced to 1 unit of the primary product of interest. This will result in multi-product functional unit.

3. Assignment of environmental burdens to a single product of value may be reported as secondary reporting metric. The method for assigning environmental burdens to multiple products shall be clearly documented and follow the guidance outlined in the NETL CO2U LCA Guidance Document, see Guidance Document Appendix C "Alternative Co-product Management Methods".

APPENDIX K: PROJECT MANAGEMENT PLAN GUIDANCE

A Project Management Plan is required for implementing the proposed project and achieving the objectives of the Announcement. The Project Management Plan establishes the baseline for the scope, schedule, and budget for the project and shall include the information given below.

- A Work Breakdown Structure to at least four levels identifying tasks to be performed;
- A Project Schedule for the entire project at the task level of detail. The Project Schedule shall follow the task structure of the Work Breakdown Structure. The schedule should include technical, business, financial, permitting and other factors to substantiate that the project will achieve the objectives of the Announcement in a timely manner. The schedule should include milestones and decision points; including a Milestone Plan to serve as the baseline for tracking performance of the project and will identify critical path project milestones for the entire project;
- A Baseline Cost Plan to establish the budget for accomplishing the planned work. The Baseline Cost Plan should identify the planned cost for each task on a monthly basis. The Baseline Cost Plan should follow the task structure of the Work Breakdown Structure;
- A description of the project management system to be used for monitoring and control of scope, schedule, and cost including the methodology and implementation of reporting earned value;
- Project Communication Protocol, to establish the frequency and type of communication between the Recipient and DOE, dependent on the complexity, value, and program significance of the project, to ensure the team has the information necessary to affect timely and effective project management. Under the award, DOE will require specific periodic technical and financial reporting as part of its Substantial Involvement;
- A Risk Management Plan that includes a summary description of the proposed approach to identify, analyze, and respond to perceived risks associated with the proposed project. Project risk events are uncertain future events that, if realized, impact the success of the project. As a minimum, include the initial identification of significant technical, resource, and management issues that have the potential to impede project progress and strategies to minimize impacts from those issues;
- An Environmental Management Plan (EMP) to establish a protocol for managing the potential environmental impacts of the project. The EMP shall establish protocols for monitoring, and reporting the potential environmental impacts to air, land and water resources, and potential impacts of waste production.

APPENDIX L: BLOCK FLOW DIAGRAM AND SUPPLEMENTAL DATA

INSTRUCTIONS OVERVIEW

NOTE: The Block Flow Diagram (BFD) & Supplemental Data (SD) template is provided as a convenient method of documenting the information required to accurately assess the projects proposed in response to this FOA. Some of this information may already be present in pre-FEED and FEED studies, it should be extracted and compiled here for assessment. The use of the BFD & SD template is not required, but the data elements presented within the BFD & SD template are required.

<u>Instructions and Overview:</u>
The purpose of the BFD & SD is to assess the merits of the selected technology and the status of the process technology in order to gain an understanding of project risks and the potential viability of the proposed project. Please answers all questions as thoroughly as possible based on current knowledge.

Please include a BFD for the entire proposed project. Similarly, please provide the filled out Supplemental Data Template (or equivalent data) for the unit operation(s) that are detailed in the proposed project's BFD.

It is expected that Applicants describe previously collected data from pilot-scale testing that will be utilized during the proposed project to design, construct, and operate the proposed commercial-scale demonstration. Pay particular attention to the proposed engineering-scale equipment when answering the questions below for each unit operation. The attached BFD & SD should relate to the proposed project.

Unit Operation Step: Unit operation steps are defined as the areas in the facility where a change occurs, such as reactions, physical changes to materials including materials handling, or chemical conversions. (A physical step physically alters material, and a chemical conversion step involves changes in the molecular form of a material.) Some examples of items to be included as unit operation steps appear below:

Production and Capture Systems

Reactors	Filters	Drying
Distillation	Ion Exchange	Gas Cleanup
Aerators	Gas Absorption	Separations

Pipeline and Reservoir

Compressors	Pumps	Drying
Separators	Wellbore	Reservoir Segments

Use a unique number for each unit operation in the BFD. Show recycle loops and waste streams as well. The characteristics of each output should directly tie to input of the respective unit operation in the process. If additional processing is required before the output of one unit can be used as the input to another, an additional unit operation should be included to describe how the stream is altered. It is particularly important to focus on the energy and material balance of each block step. The description of the process should begin with the first manipulation of the process feed in its as-received condition, such as exhaust gas following any pre-existing (non-project related) treatment operations already in line at a facility. CCS deployment has the potential to reduce emissions of other kinds of pollution in addition to CO_2 pollution, so data related to this effort should be captured where applicable. Sources of energy inputs should be identified whether it is coming from heat integration, grid, solar, etc.

<u>Block Flow Diagram & Supplemental Data Template</u>

Provide the following information for the entire process shown in the BFD

1. How and why were the proposed process and operating locations chosen? Discuss technical and business risks, benefits and opportunities associated with the process and operating locations.
2. Describe the history of pilot scale development performed by the Applicant for the proposed process including scale, duration of runs, type of data collected, etc. For the most relevant pilot test, describe the carbon capture technology components that were tested [i.e., both the equipment and capture media (e.g., the specific solvent, sorbent, or membrane)], the degree to which they were integrated during testing, and how the components differ (or not) from the components that would be tested under the proposed demonstration,"
3. Describe the reservoir characteristics and production history of the site.

Answer the following questions for <u>each unit operation</u> in your BFD

1. Name or title (as shown in the BFD)
2. Description of the PROPOSED unit operation

   For each unit operation include operating conditions including (but not limited to):

   1) Materials of construction
   2) Capacity and/or throughput
   3) Operating Temperature
   4) Operating Pressure
   5) Residence Time
   6) Yields (theoretical and actual)
   7) Conversion efficiency (theoretical and actual)

8) Material(s) of construction for key pieces of equipment
9) Expected life expectancy and expected maintenance cycles
10) Mode of operation (batch, semi-batch, plug flow, continuous flow, etc.)
11) Describe any known causes and the impacts of system upsets and contaminants (including the source(s) of the contaminants), include mitigative strategies utilized to address process upsets
12) Waste Streams

For each unit operation include mass and energy balance information for each process stream entering or leaving the unit operation including (but not limited to):

1) Pressure
2) Temperature
3) Mass Flow Rate
4) Composition by mol%
5) Phase (gas, vapor, liquid, slurry, solid, etc.)

4. Current state of technology of PROPOSED unit operation

   1) Is the technology used for this unit operation based on commercially available equipment? If so, is the proposed design and use within the manufacturer's normal operating parameters? Attach available manufacturers specifications for proposed equipment as appendices to the BFD package.
   2) Provide the following scale up information
      a. What was the previous scale the unit operation / technology has been tested?
      b. What is the proposed scale up factor for the unit operation?
         i. $Scale\ Up\ Factor = \frac{Proposed\ Scale\ or\ Capacity}{Previous\ Scale\ or\ Capacity}$
      c. How many tests/runs were performed at the previous scale?
      d. What was the longest continuous test/run at the previous scale? Include manufacturers recommended schedules for routine maintenance and discuss any necessary deviations based on the proposed process
      e. When was the most recent test run completed at the previous scale?
      f. Summarize the results of the pilot tests and discuss how the original goals and objectives were met or not met. Describe the quality and replicability of the results. (If data quality objectives were used to set minimum data quality standards, briefly describe them.)
      g. Is further R&D required prior to scaling up this unit operation / technology? Describe the goal and summarize the work needed to obtain the needed information.
      h. Provide evidence that prior test data and experience will result in a design that adequately addresses scale-up challenges, such as how non-linear scale-up parameters (e.g., surface area to mass/volume ratios) could affect fluid dynamics, mixing, reaction kinetics, heat transfer, and chemical equilibrium; how scale-up could affect the buildup of trace impurities; and how scale-up could require additional waste recovery or heat recovery to attain economic feasibility.

2) Calculate any unique Key Performance Indicators (KPI), in addition to estimated upper and lower tolerances, for each unit operation commenting on both the values observed to date as well as targets for the envisioned commercial-scale facility. The following are given as examples only, Applicant technology pathways are not limited to them:
    a. Carbon Capture: Solvent Based System
        i. Pure Solvent Characteristics
        ii. Working Solvent Characteristics
        iii. Solvent Reclaiming/Disposal
    b. Filtration and Transport: Pipeline
        i. Route and Length
        ii. Tolerances for Contaminants
        iii. Flows and Velocities
        iv. Phase
        v. Pipeline Diameter and Wall Thickness
        vi. Flow assurance mitigation strategies
        vii. Expected leak rate
        viii. Distance between control points
    c. STORAGE FIELD DEVELOPMENT
        i. Reservoir Pressure and Reservoir Fluids
        ii. Reservoir Units and Modelling Approach
        iii. Injection Rate and Mass Over Time
        iv. Injectivity
        v. Stratigraphy
        vi. Structure and Dip
        vii. Porosity
        viii. Permeability
        ix. Lithology
        x. Estimated connected pore volume
        xi. Fluid composition(s) and Saturations
        xii. In-Situ stress state
        xiii. Geochemical conditions
        xiv. Fault zone presence
        xv. Aquifer strength
        xvi. Fracture pressure
        xvii. Cap rock integrity (max injection pressure) and extent
        xviii. Water salinity
        xix. Residual reservoir impurities (in either the gas, oil, or water phase)
        xx. Flow assurance mitigation strategies

Example: Block Flow Diagram showing unit operations that will be part of the proposed project. Block flow diagram courtesy of NETL (Laumbet. al. 2019)

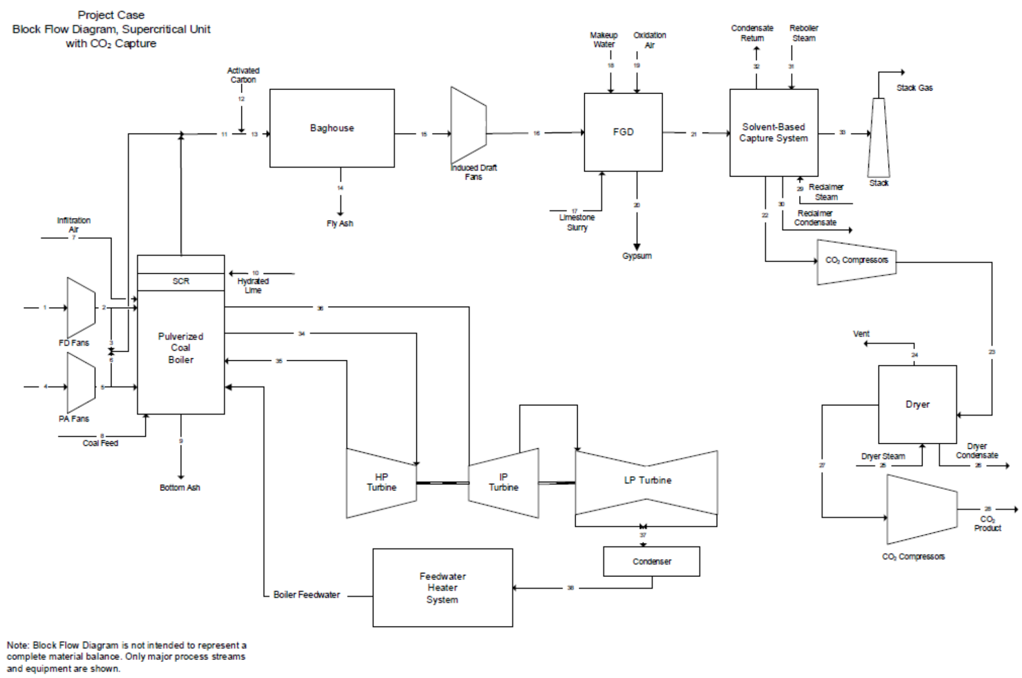

Figure L1. Block Flow Diagram

Table 1. Project Case Stream Table, Supercritical Unit with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0087	0.0000	0.0087	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1372	0.0000	0.1372	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0855	0.0000	0.0855	0.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7326	0.0000	0.7326	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0336	0.0000	0.0336	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.0000
Total	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0	1.0	0.0	1.0	0.0
V-L Flow Rate, kgmol/hr	61,725	61,725	1828	18,961	18,961	2610	1348	0	0	0	86,737	0	86,956	0
V-L Flow Rate, kg/hr	1,781,130	1,781,130	52,754	547,141	547,141	75,301	38,904	0	0	0	2,573,171	0	2,583,413	0
Solids Flow Rate, kg/hr	0	0	0	0	0	0	0	223,848	3460	4530	22,776	131	22,907	22,907
Temperature, °C	19	23	23	15	24	24	15	15	149	27	222	27	222	169
Pressure, MPa, abs	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Enthalpy, kJ/kg[a]	−93.5	−89.3	−89.3	−97.5	−88.6	−88.6	−97.5	–	–	–	−2328.8	–	−2328.8	–
Density, kg/m^3	1.2	1.2	1.2	1.2	1.3	1.3	1.2	–	–	–	0.7	–	0.7	–
V-L Molecular Weight	28.856	28.856	28.856	28.856	28.856	28.856	28.856	–	–	–	29.67	–	29.67	–
V-L Flow Rate, lb mol/hr	136,081	136,081	4030	41,802	41,802	5753	2972	0	0	0	191,223	0	191,706	0
V-L Flow Rate, lb/hr	3,926,720	3,926,720	116,302	1,206,240	1,206,240	166,011	85,769	0	0	0	5,672,870	0	5,695,450	0
Solids Flowrate, lb/hr	0	0	0	0	0	0	0	493,500	7629	9988	50,213	288	50,501	50,501
Temperature, °F	66	73	73	59	75	75	59	59	300	80	432	80	432	337
Pressure, psia	14.5	15.2	15.2	14.7	15.8	15.8	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.7
Enthalpy, Btu/lb[a]	−40.2	−38.4	−38.4	−41.9	−38.1	−38.1	−41.9	–	–	–	−1001.2	–	−1001.2	–
Density, lb/ft^3	0.074	0.076	0.076	0.076	0.080	0.080	0.076	–	–	–	0.044	–	0.044	–

[a] Reference conditions are 77°F and 14.696 psia.

Figure L2. Supplemental Data[14]

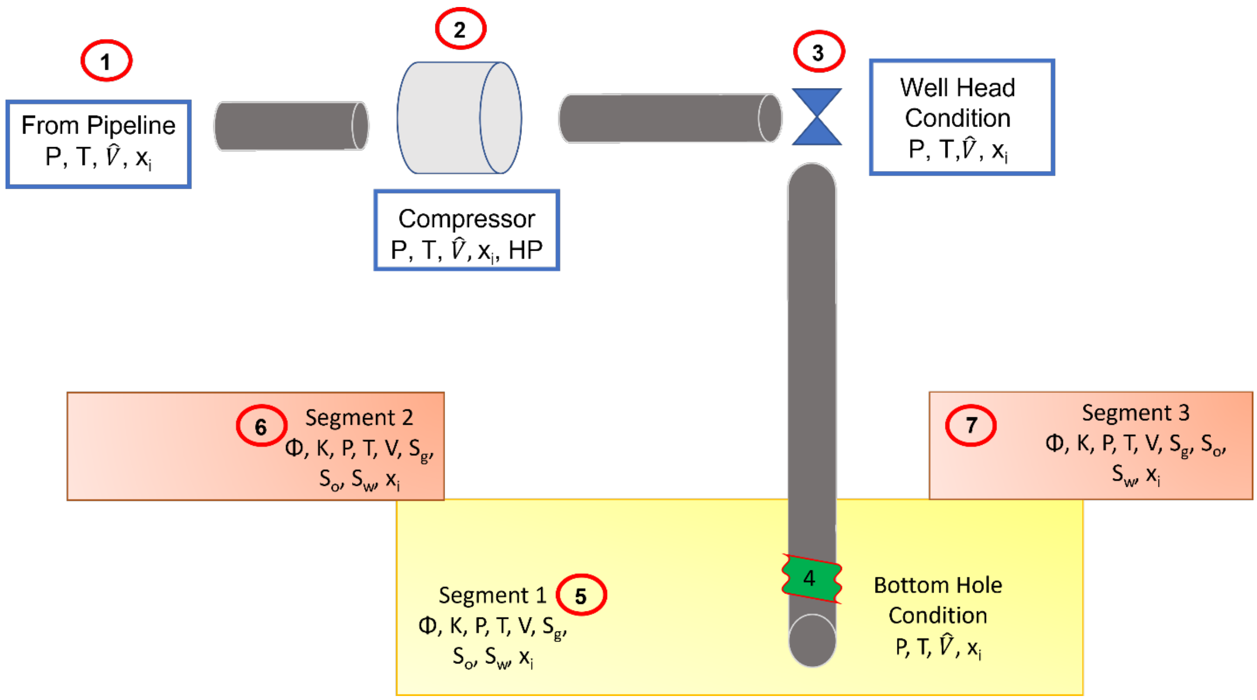

Figure L3. Example of a simple reservoir BFD

14 Laumbet, J.; Jensen, J.; Kay, J.; Dunham, D.; Folkedahl, D.; Azenkeng, A. AOI2 – INITIAL ENGINEERING, TESTING, AND DESIGN OF A COMMERCIAL-SCALE POSTCOMBUSTION CO2 CAPTURE SYSTEM ON AN EXISTING COAL-FIRED GENERATING UNIT (PROJECT CARBON). Cooperative Agreement No.: DE-FE0031602. Pittsburgh, PA: National Energy Technology Laboratory, December 2019. https://www.osti.gov/servlets/purl/1581444

APPENDIX M: GLOSSARY

Applicant – The lead organization submitting an application under the FOA.

Continuation application – A non-competitive application for an additional budget period within a previously approved project period. At least ninety (90) days before the end of each budget period, the Recipient must submit to OCED its continuation application, which includes information such as but not limited to, the following:

i. A report on the Recipient's progress towards meeting the objectives of the project, including any significant findings, conclusions, or developments, and an estimate of any unobligated balances remaining at the end of the budget period. If the remaining unobligated balance is estimated to exceed 20 percent of the funds available for the budget period, explain why the excess funds have not been obligated and how they will be used in the next budget period.

ii. A detailed budget and supporting justification if there are changes to the negotiated budget, or a budget for the upcoming budget period was not approved at the time of award.

iii. A description of any planned changes from the negotiated Statement of Project Objectives (SOPO) and/or Milestone Summary Table.

Federally Funded Research and Development Centers (FFRDC) - As specified in the Federal Acquisition Regulation (FAR) 35.017(a)(2), a FFRDC "meets some special long-term research or development need which cannot be met as effectively by existing in-house or contractor resources." A FFRDC is "operated, managed, and/or administered by either a university of consortium of universities, other not-for-profit or nonprofit organization, or an industrial firm, as an autonomous organization or as an identifiable separate operating unit of a parent organization." FAR 35.017(a)(3). A list of FFRDCs can be found at http://www.nsf.gov/statistics/ffrdclist/.

Go/No-Go Decision Points – A decision point at the end of a budget period that defines the overall objectives, milestones, and deliverables to be achieved by the recipient in that budget period. As of a result of OCED's review, OCED may take one of the following actions: 1) authorize federal funding for the next budget period; 2) recommend redirection of work; 3) discontinue providing federal funding beyond the current budget period; or 4) place a hold on federal funding pending further supporting data.

Project – The entire scope of the cooperative agreement which is contained in the recipient's Statement of Project Objectives.

Recipient or "Prime Recipient" – A non-federal entity that receives a federal award directly from a federal awarding agency to carry out an activity under a federal program. The term recipient does not include subrecipients.

Subrecipient – As specified in 2 C.F.R. § 200.331(a), a subaward is for the purpose of carrying out a portion of a Federal award and creates a Federal assistance relationship with the subrecipient. Characteristics which support the classification of the non-Federal entity as a subrecipient include when the non-Federal entity:

(1) Determines who is eligible to receive what Federal assistance;

(2) Has its performance measured in relation to whether objectives of a Federal program were met;

(3) Has responsibility for programmatic decision-making;

(4) Is responsible for adherence to applicable Federal program requirements specified in the Federal award; and

(5) In accordance with its agreement, uses the Federal funds to carry out a program for a public purpose specified in authorizing statute, as opposed to providing goods or services for the benefit of the pass-through entity.

Also, a DOE/NNSA and non-DOE/NNSA FFRDC may be proposed as a subrecipient on another entity's application. See Section 3.0. Refer to § 200.331 Subrecipient and contractor determinations. To assist Applicants in determining the difference between a subrecipient and a contractor, please refer to the "Subrecipient vs. Contractor Checklist," developed by the Association of Government Accountants.

Contractor/Vendor – As specified in 2 C.F.R. § 200.331(b), a contract is for the purpose of obtaining goods and services for the non-Federal entity's own use and creates a procurement relationship with the contractor. See the definition of contract in § 200.1 of this part. Characteristics indicative of a procurement relationship between the non-Federal entity and a contractor are when the contractor:

(1) Provides the goods and services within normal business operations;

(2) Provides similar goods or services to many different purchasers;

(3) Normally operates in a competitive environment;

(4) Provides goods or services that are ancillary to the operation of the Federal program; and

(5) Is not subject to compliance requirements of the Federal program as a result of the agreement, though similar requirements may apply for other reasons.

APPENDIX N: DOE TECHNOLOGY READINESS LEVEL SCALE

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
System Operations	**TRL 9**	Actual system operated over the full range of expected conditions	Actual operation of the technology is in its final form, under the full range of operating conditions. Examples include using the actual system with the full range of wastes.
System Commissioning	**TRL 8**	Actual system completed and qualified through test and demonstration	The technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development. Examples include developmental testing and evaluation of the system with real waste in hot commissioning.
	TRL 7	Full-scale, similar (prototypical) system demonstrated in relevant environment	Prototype full scale system. Represents a major step up from TRL 6, requiring demonstration of an actual prototype system in a relevant environment. Examples include testing the prototype in the field with a range of simulants and/or real waste and cold commissioning.
Technology Demonstration	**TRL 6**	Engineering/pilot-scale, similar (prototypical) system validation in relevant environment	Representative engineering scale model or prototype system, which is well beyond the lab scale tested for TRL 5, is tested in a relevant environment. Represents a major step up in a technology's demonstrated readiness. Examples include testing a prototype with real waste and a range of simulants.
Technology Development	**TRL 5**	Laboratory scale, similar system validation in relevant environment	The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. Examples include testing a high-fidelity system in a simulated environment and/or with a range of real waste and simulants.
	TRL 4	Component and/or system validation in laboratory environment	Basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared with the eventual system. Examples include integration of "ad hoc" hardware in a laboratory and testing with a range of simulants.
Research to Prove Feasibility	**TRL 3**	Analytical and experimental critical function and/or characteristic proof of concept	Active research and development is initiated. This includes analytical studies and laboratory scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative. Components may be tested with simulants.
	TRL 2	Technology concept and/or application formulated	Invention begins. Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples are still limited to analytic studies.
Basic Technology Research	**TRL 1**	Basic principles observed and reported	Lowest level of technology readiness. Scientific research begins to be translated into applied R&D. Examples might include paper studies of a technology's basic properties.

APPENDIX O: WAIVER REQUESTS FOR FOREIGN ENTITY PARTICIPATION AND FOREIGN WORK

Waiver for Foreign Entity Participation

Many of the technology areas DOE funds fall in the category of critical and emerging technologies (CETs). CETs are a subset of advanced technologies that are potentially significant to United States national and economic security.[15] For projects selected under this FOA, all recipients and subrecipients must be organized, chartered or incorporated (or otherwise formed) under the laws of a state or territory of the United States; have majority domestic ownership and control; and have a physical location for business operations in the United States. To request a waiver of this requirement, an applicant must submit an explicit waiver request in the Application.

Waiver Criteria

Foreign entities seeking to participate in a project under this FOA must demonstrate to the satisfaction of DOE that:

a. Its participation is in the best interest of the United States industry and United States economic development;
b. The project team has appropriate measures in place to control sensitive information and protect against unauthorized transfer of scientific and technical information;
c. Adequate protocols exist between the United States subsidiary and its foreign parent organization to comply with export control laws and any obligations to protect proprietary information from the foreign parent organization;
d. The work is conducted within the United States and the entity acknowledges and demonstrates that it has the intent and ability to comply with the U.S. Competitiveness Provisions (see Section 8.11); and
e. The foreign entity will satisfy other conditions that may be deemed necessary by DOE to protect United States government interests.

Content for Waiver Request

A foreign entity waiver request must include the following:

a. Information about the entity: name, point of contact, and proposed type of involvement in the project;

[15] See Critical and Emerging Technologies List Update (whitehouse.gov).

b. Country of incorporation, the extent of the ownership/level of control by foreign entities, whether the entity is state owned or controlled, a summary of the ownership breakdown of the foreign entity and the percentage of ownership/control by foreign entities, foreign shareholders, foreign state(s) or foreign individual(s);
c. The rationale for proposing that a foreign entity participate (must address the criteria above);
d. A description of the project's anticipated contributions to the United States economy;
e. A description of how the foreign entity's participation is essential to the project, including;
    - How the project will benefit the United States, including manufacturing, contributions to employment in the United states and growth in new markets and jobs in the United States;
    - How the project will promote manufacturing of products and/or services in the United States;
f. A description of the likelihood of Intellectual Property (IP) being created from the work and the treatment of any such IP; and
g. Countries where the work will be performed (Note: if any work is proposed to be conducted outside the United States, the applicant must also complete a separate foreign work waiver request).

DOE may also require:

- A risk assessment with respect to IP and data protection protocols that includes the export control risk based on the data protection protocols, the technology being developed and the foreign entity and country. These submissions could be prepared by the project lead (if not the prime recipient), but the prime recipient must make a representation to DOE as to whether it believes the data protection protocols are adequate and make a representation of the risk assessment – high, medium, or low risk of data leakage to a foreign entity.
- Additional language may be added to any agreement or subagreement to protect IP, mitigate risk, or other related purposes.
- DOE may require additional information before considering a waiver request.

DOE's decision concerning a waiver request is not appealable.

<u>Waiver for Performance of Work in the United States (Foreign Work Waiver)</u>

As set forth in Section 4.9.6, all work funded under this FOA must be performed in the United States. To seek a waiver of the Performance of Work in the United States requirement, the applicant must submit an explicit waiver request in the application. A separate waiver request must be submitted for each entity proposing performance of work outside of the United States.

Overall, a waiver request must demonstrate to the satisfaction of DOE that it would further the purposes of this FOA and is otherwise in the economic interests of the United States to perform work outside of the United States. A request for a foreign work waiver must include the following:

1. The rationale for performing the work outside of the United States ("foreign work");
2. A description of the work proposed to be performed outside the United States;
3. An explanation of how the foreign work is essential to the project;
4. A description of the anticipated benefits to be realized by the proposed foreign work and the anticipated contributions to the United States economy;
5. The associated benefits to be realized and the contribution to the project from the foreign work;
6. How the foreign work will benefit the United States, including manufacturing, contributions, to employment in the United States and growth in new markets and jobs in the United States;
7. How the foreign work will promote manufacturing of products and/or services in the United States;
8. A description of the likelihood of Intellectual Property (IP) being created from the foreign work and the treatment of any such IP;
9. The total estimated cost (DOE and recipient cost share) of the proposed foreign work;
10. The country(ies) in which the foreign work is proposed to be performed; and
11. The name of the entity that would perform the foreign work. Information about the entity(ies) involved in the work proposed to be conducted outside the United States (e.g., the entity seeking a waiver and the entity(ies) that will conduct the foreign work).

DOE may require additional information before considering a waiver request.

DOE's decision concerning a waiver request is not appealable.

APPENDIX P: KEY PERFORMANCE PARAMETERS TABLE FOR CURRENT AND PRIOR DEMONSTRATIONS

Use the following table to describe current key parameters of your carbon capture system. Include one for your current process and an additional table for every relevant pilot or commercial demonstration of the technology. Submit one pdf document with all of the tables.

You may add up to five key performance parameters to the tables. These should be the same in every table. Do not add more than five. These rows could be used to capture key cost and performance parameters that, after the test, still required additional development and testing in order to validate them for commercial applications.

The Notes column is intended for brief notes only; do not extend the row height by adding excessive Notes. Failure to submit at least two tables (one for the current process and one for the prior pilot-scale demonstration) will result in the application being deemed noncompliant.

Category	Value	Units	Notes
Active Component (solvent, sorbent, membrane, etc.)		-	
Source of flue gas (e.g., coal fired power plant, cement plant, etc.)		-	
Inlet Flue Gas Temperature		F	
Inlet Flue Gas Pressure		Psia	
Inlet Flue Gas (Total flow)		lb-mol	
Inlet Flue Gas Composition (including trace contaminants)*		lb-mol%	
Inlet Flue Gas (Total flow)		lbs	
Inlet Flue Gas Composition (including trace contaminants)*		mass%	

Assumptions for unknowns in Inlet Flue Gas Composition (if applicable)		-	
Observed Adverse Impacts of the contaminants on the Process Active Component and equipment		-	
Reclaiming / Regeneration / Replacement time of the Active Component		hrs	
Scale		tons of CO_2 captured per year	
Electrical Power consumption (mean)		MW electricity consumed/ton of CO_2 Captured	
Electrical Power consumption (std deviation)		MW electricity consumed/ton of CO_2 Captured	
Steam Power consumption (mean)		MW electricity consumed/ton of CO_2 Captured	
Steam Power consumption (std deviation)		MW electricity consumed/ton of CO_2 Captured	
Fresh water consumption (mean)		lb water/ton of CO_2 Captured	
Fresh water consumption (std deviation)		lb water/ton of CO_2 Captured	
Longest Time on Stream (continuous)		hrs	
Total Time on Stream (cumulative)		hrs	

CO_2 capture efficiency (mean)		mass%	
CO_2 capture efficiency (std deviation)		mass%	
Waste Emissions from Process (e.g., nitrosamines, amines, heavy metals, PM, etc.)		ppm	
Effluent stream CO_2 purity		mass%	
Non-CO_2 components in effluent stream (list)*		lb-mols	
Non-CO_2 components in effluent stream (list)*		lbs	
Cost of Capture (average)		\$/ton of CO_2 Captured	
Cost of Capture (std deviation)		\$/ton of CO_2 Captured	

*Identify the analytical method to derive all compositions in the corresponding "Notes" space for that row.

APPENDIX C

August 8, 2023

The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave, N.W.
Washington, DC 20460

Re: EPA's Proposed Clean Air Act Section 111 Rules for Power Plants.
Docket No. EPA-HQ-OAR-2023-0072.

Dear Administrator Regan:

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) proposed rules for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (Proposed 111 Rules). 88 *Fed. Reg.* 33,240 (May 23, 2023). The Proposed 111 Rules would directly regulate GHG emissions from new natural gas-based units while also setting guidelines for the states to address emissions from existing coal- and natural gas-based units.

EEI members are united in their commitment to get the energy they provide as clean as they can as fast as they can, while keeping reliability and affordability front and center, as always, for the customers and communities they serve. Across the nation, EEI members are leading a clean energy transformation, making significant progress to reduce GHG emissions, while also creating good-paying jobs and an equitable clean energy future.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the agency's full suite of climate and environmental regulations for power plants. We look forward to engaging with you and your team on these issues as the Agency works to finalize the Proposed 111 Rules. Please contact Alex Bond at abond@eei.org (202-508-5523) if you have any questions regarding EEI's comments.

Sincerely,

Emily Sanford Fisher
Executive Vice President, Clean Energy
General Counsel & Corporate Secretary

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COMMENTS FROM THE EDISON ELECTRIC INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED RULE NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL-FUEL FIRED ELECTRIC GENERATING UNITS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE

Docket No. EPA-HQ-OAR-2023-0072

August 8, 2023

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) proposed rules for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (Proposed 111 Rules). 88 *Fed. Reg.* 33,240 (May 23, 2023). The Proposed 111 Rules would directly regulate GHG emissions from new natural gas-based units while also setting guidelines for the states to address emissions from existing coal- and natural gas-based units.

EEI is the association that represents all U.S. investor-owned electric companies. EEI's member companies provide electricity for nearly 250 million Americans and operate in all 50 states and the District of Columbia. The electric power industry supports more than 7 million jobs in communities across the United States. EEI's member companies invest more than $140 billion each year, on average, to make the energy grid smarter, cleaner, more dynamic, more flexible, and more secure; to diversify the nation's energy mix; and to integrate new technologies that benefit both customers and the environment.

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This clean energy transition already has resulted in significant GHG emissions reductions, as EPA has recognized, and more than 40 percent of our nation's electricity now comes from clean, carbon-free sources.

EEI's member companies are committed to getting the energy they provide as clean as they can as fast as they can, while keeping customer reliability and affordability front and center. Across the industry, electric companies are investing in a broad range of carbon-free technologies and approaches, with the goal of demonstrating these technologies so that they can help further reduce power sector emissions when they satisfy industry performance requirements and are affordable for customers.

Electric companies and EPA agree on the long-term clean energy vision for the sector that is embodied in the Proposed 111 Rules: electric companies have reduced and will continue to reduce GHG emissions and will use emerging technologies to reduce emissions from new and existing fossil-based generation. Importantly, there are portions of EPA's rulemaking that provide a positive framework for this continued progress.

While there are challenges presented by the Proposed 111 Rules, these challenges are technical in nature. EEI and our member companies share EPA's goals of continuing to reduce emissions from the power sector and of achieving an economy-wide clean energy transition.

As we outline in these comments, electric companies are not confident that the new technologies EPA has designated to serve as the basis for proposed standards for new and existing fossil-based generation will satisfy performance and cost requirements on the timelines that EPA projects. This will impact electric companies' efforts to deliver affordable and reliable electricity to customers. These comments seek to provide perspectives on the Proposed 111 Rules such that any final rules provide durable regulatory frameworks that allow electric companies to continue to provide customers with the resilient clean energy they need and deserve, without compromising affordability.

I. Introduction and Summary of Comments.

As many EEI member companies are owners and operators of the new and existing fossil-based electric generating units (EGUs or units) that will be regulated by any final rules, they are uniquely qualified to provide feedback on EPA's proposals. EEI and its member companies actively have engaged with EPA on the full suite of climate and environmental regulations for power plants, including by filing extensive comments in the non-regulatory docket that preceded this rulemaking and by responding to proposals across the suite of environmental regulations, as well as through numerous meetings with EPA at all levels. EEI's member companies look forward to continuing to engage productively with EPA as the Agency works to finalize the Proposed 111 Rules.

EEI's member companies also are committed to developing and deploying emerging technologies, such as carbon capture and storage (CCS), hydrogen blending, small modular nuclear reactors, advanced renewables, energy storage, long-duration energy storage, and renewable natural gas, among other technologies. The successful development and deployment of these 24/7 technologies, along with the continued deployment of wind and solar generation and the operation of the existing nuclear fleet, will be necessary to achieve continued emissions reductions across the power sector and individual electric company commitments to reduce emissions to zero or net zero. They also will contribute to the reliability and resilience of an energy grid that is increasingly dependent on variable renewable generation.

The programs, funding, and tax incentives for new, clean technologies recently provided by Congress will be instrumental in driving the research, development, and demonstration necessary to make deployment of these technologies a reality. EEI's member companies already are working with the U.S. Department of Energy (DOE) and other agencies to move forward with critical demonstration projects and have received some of the project funding awards that DOE has given to date.

Consistent with electric companies' engagement with EPA and technology demonstration efforts, these comments are aimed at ensuring final standards are aligned with other regulations and their compliance timelines; afford states maximum flexibility so that they can work with unit owners and operators on affordable, reliable compliance options for all existing units; and provide a regulatory framework that supports continued industry investment in the clean energy transition. This will allow electric companies to make fully informed decisions about retiring older assets, bringing on more new, cleaner sources of generation, and building the infrastructure to support the transformation to a resilient clean energy future for all customers.

The Proposed 111 Rules are an important piece of the regulatory framework that could support the power sector's continuing clean energy transformation, including the deployment of new clean technologies. These comments identify where the Proposed 111 Rules support the transition, how they could be better structured to support affordability and reliability for customers, and where compliance flexibilities and other tools will be needed, especially if EPA chooses to finalize the proposed standards without modification. To the extent possible, these comments propose solutions that EPA should adopt in any final 111 Rules.

A. EPA Should Finalize Key Elements of the Proposed 111 Rules and Consider Other Changes That Would Help Electric Companies Comply.

These comments identify technical and legal issues raised by EPA's proposals. Regardless of how EPA chooses to address these issues, EPA must design final standards for all regulated units that allow for compliance. Key design elements that EPA incorporated into the Proposed 111 Rules—which include the use of subcategories and significant compliance flexibility for states and units—should be finalized consistent with the technical, legal, and policy recommendations set forth in these comments. EPA also should consider expanding the proposed design and compliance flexibilities and making other important changes to the proposed standards to support compliance.

Final 111 Rules should:

- Set achievable, efficiency-based standards for new natural gas-based units, consistent with EEI's February 2023 recommendation to the Agency that these units be "capable" of future retrofit to install CCS or blend hydrogen when those technologies are demonstrated and available at costs that are affordable for customers;

- Allow states to recognize changes to how existing units will be operated in the future and the emissions benefits of retiring existing units through appropriate subcategories—for both existing coal- and natural gas-based EGUs;

- Affirmatively allow states to adopt mass-based compliance approaches for both new and existing units;

- Provide states additional flexibility on the timing for state plan development and submittal to EPA; and,

- Provide units with dual-pathway approaches, which recognize that planning for new technologies during the short window for state plan development will be challenging, and provide a less prescriptive approach to the increments of progress to support these more flexible approaches.

These key program design elements and compliance flexibilities, along with the others discussed in these comments, will enable states and electric companies to implement final standards that are achievable, reliable, and affordable. In addition, EPA should be clear that the Agency will exercise considerable enforcement discretion for units that may install (or attempt to install) and use new technologies—like CCS or hydrogen blending—if those do not perform as expected or are not available on the timelines EPA predicts.

B. EEI's Member Companies Continue to Lead the Clean Energy Transition.

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This transformation is being driven by a wide range of factors, including relatively lower prices for natural gas, particularly as compared to historic high prices; increased deployment of renewable energy resources, energy efficiency measures, and demand-side management; technological improvements; changing customer, investor, and owner expectations; federal and state regulations and policies; legislation, including the Infrastructure

Investment and Jobs Act[1] (IIJA) and Inflation Reduction Act of 2022[2] (IRA); and the increasing use of distributed energy resources. Across the industry, electric companies are investing in a broad range of affordable, carbon-free technologies and approaches with the goal of finding the most cost-effective ways to deliver resilient clean energy.

The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly clean.[3] In 2022, for the first time, renewable energy sources[4] surpassed coal as a generation resource: 22.6 percent of total generation at utility-scale facilities in the United States came from renewable sources compared to 19 percent from coal-based generation.[5] In total, more than 40 percent of America's electricity came from clean carbon-free resources in 2022, including nuclear energy, hydropower, solar, and wind,[6] putting

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[1] Pub. L. No. 117-58.

[2] Pub. L. No. 117-169.

[3] *See* U.S. Energy Information Administration (EIA), Today in Energy: Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022 (Mar. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55960&src=email; *See also* EIA, Electric Power Monthly: Data for February 2023—Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2013-February 2023 (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01.xlsx; *and* EIA, Electric Power Monthly: Data for February 2023—Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors) (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01_a.xlsx.

[4] Renewables here include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, hydroelectric conventional, solar thermal, photovoltaic energy, solar, and wind. *See* EIA, Electric Power Monthly, Table 1.1, *supra,* n.3.

[5] *See id*.

[6] *See id.*

clean resources at parity with natural gas generation, which provided approximately 40 percent of the country's total electricity generation in 2022.

As part of the move toward resilient clean energy, electric companies are deploying more energy storage, which is a key asset that helps integrate increasing amounts of renewables into the energy grid while also enhancing resilience and reliability. Electric companies are the largest users and operators of the approximately 32 gigawatts (GW) of operational storage in the country—representing 93 percent of active energy storage projects.[7]

Going forward, renewable and clean energy technology deployments will continue. EIA predicts that declining capital costs for solar panels, wind turbines, and battery storage, along with government support such as that provided through the IRA, will make these technologies increasingly cost-effective compared to the alternatives when building new power generating capacity.[8] EIA projects that renewable generation in the United States will more than triple by 2050, with both wind and solar responsible for most of the growth.[9]

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[7] Compiled from the following proprietary sources: Wood Mackenzie Power & Renewables/American Clean Power Association, *U.S. Energy Storage Monitor* (2022); Dep't of Energy, *Energy Storage Database* (2022); Hitachi Energy, *The Velocity Suite Database* (2022).

[8] *See* EIA, Annual Energy Outlook 2023 (AEO 2023) 9 (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.

[9] *See* AEO 2023—Table 16. Renewable Energy Generating Capacity and Generation: Electric Power Sector: Generation: Total (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=16-AEO2023&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.25-16-AEO2023~&ctype=linechart&sid=ref2023-d020623a.25-16-AEO2023~ref2023-d020623a.64-16-AEO2023&sourcekey=0.

The changes in the mix of resources used to generate electricity have profoundly decreased the sector's carbon dioxide (CO_2) emissions, the primary GHG emissions associated with electricity production. EIA's preliminary full-year estimates for 2022 find that electric power sector CO_2 emissions were 36 percent below 2005 levels, as low as they were almost 40 years ago.[10] These reductions will continue.[11] Further, 50 EEI member companies have announced voluntary, forward-looking carbon reductions goals, 41 of which include a net-zero by 2050 or earlier equivalent goal, and member companies routinely increase the ambition or speed of their goals or altogether transform them into net-zero goals to reflect changing expectations about the cost and availability of renewable generation and other clean energy resources.

In addition, the electric power industry has significantly reduced emissions of traditional air pollutants, such as mercury, HAPs, sulfur dioxide (SO_2), and nitrogen oxides (NOx). As of 2022, SO_2 and NOx emissions have declined 95 and 88 percent, respectively, since 1990.[12] In addition, mercury emissions have declined by 95 percent since 2010,[13] and total HAPs—including all acid gas emissions—declined by 96 percent between 2010 to 2017.[14]

[10] *See* EIA, Monthly Energy Review, Environment, Table 11.6—Electric Power Sector (Mar. 2023), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

[11] *See* AEO 2023 at 4.

[12] *See* EPA, Power Plant Emissions Trends (Feb. 2023), https://www.epa.gov/power-sector/power-plant-emission-trends.

[13] *See* EPA, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, page 2-7 (Dec. 2011), https://www.epa.gov/sites/default/files/2015-11/documents/matsriafinal.pdf.

[14] *See* 84 *Fed. Reg.* 2,670, 2,689 (Feb. 7, 2019).

EEI's member companies see a clear path to continued emissions reductions over the next decade using current technologies, including nuclear energy, natural gas-based generation, energy demand efficiency, energy storage, and deployment of new renewable energy—especially wind and solar[15]—as older coal-based and less-efficient natural gas-based generating units retire.[16] These technologies will continue to enable significant, cost-effective carbon reductions.

In the long term, reaching net-zero carbon emissions also will require the deployment of next-generation, carbon-free, 24/7, dispatchable technologies not currently available commercially. Supported by the clean energy tax incentives included in the IRA and the grant funding available via the IIJA, electric companies are partnering with technology developers, academic institutions, investors, philanthropists, each other, and other stakeholders to develop, demonstrate, and deploy these new clean energy technologies. These include long-duration energy storage, CCS, advanced nuclear and renewable generation, and clean fuels (like hydrogen, renewable natural gas, and ammonia). Developing and deploying a broad range of advanced clean energy technologies will further expedite the transition of the electric power sector to one that is low- or non-emitting while keeping electricity affordable and reliable for customers.

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[15] Once built and when the resource is available, wind and solar are the least cost resources to operate to meet electricity demand because they have zero fuel costs. Over time, the combined investment and operating cost advantage increases the share of zero-carbon electricity generation. *See* AEO 2023 at 5.

[16] EIA notes that coal-based generation capacity will decline sharply by 2030 to about 50 percent of current levels (from about 200 GW to 100 GW) with a more gradual decline thereafter. *See* AEO 2023 at 13.

C. Best System of Emission Reduction Technologies Must Be Adequately Demonstrated in Order for Standards to Be Achievable.

EPA proposes to determine that the best system of emission reduction (BSER) is CCS for existing coal-based units and either CCS or hydrogen blending for new and existing natural gas-based turbines. In making these BSER determinations, EPA asserts that CCS and hydrogen blending are adequately demonstrated, that these technologies are affordable for customers, and that the resulting standards are achievable across the entire industry. Given the status of these technologies today and the uncertainty inherent in EPA's future projections—especially regarding the ability to deploy the needed infrastructure that complements these technologies across the industry in a timely fashion—EPA's assessments are not legally or technically sound based on the record before the Agency.

As discussed in these comments, EPA's rulemaking record simultaneously downplays the various infrastructure challenges to deploying these technologies, while overplaying the current state of deployment and demonstration of each technology. Given these realities, neither CCS nor hydrogen blending are adequately demonstrated today as they are not deployable, available, or affordable across the entirety of the industry, and the attendant supporting infrastructure will take more time than EPA predicts to deploy. This assessment factors in the timelines that EPA proposes for standards that may not be applicable until several years in the future. Accordingly, unit owners and operators have significant concerns about the achievability of the proposed standards.

EEI's member companies are working to demonstrate these critical technologies and intend to use them when they satisfy customer cost and industry performance requirements. In the interim, and even with emissions standards in place, it is not at all certain that state utility commissions will approve plans, which would need to be made well before compliance deadlines, to allocate capital—and impose risk and cost-recovery burdens on customers—for unproven technologies. It is similarly uncertain that electric companies will be able to obtain private financing for technologies that do not have a clear ability to meet regulatory standards, particularly given the possibility of CAA enforcement penalties. As a result, standards that require these technologies for compliance are not likely to drive the deployment necessary to improve performance and bring down costs, but instead could slow down key projects as EEI's member companies work to deploy demonstration projects and related infrastructure over the next decade and beyond. Similarly, unachievable standards could delay deployment of new generation, particularly new natural gas generation, that will be needed to serve customers reliably and affordably this decade.

EPA should not finalize the phased standards that are based on CCS or hydrogen blending as BSER given these concerns. If EPA moves forward with the standards as proposed, however, the Agency should provide electric companies and states as much compliance flexibility as possible to address achievability concerns. EPA also should commit to providing significant enforcement discretion should these technologies not perform reliably or be available on the Agency's projected timeframes.

D. Organization of EEI's Comments.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the Agency's full suite of climate and environmental regulations for power plants. EEI has provided significant feedback in the form of whitepapers addressing the waterfront of potential programmatic elements of what became the Proposed 111 Rules. Those whitepapers are attached to these comments as Appendices A, B, and C. Several of the recommendations EEI made in those whitepapers, aimed at helping EPA to develop workable final standards, are reflected in parts of EPA's Proposed 111 Rules. EEI also outlined some concerns and anticipated technical challenges expected in the Proposed 111 Rules in those whitepapers. Some of those concerns remain and are addressed below.

Section II of these comments addresses the proposed retirement subcategories, noting that these approaches are consistent with many of the trends in the sector regarding already planned unit retirements and will be beneficial for many companies and their customers. This section also provides suggested improvements to the design of these subcategories and additional policy and legal rationales for EPA's approach. It identifies potential unintended consequences that flow from the proposed approach to existing natural gas-based units and seeks additional, tailored flexibilities for these units and the states that will regulate them. Section III addresses concerns regarding EPA's determination that CCS technology is adequately demonstrated as BSER, focusing on the Agency's technical judgments and record. Section IV does the same for EPA's determination that hydrogen blending is BSER for both new and existing natural gas-based units.

Section V provides feedback on EPA's proposed efficiency standards and subcategories for new natural gas-based units with a focus on achievability and compliance flexibility for these units. Section VI addresses numerous suggested state plan flexibilities that can help the states submit, and EPA approve, compliance plans that allow companies to reduce emissions in a reliable and affordable manner. Section VII addresses certain applicability concerns raised by EPA's proposal.

II. EPA's Use Of Subcategories Is Well Supported And Should Be Strengthened And Expanded.

EPA proposes to utilize numerous subcategories for both new natural-gas based units and, crucially, for existing coal-based units. Three of the proposed subcategories for coal-based units include retirement options tied to specific retirement deadlines. Units that opt into these subcategories agree to a shutdown commitment, which becomes federally enforceable once it is included in a state's compliance plan, in exchange for less stringent emissions limitations prior to closure. *See* 88 *Fed. Reg.* at 33,341. For new natural gas-based units, EPA divides those units into three subcategories based on utilization: base load, intermediate load, and low load. *See id.* at 33,277.

EPA has clear authority to utilize subcategories, and the approach to subcategories in the Proposed 111 Rules is well-founded. EPA should, however, include in any final rules the alternative rationale that the subcategories for existing coal-based units also are a permissible use of a state's ability to utilize the statutory authority under the CAA's remaining useful life and other factors (RULOF) provisions. EPA's proposed subcategories, therefore, also represent a presumptively approvable approach for states' exercise of their statutory authority to consider RULOF when setting standards for existing units. Further, EPA should make several additional changes to the proposed subcategories in order to allow for additional flexibility and ensure that states and units can continue to plan for the operation of an affordable and reliable energy grid in transition. EPA also must provide similar subcategorization approaches for existing natural gas-based units, since these units are similarly situated to coal-based units in the value they provide to the system, and the Agency should treat them as such. Failure to do so would be arbitrary.

A. EPA's Use of Subcategories is Well-Supported.

While EPA included performance standards in the Proposed 111 Rules for fossil fuel types other than coal (i.e., natural gas- and oil-fired steam generating units), the largest category regulated will be coal-fired steam generating units. EPA proposed to "divide the subcategory for coal-fired units into additional subcategories based on operating horizon (i.e., dates for electing to permanently cease operation) and, for one of those subcategories, load level (i.e., annual capacity factor), with a separate BSER and degree of emission limitation corresponding to each subcategory." 88 *Fed. Reg.* at 33,341. The Proposed 111 Rules acknowledge that many existing coal plants may retire within coming years, such that the cost-effectiveness of installing pollution controls will depend on a power plant's operating horizon.[17] Thus, EPA proposes an emission limit based on 90 percent CCS for coal-fired units that plan to continue operating past January 2040, with less stringent standards for units that commit to an earlier, enforceable retirement date.[18]

1. EPA has clear authority to subcategorize on a plain reading of section 111.

[17] In general, EPA's assessment that many coal-based units will retire between now and 2040 tracks general trends in the industry; however, each individual facility and company faces unique circumstances and individual unit retirement decisions are complex undertakings given the unique value each plant can provide to the operation of the grid.

[18] As discussed, *infra*, while EPA has the authority under section 111 to subcategorize based on retirement horizon (for existing sources) and load level (for both new and existing sources), for both new and existing sources EPA only has authority under section 111 to select a BSER that has been adequately demonstrated *now*. That the statute provides EPA some authority to allow existing sources time to *implement* BSER following promulgation of final rules does not change that, since that authority is there to ensure that the absence of emission control while the control technology is installed (which may itself take years) does not put the source in a state of noncompliance. EPA cannot "project" that a control technology will be available at some future point.

For existing coal-based units, EPA proposed to align BSER with the planned retirement dates of the units pursuant to state plans. *See* 88 *Fed. Reg.* at 33,341. EPA has wide discretion under CAA section 111(b)(2) to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards," which is referred to as "subcategorizing." *See* 42 U.S.C. § 7411(b)(2); *see also Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (per curiam); *Sierra Club v. Costle*, 657 F.2d 298, 318-19 (D.C. Cir. 1981). CAA section 111(d)(1) provides a similarly broad grant of authority to EPA, directing it to "prescribe regulations which shall establish a procedure…under which each State shall submit to the Administrator a plan [with standards of performance for existing sources.]"[19] The subcategorization authority given EPA in CAA section 111(b)(2) has been interpreted to apply as well to section 111(d) and allows EPA to place existing sources into subcategories when these sources have characteristics that are relevant to the controls that EPA may determine to be the BSER that has been adequately demonstrated.[20]

Further buttressing the notion that EPA has authority to subcategorize existing sources under section 111(d) is the language governing the plans that EPA is required to promulgate to regulate

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[19] Regardless of whether EPA subcategorizes within a source category for purposes of determining the BSER and the emission performance level for the emission guideline, a State retains certain flexibility in assigning standards of performance to its affected EGUs.

[20] Conversely, subcategorization is not appropriate for a set of sources where the qualities in common are not relevant for determining what controls are appropriate to reduce emissions. EPA finds this view is consistent with the D.C. Circuit's interpretation of CAA section 112(d)(1), which is a subcategorization provision that is substantially similar to CAA section 111(b)(2). *See NRDC v. EPA*, 489 F.3d 1,364, 1,375–76 (D.C. Cir. 2007) (upholding EPA's decision under CAA section 112(d)(1) *not* to subcategorize sources subject to control requirements under CAA section 112(d)(3), known as the maximum achievable control technology (MACT) floor, on the basis of costs because the EPA was not authorized to consider costs in setting the MACT floor).

existing sources within a State should a State fail to submit its own plan. CAA section 111(d)(2) provides that, in promulgating such a plan, EPA "*shall* take into consideration, among other factors, remaining useful lives of the sources in the category to which such standard applies [emphasis added]." Thus, Congress has expressly contemplated that existing sources might be subcategorized, by EPA, under section 111(d) based on the anticipated length of their continued operation.

Since the 1970s, EPA has developed subcategories in several rulemakings under CAA section 111. These rulemakings include subcategories on the basis of unit characteristics, including: the size of the sources;[21] the types of fuel combusted;[22] types of equipment used to produce products;[23] types of manufacturing processes used to produce product;[24] levels of utilization of

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[21] *See* 40 C.F.R. § 60.40b(b)(1)-(2) (subcategorizing certain coal-fired steam generating units on the basis of heat input capacity).

[22] *See Sierra Club v. EPA*, 657 F.2d 298, 318-19 (D.C. Cir. 1981) (upholding a rulemaking that established different NSPS "for utility plants that burn coal of varying sulfur content"); *see also* 2015 NSPS, 80 *Fed. Reg.* 64,510, 64602 (table 15) (Oct. 23, 2015) (subdividing new combustion turbines on the basis of type of fuel combusted).

[23] *See* 81 *Fed. Reg.* 35,824 (June 3, 2016) (promulgating separate NSPS for many types of oil and gas sources, such as centrifugal compressors, pneumatic controllers, and well sites).

[24] *See* 42 *Fed. Reg*. 12,022 (Mar. 1, 1977) (announcing availability of final guideline document for control of atmospheric fluoride emissions from existing phosphate fertilizer plants); *see also* "Final Guideline Document: Control of Fluoride Emissions From Existing Phosphate Fertilizer Plants, EPA-450/2-77-005 1-7 to 1-9, including table 1-2 (applying different control requirements for different manufacturing operations for phosphate fertilizer).

the sources;[25] the activity level of the sources;[26] and geographic location of the sources.[27] EPA's proposed subcategorization based on length of period of continued operation is similar to two other instances for subcategorization on which EPA has relied in prior rules regarding load level and fuel type.

First, in the 2015 New Source Performance Standard (NSPS), EPA subcategorized new natural gas-fired combustion turbines into subcategories of base load and non-base load. *See* 80 *Fed. Reg.* at 64,602. In that instance, EPA determined the control technologies were "best" because consideration of feasibility and cost-reasonableness depended on how much the unit operated. The load level, which relates to the amount of product produced on a yearly or other basis, is similar to the limits on a period of continued operation in the Proposed 111 Rules, which concerns the amount of time remaining to produce the product. Further, in both instances, certain technologies may not be cost-reasonable because of the capacity to produce product.

Second, also in the 2015 NSPS, EPA divided new combustion turbines into subcategories based on fuel type combusted. *See id*. There, the Agency determined that the cost-reasonableness of the

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[25] *See* 2015 NSPS, 80 *Fed. Reg*. 64,510, 64,602 (table 15) (Oct. 23, 2015) (dividing new natural gas-fired combustion turbines into the subcategories of base load and non-base load).

[26] *See* 81 Fed. Reg. 59,276, 59,278-79 (Aug. 29, 2016) (dividing municipal solid waste landfills into the subcategories of active and closed landfills).

[27] *See* 71 Fed. Reg. 38,482 (July 6, 2006) (SO_2 NSPS for stationary combustion turbines subcategorizes turbines on the basis of whether they are located in, for example, a continental area, a non-continental area, the part of Alaska north of the Arctic Circle, and the rest of Alaska); *see also Costle*, 657 F.2d at 330 (stating that the EPA could create different subcategories for new sources in the Eastern and Western U.S. for requirements that depend on water-intensive controls).

control depended on the type of fuel combusted. This is similar to the Proposal's subcategorization on the basis of length of period of continued operation because, in both cases, the subcategory is based upon the reasonableness of controls. Subcategorizing based on the duration of continued operation also depends on the span of time in which the fuel will continue to be combusted, because the cost-reasonableness of this approach depends on the length of that timeframe. *See* 88 *Fed. Reg.* at 33,345, explaining that prior EPA rules for coal-fired sources explicitly link length of time for continued operation and fuel type combusted by codifying retirement dates by which the sources must "cease burning coal," citing 79 *Fed. Reg.* 5,032, 5,192 (Jan. 30, 2014).

EPA's authority to consider cost likewise supports its authority to subcategorize based on retirement date. EPA's longstanding implementing regulations explicitly recognize that subcategorization may be appropriate for sources based on "costs of control." *See* 40 C.F.R. §§ 60.22(b)(5), 60.22a(b)(5). EPA maintains that its authority to subcategorize on the basis of federally enforceable dates for permanently ceasing operations "is consistent with a central characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements." 88 *Fed. Reg*. at 33,345. Since many EEI's member companies can choose to retire these units and cease operations in response to this rulemaking and other factors, that implicates EPA's determination as to what controls are "best" for different subcategories. EPA's Proposal correctly reflects that cost of controls and length of operation are inextricably intertwined in evaluating BSER for existing sources, because whether costs are reasonable depends in part on the period of time which the affected sources can amortize those costs. EPA's Proposal to reflect retirement date in the subcategorization for existing source BSER thus is reasonable.

2. EPA has utilized retirement-based approaches in other CAA programs.

In another CAA example, the regional haze program, EPA has utilized its discretion to allow units that are retiring to forgo installation of control technology that would otherwise be required under an analysis of Best Available Retrofit Technology (BART) or the necessary level of control to ensure reasonable progress toward the long-term goal of the regional haze program. The CAA requires each regional haze plan to "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress" toward the statutory goal of eliminating manmade visibility impairment in Class I Federal areas.[28] When determining what measures amount to "reasonable progress" a State must consider four criteria: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and nonair quality environmental impacts of compliance; and (4) the remaining useful life of any existing source subject to such requirements.[29]

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[28] *See* 42 U.S.C. § 7491(b)(2).

[29] *Id.* at 42 U.S.C. § 7491(g)(1). To ensure states achieve "reasonable progress," every plan must require certain large-scale, stationary sources of air pollutants to implement controls known as BART, or adopt a BART alternative. *Id.* at § 7491(b)(2)(A); 40 C.F.R. § 51.308. The CAA defines BART as being based on a source-specific evaluation of five factors. *See Oklahoma v. EPA*, 723 F.3d 1201, 1208 (10th Cir. 2013). These "BART factors" are:

(1) The costs of compliance;
(2) The energy and non-air quality environmental impacts of compliance;
(3) Any existing pollution control technology in use at the source;
(4) The remaining useful life of the source; and,
(5) The degree of visibility improvement which may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

While the regional haze program focuses on source-specific evaluations of the BART factors during the first planning period, it is notable that EPA and states have concluded, in numerous different contexts, that an evaluation of all of the factors listed above leads to the imposition of no further controls given the pending retirement of the source in question. This has primarily been the result of an analysis of the remaining useful life of the source when weighed against the other four BART factors—specifically, that the installation of pollution control technology can impose significant costs for some environmental gains, but that those costs and environmental benefits do not outweigh the environmental and economic benefits of simply retiring the source.[30]

3. EPA has used retirement subcategories in other environmental rulemakings for the power sector.

Courts have long recognized that EPA has broad discretion in determining how to evaluate and weigh these factors. *See, e.g.*, *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) ("The EPA nonetheless has considerable discretion in evaluating the relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination. EPA's authority under the CWA to subcategorize is analogous to that of the CAA. For example, EPA has ample legal authority to establish (or revise) retirement subcategories when promulgating

[30] EPA has endorsed such an approach in its approval of Arkansas' Regional Haze State Implementation Plan and withdrawal of a Federal Implementation Plan wherein the Agency determined that there was no need to install pollution control technology on BART eligible units given that those units had an enforceable order to switch the type of coal used and then to cease use off coal by the end of 2028. *See* Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas, 84 *Fed. Reg.* 51,033 (Sept. 27, 2019). Specifically, EPA concluded that Arkansas satisfied the requirements of the CAA by "fully considering the five statutory factors…Taking into account the remaining useful life of White Bluff Units 1 and 2 (based on Entergy's enforceable Administrative Order to cease coal combustion by December 31, 2028), and the resulting cost-effectiveness of controls, as well as the anticipated visibility improvement of the SO_2 control options and the other BART factors." *Id*. at 51,036.

effluent limitation guidelines (ELGs). In developing best available technology (BAT) limits, EPA must consider "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." 33 U.S.C. § 1314(b)(2)(B). Thus, the EPA has significant leeway in determining how the BAT standard will be incorporated into final ELGs."); *NRDC v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988) ("EPA has considerable discretion in weighing the costs of BAT."); *Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1046 (D.C. Cir. 1978) ("[T]he listing of factors seems aimed at noting all of the matters that Congress considered worthy of study before making limitation decisions, without preventing EPA from identifying other factors that it considers worthy of study. So long as EPA pays some attention to the congressionally specified factors, the section on its face lets EPA relate the various factors as it deems necessary.").

The same statutory factors that EPA must account for when developing BAT limits are relevant to the question of whether to subcategorize within a category of point sources.[31] Accordingly, it is unsurprising that courts have upheld EPA determinations to promulgate different limits for

[31] *See* 67 *Fed. Reg.* 42,644, 42,656 (June 24, 2002) ("The CWA requires EPA, in developing effluent limitation guidelines and pretreatment standards, to consider a number of different factors, which are also relevant for subcategorization."); *see also* 64 *Fed. Reg.* 2,280, 2,300-01 (Jan. 13, 1999) ("One way in which the Agency has taken some of these factors into account is by breaking down categories of industries into separate classes of similar characteristics. This recognizes the major differences among companies within an industry that may reflect, for example, different manufacturing processes, economies of scale, or other factors. One result of subdividing an industry by subcategories is to safeguard against overzealous regulatory standards, increase the confidence that the regulations are practicable, and diminish the need to address variations between facilities through a variance process.").

different subcategories or classes of sources within a particular point source category based on EPA's consideration of the statutory factors in CWA section 304(b).[32]

Of particular relevance here, the importance of evaluating the statutory age and cost factors, and how they affect economic achievability, cannot be overstated. EPA is required to "consider age as it might pertain to the cost or feasibility of retrofitting plants with new pollution control technology." *Am. Iron & Steel Inst. v. EPA*, 568 F.2d 284, 299 (3d Cir. 1977) (referencing the holding in *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1048 (3d Cir. 1975)). This may entail accounting for "the fact that all the plants within [a particular] subcategory were built long before plants in another subcategory [which can] present special problems in installing anti-pollution devices." 526 F.2d at 1048. "Similarly, in a subcategory where there is considerable variation in age, the fact that the processes are similar may mean that the same type of control technology can be installed, but it does not necessarily mean that the ease with which that technology can be installed, or the ability to comply with effluent limitations once it has been installed, is not affected by age." *Id*. Thus, EPA's approach on both ELGs here for existing sources is sound.

4. EPA should also conclude in the alternative that its retirement subcategories are optional compliance approaches that are equivalent to or more stringent than its CCS-based BSER determination.

In the Proposed 111 Rules for existing coal-based units, EPA proposes that each subcategory—imminent-, near-, medium- and long-term operating units—has its own specific BSER based on

[32] *See e.g.*, *Texas Oil & Gas Ass'n*, 161 F.3d at 939 (upholding EPA decision "to set more lenient effluent limits for Cook Inlet facilities than for other members of the Coastal Subcategory"); *BP Exploration & Oil, Inc. v. EPA*, 66 F.3d 784, 802 (6th Cir. 1995) (upholding EPA's rejection of zero discharge of drilling wastes in Alaska based on consideration of various factors, such as infeasibility of reinjection technology).

the characteristics of the units included. As discussed immediately *supra*, EPA is well justified in doing so. However, EPA should also conclude in the alternative that the retirement-based subcategories (imminent-, near-, and medium-term) are optional, compliance-based subcategorizations that are at a minimum equivalent if not more stringent in the aggregate than EPA's BSER determination for long-term units.

Such a determination would be consistent with EPA's ability to subcategorize under CAA section 111 and would also legally ensure that EPA's principal BSER determination was technological in nature since EPA's BSER determination would be singular and the subcategories would be optional, compliance options to comply with EPA's proposal. This would allow for retirement subcategories to be squarely within EPA's discretion from a compliance perspective. Under such an approach, EPA would not need to analyze all of the BSER factors described above to justify each subcategory individually, as the Agency's determination that the subcategory would result in equivalent or greater reductions would provide justification for each subcategory.

Such an approach also would be grounded in the statute, specifically CAA section 111(d)(1)(B), which allows the Administrator to take into consideration, among other factors, the "remaining useful life" of the existing source to which any standard applies. EPA should note that each retirement-based subcategory specifically relies on the language in section 111(d)(1)(B) as part of the Agency's ability to offer each subcategory. Such a conclusion flows logically from the statute. Each subcategory is already designed to take into account the remaining useful life of sources that are in each subcategory—to be eligible for the imminent-, near- or medium-term subcategory, a unit must have an enforceable shutdown commitment, and would have a standard different from the one applied to long-term units (in the case of the current proposal, this would be CCS technology for existing coal-based units).

As noted, *supra*, this approach would be consistent both with EPA's approach to regional haze, and the ELG rulemaking under the CWA. This approach would also comport with EPA's proposed Section 111(d) implementing regulations for state plans, which EPA states are intended to "improve flexibility and efficiency in the submission, review, approval, revision, and implementation of state plans." 87 *Fed. Reg.* 79,176 (Dec. 23, 2022). Importantly, this compliance flexibility also reflects the "core principle of cooperative federalism" embedded in the CAA. *Miss. Comm'n on Envt'l. Quality v. EPA*, 790 F.3d 138, 156 (D.C. Cir. 2015); *Am. Lung Ass'n*, 985 F.3d at 420 (reiterating "the importance of allowing States maneuvering room under the cooperative federalism scheme"). Further, given the D.C. Circuit's decision in *American Lung Association* noting that EPA could offer significant compliance flexibility to states and units and was not required to have sources implement the specific BSER prescribed by EPA, the Agency would be well served to make this argument as an alternative basis for its proposal. 985 F.3d at 942-43, 963.

B. Subcategories Are Essential to Finalizing a Workable Rule for Existing Coal-Based Units and the Proposed Subcategories Must Be Retained in Any Final Rule.

For existing coal-based units, EPA proposes several subcategories. *See* 88 *Fed. Reg*. at 33,341. Three of the proposed subcategories are based on operating horizon and are tied to specific retirement deadlines, intended to reflect many of the already-announced retirements of coal-based EGUs. Units that opt into these subcategories agree to a shutdown commitment, which becomes federally enforceable once it is included in a state's compliance plan, in exchange for lesser, and in some cases, effectively no, emissions limitations before closure. As proposed, facilities would be required to commit to a particular subcategory at the time that the relevant state submits its compliance plan to EPA. *See id*. at 33,344. These retirement subcategories recognize that the long-term emissions benefits of announced unit closures could be undermined by standards that would require owners/operators to invest in control technologies that could extend the lives of the units to ensure cost recovery. *See id*. at 33,341.

EPA's proposed retirement subcategories support ongoing power sector efforts to achieve significant and permanent emissions reductions, are well-founded, and should be included in any final rule. However, the proposed subcategories should be adjusted to address issues identified in these comments. The Agency should finalize this subcategory-based approach, with the changes suggested here.

1. **EPA's use of retirement subcategories for existing coal-based units is broadly consistent with the power sector's ongoing transformation and EPA should finalize this approach.**

The proposed retirement subcategories, as a general matter, track the ongoing clean energy transformation under way in the industry and allow companies to align retirements and investments in a way that balances reliability and affordability for customers should those decisions lead to a decision to retire a unit or units. Many of EEI's member companies are in the process of decommissioning or repowering existing coal-based EGUs, which will result in significant pollution reductions through avoided future emissions. Fifty of EEI's member companies have announced voluntary, forward-looking carbon reductions goals, 41 of which include a net-zero by 2050 or earlier equivalent goal, and members routinely increase the ambition or speed of their goals or altogether transform them into net-zero goals to reflect changing expectations about the cost and availability of renewable generation and other clean energy resources.

As discussed above, EPA has created targeted subcategories for unit closures in other contexts, most notably the cessation of coal subcategory in the Proposed ELG Rule. *See* 85 *Fed. Reg.* 64,650 (Oct. 13, 2020); 88 *Fed. Reg.* 18,824 (Mar. 29, 2023). The subcategories allow for decommissioning/repowering of units, recognizing that standards requiring investments in new control equipment could extend the lives of these units to support cost recovery, and that unit retirements provide long-term environmental benefits through permanent closure and cessation of related emissions. Critically, retirement-based subcategories result in significant avoided future emissions, leading to greater overall reductions than those that could be expected from any existing source guidelines and/or state plans that only provide emissions limits for these units. EPA's proposed approach to these subcategories, therefore, is well-founded in terms of environmental benefits, and the Agency should include them in any final rule.[33]

2. EPA's proposed retirement dates for applicability of the various subcategories are appropriate and broadly consistent with system reliability needs; EPA should not accelerate the dates by which units must retire to access the subcategories.

EPA has proposed that the various retirement subcategories extend out until 2040 to track the industry's ongoing clean energy trends and announced retirement schedules of several EEI's member companies. *See* 88 *Fed. Reg*. at 33,343. Indeed, EPA says as much in the Proposed 111 Rules, noting that industry stakeholders—including EEI—recommended "that EPA allow

[33] As discussed, *supra*, EPA has clear authority to subcategorize units both in the setting of standards and for determining compliance. Importantly, retirement subcategories also are squarely consistent with states' authority to consider the remaining useful life when setting standards for existing units based on EPA's emissions guidelines.

existing sources that are on a path to near term retirement to continue on that path without having to install additional control equipment. The proposed emission guidelines are aligned with this recommendation…and [retirement plans] are part of utilities with commitments to net zero power by certain dates, or are in States or localities with commitments to net zero power by certain dates." *Id*. EPA notes further that over one-third of existing coal-based steam generating capacity has planned to cease operation by 2032, and approximately half of the capacity has planned to cease operations by 2040. *See id*.

The closure dates reflected in the proposed retirement subcategories broadly reflect the ongoing fleet transition writ large; electric company commitments, costs, and the other factors driving clean energy deployment are all playing a significant role in transforming the sector and reducing emissions. Crucially, the retirement dates for the subcategories chosen by EPA also generally align with the overall ability of the electric sector to retire these units in a manner consistent with reliable and affordable system operations; the time provided by EPA allows for coal-based capacity to remain available on the system in a manner that helps address changing system conditions given the integration of clean energy resources and increasing demand due to electrification. System operators across the country and the North American Electric Reliability Corporation (NERC), the designated electric reliability organization under the Federal Power Act, have assessed the potential for capacity shortfalls for the rest of this decade as the energy system continues the clean energy transformation. One cause of these capacity shortfalls is the difficulty of interconnecting new resources to the grid as a result of the growing number of new sources seeking such interconnection and the increasing retirement of existing units.[34] In short, capacity additions (the vast majority of which are intermittent resources with lesser accredited capacity) are not keeping pace with capacity retirements. This presents significant near-term risks to system reliability, particularly during extreme events.[35] Allowing coal-based EGUs to be available throughout the rest of this decade and into the 2030s, therefore, is crucial to preparing for these events and for maintaining overall grid reliability.[36] On a more localized-level, many of the planned retirements that EPA notes in the proposed subcategories already are factored into company's long-term plans. The dates selected reflect their assessments by which these units can be reliably retired and correspond with the availability of other capacity or transmission solutions to replace that which is being lost. However, some of the dates EPA has proposed do not currently match the filed plans and projected availability of replacement capacity; as discussed, *infra*, EPA should note that states can alter the presumptive dates in the subcategories to take specific circumstances into account.

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[34] *See, e.g.*, NERC, 2023 Summer Reliability Assessment (May 17, 2023)(warning that two-thirds of North America would be at risk of energy shortfalls this summer in the event of widespread heatwaves), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

[35] *See* NERC, 2023 State of Reliability Technical Assessment, Technical Assessment of the 2022 Bulk Power System (June 2023), https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf

[36] For example, last year several units in Wisconsin last year delayed imminent planned closures for 18 months to ensure sufficient accredited capacity in MISO over the summer to prepare for peak demand. These delays promoted reliability and were still consistent with the owners'/operators' long-term clean energy goals. *See* Iulia Gheorghiu, Alliant, *We Energies Walk back Wisconsin Coal Retirement Plans in Light of MISO's Expected Capacity Shortfalls*, UTILITY DIVE (June 24, 2022), https://www.utilitydive.com/news/wisconsin-utilities-coal-retirement-miso-delay/626005/. Due to improved accreditation procedures and the interconnection of new generating resources, among other factors, MISO North's capacity situation was improved for the summer of 2023. The extended availability of these coal EGUs, therefore, provided an appropriate buffer while MISO implemented other reliability solutions.

Any movement of these dates forward in time (especially if EPA decides to limit post-2030 retirement options) would undermine significant time and investment in companies' clean energy transformation plans, which also factor in customer costs and which, in many instances, have already been approved by state regulators. Accordingly, in any final rule, EPA should not move these dates forward in time. The Agency's rationale for including these dates is that they closely track the industry's ongoing plans for unit closure and fleet transition and is a reasonable exercise of the Agency's discretion to subcategorize, as discussed in more detail *supra*. EPA's rationale is generally correct, and such an approach can help to support system reliability by ensuring that critical capacity is available over the next decade.

3. EPA can propose presumptively approvable retirement subcategories for existing units, but states have the authority to alter the closure deadlines for specific units based on each's remaining useful life.

EPA can provide presumptively approvable retirement subcategories for states to use in the CAA section 11 implementation plans. This is consistent with EPA's statutory obligations to provide states with emissions guidelines to use in setting standards for existing units under CAA section 111(d). *See* 42 U.S.C. § 7411(d). EPA recognizes both its role and the role of the states in setting standards for existing units throughout the Proposed 111 Rules, including a recognition of the fact that states retain discretion in applying presumptive standards to any individual unit. *See, e.g.*, 88 *Fed. Reg*. at 33,276. Despite this, in proposing the retirement subcategories for existing coal-based EGUs, EPA does not appropriately recognize that states can alter the deadlines for particular units to retire, based on the states assessment of a range of relevant factors, including the remaining useful life of the unit. *See* 42 U.S.C. § 7411(d)(1). Accordingly, EPA must make clear that states can exercise their statutory discretion to alter the presumptive retirement subcategories for existing units, provided such decisions are well supported in a state's implementation plan and result in appropriate emissions reductions. In addition to the express statutory authority to consider remaining useful life, states also can take into consideration other factors. These factors could include state-specific laws and regulations that could require units retire by certain dates that are later than those proposed by EPA.

In any final rule, therefore, EPA should affirmatively recognize that states have the ability to alter the applicability of the presumptively approvable subcategories to account for a range of factors, as required by the CAA. Moreover, EPA should make clear that it will evaluate any state proposals fully and not dismiss them for applying a standard other than the presumptively approvable subcategories proposed by the agency. This approach not only is grounded in the text of CAA section 111(d), but also will have environmental benefits as having units retire—even on a different schedule or with modified emissions limitations that apply in the period before retirement—results in *significant* emissions reductions in the aggregate. EPA should note that it is open to consideration of state plans that make modifications to the presumptively approvable subcategories, as long as those approaches are well-justified and track the ongoing fleet transition plans within those states.

4. EPA should align the subcategories in the proposal with the subcategories included in other rulemakings to help align decision making.

EPA has proposed retirement subcategories in other proposed rules for EGUs. Without explanation, and contrary to the Administrator's stated goal of a holistic approach to the suite of rules impacting the power sector, these retirement subcategories do not align. This significantly undercuts the benefits that could be achieved by these subcategories and frustrates owners'/operators' compliance planning. Accordingly, EPA should ensure that any final rule adjusts the retirement deadlines so that they are consistent across rulemakings, as described below.

EPA's Proposed ELG Rule also includes a subcategory for coal-based units that will soon cease combustion of coal. *See* 88 *Fed. Reg.* at 18,824. Along with the subcategory in the Proposed ELG Rule, EPA issued a direct final rule—which went into effect May 30, 2023—extending the deadline to enter the subcategory for coal-based units that will soon cease combustion of coal that was part of the 2020 ELG Rule, codified at 40 C.F.R. § 423.19(f). *See* 88 *Fed. Reg.* at 18,440. While EPA has announced the goal of achieving a "holistic" approach to the various regulations for the power sector, the closure subcategories for the Proposed 111 Rule and the Proposed ELG rule do not align in several ways.

The subcategory in the Proposed ELG Rule is available to "early adopters," defined as those units that, as of March 24, 2023,[37] have installed technologies to comply with the requirements in the 2020 ELG Rule or the 2015 ELG Rule.[38] *See* 88 *Fed. Reg.* at 18,896 (to be codified at 40 C.F.R. § 423.11(x)). As proposed, "early adopters" entering this subcategory would not be required to install new technologies for flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW) prior to ceasing combustion of coal by December 31, 2032. "Ceasing combustion of coal" includes both plant retirement and repowering to a cleaner fuel source, such as natural gas. The deadline for submitting a Notice of Planned Participation

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[37] The March 24, 2023, deadline corresponds to the publication of the Proposed ELG Rule in the *Federal Register*.

[38] *See* EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 *Fed. Reg.* 67,838 (Nov. 3, 2015).

(NOPP) to enter this subcategory is one year after publication of the final rule. As a preliminary matter, the proposed ELG subcategories allow for repowering as well as retirement because once coal ceases to be combusted, the regulated waste streams, FGD wastewater and BATW, are no longer generated. However, as noted, the retirement subcategories in the Proposed 111 Rule do not appear to envision repowering. EPA should consider allowing for units in the imminent or near-term retirement subcategory to repower to become gas-steam units to better align with the requirements of the Proposed ELG Rule.

In addition, there is a misalignment with the subcategory timelines across both proposed rules. For example, as proposed, the "early adopter" subcategory in the Proposed ELG rule requires retirement by December 31, 2032. *See* 88 *Fed. Reg.* at 18,1896. However, the imminent-term retirement subcategory in the Proposed 111 Rules is December 31, 2031. *See* 88 *Fed. Reg.* at 33,361. EPA should align the Proposed ELG subcategory timelines and deadlines with the Proposed 111 Rules to the maximum extent practicable in order to allow for integrated and holistic decision making by EEI's member companies that are making retirement and investment decisions surrounding these units. EPA should finalize in both the Proposed ELG Rule and also the Proposed 111 Rules a deadline of December 31, 2032, for these subcategories. To the extent that EPA also considers creation of any additional subcategories in the Proposed ELG Rule beyond 2032, EPA should also ensure alignment of any new or extended ELG subcategory with the Proposed 111 Rule's near-term subcategory deadline, with a common deadline of December 31, 2035. Aligning these rules would support cost-effective and fully informed investment/retirement decision making, as well as provide EEI's member companies with significant certainty regarding avoiding investment in units that would otherwise retire.

5. The proposed near-term subcategory is inconsistent with the other retirement subcategories and should be designed to permit more flexible operation in the latter years of a unit's operating life.

The Agency also should consider changes to the proposed subcategory for near-term retiring units, which are those units slated to retire by December 31, 2034. As currently constituted, EPA's near-term subcategory unnecessarily and inconsistently limits operating flexibility for these units, resulting in more stringent standards for these units than for other coal-based units. EPA should consider a different presumptive standard for these units that accommodates a more gradual decrease in capacity factors for these units as they move toward retirement. EPA should also acknowledge that, consistent with EEI's other comments on these subcategories, that states can modify the parameters of these subcategories to address state-specific concerns.

EPA's proposed imposition of a strict capacity factor limitation of 20 percent beginning in 2030 and applicable until the date of unit retirement or December 31, 2034, under this subcategory is arbitrary and is central to the issues owners/operators have identified with respect to EPA's approach to these units. This appears to result in the application of an emissions limitation that is more stringent than EPA's requirements for medium-term retiring coal-based units, which are required to reduce their emissions rate by 16 percent, based on a BSER of co-firing with natural gas. *See* 88 *Fed. Reg.* at 33,377. While not explicit in the Proposed 111 Rules, it appears that EPA intended to ensure an increasing level of stringency in the standards that applied to existing coal-based units the longer that these units operate, with the most stringent standards applicable to those units that operate after 2040. The one exception to this pattern of increasing stringency is the capacity factor-based operating limitations proposed as the presumptive standard for those units that would retire no later than 2035. This capacity factor limitation for near-term retiring units is an outlier. Further, a 20 percent-capacity factor restriction might be difficult to translate into a unit-specific emissions rate; or, at least, EPA has not provided any guidance on how states might make such a conversion.[39] EPA might accept a capacity factor restriction in lieu of an emissions rate limitation, although this is not clear from the Proposed 111 Rule. EPA should clarify this in any final rule if it retains a capacity-factor approach to units that retire no later than 2035.[40]

There are several options that the Agency could take that may offer additional flexibility and improved workability for this subcategory. EPA should consider adopting a "stair step" approach to establishing limitations for near-term retiring units, which would both allow units in the near-term subcategory to provide needed capacity in the early 2030s, while also better tracking the utilization of units that are slated to retire—e.g., units facing a retirement tend to operate less as they approach their final in-service date. To that end, the Agency could continue to utilize a capacity factor restriction approach and reduce the allowed capacity factor over the period from 2030 until 2035. For example: 40 percent in 2030, 35 percent in 2031, 30 percent in 2032, 25 percent in 2033, 20 percent in 2034, and retirement or refuel/retrofit/repower in 2035. The levels themselves could also be subject to state specific circumstances.

EPA could also consider that capacity factor restrictions, instead of beginning in 2030 as proposed, could begin after 2032, allowing units in this subcategory to utilize existing methods of operation and maintenance for the years immediately after 2030, as is proposed for the

[39] Neither has EPA explained how states could convert this into a unit-specific mass-based emissions cap, which would provide more operational flexibility.
[40] States might find this guidance useful for other units as well.

imminent-term subcategory. EPA could consider such a phased approach for increasing standard stringency across the entirety of its program as opposed to a beginning compliance in 2030 for all subcategories, which would track ongoing operational flexibility considerations.

This could provide operational flexibility to ensure that these units can continue to support reliability while also addressing the arbitrary increased stringency of the proposed presumptive standards for these units. EPA should consider adopting such an approach that would allow for these units to gradually operate less before retirement. At minimum, EPA should confirm in any final rule that states could choose to employ alternative approaches for particular units as part of exercising their RULOF authority, as discussed *supra*.

6. The Agency should authorize states to consider access to natural gas when establishing standards for medium-term units.

EPA also should consider changes to the presumptively approvable standards in the medium-term retiring unit subcategory in order to consider lower levels of natural gas cofiring based on state or regional specific circumstances. Not all regions of the country will have access to natural gas pipeline capacity to allow for co-firing up to 40 percent natural gas at units in this subcategory. Although not all units will be medium-term retiring units or actively will consider co-firing with natural gas as a control strategy, some regions might be more constrained than others, especially given existing pipeline capacity. Other states may, for reliability or other reasons, choose to have medium-term retiring units co-fire with more than 40 percent natural gas to address specific circumstances and situations, such as the existence of transmission constrained load pockets.

Given these concerns, EPA should allow states to adjust the requirements for medium-term retiring units to reflect regional and situationally specific circumstances. At minimum, EPA should note that it is open to consideration of state plans that make modifications to the medium-term retirement subcategory as a result of these scenarios.

C. EPA's Proposed Approach to Existing Natural Gas-Based Turbines is Not Supported by Sufficient Analysis; EPA Should Either Repropose These Guidelines or Significantly Supplement Them, Providing Additional and Comparable Compliance Flexibility as That Provided to Existing Coal-Based Generation.

EPA proposes existing source guidelines for states to regulate a subset of existing natural gas-based turbines, which are applicable to combined cycle units that have a nameplate capacity equal to or greater than 300 MW and operate at a capacity factor of greater than 50 percent. *See* 88 *Fed. Reg.* at 33,245. As noted, *supra*, EPA proposes a multi-phased BSER that tracks the requirements for new natural gas-based turbines, including the ability to opt into a hydrogen blending- or CCS-based compliance pathway that would become applicable in the 2030s. Notably, EPA does not propose any subcategories for affected existing natural gas-based turbines as part of the proposed guidelines.

EPA's inflexible, rate-based approach to regulating existing natural gas-based turbines presents significant challenges and is likely to result in perverse outcomes that are inconsistent with EPA's larger emissions reductions goals. EPA's failure to offer similar compliance flexibilities to existing natural gas-based turbines as those offered to states for existing coal-based units is fundamentally arbitrary. If EPA moves to finalize the proposed emissions guidelines for existing natural gas-based units, EPA must provide comparable compliance flexibilities for states to use when setting emissions limits for these turbines.

Existing natural gas-based units also are retiring as part of the industry's ongoing transition and provide many of the same reliability services that coal-based units do, including acting as a capacity resource and providing inertia and voltage support. In addition, many of these units also can provide fast ramping support that can be essential to the reliable integration of variable renewable resources. The same rationales that support the retirement categories that EPA proposes to allow states to use for existing coal-based units also support providing similar compliance flexibilities for these units. EPA should develop and provide the full range of flexibilities for existing natural gas-based units, including the development of retirement-based subcategories, the use of averaging and trading, mass-based compliance demonstration approaches, alternative fuel flexibilities, dual path options, and more (as discussed elsewhere in these comments), and these flexibilities should be tailored to the existing natural gas-based turbine fleet and its circumstances. Not to do so is arbitrary given that existing natural gas units are similarly situated to existing coal-based units in terms of how they operate and the role that they play in the reliability of the grid.

Further, the Agency's choice to have the proposal apply only to "larger" units that operate at capacity factors of 50 percent or greater could have significant unintended consequences for reliability, affordability, and emissions from the sector. The reliability requirements of the sector—handling increasing load due to electrification, providing reliable service in a resilient manner responding to storms, all while advancing clean energy deployment to meet the incentives provided by Congress—will continue to grow regardless of what resources are available to meet those needs.

Principally, EPA's approach—requiring units take either a capacity factor restriction or engage in a costly, capital intensive rebuild/retrofit to either blend with hydrogen or install CCS technology in the 2030s—has two potential likely outcomes: first, electric companies either will invest in costly retrofits or conversions to attempt to achieve EPA's proposed standards, deploying capital in a manner that requires long payback periods; or, second, the large and highly efficient units subject to the proposal will take a capacity factor restriction, effectively exempting themselves from EPA's requirements (on EPA's own terms) and limiting their usefulness in responding to larger grid reliability and resilience needs. Given expectations around increasing load as a result of increased electrification through the 2030s (which is already manifesting), once these large and efficient units near their capacity factor limits, electric companies will be forced to use other sources—including smaller, less efficient and older natural gas-based units, reciprocal internal combustion engine (RICE) units that operate primarily on diesel fuel, build additional renewables and storage, or extend the life of coal-based units that would have otherwise retired in the imminent or near-term category into either the medium or long-term based subcategory.[41] Under several plausible scenarios, this could result in an aggregate *increase* in emissions during the 2030s, at the expense of reliability. This is an outcome that should be avoided by the Agency.

Finally, EPA's entire existing natural gas-based turbine proposal needs significant additional analysis to support any final rule providing emissions guidelines for these units. The vast

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[41] Earlier this summer in New England, dual fuel natural gas and oil-fired units were dispatched into the power market to ensure reliable system operations to address capacity shortfalls after a transmission line issue—indicative of what units are called on when capacity requirements must be met. *See* https://isonewswire.com/2023/07/06/iso-ne-successfully-manages-through-july-5-capacity-deficiency/.

majority of EPA's analysis to identify units to which to apply the existing source guidelines appears to be a single chart focusing on a subset of identified units that have historically been dispatched at capacity factors of 50 percent or greater. *See* 88 *Fed. Reg.* at 33,363. Since then, EPA has released additional modeling and docket materials to try and buttress this approach given its limited nature. EPA then selects a BSER identical to the new source requirements, mostly upon an assertion that existing and new sources are "similar," and then states that these units are not able to access the same type of flexibilities that are offered coal-based existing units. *Id*. This adequate demonstration analysis and EPA's approach to applicability for existing natural gas-based turbines are arbitrary and insufficient. One of the most glaring omissions is EPA's complete failure to grapple with the significant role that existing natural gas-based generation plays in overall system reliability and the challenges associated with retrofitting existing natural gas-based units.

As the fleet continues to transition, natural gas-based turbines will continue to play a critical and evolving role in integrating increasing amounts of renewable generation and providing essential reliability services to allow for the ongoing retirement of the coal-based generation fleet while preserving customer affordability. Natural gas-based turbines are significantly more flexible than coal-based units given their ability to ramp quickly, especially as compared to other dispatchable units, including nuclear units and coal-based EGUs—e.g., they are able to come online quickly and provide power to the grid much faster while also being able to ramp down as needed. This fast-ramping ability both minimizes emissions related to start up and shut down and also helps to avoid emissions by supporting the integration of variable renewable generating resources.

Some units may operate at significant capacity factors—greater than 80 percent—for long periods of time to respond to system considerations, resulting in highly efficient generation from an emissions rate perspective.[42] Other units might instead respond to intermittent system needs, operating at capacity factors of less than 15 percent while still providing essential reliability services and helping to reduce overall system emissions. Further complicating matters, units that operate at high or low (or even in between) capacity factors for long stretches are not guaranteed to remain in that mode while demand for their energy and other services changes continuously in response to system needs. Units are obligated to respond when called upon based on these system needs, which will change further in coming years as the generation mix of the grid continues to evolve.

One consequence is that these units likely will be required operate differently.[43] These changes will have a significant impact on the emissions and emissions rates associated with these units. This includes the potential for: units switching between operational modes (e.g., simple v. combined cycle) to respond to voltage demands; units in specific locations running more or less often to respond to generation intermittency, transmission congestion or new transmission coming online changing the dynamics of the operating grid; and the aging of the existing gas fleet, which will continue as the fleet transition continues. Each of these scenarios will result in a significant impact on the efficiency rates and the CO_2 profile of existing gas-based units and the

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[42] In general, the emissions rate of an individual unit is more efficient (resultingly, lower) when it run at higher capacity factors. Units that operate at lower capacity factors have concomitantly higher, less efficient emissions rates despite having fewer mass emissions of CO_2.

[43] *See, e.g.*, Eric Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Final report (Princeton University, Oct. 2021), https://netzeroamerica.princeton.edu/the-report.

associated efficiency rates for those units. Consequently, the sheer diversity of the types of units and the range of possible operating characteristics of the existing turbine fleet makes determining an implementable BSER for these units extremely difficult, as EEI noted to the Agency in April 2023 comments to the non-regulatory docket that are attached as Appendix C. EPA addresses none of these salient issues in its analysis of the feasibility of the proposed standards, which would be effective far into the future.

Taken together—the lack of compliance flexibility, the potential unintended emissions consequences of EPA's approach, and the Agency's insufficient analysis regarding the changes and variability in how these units operate—are significant flaws with the proposed emissions guidelines for existing natural gas-based units. They likely render the Proposed 111 Rules arbitrary, capricious, and unsupported on the record for existing gas-based units.

The Agency, therefore, should repropose or significantly supplement its existing source emissions guidelines for existing natural gas-based turbines to address these concerns. In the context of the analysis that will be necessary to support any re-proposal or supplemental rulemaking, EPA should focus on crafting an approach that includes subcategories that reflect the vast array of types and categories of units, including those that reflect more nuances with respect to operational modes; the ability to convert rate-based standards into mass-based compliance options; multiple different averaging forms; and the ability of states to leverage existing programs, among many other approaches. EPA should adopt options that could allow units to choose among multiple paths to comply with EPA's BSER, helping to facilitate diverse unit owner/operator approaches that also consider customer affordability and grid reliability. If EPA opts not to repropose the emissions guidelines for existing natural gas-based EGUs, the Agency must provide comparable compliance flexibility, including retirement-based subcategories tailored to the circumstances of the natural gas turbine fleet, to these units as that provided to existing coal-based units.

D. There are Significant Procedural Considerations EPA Must Account for when Finalizing These Rules.

Agencies are not bound to finalize rules exactly as they were proposed. However, final rules must be a "logical outgrowth" of the proposal. *See, e.g., Nat'l Mining Ass'n v. Mine Safety & Health Admin.*, 512 F.3d 696, 699 (D.C. Cir. 2008). "The key question is whether commenters 'should have anticipated'" that the agency might take the course of action it ultimately chose. *City of Waukesha v. EPA*, 320 F.3d 228, 245 (D.C. Cir. 2003) (citation omitted). Under this standard, "incremental changes are permissible." *Sierra Club v. Costle*, 657 F.2d 298, 352 (D.C. Cir. 1981).

Final standards or guidelines should be an expectable result of the rulemaking process based on the proposal and the feedback received to avoid subjecting EPA to additional scrutiny. "One logical outgrowth of a proposal is surely … to refrain from taking the proposed step." *New York v. EPA*, 413 F.3d 3, 44 (D.C. Cir. 2005) (citation omitted); *Ariz. Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1299–1300 (D.C. Cir. 2000). However, what is *not* permissible is finalizing a rule that, instead of declining to adopt a rule as proposed, adopts a wholly *new* interpretation of the statute without additional notice and opportunity for comment. *Envt'l Integrity Proj. v. EPA*, 425 F.3d 992, 997 (D.C. Cir. 2005); *id.* at 998 ("Whatever a 'logical outgrowth' of [an agency's] proposal may include, it certainly does not include the Agency's decision to repudiate its proposed [position] and adopt its inverse."). For such changes to be lawful, EPA must first have "alerted interested parties to the possibility of the agency's adopting a rule different than the one proposed." *Kooritzky v. Reich*, 17 F.3d 1509, 1513 (D.C. Cir. 1994).

EPA faces a particular challenge with rulemaking under section 111—because EPA's rule will apply to all new facilities constructed following the date of *proposal*, the reliance interests engendered by the proposal are heightened. *Cf. Smiley v. Citibank (S.D.), N.A*., 517 U.S. 735, 742 (1996) (a change in position "that does not take account of legitimate reliance on" the prior position may be arbitrary and capricious); *MediNatura, Inc. v. Food & Drug Admin.*, 998 F.3d 931, 940 (D.C. Cir. 2021) (reiterating need to evaluate reliance interests "[w]hen an agency changes policy" (cleaned up)). So too, therefore, are the consequences of failing to provide notice and an opportunity to comment on any unanticipated changes in the final rule. Section 111(b) rules, in this way, are fundamentally unlike the typical rule, which is finalized and only sometime thereafter becomes effective. Under section 111(b), regulated entities have to begin preparing *immediately* to comply with whatever rule EPA decides to make final. This fact must result in a narrowing of the range of potentially logical outgrowths of the proposal, with a corresponding widening of situations in which a new proposal or revision with an additional comment period becomes necessary.

This is especially pertinent for EPA's rulemakings here; should EPA significantly overhaul and accelerate its timelines—or provide the additional flexibilities for existing natural gas units these comments recommend—the Agency likely will need to address logical outgrowth issues. As a result, as the Agency moves forward, it should take care not to completely overhaul its proposals without providing stakeholders the opportunity to comment specifically on the range of approaches EPA is considering.

Ultimately, to help continue the successful and ongoing clean energy transition of the power sector, EPA must design standards for both new and existing units that achieve emissions reductions goals, are consistent with electric company clean energy commitments, and support affordable and reliable electricity. Commenters must have the ability to provide substantive feedback on EPA's specific proposals to ensure that they are achievable and not inconsistent with the rest of EPA's rulemaking agenda for the sector. Providing additional opportunities for comment and feedback will only assist the Agency in this task—and it is EPA's obligation to do so as well.

The time afforded for comment on the Proposed 111 Rules was comparatively short. EEI will continue to consider options to improve the Proposed Rules, particularly those for natural gas-based generation, even after these comments are filed and will share any developments with EPA and other stakeholders. In addition, the Federal Energy Regulatory Commission has announced that the 2023 Annual Reliability Technical Conference will address policy issues related to the reliability and security of the bulk power system, as well as the Proposed 111 Rules. EPA should consider the outcomes of these efforts as it works to finalize standards for new and existing fossil-based generation.

III. EPA Has Not Shown That Either CCS Or Hydrogen Blending Are Adequately Demonstrated And That The Proposed Standards Are Achievable Across All Regulated Units.

EPA has failed to show that either CCS or the hydrogen blending requirements are adequately demonstrated and can be BSER. As a result, the proposed standards based on the application of these BSERs may not be achievable across all regulated units.

While EPA asserts that individual constituent elements of each technology are adequately demonstrated, EPA does not address that these disparate pieces must function as a whole if the standards are to be achievable. EPA's statutory obligations are clear: to select as BSER a technology that is adequately demonstrated and then set emissions limits are achievable across the entire sector (or provide guidelines for the statues to set achievable emissions limits). By not ensuring that the component pieces of each technology are demonstrated as one, integrated whole, EPA falls short of its statutory obligations and the Agency's expansive reading of CAA section 111 and the related caselaw do not overcome this failure.

A. EPA's Determination That CCS and Hydrogen Blending Are Adequately Demonstrated is Legally Insufficient.

For the purposes of section 111, a "standard of performance" is currently defined as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the *best system of emission reduction* which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines *has been adequately demonstrated*.

See 42 U.S.C. § 7411(a)(1) (emphasis added). In promulgating CAA section 111(b) standards for new and modified sources, EPA has typically used a straightforward process to: (a) identify what emission reduction technology/systems exist for a source category; (b) assess related costs and secondary air benefits (or disbenefits) from associated energy requirements; and (c) examine any non-air quality impacts of employing those technologies or systems.[44] Following this analysis, EPA promulgates a standard of performance, usually in the form of a numeric emission limit based on installation and operation of the identified technologies or systems—that is, the "best system of emission reduction," or BSER.

Section 111(d) provides that EPA must establish procedures under which each State must submit a plan that establishes standards of performance for any existing source within its borders for any pollutant "to which a standard of performance … would apply if such existing source were a new source."[45] The statute further provides that regulations promulgated under section 111(d) shall allow States in "applying a standard of performance to any particular source [under a state plan submitted to EPA] to take into consideration, *among other factors*, the remaining useful life of the existing source to which such standard applies."[46]

Although in the first instance section 111(d) authorizes the individual states, and not EPA, to set standards of performance for and to apply those standards to existing sources, EPA promulgated section 111(d) implementing regulations in 1975 that require the Agency to both identify the BSER *and* develop "guidelines" reflecting emission reductions that can be achieved by existing

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[44] *See, e.g.,* Env't Prot. Agency, Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act, https://archive.epa.gov/epa/sites/production/files/2013-09/documents/111background.pdf.

[45] 42 U.S.C. § 7411(d)(1). Section 111(d) authority is, as an initial matter, contingent on the existence of a corresponding 111(b) rule (*i.e.*, it exists only where a "standard of performance under this section would apply if such existing source were a new source").

[46] 42 U.S.C. § 7411(d)(1) (emphasis added). If a State fails to submit a satisfactory plan, EPA must develop and implement a federal plan for that state that meets the requirements of the section. *Id.* at § 7411(d)(2).

sources through the application of the selected BSER. *See* 40 C.F.R. sections 60.22(b)(2) and (b)(5). EPA's guidelines must provide information for the development of state plans that:

- Reflect application of the BSER (considering the cost of such reduction) that has been *adequately demonstrated*;
- Address "the *time* within which compliance with emissions standards of equivalent stringency can be achieved"; and
- Specify "different emission guidelines or compliance times or both for different sizes, types, and *classes* of designated facilities when *costs of control, physical limitations, geographic location, or similar factors* make subcategorization appropriate."

Id. (emphasis added). EPA's section 111(d) implementing regulations further provide that, where a designated pollutant has been determined to endanger public health, standards of performance developed as part of a state implementation plan must be at least as stringent as those established by EPA's section 111(d) guidelines and compliance achieved "as expeditiously as practicable." *See* 40 C.F.R. section 60.24(c). Thus, how EPA defines BSER in its guidelines, in general, drives the minimum stringency of state standards of performance for existing sources. At the same time, however, states have considerable flexibility in applying BSER to affected sources on a case-by-case basis.

Per the express language of section 111(b)(1)(B), a standard of performance "become[s] effective upon promulgation," and under section 111(a)(2) is applicable to any "new source"—defined as any source "the construction or modification of which is commenced after the publication of [an applicable NSPS] (or, if earlier, proposed regulations)." 42 U.S.C. § 7411(b)(1)(B), (a)(2). For new sources, two things are apparent from this: first, any New Source Performance Standard (NSPS) is effective immediately upon finalization; second, to ensure that sources do not rush commencement of construction during the pre-finalization notice-and-comment period, all sources that are built after the NSPS's proposal date are covered. Because of this, the statute expressly requires that Administrator determine that the BSER upon which the standards are based "has been adequately demonstrated"—in the *past* tense—and not that EPA projects that it might at some *future* date be adequately demonstrated.

EPA must therefore select a "best system of emission reduction" that is *presently* adequately demonstrated, and it must set a standard of performance that is achievable—these are two separate requirements. *See* 42 U.S.C. § 111(a)(1). As the D.C. Circuit has explained, "it is the system which must be adequately demonstrated and the standard which must be achievable." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); *see also Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 785 (D.C. Circ. 1976) (quoting same). With regard to whether the technology underlying an NSPS "has been adequately demonstrated," the D.C. Circuit has opined that "section 111 most reasonably seems to require that EPA identify the emission levels that are 'achievable' with 'adequately demonstrated technology' … which represents the best balance of economic, environmental, and energy considerations." *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981). Moreover, "[s]ince the standards here put into effect [that is, under section 111(b)] will control new plants *immediately*, as opposed to one or two years in the future, *the latitude of projection is correspondingly narrowed*." *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 392 (D.C. Cir. 1973) (emphasis added).

For both new and existing sources, an adequately demonstrated system is "one which has been *shown* to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (emphases added). EPA is not limited to what may currently be the "state of the art" in a sector but may instead "look[] toward what may fairly be projected for the regulated future." *Portland Cement*, 486 F.2d at at 392. EPA may also rely on projections that a technology will become available, but it is not permitted to engage in a "crystal ball inquiry." *Portland Cement*, 486 F.2d at 391-92 (citing *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)). *See also Essex Chem. Corp.*, 486 F.2d at 433 ("An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."). As with adequate demonstration, EPA's determination of a standard's achievability cannot rest on "mere speculation or conjecture." *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (per curiam).

Further, for both new and existing sources EPA also is required under CAA section 111 to show that standards must be achievable by sources across a wide range of operating conditions. "A uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431-33, n.46 (D.C. Cir. 1980).

EPA has fallen short of these requirements in the Proposed 111 Rules.

1. **EPA's CCS and hydrogen blending adequate demonstration analysis does not address the necessary integration of the constituent elements of these technologies now.**

EPA has not legally supported its conclusion that CCS or hydrogen blending are BSER. The record lacks substantial evidence showing that these technologies are currently demonstrated at scale, or could be demonstrated at scale in a commercial setting.[47] Most critically, while EPA cites individual components of both CCS and hydrogen blending—e.g., a functioning capture amine system, the existence of a CO_2 pipeline, hydrogen blending pilots—it *never* shows in its record that these components are integrated at scale across the industry and are available for sources to use to meet the resulting emissions limitations.

The statute expressly requires that EPA identify a BSER that "has been adequately demonstrated." By its very terms, that phrase connotes something that is available *now* for existing units to employ because it has *already been demonstrated*. That is not the case for CCS or hydrogen blending. EPA enjoys a certain amount of latitude in its predictive judgments, "[o]ne must distinguish between prediction and prophecy." *Int'l Harvester*, 478 F.2d at 642 (citation omitted). But when predicting future conditions, the Agency must provide "a reasoned presentation of the reliability of [the] prediction and the methodology that is relied upon …." *Id.* at 648. Neither may EPA rely on prototypes, nor leave unanswered critical questions about the practical aspects of a system such as waste disposal. *See Costle*, 657 F.2d at 341, n. 157, *Essex Chem.*, 486 F.2d at 435, n.19, 438.

EPA recognizes that any standard relying on "improved design and operational advances" must be grounded in "substantial evidence that such improvements are feasible," but misses the mark

[47] *See* Appendix A, Chapter 2 – New Technologies Will be Essential to Achieving the Clean Energy Transformation, and EPA's Regulatory Structure Can Help Advance Those Technologies.

with its determination that CCS and hydrogen blending are BSER. No “substantial evidence” regarding the present feasibility of CCS or hydrogen blending as BSER for a nationwide standard exists in the record. *See* 88 *Fed. Reg.* at 33,272. As discussed later in this section, there are real, practical constraints on the ability of CCS to be widely available in the timeframe posited—much less “immediately,” as required by the *Portland Cement* decision—and with sufficient ability to achieve the proposed standards of performance. *See Portland Cement*, 486 F.2d at 391-92. This is critically also problematic, as discussed *infra* in this section as well, for EPA’s determination that hydrogen blending is likewise feasible and available across the industry today. These include insufficient pipeline infrastructure and the absence of any federal regime for pipeline permitting or eminent domain authority for those pipelines. For CCS, permitting of the other elements of infrastructure and storage, not to mention concerns regarding long-term liabilities associated with storage, must also be resolved before this technology can be said to be adequately demonstrated for and available to the power industry nationwide. For hydrogen blending, these projects are at most at pilot stage and have not been utilized at load, at scale, or cross different grid scenarios, not to mention the lack of hydrogen related infrastructure to produce, transport and utilize hydrogen in the power sector.

EPA has not shown how those issues can be overcome by the time this Rule is finalized, and it is therefore impossible to see how EPA can lawfully conclude that either CCS or hydrogen blending are adequately demonstrated now. As of now and with the record in this proposal, EPA cannot claim with any measure of certainty that CCS or hydrogen blending is or “has been adequately demonstrated” or that it will be available at a date certain in the near future.

Moreover, EPA acknowledges that a standard is only achievable if the technology to be used "can reasonably be projected to be available to an individual source *at the time it is constructed* that will allow it to meet the standard." *See* 88 *Fed. Reg.* 33,275, citing *Sierra Club v. Costle*, 657 F.2d at 364 n.276 (emphasis added). That is *not* what EPA has proposed. EPA expressly recognizes that "building the infrastructure required to support widespread use of CCS and low-GHG hydrogen in the power sector will take place on a multi-year time scale." 88 *Fed. Reg.* at 33,283. EPA provides no assurance (and cannot provide assurance) that such infrastructure will in fact be in place by 2038, much less by 2032. Given the lack of that infrastructure, EPA cannot determine that either technology is adequately demonstrated, since on its own terms EPA cannot prove that the individual components of each technology can work together across the industry and be available—as EPA itself acknowledges.

EPA attempts to address concerns about adequate demonstration by conceding that these technologies are not yet widely available and thus will not be truly adequately demonstrated until some date in the future but contends that CCS actually *is* adequately demonstrated now on a *unit* basis. However, EPA lacks substantial evidence to support this lesser conclusion. For existing sources, EPA's proposal to include retrofitting CCS for existing coal- and natural gas-based facilities misses the mark. Retrofitting is prohibitively difficult, given the likely space constraints and other associated technical challenges. And EPA is not even certain there will be sufficient geologic space to sequester the carbon. The Agency, for example, expressly acknowledges the complications of permitting geologic sequestration on federal land. *See* 88 *Fed. Reg.* at 33,297. EPA implies there are numerous extant examples of CCS currently in operation, but in truth can point to only one facility, in Canada, that is approaching the levels of CCS capture that EPA would require in this proposal. *See id*. at 33,368. As discussed *infra*, this is not enough to show that CCS is adequately demonstrated for deployment on a nationwide scale, without regard to location, geology, and other constraints on plant design. For hydrogen blending, EPA attempts to note that numerous pilot studies and federal efforts to establish infrastructure is proof positive of achievability on a unit basis. As discussed in these comments, EPA has not grappled with an array of issues regarding these assertions.

Aside from the substantive concerns underlying EPA's lack of record-based support for its adequate demonstration determination, there are both a procedural and a structural issue that are central to why EPA must show that the BSER it selects is achievable and demonstrated not just in component pieces but as an integrated whole: What happens if EPA's projections are wrong? Any challenge to EPA's final rule brought at the time that it is clear that EPA's projections were not correct—that is, in 2030, 2032, 2035, or 2038 when compliance obligations are incumbent on states and units—will be years too late under the CAA's judicial review provision, which requires that challenges to regulations be brought within 60 days of their finalization. *See* 42 U.S.C. § 7607(b). The Act's structure—both the substantive provisions of section 111, which require immediate application of an NSPS, and the procedural provisions of section 307, which require immediate judicial review—leads to the conclusion that EPA must demonstrate that its chosen BSER is adequately demonstrated and available to the regulated industry *now*.

Another issue with EPA's reasoning is the Agency's lack of acknowledgment that, in promulgating a phased BSER with multiple compliance "pathways," those pathways—however distinct—must operate as an integrated whole, *i.e.*, a "system" of emission regulation. Thus, EPA must determine that it has been adequately demonstrated that, no matter which pathway a new unit chooses, those units will be able to work together throughout their respective electrical grids. Similarly, any BSER discussion that does not address whether all elements of EPA's chosen technology system can be integrated at commercial scale by sources across the country is inherently lacking. This is particularly important in this source category, because it is the *only* source category with a public service obligation to operate, and because the entities making up that category face penalties for failing to provide reliable electricity to their customers. The full operability of *all* elements of a technology system is vital for EGUs, given the power sector's unique obligation to be available and on call to provide power whenever it is needed. As a result, for example, a demonstration of the integration of hydrogen, including all system elements, with EGUs is critical in order to make a finding on adequate demonstration: the nation's electricity customers must be assured not only that the technology works, but also that it allows generators to meet their capacity and reliability obligations at the same time.

While EPA recognizes in the abstract that it "may assess whether controls it is considering would create risks to the reliability of the electricity system in a particular area or nationwide," 88 *Fed. Reg.* at 33,274, EPA has ignored the very real possibility of this concern materializing in this very rule, rendering the BSER determination inadequate.

Given these very real concerns, EPA's ultimate determination that CCS and hydrogen blending constitute BSER is insufficient legally.

2. EPA does not have the authority under CAA section 111 to develop "phased" future standards for either new or existing units based on projections of technology development.

For natural gas-based units, EPA proposes that BSER for new stationary combustion turbines, depending upon the pathway chosen, is 90 percent CCS *by 2035* or 96 percent low-GHG hydrogen blending *by 2038*, coupled with an interim milestone of 30 percent low-GHG hydrogen blending *by 2032*. For existing natural gas-based combustion turbines, EPA has likewise proposed CCS or low-GHG hydrogen as the BSER, while BSER for existing coal-based steam generating plants will be a combination of routine operation and maintenance/no increase in emission rate, natural gas use, and CCS.

As a general matter, EPA's approach to the near-term requirements—"phase one" for new units, and routine operation and maintenance/emission rate stasis for existing units—appears to meet the requirements of the statute despite some technical questions regarding EPA's determinations about the ability to comply with the rate chosen by the Agency, which are addressed in these comments *infra*.[48] EPA's proposed requirements for CCS and low-GHG hydrogen in subsequent phases, however, are not legally supportable. For low-GHG hydrogen blending, EPA is not actually suggesting that this technology is adequately demonstrated *now*; rather, EPA merely *projects* that it will be adequately demonstrated in and through the 2030s. Similarly, for CCS, while EPA contends that the technology is adequately demonstrated now on a *unit* basis, the Agency concedes that CCS is not yet able to be implemented nationwide due to geologic, infrastructure, and other present constraints.

[48] To be clear, EEI's concerns—detailed *infra*—have to do with the proposed emission rate, not the use of an efficiency-based standard.

Concluding now that these technologies are BSER is therefore an unsustainably expansive reading of EPA's authority under the statute. As noted above, section 111 requires that standards of performance be "achievable" through a BSER that "*has been* adequately demonstrated."[49] This makes sense, because by section 111's express terms, all new sources the construction or modification of which commences after the date a new NSPS is *proposed* must incorporate or meet the level of emission reductions achieved by that new system of emission reduction. As the D.C. Circuit noted in *Portland Cement*, an NSPS is effectively *immediately*, and EPA's ability to project the availability of technologies at some future date is correspondingly narrowly cabined. *Portland Cement*, 486 F.2d at 391-92. EPA's approach does not accord with the text of the statute, which requires EPA to base BSER on a technology that "*has been* adequately demonstrated"—not one that "will be" (or, more accurately here, might be) demonstrated by some "future date certain."[50]

a. EPA's assertion that "lead time" allows for the development of phased standards is mistaken.

Instead of locating support in the statute, EPA relies inappropriately on just one decades-old case stating that the courts will evaluate EPA's conclusions regarding availability of a technology in conjunction with the "lead time" afforded before the technology is required to be deployed. *See* 88 *Fed. Reg.* at 33,289, citing *Portland Cement*, 486 F.2d at 391. Put simply, it is one thing for a technology to be adequately demonstrated today but to require some "lead time" for implementation; it is another for EPA to project a date some years in the future when an

[49] 42 U.S.C. § 7411(a)(1).

[50] *Compare* 42 U.S.C. § 7411(a)(1) (using past tense to refer to a BSER that "has been adequately demonstrated"), *with* 88 *Fed. Reg*. at 33,273 ("EPA may determine a 'system of emission reduction' to be 'adequately demonstrated' if the EPA reasonably projects that it will be available by a future date certain").

emerging technology might be adequately demonstrated and available for use. The former *might* pass muster under the Act; the latter does not. *See Am. Fuel & Petrochem. Mfrs. v. EPA*, 3 F.4th 373, 383 (D.C. Cir. 2021) (allowing specific statutory percentage to be read to include a margin for compliance but not an entirely different percentage altogether).

NSPS are to be "effective upon promulgation," and a "new source" to which the NSPS is applicable is one "the construction or modification of which is commenced after the publication of regulations (*or, if earlier, proposed regulations*)." *See* 42 U.S.C. §§ 7411(b)(1)(B) and 7411(a)(2) (emphasis added). A system of emission reduction that does not yet exist—that is, one that is not yet adequately demonstrated—cannot be made "effective upon promulgation" and cannot be implemented by a source constructed immediately after the date of the NSPS's proposal.

Likewise, setting a BSER that is not predicted to be adequately demonstrated until more than a decade in the future undermines Congress' requirement that EPA consider NSPS revisions on an eight-year cycle. *See* 42 U.S.C. § 7411(b)(1)(B). Congress anticipated that technologies would develop sufficiently quickly that what might be state-of-the-art one year may be overtaken by superior technologies in relatively short order—and determined that EPA should regularly consider and, if appropriate, require sources built after that statutorily-required reexamination to implement those new technologies. EPA's determination in the proposed rule that critical elements of its BSER are not presently adequately demonstrated—thus proposing to delay their implementation until some future time a decade or more away, but nonetheless applying the rule to all sources built after the date on which this proposed NSPS is published in the Federal Register—runs contrary to Congress's carefully-constructed statutory framework.

Further, EPA has identified no limiting principle to its "lead time" construct. Taken to its logical conclusion, EPA's interpretation as allowing the Agency to predict the availability of future technologies and apply them to sources built *now* would mean that the Agency could promulgate an NSPS with a BSER that isn't projected to be available for decades, as long as the Agency promises not to enforce the requirement until a "future date certain."[51] Critically, Congress did not provide EPA with such authority.

EPA relies on *Portland Cement* to support its assertion of authority to require a phased BSER spread over more than a decade. *See* 88 *Fed. Reg.* at 33,275. Such reliance is misplaced. As an initial matter, there, unlike here, the court was not presented with a phased NSPS.[52] True, the court in that case described "lead time" as "the time in which the technology will have to be available." *See Portland Cement*, 486 F.2d at 391. Crucially, though, that is not all the court said. In the immediately preceding sentence, the court stated explicitly that any projections about the

[51] *See, e.g.*, 88 *Fed. Reg.* at 33,275, among many (reflecting an essentially limitless ability to project requirements applicable "at a future time"). Query, though, what happens if the technology does not develop as EPA predicts. Sources built after the date of the NSPS's proposal would still be required to meet the BSER at that future time, even though it would be impossible for them to do so. And the time for challenging the rule—limited to 60 days from its finalization—would long since have run.

[52] For the Portland Cement plants at issue in *Portland Cement*, there was no substantive dispute about the availability of the PM control technologies at issue; they had been deployed and used by a notable subset of the industry. The dispute was regarding costs and level of the standard, knowing that the technology itself was in fact available and demonstrated as a technical matter across operating conditions. That is a markedly different scenario than is presented here, and one that does not inure to EPA's benefit.

future availability or performance of a system of emission reduction for the source category are "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry" or "mere speculation or conjecture." *Id*. The court also explained that in the context of section 111(b), where "the standards … will control new plants *immediately*, as opposed to one or two years in the future, the latitude of projection is correspondingly narrowed." *Id*. at 391-92 (emphasis added). EPA simply ignores this express judicial caveat in its proposal.[53]

b. EPA has no other regulatory precedents for proposing phased standards.

EPA offers no regulatory precedent for promulgating a BSER that is reliant on a technology that is not available now but that the Agency projects will be adequately demonstrated sometime in the future. The examples upon which EPA relies do not support EPA's current proposals. Rather, those rules merely demonstrate that the Agency may accommodate logistical and other impediments to deployment of an already existing technology.[54] In cases such as this, where an

[53] Moreover, EPA ignores that *Portland Cement*'s discussion of lead time hearkened back to *International Harvester Co. v. Ruckelshaus*, a case involving the *mobile source* provisions of the Act.[53] In those provisions, the concept of "lead time" not only makes eminent sense given the implementation timeframes required to design and roll out millions of new motor vehicles, but also (and in stark contrast to section 111) finds support directly in the statute itself. Instead of being "effective upon promulgation" and applicable to sources built after the date an NSPS is proposed, mobile source standards "shall take effect *after* such period as the Administrator finds necessary to permit the development and application of the requisite technology." Indeed, in the case of mobile source-related air toxics, EPA is to promulgate requirements reflecting "the greatest degree of emission reduction achievable through the application of technology which *will be available*…." Congress understands verb tense, understands the concept of lead time, and knows when and how to allow EPA to plan for future availability of a technology. While it plainly did so for mobile sources, Congress very clearly chose *not* to do that for stationary sources in the statute's NSPS provision.

[54] *See, e.g.*, 81 *Fed. Reg.* 59,332 (Aug. 29, 2016) (establishing NSPS for municipal solid waste landfills with 30-month compliance timeframe for installation of control device, with interim milestones); 80 *Fed. Reg.* 13,672 (Mar. 16, 2015) (establishing wood heaters NSPS with stepped compliance approach to permit manufacturers lead time to develop, test, field evaluate and certify current technologies to meet Step 2 emission limits that were already being met by

agency uncovers new authority where none was thought to exist previously, courts may at minimum apply additional scrutiny to this new claim. *See Utility Air Regul. Grp. V. EPA*, 573 U.S. 302, 324 (2014).

Congress provided for review and, as appropriate, revision of each NSPS every eight years. It stands to reason, then, that what is reasonable "lead time"—even for implementation, not technology development—cannot extend beyond the next round of NSPS review, at which time a once-new source ceases to be a statutory "new source."[55] As the D.C. Circuit recognized in *Sierra Club v. Costle*, "[a]lthough it is conceivable that a particular control technique could be considered both an emerging technology and an adequately demonstrated technology, there is inherent tension between the two concepts…." *Costle*, 657 F.2d at 341, n.157. Instead of grappling with and attempting to reconcile this tension, EPA does not address it.

c. EPA has no statutory basis for a phased approach.

An additional and important constraint on EPA's legal authority concerns *when* section 111 requires compliance. As noted, section 111(b)(1)(A) specifies that an NSPS "shall become effective *upon promulgation*," and section 111(a)(2) specifies that it applies to any source constructed after the NSPS is *proposed*. *See* 42 U.S.C. §§ 7411(b)(1)(A) and 7411(a)(2), respectively. The D.C. Circuit has stated that NSPS "control new plants immediately" and

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existing sources); 78 *Fed. Reg.* 58,416 (Sept. 23, 2013) (revising oil and gas NSPS to establish phase-in period to permit sufficient time for production of necessary supply of control devices and for trained personnel to perform installation).

[55] As the statute makes clear, for purposes of section 111, a "new source" is one "the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section *which will be applicable to such source*." 42 U.S.C. § 7411(a)(2). Stated another way, once EPA conducts its eight-year review and promulgates a new NSPS for a source category, a "new source" is one to which that new NSPS applies.

therefore that EPA's discretion to project the future availability of technology is "correspondingly narrowed." *Portland Cement*, 486 F.2d at 391-92. Section 111(b) also provides that "[*a]fter the effective date of standards* of performance promulgated under this section, it shall be unlawful for any owner or operator of any new source *to operate such source in violation of any standard of performance applicable to such source*." These three provisions, when read together, mean that all requirements contained in an NSPS must apply to all affected sources as of the date of promulgation, at the very latest. This in turn means that the BSER must be adequately demonstrated at the time the rule is proposed.

While EPA claims that phase two standards will be "effective upon promulgation," that is plainly not the case. EPA adopts a strained reading of the statute under which phase two standards are "effective upon promulgation" simply by virtue of the fact that it *appears in* the NSPS, even though no source will be held to it (or indeed could be held to it) for many years to come. *See* 88 *Fed. Reg.* at 33,289. EPA appears to read the term "effective" as allowing an NSPS to apply in a partial fashion both initially and in the future—as the Agency states, "upon promulgation, affected sources become subject to a standard of performance that limits their emissions immediately, … and they *also* become subject to more stringent standards beginning in 2032 or later." *Id.* (emphasis added). The Agency, however, cites nothing in the statute that allows this broad and counterintuitive reading of section 111, nor any case law supporting such a reading. If the Agency believes more stringent standards will be justifiable in the future, it may promulgate a new NSPS *at that time*.

Indeed, this appears to get to the heart of why EPA advances such a strained reading of the statute. As EPA admits, applying the statute according to its plain terms would cede its ability to proactively regulate later-built sources pursuant to the more stringent low-GHG hydrogen and enhanced CCS technology requirements:

> It should be noted that the multi-phased implementation of the standards of performance that the EPA is proposing in this rule … is distinct from the promulgation of revised standards of performance under the 8-year review provision of CAA section 111(b)(1)(B)…[T]he EPA has determined that the proposed BSER—highly efficient generation and use of CCS or highly efficient generation and co-firing low-GHG hydrogen—meet all of the statutory criteria and are adequately demonstrated for the compliance timeframes being proposed. Thus, the second and third phases of the standard of performance, if finalized, would apply to affected facilities that commence construction after the date of this proposal. *In contrast, when the EPA later reviews and (if appropriate) revises a standard of performance under the 8-year review provision, then affected sources that commence construction after the date of that proposal of the revised standard of performance would be subject to that standard, but not sources that commenced construction earlier.*

88 *Fed. Reg.* at 33,289 (emphasis added). Those policy goals, however laudable, do not give EPA the authority to rewrite the express language of the statute.

As discussed, the judicial review provisions of the Act also provide additional support for these concerns since any challenger has only 60 days to petition for review of an NSPS following its publication in the *Federal Register*. Any regulated entity intending to start construction during the period of applicability of these rules will have no way to challenge the requirements for 2032, 2035, or 2038 in the future in the event EPA has predicted their availability incorrectly. This is yet another reason why the Agency is limited to assigning a BSER that "*has been* adequately demonstrated"—that is, one that is available *now*.

d. EPA's phased approach conflates new and existing sources, contravening the structure of the Act.

EPA's assertion of authority to promulgate a phased NSPS fails for yet another reason—it is inconsistent with the Act's distinction between new and existing sources, and the different requirements for and standards applicable to each. The structure of section 111 directs EPA first to promulgate standards for "new sources" in a category, and then to promulgate guidelines for existing sources that could not be regulated as new sources. The existing source standard does not apply to statutory new sources, because new sources are already required to be built to the state-of-the-art BSER. EPA has turned this process on its head.

A statutory "new source" is one the construction or modification of which takes place after publication of a proposed or final NSPS. 42 U.S.C. § 7411(a)(2). An "existing source," by contrast, is "any stationary source other than a new source." 42 U.S.C. § 7411(a)(6). But under EPA's proposed rule, a "new source" would have to continue to be a statutory "new source" until at least 2038 in order to allow the 2023 standards to continue to apply to the source. This would also need to be true if, as EPA recognizes, the Agency subsequently proposes a new NSPS after 2023 but prior to 2038. In that situation, there would effectively be two different "sets" of new sources—those subject to the 2023 standards and those subject to the new NSPS proposed after 2023. The above-quoted excerpt from the Proposed 111 Rules makes this abundantly clear: "[T]he second and third phases of the standard of performance, if finalized, would apply to affected facilities that commence construction *after the date of this proposal*," notwithstanding EPA's promulgation of any subsequent NSPS. 88 *Fed. Reg.* at 33,289. However, this would mean that a new source beginning construction in 2023 would be both a section 111(b) "new source" and a section 111(d) "existing source" at the same time.

The statute does not allow for such a situation, as the two are mutually exclusive categories. Because EPA retains continuing authority under section 111(b) to promulgate a new NSPS (and thus to create a new class of statutory "new sources") at least every eight years, EPA may act to require CCS and low-GHG hydrogen as part of BSER for new sources at the time CCS and low-GHG hydrogen are actually adequately demonstrated. But what EPA may not do is shoehorn a decades-spanning rule into a statutory eight-year cycle based on its "projection" that technologies will be adequately demonstrated many years into the future.

e. Given these concerns, EPA should not finalize a phased approach.

EPA lacks a sufficient legal basis to propose phased standards for natural gas-based units. And, given the lack of record evidence supporting its assertions—discussed in detail *infra* in these comments—the duplication of those requirements for existing sources is likewise invalid. EPA should repropose or significantly supplement its proposed guidelines for existing natural gas-based turbines to ensure that these rules are workable and achievable across the industry. For new units, and as EEI proposed to the Agency in its February 2023 whitepaper to the Agency's non-regulatory docket, the Agency should adopt an approach that incorporates efficiency-based standards for these units today, while setting "capable" requirements that enable future retrofits of these technologies *when they become available* in the future.[56] Such an approach would better within EPA's statutory and regulatory authorities and be consistent with existing case law.

B. CCS Technology is an Important Emerging Technology but All Constituent Elements of the Technology Have Not Been Adequately Demonstrated in an Integrated Way, Making the Proposed Emissions Rates Unachievable.

EPA proposes to determine that CCS is adequately demonstrated for existing coal-based units as well as for new and existing natural gas-based units. For coal-based units, EPA proposes that

[56] *See* Appendix B.

units that plan to operate after 2040 in the long-term subcategory, achieve a unit-specific emissions limitation reflecting a 90 percent capture rate be required by 2030. *See* 88 *Fed. Reg.* at 33,341. For natural gas-based units, the Agency proposes as a second phase of BSER for both new base load and existing units that opt for the CCS-based pathway that BSER would lead to a unit specific emissions limitation representing the installation of CCS at a 90 percent capture rate by 2035. *See id.* at 33,283.

Electric companies have long recognized the importance of carbon capture and storage technologies in addressing emissions from fossil-based EGUs. Many EEI member companies have been working for over a decade—and continue to work toward developing and improving CCS technologies—with the goal that these will be able to meet industry performance and customer cost requirements in the future. Continued research, development, demonstration, and deployment (RDD&D) is critical for the long-term success of CCS. EPA and other federal government agencies, including the DOE, should continue to collaborate on these RDD&D efforts.[57]

However, despite EPA's assertions in the Proposed 111 Rule, CCS is not adequately demonstrated, commercially viable, nor cost effective even when the new tax incentives for existing coal-, new natural gas-, or existing natural gas-based units using CCS are taken into

[57] These RDD&D efforts are important beyond the power sector. CCS will be needed not only to reduce emissions from fossil-based electricity generation, but from other commercial and industrial processes, both in the U.S. and around the world, and this essential detail has been recognized by policymakers for at least a decade. *See* International Energy Agency, *Technology Roadmap – Carbon Capture and Storage* (2013), https://webstore.iea.org/technology-roadmap-carbon-capture-and-storage-2013.

consideration. The efforts by EEI member companies as well as universities, DOE, and international organizations and governments have not yet resulted in CCS systems that perform at the levels that EPA would require for compliance. The various CCS studies and demonstration projects that EPA cites with respect to existing coal-based power plants highlight that the technology remains in the development and demonstration phase, not the commercialization and deployment phase, and that the capture levels proposed are not yet achievable.

Moreover, even if EPA is correct that some level of capture may have been demonstrated, CO_2 pipelines exist, and some small pilot storage projects have gone forward, EPA's record does not support the adequate demonstration conclusion that the Agency proposed to draw. This is because EPA's assessment of the adequate demonstration of CCS is purposefully myopic, focusing only on whether each constituent element of CCS has been demonstrated, without addressing whether all three elements of the system of CCS that would be needed for compliance have been demonstrated or could be permitted and constructed in time to allow for compliance on the timeline that EPA has projected. Further, EPA has not addressed the significant legal, regulatory, and insurance issues that must be resolved before CCS could be deployed across the industry for compliance. These issues include the development of workable legal and regulatory regimes to address liability for long-term storage of CO_2.

A technology determined to be BSER may not need to be in wide commercial operation, but EPA must show that the standards that result from the application of BSER are achievable. No one has integrated all three of these elements of CCS such that the Agency can demonstrate that it possible to achieve the CCS-based emissions rates that EPA proposes for both existing coal-based units and new and existing natural gas-based units. EPA's assertions about the need for "lead time" highlight that the proposed emissions limits are unworkable unless all three elements can be stitched together. EPA cannot point to anything in the record that would support the Agency's assessment that this system of emissions reduction, as a system, has been adequately demonstrated or that the resulting emissions limits are achievable. Without the integration of all three constituent elements of CCS and assurances that these elements can be developed and deployed along the timelines that EPA asserts are feasible, EPA is hazarding guesses about the achievability of the standards on the required timelines.

1. EPA cannot show that a 90 percent capture rate has been demonstrated such that units could comply with the proposed emissions limits.

EPA principally relies on the experience of the Petra Nova and SASK Power facilities to determine that capture at a 90 percent rate is adequately demonstrated for coal-based units. However, EPA's reliance on these projects is misplaced as neither is (or was) capable of consistently capturing 90 percent of the total CO_2 emissions from the facility.[58]

The Petra Nova capture system was designed to capture 90 percent of 37 percent of the flue gas produced by a single EGU that was part of the larger facility—amounting to a total capture of 33 percent of the total CO_2 emissions.[59] This means that the facility, which is now closed, was capable of capturing carbon from a large slip stream, not the entire flue gas, as would be required by EPA's proposed emissions limits.

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[58] EPA should consider the experiences of all CCS demonstration projects in assessing the adequate demonstration of this critical technology. For example, EEI member AEP is providing significant information about its Mountaineer project via comments filed in this docket.

[59] EIA, Today in Energy, Petra Nova is One of Two Carbon Capture and Sequestration Power Plants in the World (Oct. 17, 2017), https://www.eia.gov/todayinenergy/detail.php?id=33552.

Even for that slip stream, high rates of capture were not achieved regularly while the unit was in operation. According to one report, based on EPA emissions data, the capture rate for the CO_2 in the Petra Nova slip stream may have been as low as 65-70 percent, not the 90 percent for which the system had been designed.[60] The GeoEngineering Monitor reported that the Petra Nova capture facility experienced more than 360 downtime days between 2017 and 2019 due to technical problems—nearly one third of days of operation.[61] This level of inconsistency in operations would not meet industry performance requirements for generating units, nor would it allow a unit to demonstrate compliance with EPA's proposed emissions limits using the metrics that EPA proposes to use, which would require more consistent operation of the capture equipment. This would place units at risk of not being able to comply, despite best efforts.

EPA also relies on SASK Power's Boundary Dam Unit 3 to prove adequate demonstration of CCS for coal-based units and the proposed 90 percent capture rate. *See* 88 *Fed. Reg.* at 33,346. While the facility has been in operation since 2014, SASK Power also has struggled to keep the CCS facility operational and to achieve sustained high levels of performance of the capture system. Only recently, after nine years of operation, has the facility been able to more consistently operate at levels nearing design rates, but has mostly operated around a 70 or 75

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[60] *See* S. Mattei and D. Schlissel, Institute for Energy Economics and Financial Analysis, *The Ill-Fated Petra Nova CCS Project: NRG Energy Throws in the Towel* (Oct. 5, 20220, https://ieefa.org/resources/ill-fated-petra-nova-ccs-project-nrg-energy-throws-towel.

[61] Anja Chalmin, *The Current State of CCS in the U.S.-- Résumé after 100 Years of CO_2 Capture and 25 Years of Extensive Federal Funding*, Geoengineering Monitor (Dec. 2, 2022), https://www.geoengineeringmonitor.org/2022/12/the-current-state-of-ccs-in-the-u-s-resume-after-100-years-of-co2-capture-and-25-years-of-extensive-federal-funding/.

percent capture rate.[62] But, the facility has only intermittently been able to capture the designed 90 percent capture rate, despite significant efforts and major outages to address issues with the operation of the capture system.[63] And, in 2021, even after improvements were made, Boundary Dam was only able to achieve less than a 37 percent capture rate.[64] Accordingly, this project does not support EPA's determination that CCS is BSER, nor that the proposed resulting emissions limitations, based on continuously achieving a 90-percent capture rate, is achievable.

Moreover, while EPA may hope that time will address operational concerns with capture systems, SASK Power's efforts reveal that much more time than EPA anticipates may be necessary. If a consistently high rate of capture cannot be sustained after nine years of operation at Boundary Dam, it is not clear how EPA has determined that a 90-percent capture rate will be possible consistently by 2030 or that a 96-percent capture rate will be demonstrated in 2038. EPA does not address any of these issues in its assessment of either facility.

Neither Petra Nova nor Boundary Dam can consistently capture 90 percent of the CO_2 from those facilities. EPA, therefore, cannot show that this level of capture is adequately demonstrated for purposes of the Proposed 111 Rules. While EPA may not have to show that the proposed

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[62] *See* Dominika Janowczyk, et al., *Derates and Outages Analysis - A Diagnostic Tool for Performance Monitoring of SaskPower's Boundary Dam Unit 3 Carbon Capture Facility*, 15th International Conference on Greenhouse Gas Control Technologies GHGT-15 (Apr. 6, 2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820207.

[63] *See id*.

[64] S&P Global Market Intelligence, *Only Still-Operating Carbon Capture Project Battled Technical Difficulties in 2021* (Jan. 6, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/only-still-operating-carbon-capture-project-battled-technical-issues-in-2021-68302671. Frequent capture system outages also undermine EPA's assertions about the costs of CCS.

BSER is already deployed broadly, it must at least have some evidence that the technology can do what EPA would require an affected source to accomplish via application of that technology.[65]

While some aspects of carbon capture technology are mature, consistent performance is not yet assured. Throughout the Proposed 111 Rules when describing carbon capture technologies, EPA correctly refers to the ongoing research and activities as "emerging," "possibility," "expected," and "in development," and noting "intentions" to undertake efforts that will continue efforts to develop and demonstrate capture. Each of these terms correctly describes capture as a technology that is still under development.

2. EPA's Assertions about the Costs of CCS Are Not Reliable.

EPA also asserts incorrectly that the costs of CCS for existing coal-based units have been and will continue to decrease such that these costs are reasonable not an impediment to determining that CCS is BSER. *See* 88 *Fed. Reg.* at 33,367. However, the experience of EEI's member companies is that the numerous examples of planned and delayed or abandoned projects are proof of the opposite. Moreover, most projects to date have received significant federal and other governmental funding, which highlights that the costs of the technology to the industry—and customers—is not yet acceptable. Finally, EPA is not correct that the recently passed 45Q tax incentives will ameliorate these costs concerns. The tax incentives will help address cost concerns, but that help will be limited.

[65] EPA does not address whether the Agency would be willing to exercise enforcement discretion if capture facilities do not operate at levels, or as consistently, as would be required for compliance with final standards. If EPA finalizes the CCS-based standards as proposed, the Agency should be clear that it would exercise such enforcement discretion. This does not insulate units from citizen enforcement suits but would send strong signals to courts about whether enforcement was appropriate.

a. EPA's estimates assume CCS is a mature technology and are inconsistent with best practices for assessing costs for new technologies.

Because there is only one operating coal-based CCS project operating today, EPA's cost data in support of its BSER determination is based on modeling and other studies and not real-world costs. EPA relies heavily on an analysis conducted by Sargent & Lundy, LLC, in which the authors explicitly recognize that "[d]ue to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool *could not be benchmarked against recently executed projects* to confirm how accurately it reflects current market conditions."[66] Despite this limitation with the report prepared for this rulemaking, EPA asserts that CCS costs will decrease in the near term. There are several issues, however, that undermine the validity of the analysis used to support this conclusion.

As a preliminary matter, EPA's assertion that near-term costs for CCS will decrease is not supported by the reality of planned projects that have been put on hold or abandoned.[67] While it is true that deployment reduces costs, CCS deployment has not occurred at levels to demonstrate that EPA can rely on these decreases or that the Agency can accurately predict the timing and magnitude of such decreases.

[66] Sargent & Lundy LLC, IPM Model—Updates to Cost and Performance for APC Technologies CO2 Reduction Retrofit Cost Development Methodology, Project 13527-002 (March 2023) at 1 (emphasis added).

[67] The Agency's assertion also does not recognize updated NETL guidance, which states that "[t]he Chemical Engineering Plant Cost Index indicates relatively high volatility for capital and labor costs, with the cost index rising by 30% between December 2018 and March 2022. As these fluctuations are *not* captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data." NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity (Oct. 14, 2022) at p. 4, n.b (emphasis added).

The Sargent & Lundy analysis assumes that carbon capture technology is a mature technology for purposes of its work, without a basis in fact for that assumption. Further, this EPA-sponsored analysis assumes that there have been Nth-of-a-kind (NOAK) CCS plants; there are, however, no NOAK plants. Presently, there is one operating in North America, and two other projects have been idled or operate as a traditional natural gas-based unit without any capture technology. Because the Sargent & Lundy analysis treats CCS as mature, it then draws on various National Technology Energy Laboratory (NETL) models to assess costs. However, given the emerging nature of the technology and the few existing projects, reliance on these cost frameworks is misplaced. As recent new guidelines for assessing CCS costs have asserted, efforts to estimate NOAK costs for emerging technologies must first be grounded in the costs of FOAK (first-of-a-kind) facilities and retrofit assessments are particularly fraught because of the unit-specific nature of these costs.[68]

b. CCS projects to date have received significant federal funding, which does not support a determination that the technology's costs are reasonable.

EPA's assessment of the costs of CSS as reasonable does not adequately address the significant amount of federal funding that the two projects relied on received. For example, Boundary Dam

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[68] Simon Roussanaly, et al., *Towards Improved Guidelines for Cost Evaluation for Carbon Capture and Storage*, White Paper (Mar. 2021), https://www.osti.gov/servlets/purl/1779820. These guidelines assert that a better approach is a hybrid costing method that combines a bottom-up analysis of FOAK commercial cost of an advanced technology with an empirical model employing experience curves to project its future cost. They also recommend extensive analysis related to the uncertainties of such future cost estimates. These guidelines also address the intricacies of assessing costs for retrofits, which are inherently unit-specific, and which the authors note have not been well addressed to date. They call for particular attention to be paid to the following aspects: economic impact of potentially required plant production stoppages, impacts on the main output product quality and plant operation, flue gas treatment requirements, spatial constraints in plant sites, and flue gas interconnection, among others.

received CA $240 million in support from the Canadian government, as well as support from the provincial government. The project also was supported not only by the sale of electricity, but by the sale of the captured CO_2, which was used in enhanced oil recovery, as well as the sale of sulfuric acid and fly ash.[69] This combination of support indicates that the project was not economic on its own, which undermines EPA's assertions that costs are reasonable.

Similarly, the Petra Nova facility also received significant federal funding, without which it would not have been built. According to DOE, it entered into a cost sharing agreement with the project in 2010 to provide $190 million in total cost share with $167 million in financial assistance through the original Clean Coal Power Initiative (CCPI) Round 3, which included funding from the Recovery Act, and additional $23 million in February 2016 under the Section 313 of the FY2016 Consolidated Appropriations Act. Ultimately, Petra Nova received around 15 percent of the $160 million based on project recipient cost share under the Section 313 of the FY2016 Consolidated Appropriations Act mandated reallocation of funds.[70]

Federal funding support will be necessary to drive continued RDD&D of this technology and should continue, but it is difficult to say that the costs of a technology are not an impediment to a BSER determination when projects would not be built without such support.

c. Tax incentives will not fully offset CCS costs and may not offset costs very much at all.

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[69] *See* Massachusetts Institute of Technology, Carbon Capture & Sequestration Database, Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project. Due to the decreased capture rate, Boundary Dam had to pay penalties to the CO_2 offtaker in 2014.

[70] DOE, Office of Fossil Energy & Carbon Management, Petra Nova—W.A. Parish Project, https://www.energy.gov/fecm/petra-nova-wa-parish-project.

EPA also points to the 45Q tax incentives, which were extended and increased under the IRA, as support for the reasonableness of the costs of CCS. EPA assumes that unit owners/operators will be able to utilize the recently passed tax incentive for CO_2 storage for the full 12 years that the tax incentive will be available. *See* 88 *Fed. Reg*. at 33,346. While important for addressing some CCS project costs, is not clear that these tax incentives will meaningfully offset the increased costs associated with adding CCS to a facility.

As a preliminary matter, the IRS has not finalized the rules for 45Q for carbon capture, which means that an entity conducting a near-term carbon capture project might not be able to claim a tax incentive depending on the final rules. Moreover, the basic requirements, as per the statute, include that the credit is only available once a CCS facility is operational, and the CO_2 has been stored with some type of proof that such storage is secure. Because the tax credits are only available for ten years, or *until 2032*, it is not clear that projects using CCS to comply with the proposed standards would be able to access the tax credits for more than a few years. Based on EPA's own BSER determination that CCS technology for coal-based units will not be fully implementable by these units *until 2030*, when compliance with the proposed guidelines would be required, access to the any tax incentives for these units will be significantly limited. For natural gas-based units, CCS technology will not be implementable by EPA's estimates *until 2035*, which is notably *later than 2032*. As a result, these units will not benefit from the tax incentives at all. For existing natural gas-based turbines, EPA's cost assessments cannot include the tax incentives.

Further, given the cost analysis included in EPA's TSDs, EPA assumes that a facility will be able to capture 90 percent of the CO_2 coming off a stack and take full advantage of the tax credit offered from the moment that it commences operation, which assumes near perfect deployment of a technology that has yet to consistently reach the capture levels EPA asserts are BSER, as already discussed. While it is correct that the tax incentives are likely to encourage some CCS deployment, including potentially some retrofits, the startup and operation most likely will be in fits and starts, as evidenced by the experiences of the Boundary Dam facility, and therefore may not allow an entity to earn the full tax incentive. EPA's cost assumptions based on the existence of the tax incentives are thus aspirational and inconsistent with how the credits are structured and how new technologies are likely to perform.

3. EPA's determination that CCS is adequately demonstrated for new natural gas-based units is unsupported by the record.

The Agency proposes that CCS is the BSER for phase two standards for base load natural gas-based units, requiring that these units meet a standard equivalent to capturing 90 percent of CO_2 by 2035. *See* 88 *Fed. Reg*. at 33,283. EPA asserts that the individual component pieces of CCS for natural gas-based generation are themselves demonstrated separately, with a focus on the "capture element" at the unit itself being demonstrated "based on the demonstration of the technology at existing coal-fired steam generating units and industrial sources and combustion turbines." *Id*. at 33,291.

EPA cites one dismantled project in Massachusetts that captured CO_2 from a 40 MW "slip" stream at a natural gas-based unit via an amine system, and then piped that product directly to a food and beverage industry facility that was located adjacent to the plant for use in food products. The Agency also downplays several relevant facts this facility. This project did not capture 90 percent of the flue gas. In addition, the CO_2 did not have to be transported via a pipeline and it did not need to be stored underground. In short, EPA relies on a facility that operated a relatively small (e.g., less than 10 percent of facility output) slip stream project to capture CO_2 for use at an adjacent facility, and which was entirely dismantled 18 years before the current proposal as its principal example for demonstration within the industry. This is not sufficient to conclude that 90 percent capture at natural gas-based units is adequately demonstrated.

While EPA tries to make up for its lack of actual, existing, on the ground examples in the power sector by detailing current capture RDD&D, this discussion mostly serves to point out that CCS technology is clearly still in an RDD&D phase. EPA points to numerous Front End Engineering Designs (FEED) studies for natural gas fired turbines that are using DOE funding. FEED studies, however, are just studies. They are not guaranteed to result in actual projects. To date, none of the six FEED studies that have been concluded have resulted in actual construction or permitting of a facility utilizing CCS. *See* 88 *Fed. Reg.* at 33,293-94.

EPA also points to recent grants and awards from DOE to begin work or study the impacts of potential deployment of CCS projects. *See id*. However, the body of evidence EPA cites—funding for studies to begin work on attempting to better understand and advance the still nascent technology with respect to natural gas-based units—serves to underscore the lack of adequate demonstration of CCS technology, rather than support EPA's conclusions that it is adequately demonstrated and part of BSER at this time.

EPA also references work being done by NETL, which conducted computer simulations of CCS on NGCC units and gathered potential cost data for specific generic facilities to be built on a greenfield. However, *these are simulations*, which are not real in any practical sense and have also not resulted in any activity to install, permit, or build CCS technology on NGCC units.

EPA strays beyond power sector studies and examines some demonstrations at coal-based steam generating units and other industrial processes, but that the experience is not comparable or applicable to natural gas-based units given the different engineering between coal powered steam turbines and natural gas combined cycle units. Moreover, as discussed above, EPA's adequate demonstration conclusion for coal-based EGUs is itself insufficient. The Agency also cites a number of small slip stream carbon capture operations and *anticipated* larger projects that it assumes will be able to meet the proposed same capture levels. *See* 88 *Fed. Reg.* at 33,292. EPA fails to address that capturing 90 percent of a five or ten percent slip stream of flue gas is a significantly different task than capturing 90 percent of 100 percent of the flue gas on a fully commercially operational EGU. In addition, as noted, unbuilt projects cannot serve as evidence that a technology can achieve the standards that EPA proposes. Again, EPA's examples only serve to underscore the lack of demonstration projects for the technology it is asserting is demonstrated.

The record in this proposal does not support EPA's determination that CCS is adequately demonstrated for new natural gas-based units. As a result, the Agency should not move forward with standards based on CCS for these units.

4. EPA's determination that CCS is adequately demonstrated for existing natural gas-based units is even less supported by the record than EPA's new source determination.

While EPA's determination that CCS is BSER for new natural gas-based units is not supported by the record, the Agency's determination that CCS is BSER for certain *existing* natural gas-based turbines is even less supported. *See* 88 *Fed. Reg.* at 33,633. EPA's BSER determination for existing natural gas-based units is identical to the Agency's proposed BSER, along with identical proposed emissions limits that would require that affected sources either install CCS with a 90 percent capture rate by 2035 or blend hydrogen at 40 percent and 96 percent in 2032 and 2038, respectively. *See id*.

The Agency notes that it relies on the same body of evidence for its BSER determination for existing natural gas-based sources as it did for the new source determination. This slim analysis consists of almost an identical set of assertions as EPA made for new units—the existence of FEED studies, modeling assumptions, tax credits to address costs, and that some efforts in unrelated industries with intentions to deploy CCS in their operations—only with less tangible evidence. *See id.* at 33,366-68.

EPA also focuses on the fact that a limited number of existing units would be required to comply with the CCS-based standards—those larger than 300 MW and operating at capacity factors of 50 percent or greater. Based on a cursory, spreadsheet-based analysis of the existing fleet, EPA notes that the CCS retrofit requirements would only cover about 35 GW of potential CCS capacity across the existing natural gas-based fleet. As a result, EPA asserts that the proposed CCS BSER determination is "reasonable" since "there will be significant time to deploy the needed infrastructure, a total of eleven years from the likely finalization of these guidelines…in addition, it is unlikely that all of the units that EPA projects would be affected in 2035 would choose to install CCS; some would likely choose to co-fire low-GHG hydrogen…for these reasons, the EPA believes that there will be adequate capability to build enough CCS for the existing combustion turbine EGUs subject to a CCS BSER at a capacity threshold of 300 MW, given the amount of time provided." *Id.* at 33,367. This does not meaningfully address the challenges related to retrofitting CCS on existing units, which are not merely a function of time. As has been noted, these also are a function of the current design of the unit and the availability of existing space for large capture equipment.[71] EPA does not address these real issues regarding the feasibility of retrofits and how they are different from new builds.

In fact, EPA makes no mention of the fundamental difference between new and existing sources: that new sources can be designed to adopt and deploy new technologies, to the extent they are demonstrated, as part of their initial design. Existing sources, by their very definition, would be required to retrofit—a process that would involve significant capital outlay, and presents numerous potential impossibilities—including inability for sources to be redesigned to accommodate new and potentially sizeable capture technology, a lack of available unit space or water, the need for units to be down and non-operative to accommodate significant retrofit time, or the need to make potentially significant permitting modifications to already existing permits and conditions.

[71] *See* Roussanaly, *supra*, n.68.

Despite these real differences between employing CCS at new and existing units, EPA proposes that existing sources comply with standards based on CCS technology *on the same exact timeline as new sources*. Even assuming that CCS is adequately demonstrated, it is readily apparent that existing sources will face greater challenges and significant additional hurdles related to retrofitting. At minimum, this should be reflected in a different compliance timeline; but, as noted, time can only address some of the challenges of retrofits.

5. Without the capture and storage elements, EPA's proposed CCS-based standards are not achievable.

Capturing CO_2 from the flue gas of fossil-based generation would not enable compliance with the proposed standards as EPA conditions compliance on demonstrations that the CO_2 was stored in ways that EPA deems acceptable. *See, e.g.,* proposed 40 C.F.R. § 60.5555a(f). Accordingly, EPA recognizes that the transport and storage of CO_2 are necessary constituent elements of CCS as the proposed BSER.

However, while recognizing that transport and storage are integral to the successful environmental performance of CCS, EPA does not appropriately consider how these could impact EPA's BSER determination or the selection of the resulting emissions limitations or guidelines, focusing on whether they are demonstrated themselves and not on what they could mean for the achievability of the proposed standards.

i. EPA does not address the numerous supporting infrastructure challenges regarding transportation of captured CO2.

EPA makes significant assumptions regarding the availability and ease of operation of CO_2 pipelines to transport the captured carbon that would likely result from any unit installing CCS as part of compliance with EPA's BSER determination. EPA assumes that CO_2 pipelines will be available to transport the captured CO_2 from all of the facilities required to install CCS by 2030 or 2035 for coal-based and natural gas-based units, respectively, yet admits that there are only CO_2 pipelines in 11 states today. The Agency lists a number of CO_2 pipelines that have been announced, noting that they are "likely to be developed" and have been in the planning stage for in some cases four years. *See* 88 *Fed. Reg.* at 33,366. However, "likely to be developed" does not mean "has been developed" or "will be developed," and does not provide assurances to the EGUs that there will be CO_2 transportation available when needed. Critically, these pipelines are outside the purview of EGU owner/operators and EEI member companies would need to depend on other parties to develop the infrastructure and build it successfully inside the next decade.

The status of the CO_2 pipelines cited by the Agency follows:

- *Midwest Carbon Express*: According to Summit Carbon Solutions' website, the entity developing the 2,067-mile Midwest Carbon Express CO_2 pipeline, they have reached agreements with over 2,700[72] landowners with an undisclosed number that still remain. Summit announced in 2021 that they are building the Midwest Carbon Express with the goal of completing the pipeline in 2024. Given that not all the land-lease rights have been approved, the timing of completion is uncertain.[73]

- *Heartland Greenway Phase 1A +1B*: the 1,302-mile pipeline announced its first permit filing in Iowa 2022, it too crosses several states (NE, IA, SD, MN, and IL) whereby each state, county and landholder will require approvals or agreements and hopes to have the initial system commissioning in 2025.

- *Mt. Simon Hub*: According to the developer—Wolf Carbon Solutions—the 280 mile Iowa-centric pipeline began community outreach efforts in the first quarter of 2022 with a projected in-service date is 2025.[74] However, Wolf Carbon Solutions does not have all of

[72] Summit Carbon Solutions, https://summitcarbonfacts.com/.

[73] Adam Willis, Massive Midwest pipeline, a test for North Dakota's carbon capture goals, hits landowner snags, AgWeek Business (Dec. 4, 2021), https://www.agweek.com/business/massive-midwest-pipeline-a-test-for-north-dakotas-carbon-capture-goals-hits-landowner-snags.

[74] *See* Wolf Carbon Solutions, https://wolfcarbonsolutions.com/mt-simon-hub/.

> its easements in Iowa and plans to try and get voluntary easements from landowners whereas both Midwest Carbon Express and Heartland Greenway are resorting to eminent domain which falls under each states' jurisdiction.[75] Wolf Carbon Solutions filed a permit application with the Illinois Commerce Commission in June 2023. The pipeline is projected to be operational also in 2025 but has not started construction.

EPA tries to counter these obvious concerns by noting in the Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document (TSD) by listing "planned or announced" pipelines to try and support that CO_2 pipelines will be available and are expanding. While they may be expanding, CO_2 transportation is not yet widely available, and the regulatory hurdles to increased deployment are significant.[76] It should be noted that each of the announced or planned pipelines requires years to obtain permits and get financing. Moreover, they will not be available for any new CCS projects that would be motivated by compliance with EPA's standards and instead will be dedicated for the use of specific facilities/customers. In particular, these pipelines, therefore, do not necessarily represent available capacity for coal-based EGUs that EPA is proposing that they must install CCS *by 2030*.

Moreover, given the absence of federal authority, siting and economic regulation of CO_2 pipelines generally falls to the states. As a result, eminent domain authority for CO_2 pipeline projects depends on and varies by the states. This is a time-consuming process. Where states do not provide eminent domain authority, pipeline developers must depend on reaching agreements with each landowner to obtain rights-of-way. In addition, in some states, project developers must

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[75] *See* Jared Strong,Wolf proceeds with voluntary pipeline approach despite neighbors' growing blockade, Iowa Capital Dispatch (Apr. 7, 2023), https://iowacapitaldispatch.com/2023/04/07/wolf-proceeds-with-voluntary-pipeline-approach-despite-neighbors-growing-blockade/.

[76] *See* J. Garofalo and M. Lewis, *Sources to Sinks: Expanding A National CO_2 Pipeline Network*, Environmental Law Institute (Jan. 1, 2020).

go county by county to seek approval from each jurisdiction. The diffuse nature of the regulatory regime for CO_2 pipelines creates multiple opportunities for opponents to slow or stop project development, which infuses uncertainty into the process and can be a significant barrier to getting investor interest in CO_2 pipeline projects and to getting this necessary infrastructure ultimately built. These regulatory delays and the potential lack of community acceptance for the CO_2 pipelines are one more challenge for any EGU to demonstrate compliance with the proposed standards. Moreover, EPA has not provided any evidence that its assumptions about how quickly new pipelines could be built—in some instances in 3.5 years—are grounded in actual experience permitting and siting these transmission facilities. It certainly is not consistent with the recent experiences siting and permitting new natural gas or oil pipeline.

ii. EPA's analysis ignores challenges related to permitting new storage facilities, including advocacy group opposition.

EPA acknowledges that not all EGUs have equal access to appropriate geologic storage. However, even if these access challenges could be addressed via pipeline deployment, EPA still have not addressed the challenges related to permitting new storage facilities. While regulations exist to permit storage facilities under the Safe Drinking Water Act's Underground Injection Control Program, EPA has issued one such permit to date.[77] As a result, a significant number of new storage facilities would need to be permitted in order to allow for EGUs to comply with the proposed CCS-based emissions limits. EPA has not addressed whether it has the resources to undertake this expansion in permitting needs.

[77] *See* EPA, Class VI Wells Permitted by EPA, Table, https://www.epa.gov/uic/class-vi-wells-permitted-epa#table. The Table lists several pending permit applications, but provides no information about when those were filed or how long they have been under consideration by EPA.

States could elect to issue these permits to address the potential future demand for new storage sites, but, at this time, only North Dakota and Wyoming have been granted primacy to do so.[78] The challenge for states seeking primacy is significant. For example, Louisiana currently is seeking primacy, but EPA has moved slowly to act on the state's application. In addition, many of the same groups that advocate for EPA to determine that CCS is adequately demonstrated actively oppose Louisiana's quest for primacy. The concerns that they have raised in their comments on the application indicate that they are likely to oppose other states' future primacy efforts (and future CCS projects generally) because they do not want the technology deployed. For example, in urging EPA not to accept Louisiana's application for primacy, the Sierra Club both proposed a list of additional, unrelated requirements designed to make Class VI unobtainable (e.g., requiring that all other, non-CO_2 wells be plugged first) and asserted that "[c]arbon capture and sequestration is not a step in the direction of a clean energy economy. It is an unproven technology, a false solution, and far too expensive." *See* Sierra Club letter, Appendix D. Similarly, the Center for Biological Diversity (CBD) opposed primacy, stating that "[a]s a foundational matter, we reject the premise that CCS is a necessary—or even appropriate—approach to addressing the climate crisis and pollution burdens borne by frontline and fenceline communities. After billions of dollars of investment and decades of development, deployment of CCS has consistently proven to be ineffective, uneconomic, and unwise." *See* CBD letter, Appendix E. Given this level of opposition to a state having permitting authority for CO_2 injection wells, it seems clear that these groups also will oppose applications for actual

[78] *See* EPA, Primary Enforcement Authority for the Underground Injection Control Program, https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.

storage facilities, as well as the other constituent elements of CCS. At minimum, this level of opposition should be factored into EPA's timelines.

6. Adequate demonstration determinations that result in standards that are not achievable can harm broader efforts to develop and demonstrate key technologies needed to reduce GHG emissions.

Ironically, EPA's proposed standards, if finalized, could have the unintended consequence of dissuading companies from moving forward with projects that would help address the concerns with CCS performance and costs identified in these comments. It is one thing to test a new technology to learn more about its costs and operation, but it is another to subject that test project to the CAA's enforcement regime. If the potential owners and operators of these projects are not confident that they can demonstrate compliance with the proposed standards, which would require consistent performance of not only the capture systems, but also the related pipeline infrastructure and storage facilities, they may choose not to move forward to avoid compliance penalties. Rather than face non-compliance, project advocates and their investors may prefer to take less risk—and not build or retrofit facilities. In this way, stringent standards can slow down RDD&D efforts.

Section 111 already acknowledges that new technologies may not operate as expected and that some relief from strict compliance with standards might be necessary to encourage deployment of new technologies. Specifically, section 111(j) provides for innovative technology waivers in the event that the owner or operator of a new unit would like to employ an emerging technology. *See* 42 U.S.C. § 7411(j)(1)(A). These innovative technology waivers are not available, however, if a technology is adequately demonstrated, so they could not be sought if EPA determines in any final rules that CCS is adequately demonstrated. These waivers also likely will not be available to address concerns about consistent performance of capture systems as they are intended to provide some regulatory relief only to systems of continuous emissions reduction. *See id*. at §§ 7411(j)(1)(A)(i) and (ii). Regardless, the existence of section 111(j) highlights that the Act contemplates that strict regulatory regimes can serve to discourage deployment of emerging technologies that could ultimately result in better environmental performance.

One way to address concerns that stringent standards and inflexible compliance demonstration requirements may harm RDDD&D efforts is via enforcement discretion. As noted, EPA has not indicated that it is willing to exercise any enforcement discretion if CCS does not perform as expected. At minimum, EPA should be clear that it would consider exercising enforcement discretion to support RDD&D efforts.

7. EPA should consider alternative approaches.

Ultimately, the Agency's proposed determination that CCS is the BSER for all affected sources across its three proposals falls short for separate reasons for each rulemaking. As a result, and in order to finalize rulemakings that are durable and will continue to drive progress across the electric sector, EPA should consider not finalizing the proposed determination that CCS is BSER for existing coal-based units, new natural gas-based units, or existing natural gas-based units. For existing coal-based units, there are a variety of other options that EPA could consider as BSER—several of which the Agency has determined on an individual basis are BSER for certain other subcategories of sources. The Agency should consider using these approaches instead.

For new natural-gas based units—and as noted *infra*—EPA should focus on ensuring continued emissions progress through the use of efficiency-based approaches, like the Agency has proposed in its phase one approaches and should set additional requirements that these units be capable of CCS (or hydrogen) retrofits/conversions in future years once the technology matures and is adequately demonstrated. At present there are limited options for reducing emissions other than improved efficiency. In the future, however, new natural gas units may be able to blend hydrogen or use carbon capture technology to reduce emissions in ways that satisfy industry performance and customer cost requirements—in addition to or instead of efficiency measures. EPA can set a hydrogen *or* carbon capture "capable" standard now in conjunction with this traditional emissions rate-based efficiency approach. This would ensure that any new generation not only would use the most efficient technologies available—as regulated by the lb CO_2/MWh emissions limitation or through a mass-based compliance option in terms of tons of CO_2—but also could enable future emissions reductions once hydrogen or carbon capture technologies are demonstrated and cost effective for the power sector, while supporting reduced outage times associated with retrofits.[79] It would send clear signals that owners and operators should be thinking about the future operation of these units.

For existing natural-gas based units, EPA should repropose or significantly supplement its insufficient proposal and instead focus on conducting significant more analysis to propose a workable set of guidelines for these sources, one that is both justified technically and also—as

[79] "Capable" standards—sometimes referred to as "ready" or "capable-to-ready" standards—are not self-executing. Any future emissions limitations for then-existing units based on hydrogen co-firing or CCS technology would have to be the result of a future rulemaking under CAA section 111(d) in which EPA would analyze whether such technologies had been adequately demonstrated considering all the statutory factors. The statutory text of CAA section 111 itself supports a flexibility-centered approach to both standard setting and compliance, but not automatic increases in the stringency of standards.

discussed *supra* and *infra*—works in conjunction with the other proposed rules and the Administrator's announced holistic approach.

C. Hydrogen Blending is a Promising Approach For Reducing Emissions From The Power Sector But is Not Adequately Demonstrated Today.

EPA's interest in hydrogen as a technology to reduce power sector emissions is well-founded and is shared by EEI's member companies. EEI and its members believe in and are working to make clean hydrogen commercially available at scale. We are engaged in pilot and demonstration projects across the clean hydrogen value chain, including participating in approximately half of the Regional Clean Hydrogen Hub (H2Hubs) proposals that were encouraged by the U.S. Department of Energy (DOE) to submit full applications; we are working with agencies and the National Laboratories to help advance clean hydrogen technology, delivery, and safety; and we are designing the power generation facilities of the future to be hydrogen capable.

This potential tool holds promise and should be maintained as a compliance option regardless of whether EPA finalizes the Proposed 111 Rules. However, electric companies also recognize that the United States is in the nascent stages of development of the clean hydrogen fuel that will be necessary to support hydrogen blending across the economy and throughout the U.S. power sector in a manner that preserves reliability and affordability. This is evident from the various government and industry efforts underway across the hydrogen value chain—including and in addition to EEI member companies' efforts—on pilot and demonstration projects, to scale up electrolyzer manufacturing and bring down costs, to shore up necessary infrastructure, and to create the regulatory certainty needed to secure the financing and long-term offtake that ultimately will drive deployment. As discussed below, these areas of development and scale-up, many of which are detailed in DOE's *Pathways to Commercial Liftoff: Clean Hydrogen* (Clean

Hydrogen Liftoff Report),[80] still must be realized to ensure development of a U.S. clean hydrogen market at scale.

As discussed *infra*, not only is hydrogen blending in the power sector not adequately demonstrated at present, but to progress from the current hydrogen market at the necessary scale that will be needed to support reliable hydrogen blending in the power sector, a number of barriers must be overcome. These include cost barriers, technical concerns, regulatory hurdles, feasibility questions, and availability issues. These challenges permeate the core elements of the hydrogen system that are necessary to enable its potential use in the power sector. Although the current industry currently has some components of the value chain that will be needed to support achievability of hydrogen blending throughout the power sector, nearly every component faces these barriers and it has yet to put all of the pieces together and confirm that they operate as a cohesive whole. This work is no less than critical for the entities regulated under the Proposed 111 Rules—this is the *only* source category with a public service obligation to operate and the entities making up this category face penalties for failing to provide reliable electricity to their customers. While EEI and its members believe these challenges are surmountable and efforts are underway to resolve them, it is unclear when, how, and to what extent these challenges will be overcome and what the impact will be on the timing and scale of deploying clean hydrogen.

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[80] U.S. Dep't of Energy, Pathways to Commercial Liftoff: Clean Hydrogen (Mar. 2023), https://liftoff.energy.gov/clean-hydrogen/. Furthermore, it has been observed that DOE's recently issued *U.S. National Clean Hydrogen Strategy and Roadmap* "includes 110 'actions' that the U.S. government plans to take by 2025, 2029 and 2035, although most of these might be better be described as 'aims' or 'goals', and many are already under way." L. Collins,, U.S. unveils national clean hydrogen strategy and roadmap based around three key priorities, Hydrogeninsight (June 6, 2023), https://www.hydrogeninsight.com/policy/us-unveils-national-clean-hydrogen-strategy-and-roadmap-based-around-three-key-priorities/2-1-1462445.

As noted, DOE recently released the Clean Hydrogen Liftoff Report, which explores and discusses current opportunities and barriers to achieving commercial liftoff for clean hydrogen in the United States. This detailed report was "developed through extensive stakeholder engagement and a combination of system-level modeling and project-level financial modeling"[81] and draws on several dozen current articles, papers, and studies. As such, this report provides useful insight into the areas of developmental need that must be met to catalyze a U.S. clean hydrogen market at scale, efforts and strategies to overcome these gaps, and the potential impacts on liftoff.[82] In recognition of the fact that we are in the early stages and much remains unsettled, DOE explicitly cautions readers that "just as in any rapidly evolving industry, figures and numbers in this report will evolve based on additional learnings from researchers and industry, points of regulatory clarity (as released), and more. As such, this report should be viewed as a living, work-in-progress document that will be updated at a regular cadence."[83]

While EPA mentions some of the challenges noted in the Clean Hydrogen Liftoff Report and discussed below, it does not thoroughly or substantively grapple with these challenges in reaching its proposed adequate demonstration determinations. This is evident from EPA's proposed determinations regarding power sector access to low-GHG hydrogen, the infrastructure needed to support power sector access to low-GHG hydrogen, and the cost-effectiveness of low-

[81] U.S. Dep't of Energy, The Pathway To: Clean Hydrogen Commercial Liftoff, https://liftoff.energy.gov/clean-hydrogen/.
[82] The issuance of this report is itself evidence of the fact that there are challenges that must be overcome.

[83] Clean Hydrogen Liftoff Report at 7.

GHG hydrogen. The current reality of where the United States is and the required work ahead stand in stark contrast to the conclusory statements that underlie EPA's proposed adequate demonstration determinations. EPA's Proposed 111 Rules risk placing additional pressure on the current challenges that government and industry are working to overcome and could imperil, rather than support, the realization of a U.S. clean hydrogen economy at scale. While EEI and its members are working towards and hope that EPA's vision becomes a reality, the very fact that these are projections runs counter to the CAA's explicit language and the line of D.C. Circuit cases considering it, as discussed *infra*.

Moreover, throughout the preamble to the proposed standards, EPA overstates, uses incorrectly, or omits facts relevant to the current state of the hydrogen market and the availability of hydrogen blending today and in the near future. These include statements regarding the current use of hydrogen in the power sector, as well as multiple projections related to power sector access to low-GHG hydrogen under the timelines provided in the Proposed 111 Rules. As a consequence of EPA's failure to develop an adequate record and appropriately analyze the current state and the well-documented challenges to growth of the hydrogen sector, the Proposed 111 Rules are insufficient. Moreover, the Agency's improperly analyzed record has led it to the incorrect conclusion that, at present, low-GHG hydrogen blending for the power sector has been adequately demonstrated under the CAA.

1. EPA's reliance on pilot projects and potential future awards to set up supportive infrastructure is insufficient to determine hydrogen blending is adequately demonstrated as BSER under CAA section 111.

As discussed *supra*, in order to establish a standard of performance under section 111 that has been adequately demonstrated, EPA must determine that: (1) the system of emissions reduction upon which the emission limitation is based is “adequately demonstrated,” and (2) the emission limitation is “achievable.”[84] In general, courts have determined that, in order for a technology to be adequately demonstrated, EPA needs to show that both (1) the technolog is deployed in commercial-scale operations, as well as (2) the emission limitation is achievable throughout the industry.

More specifically, existing precedent consistently supports the fact that, in order to be adequately demonstrated under section 111, a system must at least be in commercial-scale use in the relevant source category or by a source of comparable design and function. In *Essex Chemical Corp. v. Ruckelshaus*, the D.C. Circuit examined EPA’s standards for sulfuric acid plants based on dual absorption systems. *Essex Chem. Corp. v. Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973). Such systems were in operational use in a U.S. elemental sulfur burning plant at the time that EPA conducted its testing for the standards. *Id.* at 435-36. As such there was no dispute about EPA’s conclusion that dual absorption systems were adequately demonstrated for elemental sulfur burning plants. *Id*. However, the court noted that “there is nothing in the record to indicate any basis for the conclusion that the dual absorption process can perform efficiently in a recycle, or spent acid, plant. As such, dual absorption simply has not been ‘adequately demonstrated’ within

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[84] In setting the requirement that a system be adequately demonstrated, Congress “stated three other key criteria – cost, non-air quality health and environmental impact, and energy requirements – as factors the EPA must take into account.” *Am. Lung Ass’n v. EPA*, 985 F.3d 914, 952 (D.C. Cir. 2021) (citing 42 U.S.C. § 7411(a)(1)). The D.C. Circuit has further explained that “[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.” *Essex Chem. Corp. v. Ruckelshaus*, 158 U.S. App. D.C. 360, 486 F.2d 427, 433 (1973). *See also Am. Lung*, 985 F.2d at 962; and *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (whether a system is adequately demonstrated “cannot be based on ‘crystal ball’ inquiry”) (citation omitted). These principles are discussed more fulsomely *supra* in this section.

the meaning of § 111(a)(1) of the Clean Air Act . . . for use with *other than elemental sulfur feedstock plants*." *Id.* at 435 n.19 (emphasis added).

The existing case law also supports the idea that, while an essential step along the road to adequately demonstrating a technology, *pilot scale data alone is insufficient* for adequate demonstration purposes. In *Sierra Club v. Costle*, the D.C. Circuit considered emissions control technology for coal-based EGUs. *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981). While the discussion focused on the standards set employing wet scrubbing technology as the BSER, which was widely used at the time and was considered BSER, the court clarified that it did "not hold that dry scrubbing is adequately demonstrated technology" despite some extrapolated pilot scale data at the time in the record. *Id.* at 341 n.157. In that instance, EPA itself had recognized that "'the major uncertainty which exists with dry SO_2 removal technology is the absence of experience at large-scale facilities.'" *Id.* (citation omitted). The court therefore determined that "it would be premature to conclude that dry scrubbing is adequately demonstrated technology." *Id*. While today dry scrubbing technology is widely utilized across the industry, at the time of *Costle* in 1981, that was notably not the case.

In addition to being in commercial-scale use in the relevant source category or by a source of comparable design and function, D.C. Circuit precedent makes clear that Congress intended section 111 standards to be valid only if achievable "throughout the industry." *See, e.g., Costle*, 657 F.2d at 341 n.157 ("We see no basis on this record which would justify extrapolating from the pilot scale data to the conclusion that dry scrubbing is adequately demonstrated for full scale plants *throughout the industry*." (emphasis added)). This requirement is well illustrated by

National Lime Association v. EPA, where the D.C. Circuit concluded that the section 111 standards were unsubstantiated because "the record d[id] not support the 'achievability' of the promulgated standards *for the industry as a whole*." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 (D.C. Cir. 1980) (emphasis added). The Court reiterated that holding throughout the case, and further indicated that EPA itself has long recognized this fundamental rule. *Id.* at 433 ("EPA itself acknowledged in this case that 'standards of performance . . . must . . . [assure achievability of the standard for the industry as a whole] for *all variations of operating conditions being considered anywhere in the country*." (emphasis in the original)).

The court in *Portland Cement Association v. EPA* reaffirmed this basic principle. There, the D.C. Circuit considered industry claims that EPA failed to consider the impact on Portland cement kilns of older design that, if modified, could become subject to section 111 standards. *Portland Cement Ass'n v. EPA,* 665 F.3d 177, 190 (D.C. Cir. 2011). The Court upheld EPA, finding that "EPA demonstrated how *all* regulated kilns could meet [the] standards. EPA based its [particulate matter (PM)] and [SO_2] limits 'on control technologies that can be applied in *any* kiln type and achieve the same control levels that would be expected with a new kiln at similar costs.'" *Id.*

EPA's existing precedent supports setting standards that are based on commercially deployed technologies that can be achieved throughout the industry, requiring EPA to stay abreast of and mirror existing technological trends in the power sector. It does not allow the Agency—as it has done here—to point towards some limited number of current pilot projects and determine that they are sufficient evidence of adequate demonstration of the technology and further conclude hydrogen blending is BSER for the entire power sector today. Such an approach is directly contradictory to the Agency's statutory obligations and existing case law—and is notable since, as discussed *supra*, EPA has not demonstrated that these technologies have been integrated and demonstrated holistically across the industry. As discussed at length *infra*, EPA's reliance on prospective supportive infrastructure without hard record evidence is problematic and counterfactual. Combined with an overreliance on pilot projects, EPA's determination that hydrogen blending is adequately demonstrated as BSER is therefore insufficient.

2. EPA's proposed conclusions regarding power sector use of low-GHG hydrogen are based on an insufficient record that does not support its proposed that the technology is adequately demonstrated.

EPA's Proposed 111 Rules include critical overstatements about current power sector use of hydrogen blending. For example, EPA states that "a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development – including . . . co-firing with lower-GHG fuels." 88 *Fed. Reg.* at 33,242. The Agency similarly notes that "recently, utility combustion turbines in the power sector have begun to co-fire hydrogen as a fuel to generate electricity." 88 *Fed. Reg.* at 33,254-545. These statements suggest a more mature level of development than is reflected in reality.

EPA also myopically focuses on the state of combustion turbine technology to support its proposed adequate demonstration determinations. However, combustion turbine technology to blend low-GHG hydrogen is still advancing and, critically, is only one component of the infrastructure necessary for the power sector to reliably and affordably obtain and blend low-GHG hydrogen. As such, the state of combustion turbine technology alone, regardless of its level of advancement, is insufficient to support EPA's proposed adequate demonstration determinations.

a. Despite EPA's statements, hydrogen blending in the power sector is nascent at present and any conclusions about when it will be adequately demonstrated are premature.

As discussed below, the current use of hydrogen blending in the power sector remains at the pilot stage. In fact, EPA does not cite a single U.S. power sector hydrogen blending project that is in commercial operation, and it does not since there are none to cite despite the significant government and industry efforts to overcome existing barriers.[85] Current hydrogen blending projects do not include critical components of the larger value chain that will be needed to support low-GHG hydrogen availability throughout the power sector. As discussed *supra*, the pilot and demonstration projects that EPA cites are insufficient under D.C. Circuit caselaw to satisfy the requirements for adequate demonstration, as are companies' "plans" and "expectations" for future hydrogen blending.

i. EPA overstates the current state of power sector hydrogen blending projects, as the current state of projects do not support EPA's proposed determination that it has been adequately demonstrated.

EPA's characterization and analysis of the state of hydrogen blending in the power sector are overstated, as evidenced by the Agency's own descriptions of actual current projects as "plans," "pilots," "demonstrations," and "test-burns." *See, e.g.,* 88 *Fed. Reg.* at 33,255. Use of this language is not limited to a few examples but permeates EPA's recitation of the specific facts for each of the current U.S. projects that the Agency discusses.

[85] The United States is not alone in this early phase of development—with the exception of a single, 320-kW project in Japan that is not comparable in size to the facilities subject to the Proposed 111 Rules, every project that EPA cites is in the testing stages.

Specifically, EPA: (1) describes the Long Ridge Energy Generation Project's (Long Ridge Energy Terminal) hydrogen blending as the successful completion of "a *test burn* of 5 percent (by volume);"[86] (2) explains the Intermountain Power Agency's *plan* to "replace an existing coal-fired EGU with a Mitsubishi 840-MW combustion turbine that *will have* the capability to co-fire 30 percent by volume low-GHG hydrogen in 2025 and 100 percent electrolytic hydrogen by 2045," 88 *Fed. Reg.* at Hydrogen TSD at 8 (emphasis added); *see also id.* at 33,255, 33,305, 33,308, 33,312, and 33,365 (all describing the "plans" and "expectations" for this project); (3) notes the Los Angeles Department of Water and Power's *plan* for the Scattergood Generating Station, which "*would be* ready to co-fire a minimum of 30 percent low-GHG hydrogen . . . *when the unit becomes operational by December 30, 2029*," *Id.* at Hydrogen TSD at 8 (emphasis added); *see also id.* at 33,255 and 33,308 (describing the "plans" for the project); (4) explains that the Lincoln Land Energy Center Project "*will be* ready to co-fire up to 30 percent by volume hydrogen upon initial operation," *Id.* at Hydrogen TSD at 8-9 (emphasis added); (5) notes that El Paso Electric "*is seeking* to convert its Newman Power Station to co-fire 30 percent by volume

[86] 88 *Fed. Reg.* at Hydrogen in Combustion Turbine Electric Generating Units: Technical Support Document, at 8 (emphasis added) (hereinafter "Hydrogen TSD"). EPA also cites to sources that explain that this project was a demonstration. *See* 88 *Fed. Reg.* at nn.74 and 377-78. For example, one of the sources explains that the Long Ridge Energy Terminal "conducted a successful [5 percent] hydrogen-blending demonstration on March 30, 2022." Clark, K., GE-Powered Gas-Fired Plant in Ohio Now Burning Hydrogen, Power Engineering (Apr. 22, 2022), https://www.power-eng.com/hydrogen/ge-powered-gas-fired-plant-in-ohio-now-burning-hydrogen/. Another source that EPA cites notes that "[t]esting will continue through next year at the 5% baseline." Defrank, R., Cleaner Future in Sight: Long Ridge Energy Terminal in Monroe County Begins Blending Hydrogen, The Intelligencer (Apr. 25, 2022), https://www.theintelligencer.net/news/community/2022/04/cleaner-future-in-sight-long-ridge-energy-terminal-in-monroe-county-begins-blending-hydrogen/. EPA itself also notes that "The Long Ridge Energy Terminal tested 5 percent hydrogen co-firing at the 485–MW combined cycle plant on a GE HA-class (GE 7HA.02) in 2022." 88 *Fed. Reg.* at 33,364.

hydrogen," *Id.* at 9 (emphasis added); (6) notes that Entergy's Orange County Advanced Power Station "*will be* ready to co-fire 30 percent hydrogen by volume at initial operation," *Id.* (emphasis added) despite the fact that the fuel itself may not actually be available; (7) explains that the Magnolia Power Plant "*is expected* to begin operations in 2025 with a GE 7HA.03 combustion turbine . . . [that] *will be* hydrogen-ready with the ability to co-fire up to 50 percent hydrogen by volume *as the fuel becomes available*," 88 *Fed. Reg.* at Hydrogen TSD at 9 (emphasis added); (8) lists Georgia Power's hydrogen blend *test run* at its McDonough Atkinson plant among "demonstrations of existing units co-firing hydrogen;" 88 *Fed. Reg.* at Hydrogen TSD at 9 (emphasis added); (9) describes the New York Power Authority's work at the Brentwood power plant as having "successfully *demonstrated* the ability to co-fire 44 percent 'carbon-free' hydrogen," *Id.* at 10 (emphasis added); (10) explains that the Cricket Valley Energy Center "*is planning* to demonstrate co-firing a 5 percent blend of hydrogen at a combined cycle facility." *Id.* (emphasis added). In addition, these projects generally are running anywhere from a few hours to a few days at the maximum, and none are in continuous commercial operation.[87]

[87] *See, e.g.,* Chemnick, J., EPA extends comment period on landmark power plant rules, E&E GreenWire (June 15, 2023) ("Standards are based on carbon capture and storage and hydrogen co-firing at gas plants, technologies not currently deployed at commercial power plants in the U.S."), https://subscriber.politicopro.com/article/eenews/2023/06/15/epa-extends-comment-period-on-landmark-power-plant-rules-00102152. EPA also overstates projects' hydrogen blending goals. For example, in the Hydrogen TSD, EPA states that the Lincoln Land Energy Center Project will have "the capability to utilize 100 percent low-GHG hydrogen by 2045." 88 *Fed. Reg.* at Hydrogen TSD at 9. However, it is unclear how EPA arrived at 2045. The website that EPA cites references the project's blend "subsequently ris[ing] to 100% *throughout the lifetime of the facility*." Cukia, M., Proposed 1.1GW Lincoln Land Energy Center Project in Illinois Approved, Constructionreview (Aug. 15, 2022), https://constructionreviewonline.com/news/proposed-1-1gw-lincoln-land-energy-center-project-in-illinois-approved/. EmberClear, the project developer, is even more ambiguous about the timing of reaching 100 percent hydrogen firing and explains that the facility "will incorporate the ability to use . . . *up to 100% within the lifespan of this project*." EmberClear, Lincoln Land: Discover What the Lincoln-Land Project is About, https://emberclear.com/lincoln-land/.

A closer look further proves that power sector hydrogen blending is in the pilot and demonstration phase and that these projects are insufficient to support EPA's proposed adequate demonstration determination. For example, the Long Ridge Energy Terminal is testing a 5 percent hydrogen blend in phase one and plans to scale up to a 20 percent hydrogen blend in phase two. The project has explained that operating data from phase one would "validate the design and operating parameters" and allow the developers to "gather information that can be used in the next phases of the hydrogen blending program at Long Ridge and, in GE's case, elsewhere in the engine fleet."[88] This project does not currently serve customers and is seeking to "use successful testing as proof of concept to attract commercial customer(s) for this power."[89]

Similarly, in its discussion of the demonstration project at the Brentwood power plant, the Electric Power Research Institute (EPRI) noted several key findings and operational lessons learned. A review of these key findings and operational lessons learned demonstrates the early phase of hydrogen co-firing in the U.S. power sector. This is underscored by the "next steps" noted in the report, which provide "[l]essons learned during the design and execution of the project are documented in this report, along with recommendations for future LM6000 hydrogen cofiring *investigations*. Researchers will take this information into account in building a foundational knowledge base and *exploring future hydrogen blending pilot projects* as part of the

[88] First Amendment to Construction Certificate Letter of Notification, Long Ridge Energy Generation Project, Ohio Power Siting Bd., 21-0789-EL-BLN, at 6 (July 23, 2021).

[89] *Id*.

clean energy transition."[90] These statements show that this project is in the early stages of testing hydrogen blending and is not sufficient to support a determination that hydrogen blending in the power sector is adequately demonstrated given where it stands in that phase of development. Further to that point, the team also has noted that "[t]ransitioning to higher concentrations of hydrogen may 'bring a new set of unknowns.'"[91]

ii. Current power sector hydrogen blending projects do not include components of the overall value chain that will be critical to the availability of low-GHG hydrogen blending throughout the power sector.

Current pilot projects also cannot demonstrate the adequacy of the overall value chain that will be necessary for low-GHG hydrogen blending to be available throughout the power sector. More specifically, based on publicly available information, current U.S. projects are either producing hydrogen onsite or trucking the hydrogen to the site.[92] However, onsite production will not be feasible for all end-users, particularly where there are emissions limitations on the hydrogen

[90] Elec. Power Res. Inst., Executive Summary: Hydrogen Cofiring Demonstration at New York Power Authority's Brentwood Site: FE LM6000 Gas Turbine, at 5, https://www.epri.com/research/products/000000003002025166 (emphasis added).
[91] Patel, S., Harnessing an H-Class for Hydrogen: Long Ridge Energy Terminal, POWER Mag. (Oct. 2, 2022), https://www.powermag.com/harnessing-an-h-class-for-hydrogen-long-ridge-energy-terminal/.

[92] For example, the hydrogen supply for phase one of the Long Ridge Energy Terminal's testing was planned through "a continuous process with approximately four to five trailers on site at any time: two trailers connected to the offloading manifold, two staged in waiting, and the fifth trailer in transit nearby." OPSB Staff Report of Investigation, Ohio Power Siting Bd., 21-0789-EL-BLN, at 2 (Aug. 13, 2021). Each hydrogen tube trailer would provide approximately 40 minutes to one hour of operational supply. *Id.* at 2. For phase two, the project plans to "transition[] to an on-site, third-party sponsored technology for hydrogen supply, [and that the] hydrogen will be delivered to the Project at a flange connection to be located near the proposed trailer offloading connection and transferred to the fuel blending skid(s) via underground piping." First Amendment to Construction Certificate Letter of Notification, Long Ridge Energy Generation Project, Ohio Power Siting Bd., 21-0789-EL-BLN, at 8 (July 23, 2021).

production pathway as the resources necessary for production (e.g., water and qualifying renewable electricity) are not abundant, available, or feasible in all regions.[93] Where onsite production is not possible, midstream transportation will be necessary.

As discussed below, current projects' onsite production and hydrogen trucking are evidence of the specific lack of midstream infrastructure. Onsite production and trucking are not expected to be feasible for growing sectors. As DOE explains "[i]nitial large-scale deployments of clean hydrogen are expected to target industries *with established supply chains* and economies of scale, such as ammonia production and the petrochemical industry. These deployments will be supplemented with smaller-scale deployments in new applications and growing sectors *as the infrastructure develops*."[94] It is also not clear whether the trucked hydrogen would meet EPA's "low-GHG" requirements, either.

Consequently, while current hydrogen blending projects and plans in the power sector are promising, these projects are only in the early stages of development and are too premature to

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[93] It also has been noted that the Long Ridge Energy Terminal is extremely well-situated. Mike Jacoby, President of Ohio Southeast Economic Development recently explained that "Long Ridge Energy Terminal has a unique site with amazing transportation infrastructure and a supply of reliable, competitively priced electricity." Press Release, Long Ridge Energy Terminal Developing Data Center Campus in Hannibal, Ohio, Ohio Southeast Economic Development (Sept. 15, 2021), https://ohiose.com/news/long-ridge-energy-terminal-developing-data-center-campus-in-hannibal-ohio/. Jacoby also notes that the project is located in an Opportunity Zone, which is an area that may be eligible for preferential tax treatment. *See* Internal Revenue Serv., Opportunity Zones Frequently Asked Questions, https://www.irs.gov/credits-deductions/opportunity-zones-frequently-asked-questions.

[94] DOE, U.S. Clean Hydrogen Strategy and Roadmap at 21 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html (emphasis added). *See also* midstream infrastructure discussion *infra.*

support a determination that low-GHG hydrogen co-firing is the BSER. In addition, these projects do not include the midstream infrastructure that will be necessary to ensure low-GHG hydrogen is available throughout the industry. Accordingly, while these projects may mature to the deployment phase and ultimately serve as useful data points for future EPA rulemaking, at present they are insufficient to satisfy section 111's requirements.

b. Current turbine technology to blend hydrogen in the power sector alone is insufficient to support EPA's proposed adequately demonstrated determinations.

EPA notes that turbines have demonstrated a 20-30 percent hydrogen blend with natural gas and that turbine manufacturers are working towards 100 percent hydrogen firing by 2030. 88 *Fed. Reg.* at 33,255 and 33,305. As discussed above, power sector hydrogen blending projects are in the pilot stage and have not been deployed in commercial operation. While turbine capability is advancing, and both turbine manufacturers and EEI's member companies are actively working to deploy these technologies, turbines are only one piece of the puzzle for demonstrating hydrogen blending. As discussed above, power sector hydrogen blending projects are in the pilot stage and have not been deployed in commercial operation. As noted, the power sector is the *only* source category with a public service obligation to operate. Combined cycle and combustion turbines play an essential role in continuing the clean energy transition by providing 24/7 and quick start power, which allows for increased renewable integration and reliable power at affordable rates for customers. As a result, the full operability of *all* elements of the technology system is vital for EGUs, given the power sector's unique obligation to be available and on call to provide power whenever it is needed. However, various elements of the overall value chain that will be needed to support reliable commercial deployment of hydrogen blending across the power sector are still developing.

For example, while GE's 7HA.02 combustion turbine is "'innately capable' of burning 15% to 20% hydrogen by volume . . . [c]rucial to this effort . . . are aligning the differences in the combustion properties of hydrogen and natural gas, as well as impacts to all gas turbine systems, and to the overall balance of plant."[95] Speaking about the Long Ridge Energy Terminal, Director of Emergent Technologies at GE Gas Power's Decarbonization Division, Jeff Goldmeer, further explained that "[t]he 7HA.02 at Long Ridge has not been modified for hydrogen. When we talk about going to 50% or 100% hydrogen, then we'll start needing to see changes in the combustion system, primarily on the gas turbine, and changes in the balance of plant to handle much more hydrogen."[96] In discussing the transition to 100 percent hydrogen by volume, Goldmeer explained that the timing will be driven by several factors—"[t]here are three pieces there, there's the technology readiness, the supply chain component, and then, when it makes sense for the customer to do so."[97]

Moreover, among its operational lessons learned for the Brentwood project, EPRI notes the importance of maintaining a stable supply of hydrogen, "which is critical to transitions of the hydrogen ratio and load of the turbine" and because "[i]nstability of the hydrogen supply could

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[95] Patel, S., First Hydrogen Burn at Long Ridge HA-Class Gas Turbine Marks Triumph for GE, POWER Mag. (Apr. 22, 2022) (quoting Jeff Goldmeer, Director of Emergent Technologies at GE Gas Power's Decarbonization Division), https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge/.

[96] *Id.*

[97] *Id.*

cause the hydrogen system to trip off."[98] Ensuring a stable supply will require either onsite hydrogen production and storage or hydrogen transportation and storage. As noted and further discussed below, co-locating hydrogen production with electric generation, particularly for low-GHG hydrogen production, likely will not be feasible for all entities. This is due to both potential physical space constraints, as well as the lack of access to the resources necessary to produce hydrogen onsite across the power sector. In addition, there are barriers at present to scaling up low-GHG hydrogen production, water availability, pipeline transportation, and storage, and potential cost barriers to hydrogen trucking.

While government and industry are working to overcome these challenges, it is unclear when and to what extent they will be surmounted and what the impact will be on the development of a U.S. clean hydrogen economy that could support reliable and affordable hydrogen co-firing in the power sector. As a result, while EEI and its members are hopeful that the U.S. clean hydrogen economy develops in line with the picture that EPA paints and are actively working to develop it, the Agency's analysis of the demonstrated nature of the technology is overstated and insufficient to support its proposed determinations, and not supported by existing case law.

c. EPA's proposed low-GHG hydrogen production conclusions are based on an insufficient record and low-GHG hydrogen production faces challenges that could limit achievability throughout the industry.

EPA proposes to conclude that the power sector is "likely to have ample access to low-GHG hydrogen and [that it will be] in sufficient quantities to support 30 percent co-firing by 2032 and

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[98] Elec. Power Res. Inst., Executive Summary: Hydrogen Cofiring Demonstration at New York Power Authority's Brentwood Site: FE LM6000 Gas Turbine, at 3, https://www.epri.com/research/products/000000003002025166.

96 percent by 2038." 88 *Fed. Reg.* at 33,309. However, as discussed below, EPA's proposed conclusion and the record it has compiled contains errors, overgeneralizations, and a failure to recognize key facts about low-GHG hydrogen production. In addition, section 111 requires EPA to take cost and other factors into consideration in reaching an adequate demonstration determination. However, in the Proposed 111 Rules, the Agency fails to consider how market dynamics and the contours of the U.S. Department of Treasury's (Treasury's) forthcoming guidance on the hydrogen production tax credit (PTC) in the Inflation Reduction Act (IRA) could impact low-GHG hydrogen production and its proposed adequate demonstration determinations.

Moreover, the Proposed 111 Rules and the record compiled by EPA also include several contradictory statements. For example, EPA states that "[w]hether there will be sufficient volumes of low-GHG hydrogen for new sources to co-fire [in line with EPA's proposal] will depend on the deployment of additional low-GHG electric generation sources, the growth of electrolyzer capacity, and market demand." *Id.* EPA also "recogniz[es] that there are likely limits to the clean hydrogen supply in the mid-term." 88 *Fed. Reg.* at 33,362. EPA does not attempt to square these statements with its proposed determination.

For these reasons, EPA's proposed determination is not the product of reasoned decision making as its record casts doubt on The Agency's conclusions, and also lacks key information. When included, the information that EPA fails to analyze shows the Agency's proposed determinations are unsupported.

i. EPA's existing record is mischaracterized and overgeneralized, and closer investigation reveals the record does not support the proposed adequate demonstration determinations.

EPA's discussion includes overgeneralizations and misstatements that it significantly relies upon for its proposed determinations. For example, EPA notes that "[p]rograms from the IIJA and IRA have been successful in promoting the development of new low-GHG hydrogen projects and infrastructure. As of August 2022, *374 new projects* had been announced that would produce 2.2 megatons (Mt) of *low-GHG hydrogen* annually, which represents a 21 percent increase over current output." 88 *Fed. Reg.* at 33,312 (citing Energy Futures Initiative, U.S. Hydrogen Demand Action Plan (Feb. 2023), https://energyfuturesinitiative.org/reports/) (emphasis added). EPA cites the Energy Futures Initiative's (EFI's) U.S. Hydrogen Demand Action Plan to support this statement. However, EFI's report actually states that it has "tracked *374 distinct clean hydrogen* project announcements . . . [and a] review of publicly announced projects shows 2.2 million metric tons (megatons [Mt]) *of potential clean hydrogen* supply, or roughly 21 percent of the current U.S. hydrogen industry's output."[99]

EFI's use of the term "clean hydrogen" encompasses multiple production pathways—namely, blue hydrogen (produced from methane reformation with carbon capture), green hydrogen (produced from water using renewable electricity), turquoise hydrogen (produced through methane pyrolysis), and pink hydrogen (produced from water using nuclear electricity).[100] By

[99] Energy Futures Initiative, U.S. Hydrogen Demand Action Plan, at 12 (Feb. 2023), https://energyfuturesinitiative.org/reports/ (emphasis added).

[100] *See, e.g.,* Energy Futures Initiative, U.S. Hydrogen Demand Action Plan, at Figure 4 (Feb. 2023), https://energyfuturesinitiative.org/reports/.

contrast, EPA's proposed definition of low-GHG hydrogen would, at a minimum, not include hydrogen produced from methane reformation with carbon capture. EPA explains that whether methane pyrolysis qualifies as low-GHG hydrogen depends on "the source of the energy used to decompose the methane." 88 *Fed. Reg.* at n.397. Further, depending on the contours of Treasury's hydrogen PTC guidance and the extent to which EPA's final rule aligns with that guidance, EPA's definition of low-GHG hydrogen also may not include hydrogen produced using nuclear electricity, as discussed *infra*. If methane pyrolysis and production using nuclear power are included, less than 0.2 MMT of the 2.2 MMT of clean hydrogen production projects noted in EFI's report would qualify as low-GHG hydrogen production under EPA's proposed definition—without these two pathways, the total is less than 0.15 MMT of the 2.2 MMT projects that EFI discusses and that EPA attempts to attribute to low-GHG hydrogen.[101] Stated differently, at maximum, less than 10 percent of the announced clean hydrogen production projects noted in EFI's report would qualify as low-GHG hydrogen production under EPA's proposal.

Importantly, EFI also explains that while "around 70 percent of the recently announced projects involve green hydrogen," this interest "may not be immediately effective for scaling regional clean hydrogen markets."[102] Moreover, "[d]espite representing a relatively small share of the total, blue hydrogen projects account for nearly 95 percent of the capacity of announced projects."[103] The difference between EPA's own proposed definition and EFI's use of the term

[101] *See id.*

[102] *See id.*, at 29 (Feb. 2023), https://energyfuturesinitiative.org/reports/.

[103] *Id.*

clean hydrogen is significant but the Agency does not discuss EFI's actual findings with respect to low-GHG hydrogen production and their implications for EPA's proposed determinations.

ii. Low-GHG hydrogen production faces challenges that could limit achievability throughout the industry.

At present, the United States produces approximately 10 MMT per year of hydrogen, the majority of which is produced from natural gas or coal without carbon capture technology. DOE estimates that "[c]lean hydrogen production for domestic demand has the potential to scale from < 1 million metric tons per year (MMTpa) to ~10 MMTpa in 2030."[104] It is important to note that DOE's estimates are of "clean" hydrogen, which DOE defines as having a carbon intensity of less than 4 kg CO_2e/kg of hydrogen on a lifecycle basis measured from well-to-gate.[105] This is in contrast to EPA's "low-GHG" hydrogen, which it proposes to define as having a carbon intensity less than or equal to 0.45 kg CO_2e/kg of hydrogen on a lifecycle basis measured from well-to-gate. 88 *Fed. Reg.* at 33,304. As noted above, the most salient production pathway to qualify under EPA's definition is through electrolysis powered by renewable electricity.[106]

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[104] Clean Hydrogen Liftoff Report at 1.

[105] U.S. Dep't of Energy Clean Hydrogen Production Standard (CHPS) Guidance, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard-guidance.pdf; and Clean Hydrogen Liftoff Report at n.1.

[106] In light of EPA's proposal to require the use of low-GHG hydrogen, the discussion below focuses on electrolytic hydrogen produced using clean electricity. However, other production pathways, which may be necessary to support the level of deployment that would be required to comply with the Proposed 111 Rules, similarly face barriers to scaling up. As noted, while entities across government agencies and industry are working to overcome these challenges, it is unclear at this point when, how, and to what extent and what the impacts will be on availability of low-GHG hydrogen.

There are several challenges to scaling production of EPA's low-GHG hydrogen, including the need to increase electrolyzer manufacturing and resolve related supply chain challenges, as well as access to clean electricity. As DOE explains in the Clean Hydrogen Liftoff Report, "[e]lectrolysis will be challenged by supply-chain constraints in both raw materials and equipment manufacturing capacity during a critical scale-up period through 2025 in addition to challenges with renewables build-out and sourcing a domestic workforce."[107] Importantly, DOE further notes that "[i]f electrolysis fails to scale during the PTC time horizon, it may not achieve sufficient cost downs prior to PTC expiration."[108] While EPA makes mention of some of the issues discussed below, the Proposed 111 Rules do not include adequate discussion or analysis of these issues and it does not appear that EPA has taken them into account in reaching its proposed determinations.

1. EPA does not adequately analyze the need for domestic electrolyzer manufacturing capacity to scale up exponentially, which could impact low-GHG hydrogen production and limit achievability throughout the industry.

It is well-recognized that increased electrolyzer manufacturing will be a necessary component to development of a hydrogen market at scale. In a 2022 report, the International Energy Agency explained that Europe and China account for 80 percent of global manufacturing capacity.[109] As countries around the world, including the United States, look to significantly increase hydrogen production to help meet their climate goals, there is a corresponding need to ramp up electrolyzer manufacturing capacity.

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[107] Clean Hydrogen Liftoff Report at 45.

[108] Clean Hydrogen Liftoff Report at 45.

[109] Int'l Energy Agency, Electrolyzers (Sept. 2022), https://www.iea.org/reports/electrolysers.

In the United States, there are "only a few small-scale electrolyzer manufacturers."[110] Meeting DOE's projected demand, which EPA repeatedly references, and avoiding "an electrolyzer bottleneck" will require a "rapid and significant ramp-up in capacity."[111] DOE explains that

> [t]o enable deployment of ~100 GW of operational electrolyzers by 2030, domestic production would need to scale from 4 GW of publicly announced capacity with target commercial operation dates (CODs) to as much as ~20–25 GW p.a. by 2030. In some instances, hydrogen producers today are already being quoted lead times of 2 to 3 years when they order electrolyzers. If the size of U.S. production facilities increases to match EU facility sizes, the U.S. could require as much as ~12–14 additional electrolyzer production facilities by 2030.[112]

The scope of the challenge of achieving this goal also is evident from the inclusion of electrolyzers in President Biden's June 6, 2022, presidential determinations under the Defense Production Act.[113]

Despite this significant and well-known potential barrier, the Proposed 111 Rules do not substantively address the need for "growth of electrolyzer capacity" and only include a high-level description of three electrolyzer factories that are "under development" in the United States. 88 *Fed. Reg.* at 33,309 and Hydrogen TSD at 23. Adequate access to electrolyzers is

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[110] Clean Hydrogen Liftoff Report at 87.

[111] *Id*. at 87.

[112] *Id*. at 46.

[113] *Memorandum on Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as amended, on Electrolyzers, Fuel Cells, and Platinum Group Metals* (June 6, 2022), https://www.whitehouse.gov/briefing-room/presidential-actions/2022/06/06/memorandum-on-presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-electrolyzers-fuel-cells-and-platinum-group-metals/.

critical to scaling the U.S. clean hydrogen economy and to the power sector's ability to deploy hydrogen blending. EPA's failure to analyze the potential barriers that electrolyzer manufacturing faces are a significant flaw in its record and undermine its proposed adequate demonstration determination. Critically, these are flaws that providing significant "lead time" alone cannot heal since the underlying issues must be actively resolved and not passively solved through the lapse of time.

2. EPA does not adequately analyze supply constraints for the raw materials required for electrolyzer production that could impact low-GHG hydrogen production and limit achievability throughout the industry.

Even if the United States is able to scale up its electrolyzer manufacturing capacity, access to the raw materials required to manufacture electrolyzers are anticipated to become constrained. DOE explains that "[w]hile global raw material shortages are not currently an issue, the global abundance of certain materials, particularly platinum group metals (PGMs), may be stressed by electrolyzer production in 2030 and beyond."[114] This concern also is underscored by the inclusion of PGMs in President Biden's June 6, 2022, presidential determinations under the Defense Production Act.[115]

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[114] Clean Hydrogen Liftoff Report at 88.

[115] *Memorandum on Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as amended, on Electrolyzers, Fuel Cells, and Platinum Group Metals* (June 6, 2022), https://www.whitehouse.gov/briefing-room/presidential-actions/2022/06/06/memorandum-on-presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-electrolyzers-fuel-cells-and-platinum-group-metals/.

Although several types of electrolyzers technologies are being explored and developed, the two technologies that are beyond the laboratory phase and at the commercial stage of maturity are alkaline water electrolysis and proton exchange membranes (PEM).[116] Alkaline electrolyzers are the dominant technology at present. These electrolyzers require nickel, which, in scaling up "may face higher costs from material constraints [as it is] widely used in other expanding industries."[117]

Alkaline electrolyzers are not highly flexible and are large. As a result, there has been significant interest in PEM electrolyzers, which have "a fast response ramp-up and ramp-down capability, as well as a wide dynamic operating range of 0-100%."[118] However, PEM electrolyzers also face a potential raw materials challenge as they require iridium, for which there is no significant domestic source.[119] In the Clean Hydrogen Liftoff Report, DOE explains that by 2030, U.S. demand for PEM electrolyzers could require approximately 15-30 percent of the global production of iridium raw material.[120] DOE also notes that its forecast for iridium demand assumes that PEM electrolyzers will have a 25 percent market share and that this "likely represents a conservative assumption" as other analyses show an approximately 30 percent

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[116] Clean Hydrogen Liftoff Report at Figure 3. *See also* Int'l Energy Agency, Hydrogen Supply (Sept. 2022), https://www.iea.org/reports/hydrogen-supply.

[117] Clean Hydrogen Liftoff Report at 59.

[118] Cockerill, R., *Electrolyser Technologies: PEM vs Alkaline Electrolysis,* H2VIEW (Nov. 2020), https://nelhydrogen.com/wp-content/uploads/2021/07/Alk-vs-PEM.pdf.

[119] Clean Hydrogen Liftoff Report at 59. *See also id.* at 46 (explaining that "[o]ver 80% of iridium supply comes from South Africa, with almost no opportunity for domestic production").

[120] *Id*. at 45.

global market share.[121] DOE notes that "[n]onetheless, the quantity of iridium required is significant."[122] Requirements to satisfy projected PEM electrolyzer production could, in fact, exceed the quantity of iridium that is economically feasible to mine,[123] as "iridium deposits are limited and only mined on a small scale."[124]

DOE also explains that U.S. electrolyzer manufacturers will need graphite, yttrium, platinum, and strontium, "most of which cannot be found domestically in sufficient quantities [and] reliance on foreign suppliers could hinder growth of U.S. based electrolyzer manufacturing."[125]

As noted *supra*, EPA does not discuss these potential supply chain concerns in the Proposed 111 Rules and does not appear to have taken these issues into consideration in its analysis, which the Agency must do as part of determining BSER. EPA's failure to analyze the potential barriers that electrolyzer manufacturing faces is a significant flaw in its record and undermine its proposed determination that hydrogen blending is adequately demonstrated.

3. EPA does not adequately analyze the need to significantly increase clean electricity production and accessibility that could impact low-GHG hydrogen production and achievability throughout the industry.

[121] *Id*. at 87.

[122] *Id*.

[123] *Id*. at 59.

[124] *Id*. at 87.

[125] *Id*. at 88.

In addition to the criticality of scaling up electrolyzer manufacturing and production, access to clean electricity is key to low-GHG hydrogen production.[126] As noted, EPA proposes to require that the hydrogen co-firing pathway utilize low-GHG hydrogen, which will require the use of clean electricity, like wind and solar. In the Clean Hydrogen Liftoff Report, DOE explains that "[f]or water electrolysis, availability of clean electricity . . . will play a critical role in the pace of growth."[127] DOE further projects that, by 2030, electrolytic hydrogen production could require up to 200 gigawatts (GW) of additional renewables. In addition to potential siting and permitting challenges, this scale of build-out implicates non-air impacts associated with land-use, as discussed below.

Further, while the share of wind and solar generation is increasing,[128] demand for clean electricity also is accelerating. This presents "a challenge across many clean energy technologies

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[126] Electrolysis is inherently reliant on access to water. DOE estimates that "10 MMT [of] hydrogen produced from water electrolysis would require 29 billion gallons of water." Clean Hydrogen Liftoff Report at endnote viii. However, access and the legal rights to use water vary in the United States. For example, in many states in the West where water is constrained, the governing legal regimes generally are restrictive and require water rights or permits for most uses. *See, e.g.,* Water Resource Considerations for the Hydrogen Economy, K&L Gates LLP (Dec. 16, 2020), https://www.klgates.com/Water-Resource-Considerations-for-the-Hydrogen-Economy-12-16-2020. These regimes often also include senior and junior water rights based on when the rights were obtained. During droughts, senior right holders take precedence over junior holders. These access issues may create challenges for low-GHG hydrogen production in certain regions of the United States. EPA does not discuss these potential supply issues in the Proposed 111 Rules and does not appear to have taken these issues into consideration in its analysis.
[127] Clean Hydrogen Liftoff Report at 3.

[128] The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly cleaner. *See* U.S. Energy Information Administration (EIA), Today in Energy: Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022 (Mar. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55960&src=email; *See also* EIA, Electric Power Monthly: Data for February 2023—Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2013-February 2023 (Mar. 24, 2023),

as new electricity demand (e.g., for electrolysis, direct air capture) develops in parallel to electrification of buildings and transport."[129] Critically for the purposes of EPA's proposed determination, constraints in renewables development could impact how hydrogen production develops.[130]

DOE notes that using nuclear power to produce hydrogen could relieve some of this pressure.[131] However, it is not clear whether electricity from nuclear generation will qualify under EPA's definition of low-GHG hydrogen. More specifically, EPA proposes to align its definition of low-GHG hydrogen with Treasury's forthcoming hydrogen PTC guidance. 88 *Fed. Reg.* at 33,330. The contours of this Treasury guidance have been hotly debated, including whether Treasury should impose additionality requirements. *See, e.g., id.* at 33,330-31. Such requirements could disqualify electricity from existing nuclear generation. If Treasury imposes an additionality requirement that would disqualify existing nuclear and EPA incorporates this principle into the

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https://www.eia.gov/electricity/monthly/xls/table_1_01.xlsx; *and* EIA, Electric Power Monthly: Data for February 2023—Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors) (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01_a.xlsx. In 2022, for the first time, renewable energy sources surpassed coal as a fuel: 22.6 percent of total generation at utility scale facilities in the United States came from renewable sources compared to 19 percent from coal-based generation. *See* EIA, Electric Power Monthly, Table 1.1. In total, more than 40 percent of America's electricity came from clean carbon-free resources in 2022, including nuclear energy, hydropower, solar, and wind, putting clean resources at parity with natural gas generation, which provided approximately 40 percent of the country's total electricity generation at utility scale facilities in 2022. *See id.*

[129] Clean Hydrogen Liftoff Report at 59.
[130] *See, e.g., id*. at 37 ("If clean electricity deployment is constrained by challenges such as land use restrictions or siting/permitting bottlenecks, modeling results show reformation with CCS will dominate.").

[131] *Id*. at 59.

final rule, the challenges in accessing sufficient clean electricity to meet power sector demands under the Proposed 111 Rules, noted above, will likely be exacerbated.

The transmission grid itself also is in the midst of significant change. It is estimated that the capacity of the existing grid must increase by as much as 60 percent by 2030, and it may need to triple in size by 2050 to meet the growing demand for clean electricity to support a carbon-free economy.[132] Transmission is a key enabling technology for the clean energy transition because it allows interconnection of new resources and better utilization of both new and existing resources, including reduced curtailment of wind and solar energy. Large-scale regional and interregional transmission can enhance reliability by expanding electricity imports and exports and by improving coordination across wider geographies. Expanding the grid will require siting and construction of additional transmission infrastructure.

At present, there are several ongoing regulatory reform efforts in areas central to grid function. For example, the Federal Energy Regulatory Commission (FERC) recently issued a proposed rulemaking regarding Applications for Permits to Site Interstate Electric Transmission Facilities (commonly referred to as FERC's "backstop authority"),[133] and solicited comments in response to a Staff-led workshop regarding the possibility of a minimum requirement for Interregional

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[132] *See* Eric Larson et al., Net-Zero America by 2050: Potential Pathways, Infrastructure, and Impacts, Final Report Summary, at 76 (Princeton University, Oct. 29 2021), https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf.

[133] *Applications for Permits to Site Interstate Electric Transmission Facilities*, 181 FERC ¶ 61,205 (2022).

Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes.[134] Furthermore, as a result of the current significant backlog in the queue of projects waiting to connect to the grid concerns,[135] FERC recently issued an order seeking to resolve the interconnection backlog.[136] As of the time of this filing, the opportunity to request rehearing on that order remains open and it appears likely that such requests will be filed, which could result in modification of FERC's order. The outcome of these proceedings could significantly change the pace of development of the grid and access to clean electricity.

As discussed above, EPA does not discuss these potential supply issues—issues principally out of the control of the owner/operators of the affected sources regulated by EPA—in the Proposed 111 Rules and does not appear to have taken these issues into consideration in its analysis. Access to clean electricity—and also the water resources needed for electrolysis—is critical to scaling the U.S. clean hydrogen economy and to the power sector's ability to deploy hydrogen blending. EPA's failure to analyze the potential barriers to scaling clean electricity generation and access are a significant flaw in its record and undermine its proposed adequate demonstration determination.

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[134] Notice Requesting Post-Workshop Comment, Docket No. AD23-3-000 (filed Feb. 28, 2023).

[135] DOE has reported more than 930 gigawatts (GW) of solar, wind, hydropower, geothermal, and nuclear capacity currently are in interconnection queues seeking transmission access, as are more than 420 GW of energy storage. U.S. Dep't of Energy, Queued Up…But in Need of Transmission: Unleashing the Benefits of Clean Power with Grid Infrastructure (Apr. 2022), https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf. FERC has noted that "interconnection queue backlogs and study delays afflicting generator interconnection service nationwide hinder the timely development of new generation." *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194, P 22 (2022).

[136] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

iii. EPA does not adequately analyze critical market dynamics that could impact low-GHG hydrogen production and achievability throughout the industry.

As noted, section 111 requires EPA to take cost into consideration in its BSER determinations. In the Clean Hydrogen Liftoff Report, DOE notes several potential challenges related to market dynamics that could impact the availability of low-GHG hydrogen on the timelines that EPA projects and which EPA does not recognize or adequately analyze. These include the potential that, in the period while the challenges facing hydrogen liftoff are being resolved, there will be high perceived credit risk for hydrogen projects that will "delay[] timelines for low-cost capital providers to enter the market."[137] In addition, "[s]ome offtakers worry that, until hydrogen production scales nationally, hydrogen supplies will be insufficient and/or too variable to meet high uptime use cases. For example, if stock-outs such as those that have been experienced at refueling stations in California were to become widespread, the industry would face additional headwinds to wider adoption."[138]

It is also unclear how many of the currently announced projects will reach final investment decision (FID). In the Clean Hydrogen Liftoff Report, DOE emphasizes the current lack of long-term offtake agreements, which likely is a function of the other barriers discussed herein. These agreements are a necessary component for many projects to reach FID. While there are currently over 100 clean hydrogen production projects that, if built, would meet DOE's 2030 clean hydrogen demand projections, "[o]nly ~1.5 MMT of this announced capacity has reach final

[137] Clean Hydrogen Liftoff Report at 3.

[138] *Id*. at 57.

investment decision."[139] Importantly for EPA's low-GHG hydrogen proposal, of the announced projects "43% are electrolytic and 56% are reformation based."[140] DOE notes that "[p]roject trackers vary the way in which they log announced capacity," and explains EFI's findings, noted above. More specifically, DOE cites EFI's statement that while green hydrogen production projects account for around 70 percent of recently announced projects, "blue hydrogen projects account for nearly 95 percent of the capacity of the announced projects" and green hydrogen projects are "a relatively small share" by contrast.[141] Consequently, while there is reason to be optimistic about the scale up of U.S. clean hydrogen production capacity, the contours, timing, and size of this capacity are evolving and remain unsettled at present despite the significant efforts by DOE and industry to attempt to make this scaling up a reality.

In addition, EPA correctly notes that DOE's estimate of the potential for 10 MMT of clean hydrogen production capacity by 2030 (1) includes a wider range of hydrogen production pathways than would qualify under EPA's definition because DOE defines "clean" hydrogen to be less than 4 kg CO_2e/kg of hydrogen—as discussed in greater detail *infra*, EPA should adopt an inclusive definition of qualifying hydrogen than its current proposal to enable scale up of the U.S. clean hydrogen market and to reflect the variability of production resources across the country and electric sector; and (2) does not include significant anticipated power sector demand. While EPA may be correct that the Proposed 111 Rules will increase demand for low-GHG hydrogen beyond DOE's projections, given midstream barriers, such demand increases not only

[139] *Id*. at 23.

[140] *Id*. at n.67.

[141] *Id*. at 23 (citing Energy Futures Initiative, U.S. Hydrogen Demand Action Plan (Feb. 2023), https://energyfuturesinitiative.org/reports/).

do not necessarily result in corresponding access to low-GHG hydrogen but also have the potential to exacerbate the challenges facing the scale up of low-GHG hydrogen production discussed above. 88 *Fed. Reg.* at 33,309 ("The EPA's hydrogen co-firing BSER proposal, if finalized, would create a significant additional demand driver for electrolytic hydrogen not considered in the DOE's hydrogen production goals of 10 MMT by 2030 and 20 MMT by 2040."). As a result, despite EPA's optimism around the potential impacts of the proposed rule, the actual outcome of its determination that hydrogen blending is BSER may be counterproductive to the development of the U.S. clean hydrogen economy that will be needed to support reliable and affordable hydrogen co-firing in the power sector despite the significant efforts underway to develop this economy by DOE and industry. The level of uncertainty alone shows that EPA's proposed determinations are not consistent with a conclusion that low-GHG hydrogen blending in the power sector has been adequately demonstrated.

iv. EPA fails to adequately analyze how Treasury guidance on the hydrogen PTC could impact low-GHG hydrogen production and achievability throughout the industry.

EPA states that the hydrogen PTC has the potential to drive great volumes of electrolytic hydrogen demand. *Id.* However, as DOE notes,

> [i]mplementation details for the hydrogen PTC are forthcoming from IRS and Treasury. Until there is additional clarity, there will be uncertainty about which projects will qualify and what prices producers will have to charge to break-even. The inability to project future revenues can be a hurdle to securing financing for low carbon intensity hydrogen production projects while 45V implementation policy remains under development.[142]

In addition, as noted above, the details of Treasury's guidance may constrict the resources that project developers can use to qualify for the PTC, potentially exacerbating and elongating the

[142] *Id*. at 57.

timeline to resolve existing challenges. Further, while the production tax credits under the IRA are designed to ease the challenges currently facing scale up of a U.S. clean hydrogen economy, EPA cannot use the existence of these credits to support a conclusion that the "low-GHG" hydrogen production pathway is the BSER. EPA does not discuss these issues or appear to have taken them into account in its proposed determinations. It should do so in any final rulemaking.

d. EPA's proposed midstream infrastructure conclusions are based on an insufficient record as the Agency fails to consider challenges that could limit achievability throughout the industry.

EPA states that "[g]iven the growth in the hydrogen sector and Federal funding for the H2Hubs, which will explicitly explore and incentivize hydrogen distribution, the EPA therefore believes that hydrogen distribution and storage infrastructure will not present a barrier to access for new combustion turbines opting to co-fire with 30 percent low-GHG hydrogen by volume in 2032 and to co-fire with 96 percent low-GHG hydrogen by volume in 2038." 88 *Fed. Reg.* at 33,309. In reaching this conclusion, EPA discounts the need for midstream infrastructure and fails to adequately consider technical challenges and open regulatory questions facing midstream infrastructure buildout that could limit achievability of low-GHG hydrogen blending throughout the power sector.

i. Despite EPA's assertions, additional midstream infrastructure will be needed to enable the scaling of the U.S. clean hydrogen economy and support achievability throughout the industry.

EPA suggests in its discussion of low-GHG hydrogen costs that significant additional midstream infrastructure will not be needed to support low-GHG hydrogen blending in the power sector. More specifically, EPA notes that the "majority of announced combustion turbine EGU projects proposing to co-fire hydrogen are located close the source of hydrogen. Therefore, the fuel delivery systems (*i.e.,* pipes) for new combustion turbines can be designed to transport hydrogen without additional costs." *Id.* at 33,314. The fact that most announced projects do not require significant midstream investment does not support EPA's conclusion since many announced projects plan to co-locate with hydrogen production[143] *because of* the current lack of midstream infrastructure.[144] In fact, co-location is a function of the need to build-out this critical component of the value chain rather than proof that it will not be required. This need is even more pronounced for retrofits, which cannot be collocated with new greenfield production since they *already exist elsewhere*.

Indeed, development of the U.S. clean hydrogen markets, which will be necessary to support reliable and affordable low-GHG hydrogen blending in the power sector, will require midstream infrastructure.[145] In fact, midstream infrastructure is one of the main challenges to deployment at scale discussed in DOE's Clean Hydrogen Liftoff Report. DOE explains that

> [p]ipelines and geologic storage are costly upfront to develop, but at high hydrogen volumes provide critical economies of scale. Dedicated hydrogen pipelines and low-cost geologic storage are expected to anchor hydrogen infrastructure in the long-term (post-2035). . .As described throughout this report, in the near-term limited

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[143] *See, e.g.,* U.S. Dep't of Energy, U.S. Clean Hydrogen Strategy and Roadmap at 12 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html, ("These initial use-cases are also frequently co-located, meaning they can capitalize on low-cost hydrogen production without incurring midstream distribution/storage costs.").

[144] Clean Hydrogen Liftoff Report at 24 ("*Due to limited midstream infrastructure*, announced hydrogen production projects to date have focused on offtakers that can be co-located with production as well as offtakes that already use carbon-intensive hydrogen.")(emphasis added).

[145] EPA itself appears to recognize this and states in the TSD that "[a] viable hydrogen infrastructure requires that hydrogen be able to be delivered from where it is produced to the point of end use, such as [a] . . . power generator. That infrastructure also must be able to delivered hydrogen to the point of use at the times needed, requiring storage infrastructure." 88 *Fed. Reg.* at Hydrogen TSD at 24. However, it is unclear how this statement squares with EPA's proposed determination noted above.

> availability of midstream infrastructure is a constraint for scaling clean hydrogen where co-located production and offtake is not feasible, representing a key challenge that must be addressed.[146]

Moreover, DOE notes that "[t]he absence of affordable midstream infrastructure risks slowing the hydrogen economy."[147]

EPA's suggestion that significant midstream infrastructure will not be required is incorrect in and of itself and also off base about how the U.S. clean hydrogen economy is expected to evolve.

ii. EPA fails to adequately analyze critical pipeline-related issues that could impact achievability throughout the industry.

In contrast to the nearly three million miles of interstate and intrastate natural gas pipelines in the United States,[148] there are only approximately 1,600 miles of hydrogen pipe.[149] There are two potential methods for transporting hydrogen by pipeline: in existing non-hydrogen pipelines, which will require retrofits; and in new, dedicated hydrogen pipelines. As discussed in greater detail below, each method presents potential challenges that government agencies and industry are working to overcome. These include technical challenges, particularly for existing non-hydrogen pipelines, as well as critical open regulatory questions for interstate transportation of hydrogen by pipeline. Due in part to these issues, it is unclear how quickly pipeline transportation of hydrogen will emerge in the United States.

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[146] Clean Hydrogen Liftoff Report at 14.
[147] *Id*. at 57.

[148] U.S. Energy Info. Admin., Natural Gas Explained: Natural Gas Pipelines, (Dec. 3, 2020), https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

[149] U.S. Dep't of Energy, Hydrogen Pipelines, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines.

EPA discusses several of these challenges in the Hydrogen TSD. However, the Agency does not explain how these challenges impact its proposed determination that midstream "infrastructure will not present a barrier" to power sector low-GHG hydrogen blending under the Proposed 111 Rules. 88 *Fed. Reg.* at 33,314.

1. EPA fails to adequately analyze technical challenges that could impact achievability throughout the industry.

The ability to leverage our nation's existing natural gas pipeline system to transport hydrogen blended with natural gas presents a significant opportunity. While demonstration and pilot projects to test the effects of hydrogen blending in distribution systems have been announced, are underway, or have been recently completed,[150] "blending still faces several technical [ ] barriers."[151]

For example, blending may be limited by physical constraints, including the potential for steel

[150] For example, Dominion Energy's ThermH2 pilot project at its Training Academy in Utah will blend 5 percent hydrogen in a test gas distribution system to gather information for potential blending into its larger system. *Hydrogen: The Next Frontier of Clean Energy*, Dominion Energy, https://www.dominionenergy.com/projects-and-facilities/hydrogen. Southern California Gas and San Diego Gas and Electric announced the creation of the Hydrogen Blending Demonstration Program in November 2020 to "provide an understanding of how to safely incorporate hydrogen, a zero-emission fuel, into the gas grid." Press Release, SoCalGas and SDG&E Announce Groundbreaking Hydrogen Blending Demonstration Program to Help Reduce Carbon Emissions, Southern California Gas (Nov. 23, 2020), https://newsroom.socalgas.com/press-release/socalgas-and-sdge-announce-groundbreaking-hydrogen-blending-demonstration-program-to.

[151] Int'l Energy Agency, Global Hydrogen Review 2021, at 145 (Oct. 2021) https://www.iea.org/reports/global-hydrogen-review-2021. The International Energy Agency further explains that "[p]arameters related to natural gas quality (composition, calorific value and Wobbe index) – as regulated in different countries – can limit (or completely prevent) injection of hydrogen into gas grids. The hydrogen purity requirements of certain end users, including industrial clients, can further constrain blending. In addition, resulting changes in the physical characteristics of the gas can affect certain operations, such as metering." *Id.*

embrittlement. In the United States, steel pipe comprises more than a quarter-million miles of the natural gas transmission system.[152] The International Energy Agency explains that "[d]ue to its chemical properties . . . [hydrogen] can cause embrittlement of steel pipelines, i.e. reactions between hydrogen and steel can create fissures in pipelines."[153] As DOE explains, "hydrogen embrittlement (permeation of hydrogen into steel) can crack steel pipes, leading to leakage or combustion."[154]

EPA makes only passing reference to this in the Proposed 111 Rules. For example, in the Hydrogen TSD, EPA states that "[a] limitation on greater volumes of hydrogen being safely mixed with natural gas in existing natural gas pipelines is the potential embrittlement and weakening of pipes that leads to leakage." 88 *Fed. Reg.* at Hydrogen TSD at 28. In its single reference to embrittlement issues in the preamble, EPA explains that "the material used to construct the piping could need to be specifically designed to be able to handle higher concentrations of hydrogen that would prevent embrittlement and leaks." 88 *Fed. Reg.* at 33,313-14. However, rather than address potential issues for blending in existing pipelines, EPA simply notes that "[t]hese risks can be mitigated through deployment of new pipeline infrastructure designed for compatibility with hydrogen in support of a new combustion turbine installation,"

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[152] *See* Clean Hydrogen Liftoff Report at n.122.
[153] Int'l Energy Agency, Global Hydrogen Review 2021, at 145 (Oct. 2021), https://www.iea.org/reports/global-hydrogen-review-2021. *See also* U.S. Dep't of Energy, Hydrogen Pipelines, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines. The International Energy Agency's Global Hydrogen Review 2021 also points that that "considering that hydrogen has a higher leakage rate and an ignition range about seven times wider than that of methane, it may be necessary to upgrade leak detection and flow control systems." Int'l Energy Agency, Global Hydrogen Review 2021, at 147 (Oct. 2021), https://www.iea.org/reports/global-hydrogen-review-2021.

[154] Clean Hydrogen Liftoff Report at n.122.

88 *Fed. Reg.* at 33,314. *But see id.* at Hydrogen TSD at 25-26 ("The capital costs of new pipeline construction constitute a barrier to expanding hydrogen pipeline delivery infrastructure."), and that "[h]ydrogen blending into existing natural gas pipelines presents another mode of transport and distribution that is actively in use in Hawaii and under exploration in other areas of the country." *Id.* at 33,309. However, EPA fails to account for the challenges to building new pipeline infrastructure, discussed below, as well as distinctions between and across pipeline systems. Moreover, the fact that it *might* be feasible is insufficient to support a BSER determination, as discussed *supra*.

EPA briefly mentions several analyses of potential blend limits in the Hydrogen TSD and correctly notes that "[b]lend limits depend on the design and condition of current pipeline materials (*e.g.,* integrity, dimensions, materials of construction) [and] design and condition of pipeline infrastructure equipment (*e.g.,* compressor stations)." 88 *Fed. Reg.* at Hydrogen TSD at 26. However, EPA also notes "that the concerns relating to natural gas pipeline embrittlement from hydrogen transportation have been disputed," citing to a German paper about pipelines in Germany. *Id.* (citing Wasserstofftransport, Nationaler Wasserstoffrat (2021), https://wasserstoffwirtschaft.sh/file/nwr_wasserstofftransport_web-bf.pdf (In German).) However, this paper explains that "[i]t is known that, under certain conditions, hydrogen can lead to embrittlement of the steel materials commonly used in gas pipelines" and that fracture mechanics analyses, carried out in accordance with ASME B31.126 "have shown that the steels used in the field of natural gas pipelines and plants are *in principle* suitable for use with hydrogen and that the dimensioning and design of the pipeline for use with hydrogen can be confirmed."[155] As noted above, differences between and across pipeline systems are highly relevant to blend limits and the mere fact that blending in pipelines in Germany does not create embrittlement issues "in principle" is insufficient to justify a conclusion that the same is true throughout the U.S. pipeline system.

EPA also notes that the use of fiber reinforced polymer (FRP) may be a way to protect pipelines from embrittlement. However, EPA explains that "FRP is not authorized by Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations without a special permit" and that throughput capacity in FRPs can be limited because these pipelines "generally have a maximum nominal outer width of 6 inches." 88 *Fed. Reg.* at Hydrogen TSD at 26-27. Permitting challenges aside, it is unclear how this is a reasonable solution given that U.S. transmission pipelines "can range in size from several inches to several feet in diameter,"[156] and "normally [are] between 30 and 36 [inches] in diameter."[157]

The importance of this issue in the United States is evident from the numerous federal efforts currently underway to examine and explore the physical, engineering, and safety issues associated with transporting hydrogen blends in existing natural gas pipelines.[158] For example, in

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[155] Wasserstofftransport at 2 (translated using MS Word Translation).

[156] U.S. Dep't of Trans., Fact Sheet: Transmission Pipelines, https://primis.phmsa.dot.gov/comm/FactSheets/FSTransmissionPipelines.htm.

[157] Argonne N'tl Labs., Natural Gas Pipeline Technology Overview (Nov. 2007), https://corridoreis.anl.gov/documents/docs/technical/apt_61034_evs_tm_08_5.pdf.

[158] ClearPath also has noted that "[r]esearch shows small proportions of hydrogen can be directly blended into our existing natural gas network. Blending larger ratios requires more research because natural gas pipelines were not designed with hydrogen in mind." ClearPath, Hydrogen 101, https://clearpath.org/tech-101/hydrogen-101/.

early 2021, DOE launched its HyBlend initiative, which includes over 20 partners and 6 national labs and $15 million in R&D portfolio projects that are anticipated to run from 2021 through 2023.[159] HyBlend "aims to address technical barriers to blending hydrogen in natural gas pipelines. Key aspects of HyBlend include materials compatibility R&D, technoeconomic analysis, and environmental life cycle analysis that will inform the development of publicly accessible tools that characterize the opportunities, costs, and risks of blending."[160] Importantly, DOE also recognizes that blend limits for pipelines can vary greatly depending on the design and condition of current materials, infrastructure equipment, and applications that currently use natural gas.[161]

Furthermore, PHMSA hosted a three-day public meeting November 30 through December 2, 2021, to provide "an opportunity for pipeline stakeholders to discuss research gaps and challenges in pipeline safety and emerging fuels, including hydrogen transportation."[162] The topics for workgroup discussion included hydrogen network components and utilization of inspection tools on hydrogen pipelines, including pipelines carrying hydrogen and natural gas

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[159] U.S. Dep't of Energy, HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines, at 1 (June 2021), https://www.energy.gov/sites/default/files/2021-08/hyblend-tech-summary.pdf.

[160] *Id.*

[161] *Id.*

[162] Pipeline Safety: Pipeline Transportation; Hydrogen and Emerging Fuels Research and Development (R&D) Public Meeting and Forum, 86 *Fed. Reg.* 58,389, 58,389 (Oct. 21, 2021).

blends.[163] PHMSA's agenda explains that "[t]o advance the safe transportation of hydrogen gas and/or hydrogen gas blended with natural gas (hydrogen/blends) through the Nation's pipeline network, additional research is necessary."[164] This includes the effects of hydrogen on various pipeline materials[165] "to determine the suitability of the materials for transporting hydrogen and hydrogen/blends in distribution networks," as well as the impacts of hydrogen at varying levels on facilities that are critical to the transmission and distribution network, such as compressor station equipment and meter stations.[166] Discussion during this meeting resulted in the identification of multiple, specific R&D gaps in areas including the integrity of underground hydrogen storage, utilization of inspection tools on hydrogen pipelines, and hydrogen network components.

PHMSA currently is engaged in multiple research projects on point, including projects (1) to identify integrity threats specific to hydrogen transportation by pipeline and potential changes to the America Society of Mechanical Engineers codes;[167] (2) focused on practical methods to

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[163] Pipeline and Hazardous Materials Safety Admin., Meetings and Documents, Pipeline Transportation: Hydrogen and Emerging Fuels R&D Public Meeting and Forum, https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=153.

[164] *Id*.

[165] These include polyethylene, polyvinyl chloride, and steel pipes. *Id*.

[166] *Id*.

[167] *See* Pipeline and Hazardous Materials Safety Admin., Review of Integrity Threat Characterization Resulting from Hydrogen Gas Pipeline Service, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=985.

optimize and repurpose existing pipeline infrastructure to safely transport hydrogen;[168] (3) to advance hydrogen leak detection and quantification technologies compatible with hydrogen blends;[169] (4) focused on the development of compatibility assessment models for existing pipelines for handling hydrogen-containing natural gas;[170] (5) to develop a holistic risk assessment, mitigation measures, and decision support platforms to accelerate the transition towards sustainable, precise, and reliable hydrogen infrastructure;[171] and (6) to determine steel weld qualification and performance for hydrogen pipelines.[172] PHMSA's, other agencies', and industry's work on these issues is a critical precursor to our ability to safely and reliably transport hydrogen in existing U.S. pipelines.

Research and development of advanced sensor equipment capable of accurately detecting hydrogen emissions also are underway. For example, DOE recently issued an $8-11 million labs call that includes a request for "proposals involving lab-developed technologies for development and commercialization of technologies that can quantify leakage of H2 during its production,

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[168] *See* Pipeline and Hazardous Materials Safety Admin., Determining the Required Modifications to Safely Repurpose Existing Pipelines to Transport Pure Hydrogen and Hydrogen-Blends, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=978.

[169] *See* Pipeline and Hazardous Materials Safety Admin., Advancing Hydrogen Leak Detection and Quantification Technologies Compatible with Hydrogen Blends, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=979.

[170] *See* Pipeline and Hazardous Materials Safety Admin., Procedures for Retrofitting Indoor Gas Service Regulators, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=916.

[171] *Id*.

[172] *See* Pipeline and Hazardous Materials Safety Admin., Determining Steel Weld Qualification and Performance for Hydrogen Pipelines, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=976.

distribution, storage, and use, with detection capabilities in ambient air at the ppm or ppb (more desirable) level."[173] Moreover, while blending can move significant volumes of hydrogen, "separating and purifying the hydrogen from natural gas is difficult."[174]

These challenges present real questions about the timing and scale of a U.S. clean hydrogen economy that EPA must address in its analysis that hydrogen blending is adequately demonstrated. Hydrogen blending will not be achievable throughout the power sector without appropriate and timely scale up of midstream infrastructure. Moreover, in some regions, there may not be pipeline capacity to blend additional hydrogen, or other end users might not be able to utilize hydrogen blends. These issues are significant and unaddressed by EPA and, as a consequence, its proposed adequate demonstration determinations are insufficient.

2. EPA does not adequately analyze critical regulatory issues for interstate pipelines that could impact achievability throughout the industry.

Interstate pipelines provide an economy of scale that can promote efficient and cost-effective transportation, but modifications to our existing interstate pipeline system will be required to accommodate hydrogen. This includes building new and/or modifying existing physical infrastructure, as well as adding and/or updating statutory authority and regulations related to the use of the pipeline capacity. Currently, questions remain as to which federal agency, if any, would have jurisdiction over these areas and what level of authority the relevant agency would

[173] U.S. Dep't of Energy, National Laboratory Call for Proposals: Fossil Energy and Carbon Management Program-Led Topics, DE-LC-000L101 (FY 2023), https://www.energy.gov/fecm/lab-call-technology-commercialization-fund?utm_medium=email&utm_source=govdelivery.
[174] Clean Hydrogen Liftoff Report at 16.

have. Federal legislative efforts to resolve these questions presently are pending.[175] In the absence of federal siting and permitting authority, pipeline project developers must apply to states, which have varying requirements and approval timelines.

Even where federal siting and permitting authority exists for pipelines, as is the case for interstate natural gas pipeline facilities, the various permitting requirements and potential appeals can significantly slow down the process. This is evidenced by several recent interstate pipeline projects, including the Mountain Valley Pipeline project, which submitted its request to commence the FERC pre-filing process in 2014[176] and received FERC authorization in 2017.[177] Over the last six years, the project has faced challenges to several permits required for construction and operation.[178] Recent federal legislation expressly "ratifies and approves" all authorizations required for construction and initial operation of the Mountain Valley Pipeline,[179]

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[175] *See, e.g.,* Building American Energy Security Act of 2023, S.1399, 118th Cong. (2023) (proposing to add hydrogen to the Natural Gas Act).

[176] Pre-Filing Request, Mountain Valley Pipeline, FERC Dkt. No. PF15-3-000 (Oct. 27, 2014) (Accession number 20141027-5136).

[177] *Mountain Valley Pipeline*, 161 FERC ¶ 61,043 (2017).

[178] *See, e.g., Sierra Club v. FERC*, 68 F.4th 630, 636 (D.C. Cir. 2023); *Sierra Club v. W. Virginia Dep't of Env't Prot.*, 64 F.4th 487, 496 (4th Cir. 2023); *Sierra Club v. State Water Control Bd.*, 64 F.4th 187, 191 (4th Cir. 2023); *Sierra Club v. FERC*, 38 F.4th 220, 226 (D.C. Cir. 2022); *Appalachian Voices v. United States Dep't of Interior*, 25 F.4th 259, 265 (4th Cir. 2022); *Wild Virginia v. United States Forest Serv.*, 24 F.4th 915, 920 (4th Cir. 2022); *Mountain Valley Pipeline, LLC v. N.C. Dep't of Env't Quality*, 990 F.3d 818, 823 (4th Cir. 2021); *Sierra Club v. United States Army Corps of Eng'rs*, 981 F.3d 251, 260 (4th Cir. 2020); *Appalachian Voices v. FERC*, 2019 WL 847199, at *1 (D.C. Cir. Feb. 19, 2019); *Sierra Club v. United States Army Corps of Eng'rs*, 909 F.3d 635, 639-643 (4th Cir. 2018); *Sierra Club, Inc. v. U.S. Forest Serv.*, 897 F.3d 582 (4th Cir. 2018).

[179] Fiscal Responsibility Act of 2023, Pub. L. No. 118-5, § 324, 137 Stat. 10, 47-48 (2023).

yet the project still faces hurdles to completing construction. More specifically, in response to requests from petitioners in three pending cases, the U.S. Court of Appeals for the Fourth Circuit issued stays on July 10 and 11, 2023,[180] halting construction. Mountain Valley Pipeline filed an emergency application with the U.S. Supreme Court on July 14, 2023, seeking relief from the Fourth Circuit's decision.[181] In an unsigned order on July 27, 2023, the Supreme Court granted Mountain Valley's request to vacate the Fourth Circuit's stays, but did not grant the pipeline's request to dismiss the underlying actions entirely. Despite EPA's efforts to project future pipeline construction, it is impossible to predict how quickly pipelines will be permitted and built.[182] As a result, EPA's assertions are speculative.

As noted, midstream transportation will be necessary for hydrogen projects that cannot accommodate onsite production, either because they lack the necessary resources or because they have insufficient space.[183] For interstate pipelines, hydrogen likely will be transported in a blend

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[180] Order, *The Wilderness Society v. U.S. Forest Service*, No. 23-1592 (4th Cir. July 10, 2023); Order, *The Wilderness Society v. U.S. Forest Service*, No. 23-1594 (4th Cir. July 10, 2023); and Order, *Appalachian Voices v. United States Department of the Interior*, No. 23-1384 (4th Cir. July 11, 2023).

[181] Emergency Application to Chief Justice John G. Roberts, Jr. to Vacate the Stays of Agency Authorizations Pending Adjudication of the Petitions for Review, *Mountain Valley Pipeline, LLC v. Wilderness Soc'y, et al.*, Nos. 23-1592, 23-1594, & 23-1384 (4th Cir. June 2, 2023).

[182] Beyond permitting issues, pipeline projects also can face weather-related construction challenges. Mountain Valley Pipeline notes in its petition before the U.S. Supreme Court that, as of July 14, 2023, it "has only approximately three months to complete the Pipeline before winter weather sets in and precludes significant construction tasks until the spring of 2024." *Id.* at 7.

[183] For example, one EEI member has calculated that it would require 7.5 square miles to accommodate the solar array necessary to reach a 30 percent blend at one facility site (Facility 1) and we need double that amount of land for the array necessary to reach this blend level at a second facility site (Facility 2). To reach a 96 percent blend, the member has calculated that it would need approximately 52.4 square miles for the necessary solar array for Facility 1 and

with natural gas, as well as by itself in dedicated pipelines. It is possible that there will be attempts to regulate these methods of transportation under different statutory/regulatory frameworks. In fact, this may currently be the case as the FERC—at least under its immediately prior chairman—expressed confidence in FERC's authority to regulate pipelines carrying a hydrogen and natural gas blend under the NGA;[184] and, the Surface Transportation Board (STB) previously has exercised economic (rate-related) jurisdiction over dedicated interstate hydrogen pipelines, albeit more in a passive manner in order to resolve a dispute raised by a formal complaint. While this provides an idea of what regulation of interstate transportation of hydrogen by pipeline could look like, neither agency has explicitly confirmed its jurisdiction and some level of congressional action likely would be required to vest authority with either agency.[185]

Importantly, these two regulatory regimes provide the agencies with very different levels of authority. FERC has certificate authority over interstate natural gas pipelines[186] and serves as the lead National Environmental Policy Act agency for new and expansion pipeline development. In recent years, the FERC process has been lengthy, and potential changes to the scope of FERC's

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double that for Facility 2. These significant land requirements make it infeasible to co-locate low-GHG hydrogen production with use at Facilities 1 and 2.

[184] In response to questions from Senator Heinrich, then FERC Chairman Glick indicated that "the Commission has authority under the Natural Gas Act over hydrogen blending with natural gas on interstate pipelines" and that "[t]he Commission would maintain its jurisdiction over an interstate natural gas pipeline if that pipeline were to blend some amount of hydrogen into the gas stream." Letter from Richard Glick, FERC Chairman to Sen. Martin Heinrich, FERC Accession No. 20211027-4000, at 2 (Oct. 26, 2021).

[185] *See, e.g.,* Building American Energy Security Act of 2023, S.1399, 118th Cong. (2023) (proposing to add hydrogen to the NGA).

[186] 15 U.S.C. § 717f.

approach toward pipeline certification and review of greenhouse gas emissions in the environmental review for pipeline projects are pending, which could add complexity to the process.[187] However, rather than apply to each state, interstate natural gas pipeline developers only have to obtain a certificate of public convenience and necessity (CPCN) from FERC. FERC also provides certificate holders with federal eminent domain authority[188] and preempts state and local regulations that "interfere" with FERC's certificate authority.[189]

By contrast, STB's jurisdiction does not include federal siting authority or provide federal eminent domain authority. Instead, pipelines regulated by STB must obtain a CPCN from each of the states that they enter. The requirements for obtaining a CPCN vary by state. Additionally, each state has the ability to impact the overall pipeline process and each state's authorization is susceptible to separate challenge in court.

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[187] In early 2022, FERC issued a Draft Updated Pipeline Certificate Policy Statement modifying its 1999 policy statement on the certification of new interstate natural gas facilities under Section 7(c) of the NGA to provide a more comprehensive analytical framework. *Consideration of New Interstate Natural Gas Facilities*, 178 FERC ¶ 61,107 (2022). The Commission also issued a Draft Interim GHG Policy Statement seeking to explain how the Commission will assess the impacts of natural gas infrastructure projects on climate change in its reviews under NEPA and Sections 3 and 7 of the NGA. *Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews*, 178 FERC ¶ 61,108 (2022). Final versions of these policy statements remain pending.

[188] 15 U.S.C. § 717f.

[189] *See, e.g., Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 310 (1988) (state regulation that interferes with FERC's regulatory authority over the transportation of natural gas is preempted); and *Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, 245 (D.C. Cir. 2013) (noting that state and local regulation is preempted by the NGA to the extent it conflicts with federal regulation, or would delay the construction and operation of facilities approved by the Commission).

These significant process differences can yield different timelines for permitting, siting, and constructing new pipelines. The duration of the permitting and construction process is expected to impact development of midstream infrastructure. DOE explains that "[n]ew, dedicated hydrogen pipelines will take time to break ground, in part due to the nascency of the hydrogen economy combined with long construction and permitting timelines."[190] It further explains that "[t]hrough 2030, new hydrogen pipeline use will likely remain limited, as . . . pipeline permitting and construction is a multi-year process; new pipelines are unlikely to be operational until *at least* the late 2020s."[191]

Additional regulatory questions also remain regarding the economic regulation of interstate hydrogen transportation by pipeline. For blended pipelines, these questions include the quantities of hydrogen that could be transported on existing pipelines and allocation of the costs of upgrades that may be needed to allow hydrogen to be carried in existing pipelines.[192] For both blended and dedicated hydrogen pipelines, there are also open questions around the extent to which transportation rates will be regulated and how pipeline capacity will be structured.

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[190] Clean Hydrogen Liftoff Report at 50.

[191] *Id*. at n.124 (emphasis added).

[192] As former FERC Chairman Glick explained in a 2021 letter to U.S. Senator Heinrich, for interstate natural as pipelines, this would require that a "pipeline follow the Commission's Policy Statement on Gas Quality and Interchangeability," which includes stakeholder participation and coordination between and among shippers and the pipeline. Letter from FERC Responding to Sen. Heinrich, Oct. 26, 2021 (FERC accession number 20211027-4000) (citing *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs,* 115 FERC ¶ 61,325 (2006)).

Resolving these regulatory issues will take time and the uncertainty that they create could delay investment in this sector. EPA does not discuss or appear to have considered these issues in reaching its proposed adequate demonstration determinations. Adequate access to midstream infrastructure is critical to scaling the U.S. clean hydrogen economy and to the power sector's ability to deploy hydrogen blending. EPA's failure to analyze these regulatory gaps and their impact is a significant flaw in its record and undermines its proposed adequate demonstration determination.

3. EPA does not adequately analyze the investment gap for new infrastructure, which could impact achievability throughout the industry.

In addition to the open regulatory questions noted above, new pipeline construction is capital intensive. EPA recognizes this challenge in the Hydrogen TSD, noting that "[t]he capital costs of new pipeline construction constitute a barrier to expanding hydrogen pipeline delivery infrastructure." 88 *Fed. Reg.* at Hydrogen TSD at 26. However, the Agency does not include significant discussion of this challenge or appear to have taken it into consideration in its proposed determinations.

While there has been investment in hydrogen production, driven by the hydrogen PTC, "[m]idstream and end-use infrastructure investments face a more acute financing gap."[193] More specifically, DOE explains as much as half of the "$85-215B of cumulative investment [that] is required to scale the domestic hydrogen economy through 2030" will be for midstream and end-use infrastructure.[194] At present, while almost all of the investment requirements for 2030

[193] Clean Hydrogen Liftoff Report at 42.

[194] *Id*.

production would be covered if production projects secure financing, "project announcements only cover . . . ~5% of distribution and storage infrastructure needs."[195]

EPA notes that the funding that H2Hubs will provide for infrastructure. While the H2Hubs are anticipated to help support infrastructure development, infrastructure that is part of these projects may not be in full operation until the early- to mid-2030s despite the best efforts of both DOE and industry at getting the hubs operational.[196] In addition, the H2Hubs are intended to be regionally focused at first and eventually to provide connective tissue to support a national clean hydrogen economy. As a result, it is unclear whether the H2Hubs will provide sufficient midstream infrastructure to support clean hydrogen deployment at scale early in their operation and EPA's reliance on this program alone is insufficient evidence to support its proposed adequate demonstration determinations.

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[195] *Id*. at 43.

[196] H2Hub awards are anticipated in Fall 2023. DOE plans to execute H2Hubs funding over four phases that could range from 8-12 years. Under DOE's plan, the construction is not anticipated to begin for three to five years after the award and could take an additional two to four years to complete, with ramp-up to full operation occurring over the subsequent two to four years. U.S. Dep't of Energy, *Funding Opportunity Announcement: Regional Clean Hydrogen Hubs*, at 19-22 (Jan. 26, 2023), https://oced-exchange.energy.gov/. Assuming awards are made on the anticipated timeline, H2Hub project construction would begin in late 2026 on the early end and late 2028 on the later end. For projects that begin construction in late 2026, construction could be complete between late 2028 and late 2030 and operations would ramp up between 2030 and 2034. For projects that begin construction in late 2028, it could be complete between late 2030 and late 2032 with operations ramping up between 2032 and 2036. These timelines are based on DOE's projections for the H2Hubs and could be elongated by factors including permitting delays, supply chain challenges, and workforce shortages.

iii. EPA does not adequately analyze storage-related challenges that could impact achievability throughout the industry.

As noted above, EPA explains that it "believes hydrogen distribution and storage infrastructure will not present a barrier to access for" combustion turbines opting for low-GHG hydrogen blending under the Proposed 111 Rules. *See, e.g.,* 88 *Fed. Reg.* at 33,309. However, EPA does not discuss several technical challenges associated with hydrogen storage and bases its conclusions on H2Hubs funding, which, as discussed above, may not be in full operation until the early- to mid- 2030s.

Hydrogen can be stored in above ground or underground facilities and can be stored as a pressurized gas or as a cryogenic liquid. DOE explains "[h]ydrogen storage is a key enabling technology for the advancement of hydrogen and fuel cell technologies in applications including stationary power," but given hydrogen's properties, "[it] require[es] the development of advanced storage methods that have potential for higher energy density."[197] This is particularly the case for underground storage, which is anticipated to be critical for scaling up hydrogen deployment beyond the current levels. As discussed below, underground hydrogen storage presently faces several challenges and technical barriers.

From a safety perspective, in addition to the pipeline-related topics noted above, PHMSA explored several topics related to hydrogen storage during its three-day meeting. This included "expand[ing] its research portfolio in the safe underground storage of hydrogen gas and/or

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[197] U.S. Dep't of Energy, Hydrogen Storage, https://www.energy.gov/eere/fuelcells/hydrogen-storage.

hydrogen blended with natural gas."[198] With respect to integrity of underground storage systems, PHMSA plans to explore a "wide array of topics" including reducing leaks from underground storage facilities and new technologies to mitigate leaks, the degree and consequences of mixing hydrogen with cushion gas, and the compatibility of hydrogen with underground storage environments.[199] Utilization of geologic storage also would be limited by geography. Furthermore, the International Energy Agency recently explained that "[w]hile there is no practical experience in repurposing methane caverns for hydrogen service, it is estimated that such an approach would require about the same amount of time as developing a new salt cavern."[200]

It has also been noted that while underground storage would be useful for storing the large quantities of hydrogen required for applications like power generation, it presents a number of challenges. These include: "1) assessment of the risks of corrosion of storage vessels and development of mitigation strategies, 2) determination of the effects of soil pressure on the tank, [and] 3) assessment of the effects of tank leakage on the surroundings."[201] Where hydrogen is stored in a liquid (cryogenic state), ground freezing is a potential challenge and the potential for

[198] Pipeline and Hazardous Materials Safety Admin., Meetings and Documents, Pipeline Transportation: Hydrogen and Emerging Fuels R&D Public Meeting and Forum, https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=153.
[199] *Id*.

[200] Int'l Energy Agency, Global Hydrogen Review 2021, p 151 (Oct. 2021) https://www.iea.org/reports/global-hydrogen-review-2021.

[201] U.S. DRIVE Partnership, Hydrogen Delivery Technical Team Roadmap, at 20 (July 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/hdtt_roadmap_July2017.pdf.

seismic activity and resulting effects on storage need to be determined.[202] In addition, advances in materials, including those for aboveground storage, may be needed. For example, materials to store hydrogen must be resistant to embrittlement and fatigue and be capable of maintaining structural integrity at cryogenic temperatures.[203] This may require the use of novel construction materials.[204]

As noted, EPA points to the H2Hubs to support its conclusion that storage infrastructure will not present a barrier to reliable and affordable low-GHG hydrogen blending in compliance with the Proposed 111 Rules. However, EPA proposes that combustion turbines blend 30 percent low-GHG hydrogen by 2032. As discussed in the preceding section, DOE's plan for the H2Hubs includes four phases and the project funding is expected to span 8-12 years. With award announcements anticipated in Fall 2023, the H2Hubs projects may not be operational until the early- to mid-2030s, potentially after 2032 even despite the best efforts of DOE and industry to make the hubs a reality. As such, the H2Hubs may not be ready in time to provide the support that EPA assumes and EPA's reliance on this program alone is insufficient to support its proposed adequate demonstration determinations.

e. EPA's proposed conclusions are based on an insufficient record as the Agency fails to consider factors that could impact low-GHG hydrogen's cost-effectiveness and achievability throughout the industry.

EPA states that low-GHG hydrogen, as proposed, will be cost-effective, *see, e.g.,* 88 *Fed. Reg.* at 33,242-43, and proposes to conclude that "the increase in operating costs from a BSER based on

[202] *Id.*
[203] *Id.*

[204] *Id.*

low-GHG hydrogen is reasonable." *Id.* at 33,314. However, as the starting point for its cost analysis, EPA relies on DOE's Hydrogen Earthshot, which aims to reduce electrolytic hydrogen production costs to $1/kg by 2030. Critically, this represents an 80 percent reduction in the cost of clean hydrogen[205] and DOE itself explains that the Hydrogen Earthshot "sets an ambitious . . . target based on stretch R&D goals"[206] and that it "create[es] bold, ambitious goals to galvanize domestic and global industry."[207] While industry and government will continue to aim to meet this target, it is not a reasonable basis for EPA's cost analysis, particularly for a technology that faces the multiple hurdles set forth in these comments, which EPA also fails to analyze. As discussed below, EPA does not take into account a number of factors that could impact costs, including electrolyzer availability, clean electricity costs, transportation costs, water cost and availability, and the contours of the pending hydrogen PTC guidance that will inform entities' ability to use the credit. This failure is a significant flaw in the record and undermines EPA's proposed adequate demonstration determinations.

i. EPA does not adequately analyze electrolyzer availability and clean electricity costs that could impact low-GHG hydrogen's cost-effectiveness achievability throughout the industry.

Two significant components of the cost of low-GHG hydrogen are electrolyzer availability and clean electricity costs. Current areas of development and related challenges that government and industry are working to overcome for each are discussed above. Importantly, the timing and

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[205] *See* U.S. Dep't of Energy, Hydrogen Shot, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

[206] Clean Hydrogen Liftoff Report at 2.

[207] U.S. Dep't of Energy, U.S. Clean Hydrogen Strategy and Roadmap, at 39 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html.

scope of scale up for these two components, which currently are unknown, could impact the cost of low-GHG hydrogen.

For example, DOE explains in the Clean Hydrogen Liftoff Report that reducing the capex for electrolyzer manufacturing "will be the largest driver of near-term electrolysis cost reductions (through 2030)."[208] The scale of cost reductions needed is not insignificant—"[e]lectrolyzers need to see 50–80% cost declines by 2030 to follow the growth pathway detailed in [the Clean Hydrogen Liftoff] report. While standardization, design to value and manufacturing scale-up will represent a significant portion of the cost-down, technological innovation is also needed."[209] DOE also notes that industry forecasts for electrolyzer capex cost-downs "do not yet reach the Hydrogen Fuel Cell Technology Office (HFTO) targets of ~$100 - $250/kW (late 2020s to early 2030s) motivating the need for additional R&D funding to bridge the gap."[210]

The cost of clean electricity is similarly a significant factor in the overall cost of low-GHG hydrogen production. For example, DOE explains that "a 15% increase in electricity costs can reduce returns 3-5%. Constrained clean power build out can also limit the deployment of electrolyzers."[211] As discussed above, competition for clean electricity is anticipated to be significant, particularly as multiple sectors simultaneously seek to use increasing quantities of clean electricity and as challenges to its scale up remain.

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[208] *Id*. at 13.

[209] *Id*. at 66.

[210] *Id*. at 13.

[211] *Id*. at 35.

Moreover, the levelized capex costs for electrolyzers are inversely proportional to their utilization (capacity factor). As a result, "[r]enewable capacity factors will impact hydrogen production costs."[212] While energy storage can improve the capacity factors associated with wind and solar, energy storage technologies are experiencing their own scale up and related challenges.[213] DOE also notes that "using hydro and nuclear power can run at high-capacity factors (>90%) allowing for lower levelized capex costs."[214] However, as noted above, it is unclear whether and to what extent existing energy resources, such as hydropower and nuclear, will qualify under the hydrogen PTC. Similarly, while power purchase agreements can be used to contract for non-dedicated clean electricity, "[a]dditional regulatory clarity for producers seeking to capture the PTC would help accelerate further private upstream investment."[215] Moreover, while using electricity from the grid enhances electrolyzer utilization, it also is unclear whether and to what extent this pathway could take advantage of the hydrogen PTC.

As noted, EPA does not discuss these factors or take them into account in its analysis. Not doing so is a significant gap in EPA's record and undermines EPA's proposed adequate demonstration determinations.

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[212] *Id*. at 12.

[213] *See* U.S. Dep't of Energy, Pathways to Commercial Liftoff: Long Duration Energy Storage (Mar 2023), https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-LDES-vPUB.pdf.

[214] Clean Hydrogen Liftoff Report at 12.

[215] *Id*. at 12.

ii. EPA does not adequately analyze midstream costs that could impact low-GHG hydrogen's cost-effectiveness and achievability throughout the industry.

The delivered cost of low-GHG hydrogen also will depend significantly on the cost of transportation and storage. As DOE explains, "[d]istribution and storage can more than double the delivered cost of hydrogen. Near-term use cases where hydrogen supply and demand are not co-located will be significantly affected by the high cost of hydrogen distribution, with the exception of regions with existing, scaled hydrogen pipeline networks."[216] These costs will vary, but some stakeholders have reported current distribution and storage costs of up to $10/kg, depending on the storage and transportation methods used.[217]

EPA also cites DOE's estimate that, with a potential electrolytic production cost of $0.40/kg by 2030 (inclusive of the hydrogen PTC), the delivered cost of hydrogen could be approximately $0.70/kg to $1.15/kg. 88 *Fed. Reg.* at 33,309. Critically, DOE notes that these estimates "assume[ ] lowest-cost clean hydrogen production in 2030 as well as a range of distribution / storage options (compression to pipeline, pipeline, and storage fee associated with pipeline storage)."[218] As discussed above, the extent of development of pipelines capable of carrying hydrogen remains unclear and government and industry are working to overcome the hurdles necessary to support a U.S. clean hydrogen market at scale.

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[216] *Id*. at 57.

[217] *Id*. at n.133.

[218] *Id*. at n.65.

Where pipelines are not available, hydrogen trucking is anticipated to be the main mode of transportation. However, the costs alone for delivering hydrogen by truck could exceed EPA's anticipated delivered cost of hydrogen noted above. More specifically, DOE estimates that in 2030,[219] midstream transportation costs could be \$0.2-0.4/kg for compression for trucking plus \$0.7-1.5/kg for gas phase trucking service, for a total of \$0.9-1.9/kg for compressed hydrogen by truck—for liquid hydrogen delivery by truck, which EPA notes will be required for longer distances, 88 *Fed. Reg.* at Hydrogen TSD at 29, DOE estimates \$2.7/kg for liquefaction and \$0.2-0.3/kg for liquid hydrogen trucking service, for a total delivered transportation cost of \$2.9-3.0/kg. By comparison, DOE's estimated 2030 costs for pipeline delivery are \$0.1/kg for compression and \$0.1/kg for pipeline transportation, for a total delivered cost of \$0.2/kg.

The Proposed 111 Rules do not analyze these potential costs and their impact on EPA's proposed determination beyond mentioning that gas phase and liquid trucking are distribution options, 88 *Fed. Reg.* at 33,309; *see also id.* at Hydrogen TSD at 25 and 28, and a cursory mention of related costs. *Id.* at Hydrogen TSD at 29. This failure is a significant gap in EPA's rulemaking record and undermines EPA's proposed adequate demonstration determinations.

iii. EPA does not adequately analyze how the potential contours of the IRA hydrogen PTC could impact low-GHG hydrogen's cost-effectiveness and achievability throughout the industry.

As discussed above, Treasury guidance on the hydrogen PTC remains outstanding and has the potential to help or hinder low-GHG hydrogen costs and, in turn, demand. For example, as discussed above, it is anticipated that Treasury may include additionality requirements in its guidance. Depending on the terms of these requirements, hydrogen producers seeking to use

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[219] *Id*. at 4.

electricity from existing hydropower and nuclear facilities may not qualify for the full hydrogen PTC.

Treasury also is considering the timeframe over which the lifecycle greenhouse gas emissions for hydrogen production must be measured and discussion has centered around either annual matching or hourly matching. As EEI explained in its comments to Treasury,[220] hourly matching is estimated to increase the cost of green hydrogen production by 70-170 percent[221] versus annual matching, eliminating the ability of the PTC to make low-GHG hydrogen cost competitive with other forms of hydrogen. This is because hourly matching would require a low-GHG hydrogen project to buy time-correlated renewables during periods of under-generation, which corresponds to higher market price periods, increasing the overall cost of green hydrogen. If time-correlated renewables are not available, the low-GHG hydrogen project may curtail its electrolyzer, leading to long idle times. Hydrogen production equipment remains expensive and requires high utilization to make hydrogen production facilities economic. If a low-GHG hydrogen production facility can only produce during hours when wind and solar are available, the low utilization rate will dramatically increase the price of the hydrogen produced. Furthermore, applications requiring an uninterrupted flow of hydrogen represent substantially all existing hydrogen uses, and thus, requiring hourly matching would severely limit the adoption of low-GHG hydrogen.

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[220] Comments of the Edison Electric Institute, U.S. Dep't of Treasury Request for Comments on Credits for Clean Hydrogen and Clean Fuel Production (Notice 2022-58), (Dec. 6, 2022), https://www.regulations.gov/comment/IRS-2022-0029-0072.

[221] Assumes 95 percent electrolyzer capacity for annual matching and 70 percent, 60 percent, and 50 percent capacity for hourly matching at high, mid, and low renewable resource, respectively.

As with the factors discussed above, EPA does not discuss these issues or appear to take them into account in its analysis. This failure is a gap in the rulemaking record and undermines EPA's proposed adequate demonstration determinations.

f. EPA's proposed conclusions are based on an insufficient record as the Agency fails to consider several other issues that could impact achievability throughout the industry.

In addition to those noted above, there are several other areas of developmental need that must be met to ensure development of the U.S. clean hydrogen market that will be necessary to support reliable and affordable low-GHG hydrogen blending in the power sector. These include the need to scale up and train the workforce that will underpin this hydrogen market and the need to resolve accounting-related questions.

i. EPA fails to adequately analyze workforce challenges that could impact achievability throughout the industry.

Although well-recognized, EPA does not mention workforce-related challenges. In the Clean Hydrogen Liftoff Report, DOE explains that expansion of a skilled workforce will be critical to near-term expansion.[222] For example, DOE notes that "[e]lectrolysis will be challenged by supply-chain constraints in both raw materials and equipment manufacturing capacity during a critical scale-up period through 2025 in addition to challenges with renewables build-out and *sourcing a domestic workforce*."[223] In terms of scope, in 2030, DOE estimates that

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[222] *See, e.g.,* Clean Hydrogen Liftoff Report at 3.

[223] *Id*. at 45 (emphasis added).

approximately 200,000 workers across direct and indirect jobs would be needed to support the deployment of clean hydrogen at scale.[224] In addition,

> [Engineering procurement, and construction (EPC)] providers will need specialized experience, sufficient workforce, and established contract structures for hydrogen production and refueling projects. The U.S. does not currently have a sufficient, appropriately skilled workforce to manufacture, construct, or operate the volume of hydrogen infrastructure required to meet projected demand, so scaling this workforce presents both a challenge and an opportunity.[225]

New skills that would be required include "electrolyzer and electrolyzer component manufacturing, fuel cell expertise, and electrolysis facility engineering, procurement, and construction (EPC) expertise."[226] Moreover, "accelerated clean energy deployment is likely to further constrain EPC capacity."[227]

As noted, EPA does not discuss these issues or appear to have taken them into consideration in its proposed determinations. This failure is a significant flaw in the record and undermines EPA's proposed adequate demonstration determinations.

ii. EPA fails adequately analyze the impact of other sectors' use of hydrogen on achievability of low-GHG blending throughout the power sector.

Building the U.S. clean hydrogen market will require a thoughtful approach that recognizes that scale up in certain sectors, like the power sector, will rely heavily on other sectors' clean hydrogen deployment. DOE's H2Hubs program is a good example of such an approach. As

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[224] *Id*. at 58.
[225] *Id*. at 48.

[226] *Id*. at 58.

[227] *Id*. at 58.

explained above, DOE intends to engage in a four-phased process with awardees and to initially focus on regional and local market development. The ultimate hope is to connect the H2Hubs to form a nationwide clean hydrogen market economy. While such a market would support achievability of hydrogen blending throughout the power sector, we must first build up local and regional markets. These markets will be critical to enabling development of the economies of scale necessary to reduce cost and increase both supply and demand and will form the necessary foundation for the deployment of clean hydrogen at scale.

Moreover, as DOE explains based on its analysis of the various current barriers facing hydrogen liftoff, "[b]y 2030, most demand for low carbon hydrogen is likely to be as a drop-in replacement for carbon-intensive hydrogen currently used in ammonia and oil refining. Sectors where hydrogen is not an incumbent technology, such as other industrial sectors (steel, chemicals), transportation, heat, *and power, will take more time to uptake clean hydrogen*."[228] Furthermore, "[i]nitial deployments using clean hydrogen are expected to leverage regional energy resources and target industries that currently rely on conventional natural gas to hydrogen technologies (without CCS)."[229] This expectation is logical as these sectors already have the infrastructure in place to support clean hydrogen use. These sectors will be key to scaling up clean hydrogen production, reducing cost, and, critically, supporting the buildout of the midstream infrastructure,[230] all of which will be needed to support achievability of hydrogen blending

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[228] *Id*. at 9 (emphasis added).

[229] U.S. Dep't of Energy, U.S. Clean Hydrogen Strategy and Roadmap, at 12 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html.

[230] *See, e.g.,* Clean Hydrogen Liftoff Report at 16 ("Pipelines also require a stable, credit-worthy offtakers who will demand significant volumes of hydrogen sufficient to justify dedicated infrastructure build-out."). *See also id.* at 57 ("Near-term use cases where hydrogen supply and

throughout the power sector.

Whether and to what extent these sectors will adopt clean hydrogen remains to be seen, particularly given the challenges noted above. EPA does not analyze how other sectors' adoption of clean hydrogen will impact access to low-GHG hydrogen and, ultimately, achievability of hydrogen blending throughout the power sector.

iii. EPA fails to adequately analyze accounting-related gaps and their impact on achievability throughout the industry.

Given that hydrogen is a fungible molecule once produced, any emissions requirements for hydrogen production will require standardized accounting and traceability. EPA recognizes this fact and seeks comment on "what forms of acceptable mechanisms and documentary evidence should be required for EGUs to demonstrate compliance with the obligation to blend low-GHG hydrogen, including proof of production pathway, overall emissions calculations or modeling results and input, purchasing agreements, contracts, and energy attribute certificates." 88 *Fed. Reg.* 33,240, at 33,328. Efforts are underway to establish these mechanisms, but they are nascent at present. The absence of these mechanisms further demonstrates the current early stage of development of a clean hydrogen market, the important open questions that entities are working to resolve, and the premature nature of EPA's proposal. Furthermore, how these questions are resolved could impact development of the U.S. clean hydrogen market—if cumbersome accounting regimes emerge, they could have a chilling effect on market growth.

3. EPA's proposal to define low-GHG hydrogen in the Proposed 111 Rules is arbitrary and EPA should instead propose separate rules for hydrogen producers.

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demand are not co-located will be significantly affected by the high cost of hydrogen distribution, with the exception of regions with existing, scaled hydrogen pipeline networks.").

There are several issues that stem from EPA's proposal to mandate the use of "low-GHG" hydrogen for units that opt for the blending pathway and to include emissions reductions requirements for hydrogen production as part of that mandate. As a preliminary matter, the regulation of hydrogen production is beyond the scope of proposed rule; if EPA seeks to regulate emissions from hydrogen production, it must do so through a process that satisfies the section 111 requirements for that separate source category and does not impede development of this nascent, but important resource.

a. EPA's "low-GHG" hydrogen requirement is beyond its authority and the Agency should utilize a separate 111 process to set any production standard.

EPA's proposal to define "low-GHG" hydrogen effectively seeks to establish an emissions limitation for hydrogen production. Setting novel, upstream requirements for hydrogen as part of this CAA section 111 proposal is beyond the appropriate scope of the proposed rule.

EPA has set upstream emissions limitations for other fuels used in EGUs—namely, natural gas. Notably, EPA's emissions limitations for natural gas production have been set through rulemakings regulating natural gas production, transportation, and storage, not the power sector as one of the consumers of natural gas.[231] Such an approach tailors EPA's regulations to the sector and facilities that own and operate the affected facilities. EPA's regulation of source categories under section 111 should be focused on the facilities with emissions. For the power sector, those source categories, therefore, appropriately focus on the emissions stack. Fuel production, like natural gas and hydrogen, occurs outside of the stack—in some instances,

[231] *See, e.g., Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 *Fed. Reg.* 74,702 (Dec. 6, 2022).

hundreds or even thousands of miles away. Accordingly, it is not part of the relevant source categories and should not be included in a rule that addresses power sector stack emissions.

If EPA wishes to regulate emissions associated with hydrogen production industry, it should do so in a separate section 111 process focused on the hydrogen industry. To do otherwise would be arbitrary as it would treat differently the two fuels that would be used in EGUs—hydrogen and natural gas—without viable rationale for doing so. Further, as EPA notes, hydrogen combustion in EGUs has no carbon emissions. This is the case regardless of how the hydrogen is produced because, once produced, hydrogen molecules effectively are fungible. As a result, emissions at an EGU, which are the focus of the proposed rule, are not impacted by the hydrogen production pathway.

Moreover, while some electric companies may produce hydrogen, electric companies are not the only entities who will produce hydrogen for use in EGUs or otherwise. Given its focus on the power sector, the attempt to regulate hydrogen producers through the proposed rule is inappropriate.

Additionally, given that hydrogen is a fungible molecule once produced, any emissions requirements for hydrogen production will require standardized accounting and traceability. As noted *supra*, EPA recognizes this fact and seeks comment on "what forms of acceptable mechanisms and documentary evidence should be required for EGUs to demonstrate compliance with the obligation to co-fire low-GHG hydrogen, including proof of production pathway, overall emissions calculations or modeling results and input, purchasing agreements, contracts, and energy attribute certificates." 88 *Fed. Reg.* 33,240, at 33,328. Efforts are underway to establish these mechanisms, but they are nascent at present.

The challenges with accounting and traceability run counter to EPA's traditional methods of compliance for the power sector. The power sector complies at the stack—not at the input of fuel. This fact is further reason why EPA should issue a separate standard for hydrogen production emissions and why it is inappropriate to include production emissions reductions requirements in the proposed rule.

Consequently, regulation of hydrogen production is outside of the scope of EPA's authority to regulate at the unit and therefore beyond the scope of the proposed rule. EPA should propose any such standards in a separate rulemaking.

b. EPA should address hydrogen production challenges in a separate rulemaking.

In seeking to set hydrogen production requirements, EPA notably eschews setting a separate standard for hydrogen production, although it notes it has the authority to set hydrogen production standards. Indeed, as noted, EPA has set section 111 standards for natural gas production and it could, and should, do so for hydrogen production as well, particularly if it seeks to use "Low-GHG" hydrogen as part of the BSER for EGUs. However, there are several important factors that any hydrogen production standard must take into account, including that EPA must adhere to the section 111 process in setting a hydrogen production emissions standard. In addition, EPA must also consider that setting a hydrogen production standard for the power sector will have *de facto* impacts on development of the hydrogen economy more broadly, which is critical to hydrogen's ability to overcome the challenges that will be necessary to enable its use in EGUs. This includes:

- *Achievability Challenges EPA Needs to Address:* For "low-GHG" hydrogen production, the elements of the system include renewable electricity, water, and electrolyzers—and, as discussed above, each faces challenges. Taken together, these demonstrate that EPA's assumptions that there will be sufficient "low-GHG" hydrogen to support "achievability throughout the industry" is simply unsubstantiated and is not addressed by EPA in attempting to set an upstream hydrogen production standard in the proposal.[232]
- *Cost Barriers*: As discussed above, it is well-recognized that there currently are cost barriers to electrolytic hydrogen production. For example, DOE is highly focused on reducing the cost of hydrogen to assist in providing a foundation for development of hydrogen at scale. As noted in 2021, DOE launched the Hydrogen Earthshot, aimed at reducing the cost of electrolytic hydrogen from $5/kg to $1/kg by 2030.[233] In addition, the IIJA includes a $1 billion investment in Clean Hydrogen Electrolysis Program.[234] The purpose of this program is to establish a research, development, demonstration, commercialization, and deployment program for purposes of commercialization to

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[232] DOE also notes several other challenges to development of a hydrogen economy at scale, including the absence of standard contract structures, which are delaying project financing; hesitancy to commit to long-term, scaled offtake for several potential reasons, including limited price discovery or price certainty, unavailability and reliability of supply, near-term policy implementation uncertainty, and long-term political uncertainty; limited cost-effective midstream infrastructure, which negatively impacts market development beyond production centers; limited availability of specialized hydrogen workforce; credit risk that is constraining widespread debt-financing; scale-up challenges for specific end-uses; and various challenges impacting long-term growth. Clean Hydrogen Liftoff Report at 56-62.

[233] U.S. Dep't of Energy, Hydrogen Shot, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

[234] IIJA at § 816(b).

improve the efficiency, increase the durability, and reduce the cost of producing clean hydrogen using electrolyzers.[235]

- *Non-Air Quality Health and Environmental Impacts*: In addition, producing electrolytic hydrogen using renewable energy may implicate non-air quality health and environmental impacts. For example, it is anticipated that hydrogen may drive significant demand for new renewable energy projects—particularly if Treasury's 45V guidance includes hourly matching and additionality requirements, as discussed further below. The International Renewable Energy Agency has projected that renewable electricity demand for hydrogen will range from 30-120 exajoules by 2050.[236] In addition, the Hydrogen Council has noted that "gigawatt-scale projects can be a significant local water consumer. In regions prone to water supply stress, sea water desalination is required."[237]

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[235] *See* U.S. Dep't of Energy, Clean Hydrogen Electrolysis Program, https://www.energy.gov/bil/clean-hydrogen-electrolysis-program.

[236] Int'l Renewable Energy Agency, *Hydrogen: A Renewable Energy Perspective,* p 22 (Sept. 2019), https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective. Columbia University SIPA's Center on Global Energy Policy recently noted that "[g]rowing demand of green hydrogen will require enormous investment and construction of electricity transmission, distribution and storage networks, and much larger volumes of zero-carbon power generation, as well as electrolyzer production systems, some hydrogen pipelines, and hydrogen fueling systems. An 88 million tons per annum (Mtpa) green hydrogen production by 2030, corresponding to the Stated Policies Scenario from the International Energy Agency (IEA) for that year, could cost $2.4 trillion and require 1,238 gigawatts (GW) of additional zero-carbon power generation capacity." Columbia Univ. SIPA: Ctr. on Global Energy Policy, *Green Hydrogen in a Circular Carbon Economy: Opportunities and Limits*, pp 8-9 (Aug. 2021), https://www.energypolicy.columbia.edu/research/report/green-hydrogen-circular-carbon-economy-opportunities-and-limits.

[237] Hydrogen Council, *Hydrogen Decarbonization Pathways: A Lifecycle Assessment*, p 8 (Jan. 2021), https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf.

- *Reliance on Tax Credits*: As discussed above, electrolytic hydrogen production faces several cost barriers at present. Treasury is in the process of developing guidance for implementation of these tax credits. This guidance will dictate entities' ability to utilize the credit and, in turn, whether the tax credit actually enables "low-GHG" hydrogen to overcome its current cost barriers. Without the Treasury guidance and market reaction, it is unclear whether the 45V tax credits will be successful. The potential for either outcome increases the uncertainty around whether and how successful the 45V tax credits will be in enabling "low-GHG" hydrogen to overcome current cost barriers. Moreover, even if the IRA tax credits remain in place and are funded, they are set to expire December 31, 2032. Development of the hydrogen economy is anticipated to take place over several decades and it is unclear how expiration of the 45V tax credits in the early stages of hydrogen deployment will impact future development. It is possible, given the various other challenges to be overcome, that "low-GHG" hydrogen will not be cost-effective relative to other energy resources by December 31, 2032.[238]
- *Requiring "Low-GHG" Hydrogen for the power sector will have impacts on other sectors*: In setting a requirement that the power sector only utilize "Low-GHG" hydrogen, EPA should bear in mind that its standard will have impacts on the development of the hydrogen economy more broadly. The power sector is one of many sectors exploring the potential to use hydrogen as a tool to continue to reduce emissions and meet climate goals. Any production standard that EPA sets for the power sector will

[238] Clean Hydrogen Liftoff Report at 3 ("If electrolysis projects fail to scale during the IRA credit period, electrolysis may not achieve the necessary learning curves to remain competitive in the absence of tax credits.").

flow through to commercial agreements and has the potential to influence how other sectors define "low-GHG" hydrogen in their operations, which should be done in a separate rulemaking for addressing emissions from hydrogen production.

While it is anticipated that these issues will be surmounted in the near term, at present these issues have yet to be overcome and create challenges for "low-GHG" hydrogen production.

c. EPA should take the lead in setting a hydrogen production emissions standard.

EPA defers significantly to Treasury in the proposed rule in setting the emissions requirements for hydrogen production—both in defining "low-GHG" hydrogen to align with the most stringent emissions level for the hydrogen production tax credit under the IRA and in proposing to adopt Treasury's ultimate guidance on point, including potentially adopting temporal matching, geographic limitation, and additionality requirements. However, authority to regulate air emissions under the CAA rests with EPA, not with Treasury. Moreover, as noted above, EPA is bound by CAA section 111 when it sets emissions limitations. While it may defer to other agencies as appropriate, it cannot use such deference to avoid satisfaction of these process requirements. As part of that rulemaking process, EPA should fulsomely consider the impact of hydrogen production and focus on emissions standards that can be achieved across the spectrum while taking into account the statutory factors described above. To that end, EPA should consider allowing a wider array of hydrogen production sources to qualify as "low-GHG" hydrogen than is contemplated under the current definition, including hydrogen produced using CCS and other sources beyond renewable energy. As noted, availability of resources to produce hydrogen varies across the United States and the infrastructure required to cost-effectively transport hydrogen, faces several challenges to development. These factors weigh strongly in favor of a more inclusive standard to promote development of the U.S. clean hydrogen economy at scale and to enable availability of hydrogen blending throughout the power sector. EPA should also consider whether it has the ability to require these resources to be additional, as well, given the structure and set up of CAA section 111's regulation of both new and existing sources.

Moreover, as discussed *supra*, some of the principles Treasury is considering as part of its 45V guidance would hinder the near-term hydrogen development that will be critical to ensuring a robust hydrogen economy that ultimately could support the use of hydrogen in EGUs. These principles include Treasury's consideration of an hourly matching requirement.

Hydrogen production equipment remains expensive and requires high utilization to make hydrogen production facilities economic. If a green hydrogen production facility can only produce during hours when wind and solar are available, the low utilization rate will dramatically increase the price of the hydrogen produced. Furthermore, applications requiring an uninterrupted flow of hydrogen represent substantially all existing hydrogen uses, and thus, requiring hourly matching would severely limit the adoption of green hydrogen. Such limitation ultimately would undermine the ability to meet EPA's proposed standards for EGUs.

4. Conclusion.

EPA states that it is "confident that these proposed NSPS and emission guidelines – with the extensive lead time and compliance flexibilities they provide – can be successfully implemented in a manner that preservers the ability of power companies and grid operators to maintain the reliability of the nation's electric power system." 88 *Fed. Reg.* at 33,246. However, as set forth above, EPA does not analyze or appear to take into account the various, significant, interrelated areas of development and scale ups that must occur to achieve the hydrogen economy that will be needed to support its Proposed 111 Rules, the infrastructure necessary to deliver the low-GHG hydrogen to EGUs across the industry, or the market necessary to support low-GHG hydrogen cost effectiveness. While efforts across government and industry are underway to overcome these well-recognized challenges, they create uncertainties about how and when the U.S. clean hydrogen economy that will be needed to support reliable and affordable hydrogen blending in the power sector will emerge.

IV. EPA's Proposed Phase One Standards for New Natural-Gas Based Units Are Appropriate But Several Key Technical Changes Are Required To Ensure These Standards Are Achievable.

For new units, the CAA requires that EPA make a BSER determination for the source category and then define the resulting emissions limitations that will be applicable to all units in that source category. *See* 42 U.S.C. § 7411(b). EPA proposes three subcategories for new natural gas turbines regulated under 40 C.F.R. part TTTT, which includes both NGCCs and CTs, each with its own proposed BSER and resulting emissions limits: a low load, intermediate load, and base load units. *See* 88 *Fed. Reg.* at 33,277.[239] The phase one requirements for each subcategory are detailed below:

- **Low load units:** For units with capacity factors less than 20 percent, the proposed BSER is the use of lower emitting fuel. EPA proposes that the use of natural gas, Nos. 1 and 2 fuel oils, and low-GHG hydrogen qualify as lower emitting fuels. EPA is proposing an emission standard of between 120 and 160 lb CO_2/MMBtu.

- **Intermediate load units:** A new combustion turbine NGCC qualifies as an intermediate unit if it has a capacity factor less than 45-55 percent; a new CT qualifies if it has a capacity factor less than 33-40 percent. For these units, EPA proposes efficient operations as the phase one BSER, with an emissions limit of 1,150 lb CO_2/MWh.

[239] EPA proposes these revised standards in light of the Agency's decision to revisit these existing standards for subpart TTTT units as part of the statutorily required eight-year review. *See* 88 *Fed. Reg*. at 33,277; *see also id*. at 33,279.

- **Base load units:** An combustion turbine with a capacity factor greater than 45-55 percent qualifies as a baseload unit. EPA is proposing efficient operations as the phase one BSER, with an emissions limitation of 770 lb CO_2/MWh for units with nameplate heat inputs greater than 2,000 MMBtu/hr; for smaller units, the proposed emissions limitation is between 770 and 900 lb CO_2/MWh depending on the specific base load rating of the combustion.[240]

Id.[241] EPA also proposes phase two standards for base load and intermediate load units and—for base load hydrogen units—phase three standards. *See id*. Legal and technical issues raised by EPA's proposed phase two and three standards are discussed *supra*.

EPA is correct that the BSER for the proposed phase one standards for new baseload and intermediate natural gas units is the most efficient generation. Because these phase one standards are applicable upon proposal, *see* 42 U.S.C. § 7411(a)(2)(defining a new source as one that commences construction or modification after the publication of proposed regulations), efficient generation is the only adequately demonstrated technology that could serve as BSER for immediately applicable standards. EPA acknowledges this indirectly by proposing a phased

[240] Actual capacity factor and utilization data that determine membership in a particular subcategory will be a unit-specific inquiry that also considers a unit's design efficiency. Confusingly, EPA proposes that units undertake this analysis annually, meaning that units could move between subcategories every year, often due to factors outside of their control (e.g., system needs). *See* proposed 40 C.F.R. § 60.5580a. This poses significant challenges for compliance planning, as discussed herein.

[241] The phase one standards also require that affected units be operated and maintained efficiently. *See* 88 *Fed. Reg*. at 33,283; *see also* proposed 40 C.F.R. § 60.5525a(b). Efficient—or as the proposed regulatory text states—operations and maintenance (O&M) consistent with safety and good air pollution control and using "consistent operations and maintenance procedures" is an appropriate requirement. EPA states that good practices include but are not limited to minimizing energy losses uses insulation and blowdown heat recovery. *See* 88 *Fed. Reg*. at 33,287. In any final rule, EPA should provide more details about what else the Agency considers good O&M practices and how the Agency will evaluate compliance with such requirements. EPA also clearly should state that the Agency will not second guess operations, particularly those that are in response to grid emergencies.

approach to BSER, implicitly recognizing that the control technologies that it asserts are BSER for later phases have not been adequately demonstrated at this time. *See* 88 *Fed. Reg*. at 33,283. Further, as EPA notes, efficient generation quantifies as BSER because it also can be implemented at reasonable cost and does not have adverse environmental or energy impacts. *See id*. at 33,288. For similar reasons, EPA is correct that clean fuels are BSER for low load units.

EPA should, however, make several key technical changes to the proposed standards that result from these BSER determinations. EPA must show that these standards are achievable, as required by CAA section 111(a). See 42 U.S.C. § 7411(a)(1). In order for the standards to be achievable, EPA must account for the future operations of these units in an evolving and cleaner grid that is actively integrating increasing amounts of more intermittent, renewable resources. EPA also must demonstrate that the proposed emission rate limit is achievable over a 12-month rolling average period, which is how affected units are required to demonstrate compliance.

EPA should set achievable, efficiency-based standards for new natural gas-based units, consistent with EEI's February 2023 recommendation to the Agency that these units be "capable" of future retrofit to install CCS or blend hydrogen when those technologies are demonstrated and available at costs that are affordable for customers. Further, EPA should adopt a modified approach to intermediate load units to account for the differences between combined cycle units and CTs and should increase the capacity factor limitation for low load units to allow these units to play the reliability critical role for which they usually are deployed. Finally, EPA should make clear that new units are able to take a mass-based approach to compliance, which will offer necessary and significant operational flexibility.

A. EPA Must Adjust the Phase One Standards for Base Load Units to Account for Unit Operations and Consistent With EPA's Own Compliance Demonstration Requirements.

EPA is correct that the phase 1 BSER for new "base load" natural gas NGCC units is the most efficient generation. *See* 88 *Fed. Reg*. at 33,277. Using this BSER, EPA proposes to establish an emissions rate standard of 770 lb CO_2/MWh for NGCCs with nameplate heat inputs greater than 2,000 MMBtu/hr. *See id*. at 33,322. However, EPA has not demonstrated that this proposed emissions rate is achievable across the industry and across a full range of likely operating conditions. Principally, EPA does not take into consideration how these units actually operate to support variable renewable resources, nor does it consider how emissions performance degrades over time. EPA should increase the emissions rate to account for these realities and finalize an emissions rate that is more supported by recently permitted new units than EPA's proposed standard.[242] EPA also should provide for mass-based compliance options with the phase 1 standards. EPA also should provide full weight to the comments of turbine manufacturers and EEI's member companies that are working to build and deploy these NGCC units, since the potential for cycling and the ability of these manufacturers to guarantee the phase one performance limits is essential for ensuring that EPA's initial, efficiency-based approaches are done appropriately and supported by the record and are technically achievable.

1. The phase one standards for new base load NGCCs does not take into consideration expected unit operations that will result in higher emissions rates.

[242] EPA is seeking comment on a range of potential standards, from 730 to 800 lb CO_2/MWh. *See* 88 *Fed. Reg*. at 33,332. EPA should not lower the standard. The reasons cited in these comments for increasing the standard also militate that the standard not be lowered further than the proposed 770 lb CO_2/MWh level.

EPA's proposed phase 1 standard does not appropriately consider the variability in the operating modes of new "base load" NGCCs. Even those units that operate at higher relative capacity factors, when measured on an annual basis, are unlikely to maintain high capacity factors at all times. EPA, without discussion, assumes that all units that operate at higher annual capacity factors are serving as "base load" generation at all times and that intermediate load units are load following and provide dispatchable backup power to support variable renewable generating sources. *See id*. at 33,278. But this is overly simplistic and ignores the changes in the generating fleet that EPA acknowledges elsewhere in the Proposed 111 Rules. Because of the increase in generation from variable renewable energy resources—which are dispatched first when available—even higher capacity NGCC units will have to adjust their generation to meet generation needs on an hourly or daily basis. EPA provides no data to support this assumption that units operate in only one way—at high capacity factors—at all times. While this convention (higher capacity factors are baseload units and lower capacity factors are load following units) might be useful for subcategorizing units for the purposes of standards development, it can bear little relationship to actual unit operations, which presents compliance and operational challenges. EPA is obligated to ensure achievability of these standards, which means that the Agency must account for these operational realities when setting NSPS.

The generation profile of the industry is changing dramatically, including greater deployment of renewable generation, and this trend will continue.[243] As a result, the manner in which baseload NGCCs will operate in the future will result in the frequent cycling of these units—and, indeed,

[243] *See, e.g.*, AEO 2023, Release Presentation at 11-14 (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Release_Presentation.pdf.

higher levels of cycling (resulting in lower capacity factors) already are required of many currently operating newer NGCCs in areas with significant renewable deployments.[244] Renewable energy sources provide variable generation by their nature; combined cycle, simple cycle and quick start natural gas-fired units are essential elements to integrating this variable generation and are increasingly being called upon to ramp up and down in response to these often quick and unpredictable changes.[245] As EEI noted in its 2014 and 2018 comments, combined cycle and combustion turbines play an essential role in continuing the clean energy transition by providing 24/7 and quick start power, which allows for increased renewable integration and reliable power at affordable rates for customers.

The practical effect of this is that new natural gas-based units will likely cycle more often in future years, and thus not operate at steady state operations for extended periods of time, which will have an impact on the unit's ability to meet the proposed standard of 770 lb CO_2/MWh. More frequent starts and stops means that a unit is operating in periods with reduced efficiency and a higher emission rate. This increased cycling puts the achievability of EPA's proposed 770 lb CO_2/MWh in question for even the most advanced turbines.

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[244] *See, e.g.*, EIA, *Natural Gas Combined-Cycle Plant Use Varies by Region and Age* (May 20, 2021)(, https://www.eia.gov/todayinenergy/detail.php?id=48036.

[245] EPA acknowledges this in a roundabout way in the *Efficient Generation: Combustion Turbine Electric Generation Units Technical Support Document*, Docket ID No. EPA-HQ-OAR-2023-0072 (May 2023), which states that "combined cycle EGUs [are] a more dependable power source for load-following supply."

Second, as a unit cycles more frequently, the degradation in performance of that unit happens more rapidly.[246] In proposing the current standard of 770 lb CO_2/MWh, EPA asserts that the proposed rate fully accounts for degradation of the unit, *see* 88 *Fed. Reg.* at 33,323, but as discussed in more detail below, EPA does not provide any data to support this claim. As proposed, the current emission rate does not provide sufficient flexibility to account for any increases in degradation that will result from the more frequent cycling, i.e., starting and stopping of a unit, and provides no support for the assertion that the proposed emissions rate fully accounts for degradation in light of how units are anticipated to operate.

Examining the most recently issued permits issued for NGCC units is instructive. While EPA does cite a number of units operating at an annual basis at or below 770 lb CO_2/MWh, there are several caveats EPA does not address. First, these units are all very recently constructed, and are operating before significant degradation and/or wear and tear have impacted unit performance. And, as new units, these facilities are operating at higher capacity factors because they are the most efficient units available for dispatch, meaning that they are dispatched first.[247] However, these units are not *permitted* at the rates EPA asserts they are performing at on an annual basis, with many permitted near or above 800 lb CO_2/MWh. Take, for example, the Orange County Advanced Power Station (OCAPS) in Texas, which commenced construction this spring and is

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[246] *See, e.g.,* Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-Fueled Generators for Western Electricity Coordinating Council*, Report No. AIM 191210726-2-1 (May 20, 2020), https://www.wecc.org/Reliability/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf.

[247] When all units are similarly highly efficient, they all would not be able to run at the highest possible capacity factors, rendering reliance on these units even less apt.

being built by EEI member Entergy.[248] OCAPS is a 1,215 MW facility utilizing two Mitsubishi M501JAC enhanced air-cooled gas turbines in a 2x1 configuration with a heat recovery steam generator (HRSG) and advanced control system. OCAPS is also a hydrogen-capable facility, that will be initially capable of 30 percent hydrogen blending by volume and is poised to blend hydrogen in future years when it is available, with some retrofits.[249] Critically, OCAPS' Prevention of Significant Deterioration (PSD) permit requires that OCAPS meet a limit of 814.7 lb CO_2/MWh gross on a 12-month rolling average basis. *See* Texas Council on Environmental Quality PSD Permit, Special Condition 30.

OCAPS represents a very advanced combined cycle facility that includes a HRSG, which EPA deems essential to achieving high levels of efficiency, and the permitted level is notably above EPA's proposed emissions standard of 770 lb CO_2/MWh. This is practical and logical: the permitted level for new facilities—facilities that will operate for decades in the future and must be in compliance with their permitted rate at all times—must take into account long term unit operations, degradation, and other relevant factors that can impact unit performance, providing for flexibility and operational head room across a range of potential to probable operating conditions.

Also instructive is EPA's own admission that "nearly half of recently constructed combined cycle EGUs have maintained an emissions rate of 800 lb CO_2/MWh." 88 *Fed. Reg*. at 33,324. In light

[248] *See* Entergy, About the Project, https://www.entergy.com/entergypowerstexas/project/.

[249] this represents the capability of the turbine and not necessarily an expectation that sufficient hydrogen supplies (much less low-GHG hydrogen supplies) will exist to enable this level of co-firing to be sustained.

of this, EPA seeks comment on whether the Agency should instead adopt this higher emissions rate on the grounds that it "would increase flexibility and reduce costs to the regulated community by allowing more available designs to operate as base load combustion turbines." *Id*. The answer to the Agency's question is yes, EPA should consider setting a higher emissions standard than proposed since such an approach would be in line with the approach that EPA took in the final rule setting standards that are applicable to new NGCCs built after January 8, 2014. In that rulemaking, EPA selected 1,000 lb CO_2/MWh as the achievable emissions rate derived from the same BSER[250]—efficient generation—because it provided for operational flexibility, considered actual operating parameters and potential future degradation, as well as unit-specific design. *See Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule*, 80 *Fed Reg.* 64,510, 64,620 (2015 NSPS).[251] EPA should continue to adopt this approach in any final NSPS for base load NGCCs, since considering a range of factors when determining whether an emissions rate is achievable is both defensible and reasonable.

However, EPA has deviated from the approach it took in the Agency's 2015. More importantly, EPA is conflating its obligation to determine the BSER with its statutory obligation to ensure that the emissions limits based on BSER that are applied to new units are achievable. "Best" is a modifier for "system of emission reduction" in CAA section 111(a)(1); it is not a term used to

[250] EPA selected 1000 lb CO_2/MWh as the achievable emissions rate despite the fact that the "lowest emitters in the CAMD database" at that time had emissions rates of closer to 800 lb CO_2/MWh. *See* 80 *Fed. Reg*. at 64,618. EPA selected this emissions rate despite the fact that it anticipated that most new units likely would have better performance.

[251] It should be noted that whether the standard for new base load NGCCs is 770 lb CO_2/MWh or 800 lb CO_2/MWh, this would represent a significant emissions performance over the current standard.

describe the resulting emissions standard. EPA is not required by the CAA section 111(a)(1) to select the lowest or from among the lowest emissions rates that could be produced by the application of BSER, but instead is required to establish a standard that is achievable. *See* 42 U.S.C. § 7411(a)(1). While an achievable emissions standard is not required to be meetable by every single unit, as per the relevant case law, EPA has an obligation to demonstrate achievability "under the most adverse conditions that might be expected to occur" and which cannot be taken into account via an assessment of costs. *See Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).[252]

Here, EPA is not being asked to take into consideration the most adverse conditions, but merely the most likely conditions, as it did in 2015, which include increased cycling and the resulting degradation. Therefore, given the increased cycling and the attendant degradation as these units continue to adapt to changing grid conditions that EPA has not addressed and EPA's own observations about the achievability of a higher emissions standard, EPA should take these obvious likely conditions into account and select a higher standard that would provide more operational flexibility and compliance margin to account for these reasonably anticipated unit impacts. A higher standard is more appropriate, as it would account for the manner in which baseload units will be operating in the future to account for a great increase in intermittent generation resources and the increase in cycling of units.

[252] *See also Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981)(To show that a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industrywide performance, given the range of variables that affect the achievability of the standard.'').

2. EPA has not demonstrated that new NGCC units can achieve the proposed emissions rate using the required compliance demonstration metrics.

EPA asserts that the proposed 770 lb CO_2/MWh emissions rate for new base load NGCCs has been demonstrated, but EPA has not provided underlying data that is supportive of this assertion. Further, EPA appears to be using a different metric for its demonstration that this rate is achievable than the one that EPA would require units to use when proving compliance. Accordingly, this provides a separate basis for determining that EPA has not shown that that the proposed rate is achievable, contrary to the requirements of the CAA, and therefore cannot be finalized.

In the proposed Section 111 Rules, EPA states that "[a]n emissions rates of 770 lb CO_2/Mwh-gross has been demonstrated by 14 percent of the recently constructed combined cycle EGUs." 88 *Fed. Reg*. at 33,323. However, while EPA provides a chart that summarizes what EPA refers to as "the maximum 12-operating month base load emissions rate" for the "best performing" combustion turbines in an appendix to the *Technical Support Document (TSD) Efficient Generation: Combustion Turbine Electric Generating Units* that was included in this docket, *see id*. at 33,324, EPA provides insufficient information in the TSD about how the "12-operating month" rates were calculated, including information about the number of startups and shutdowns, capacity factors, total MWh generated, or other details that would help stakeholders, including the owners and operators of potential new affected NGCCs units, understand how EPA arrived at this conclusion and how the units compare to their own recently constructed NGCCs.

At minimum, EPA should provide such data and more information about how it calculated these "maximum 12-operating month rates." In addition, EPA asserts that these units cited as the best performers "have long-term emissions data that fully account for potential degradation in efficiency." *Id*. at 33,323. However, EPA does not provide that data in either this proposal or the docket to support this claim or to allow comments opportunity to review it. As noted, this approach is markedly different from the significant and detailed analysis of achievability, including degradation and other factors, undertaken by the Agency in establishing an achievable emissions limit for new NGCCs in the 2015 NSPS. EPA should provide this additional data or reconsider its approach.

EPA also appears to be using a different metric for computing the "12-operating month baseload emissions rate" than the metric that unit owners and operators would be required to use to demonstrate compliance, which can be problematic. EPA does not define what it means by a 12-operating month emissions rate, although it appears to be an annual average emissions rate. It is not clear how EPA's assertion that this rate demonstrates that the proposed emissions limit of 770 lb CO_2/MWh can be achieved when the proposed subpart TTTTa would require compliance be demonstrated using a 12-operating month rolling average. *See* proposed 40 C.F.R. at 60.5525a(a)(1).[253] EPA is correct that annual averages could provide operational flexibility, but this could be eroded if the averaging period is rolling or if EPA intends that 12-operating month rolling average is similar to a 12-month rolling average, which is the way that compliance is

[253] Assuming that the mandate "You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times" does not override any effort to provide compliance flexibility via longer averaging periods than are provided under subpart TTTT normally. *See* proposed 40 C.F.R. § 60.5525a(A).

currently demonstrated under subpart TTTT. Given this mismatch, EPA has not shown that the standard it has selected can be achieved using the appropriate compliance metric it requires. At minimum, EPA must make such a showing before asserting that a standard is achievable.

3. EPA can help units achieve compliance with the proposed emissions rate standards by authorizing mass-based compliance.

EPA also should affirmatively allow for mass-based compliance options for new units. While NSPS are traditionally set on an efficiency rate basis, allowing companies to translate the rate-based standard into a mass-based tonnage limitation would provide significant operational flexibility for units that cycle frequently—e.g., that ramp "up and down," operate at various loads, or have frequent startups and shutdowns to meet grid demands, as discussed here. Instead of having units meet a continuously applicable rate, which limits their ability to integrate newer and cleaner resources, allowing companies to translate the BSER rate into a mass-based tonnage limit would provide for environmental integrity, offer more straightforward compliance options, allow for more efficient operations, and support utility planning based on known unit constraints via tonnage limits. While such approaches could provide "less" environmental protection in the context of traditional air pollutants, these potential impacts are actively managed by state permitting agencies through the PSD permitting process, and such concerns are not relevant for GHGs, which are well mixed in the atmosphere once emitted, minimizing localized pollution concerns. EPA should affirmatively provide a mass-based compliance option for new units. Providing this flexibility does not ameliorate EPA's failure to demonstrate that the proposed emissions limit for new base load NGCC units is achievable, but, when coupled with an increase in the standard, would address many of the concerns regarding compliance raises in these comments.

B. EPA Should Clarify Requirements for Intermediate-Load Units.

The proposed intermediate subcategory applies to NGCCs that have a capacity factor less than approximately 45-55 percent and CTs that have a capacity factor less than approximately 33-40 percent. *See* 88 *Fed. Reg.* at 33,277. EPA proposed as its phase 1 emission limit for these units a rate of 1,150 lb CO_2/MWh. *See id.* at 33,319. Units that would be classified as intermediate-load units serve a key role in the ongoing transition of the electric sector by assisting with renewables integration and providing essential reliability services at smaller sizes and lower capacity factors than base load units. However, the application of a capacity factor restriction to these units, in addition to an emission rate limitation, unnecessarily constrain the ability of these units to operate in a way that supports both the transition of the sector to carbon free resources, but also grid reliability.

EEI raised similar concerns in the past about capacity factors limiting the use of efficient turbines —units opted to curtail operations rather than be subject to more stringent standards—resulting in less efficient and more carbon intensive units be called upon to support grid reliability. These same concerns are valid here with respect to the intermediate subcategory being subject to both a capacity factor and emission rate limitations. In effect, having both a rate limitation *and* a capacity factor limitation that limits the efficient operations of those units at load—despite the potential utilization of multi-year averaging—constrains the ability of units to operate and be in compliance by having both restrictions fundamentally work against one another.

To encourage the construction and use of these efficient units, EPA should remove the capacity factor limitation and only restrict units to an emission limit to ensure that the most efficient units, and correspondingly, the most environmentally protective units are operating. By providing both a capacity factor limitation and an emissions performance standard, EPA will unnecessarily limit operations while simultaneously attempting to drive for the more efficient operations, despite the fact that those efficiencies tend to only occur at higher capacity factors. If EPA nonetheless believes that lower emissions rates and limited operations can be simultaneously achieved, EPA must provide significantly more analysis showing that units that operate under a 50 percent capacity factor can also achieve the phase one standards EPA proposes—for both combined cycle turbines and CTs.

In the alternative, EPA should also consider setting a separate, capacity factor or emissions rate limit that would apply only to new CT units. This would allow EPA to have a base load and intermediate-load category approach for NGCC units, while also working to set up a parallel structure for CTs that could allow for greater flexibility for units that can help with renewables integration. Ultimately, EPA should choose between approaches—a capacity factor restriction, or an emissions rate limitation, and not both at once.

C. In defining Low-Utilization Units, EPA Should Finalize a Higher Capacity Factor to Account for Reliability Considerations.

EPA also proposes a low-load subcategory for units that operate at capacity factors less than 20 percent but is soliciting feedback on a range between 15-25 percent. *See* 88 *Fed Reg*. at 33,321. EPA acknowledges that these low load units provide critical services in support of grid reliability, including ramping capabilities during periods of peak electric demand. *See id.* at 33,320. EPA reaches this conclusion on the basis that one-third of recently constructed units operate under this capacity factor, while 80 percent of recently constructed units have operated at a capacity factor of 25 or less. *See id*.

Grid reliability is and will continue to be a top priority for EEI's member companies. With an increase in extreme weather events, including high heat events, extreme winter storms, wildfires, hurricanes, and other threats to the electric grid, in addition efforts to electrify many segments, including the transportation and industrial sectors, of the economy, the industry will require to use of all available resources at times of peak demand, which will likely become even more frequent.

As a result, many of the units that would be classified as low load units will be called upon to support grid reliability with more frequency in the future but would be unable to meet more stringent emission limitations of the intermediate subcategory because of the manner in which they are called upon to operate. This could result units operating until they reach their 20 percent capacity factor, and then shutting down to not be subject to stricter limits, resulting in a gap in generation or the generation being supplied by less efficient and more carbon intensive units such as diesel reciprocating internal combustion engine units.

EPA should therefore increase the capacity factor limitation for low load units to at least 25 percent. This will allow these low load units to operate to support grid reliability in an environmentally protective manner compared to alternatives. EEI's member companies view these low-load turbines as essential to preserving system reliability while integrating ever higher penetration of renewable resources onto the grid. Finalizing a higher capacity factor will allow for members to build fewer of these units while also allowing them to be available when needed for grid reliability situations. EEI's member companies are filing individual comments in support of EPA finalizing this higher threshold for the low-load category; EPA should full take those comments and concerns into account and finalize the 25 percent capacity factor limitation as a result.

V. Compliance Flexibilities Are Essential To A Workable Final Rule; EPA Should Both Finalize And Expand Proposed Flexibilities And Provide Additional Options To States And Units.

EPA has the ability to provide a range of flexibilities, both in the standard setting process and in defining compliance options. This is grounded in the text of CAA section 111 and, broadly, in EPA's decades-long implementation of the CAA. In general, regulatory—e.g., standard setting—and compliance flexibilities are a practical and longstanding method of helping affected sources comply with environmental regulations in efficient, cost-effective, and commonsense ways. The electric sector has long experience implementing emissions trading regimes, averaging provisions, and permit-specific terms in ways that achieve cost effective and efficient compliance. These flexibilities have contributed to the broad and continued success of the CAA in reducing pollution and promoting public health and are common features of environmental statutes: EPA generally is authorized to set standards and then provided compliance pathways that enhance the options available to industry and states—instead of limiting the methods and manners that sources can use to meet those same standards.

A recent EPA report acknowledges this important feature of environmental regulation: Since the 1990 CAA amendments, the many flexible compliance regimes promulgated by the Agency have resulted in significant emissions reductions and a marked reduction in unhealthy air quality days, all at lower than predicted costs to industry and customers.[254] Many of the regulatory programs enacted by EPA to attain and maintain the NAAQS in the past three decades have contained significant regulatory flexibilities—from market-based trading,[255] to wide ranging averaging provisions,[256] to creative permit terms,[257] to innovative methods of estimating reductions from new industry activities.[258] In summary, EPA has set standards and targets, and American industries have worked to engineer the least cost and most effective way to meet these via supportive and flexible regulatory frameworks from their states and EPA.

In this rulemaking, EPA has the opportunity and authority under CAA section 111 to incorporate compliance flexibilities and mechanisms to help EGUs reduce GHG emissions. EPA has included several important and well-founded compliance flexibilities in the Proposed Section 111 Rules. In any final rule, EPA should both retain and expand the proposed compliance flexibilities and explicitly authorize mass-based approaches to demonstrating compliance, encourage state-

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[254] EPA, Our Nation's Air, https://gispub.epa.gov/air/trendsreport/2019/#naaqs.

[255] *See, e.g.,* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 *Fed. Reg.* 57356 (Oct. 27, 1998); the Clean Air Interstate Rule, 70 *Fed. Reg.* 25,161 (May 12, 2005); the Cross-State Air Pollution Rule (CSAPR), 76 *Fed. Reg.* 48,208 (Aug. 8, 2011); the CSAPR Update Rule, 81 *Fed. Reg.* 74,504 (Oct. 26, 2016); and the Revised CSAPR Update Rule, 86 *Fed. Reg.* 23,054 (Apr. 30, 2021).

[256] *See* Florida State Implementation Plan Approval for Hillsborough County, 82 *Fed. Reg.* 30,749 (July 3, 2017).

[257] *See* Prevention of Significant Deterioration/Title V Greenhouse Gas Tailoring Rule, 75 *Fed. Reg.* 31,513 (June 3, 2010).

[258] *See* EPA, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans (July 2012), https://www.epa.gov/sites/production/files/2016-05/documents/eeremanual_0.pdf.

driven trading programs, allow units to use averaging to demonstrate compliance, and allow for these flexibilities to apply to both existing coal- and natural gas-based units. These flexibilities will be essential for compliance, particularly if EPA chooses to finalize emissions standards for new and existing sources similar to those proposed.

A. Mass-Based Approaches Should be Explicitly Authorized in the Final Guidelines and in the Final Rule for New Sources.

EPA proposes that units would demonstrate compliance with the presumptive rate-based standards annually based on the lb CO_2/MWh emission rate derived by dividing the total reported CO_2 mass emissions by the total reported electric generation for an affected EGU during the compliance year, which is consistent with the expression of the degree of emission limitation proposed for each subcategory. *See* 88 *Fed. Reg.* 33,375. EPA also separately takes comment on, and notes that states could implement, mass-based emissions approaches, including mass-based trading. *Id*. at 33,393.

1. EPA should explicitly authorize mass-based approaches for existing sources to allow for straightforward compliance.

Given that EPA references the D.C. Circuit's decision in *American Lung Association* finding that states and units are not required to implement EPA's proposed BSER in order to comply with CAA section 111 standards, and that a mass-based input is required for compliance with a rate-based approach, states seemingly could choose to propose mass-based compliance approaches for existing units. *American Lung Association*, 985 F.3d 914, 957. EPA should be explicit in any final rule that it will approve mass-based compliance demonstrations included in state plans. This would enable straightforward compliance with an annual emissions tonnage limit instead of the annual emissions rate and provide a more direct route to implementing any trading program. As discussed in detail in a whitepaper that EEI filed in the non-regulatory docket that preceded this proposal, mass-based compliance also provides significant operational flexibility.[259] This allows units to operate within a mass-based limitation and ensure availability to cycle, incorporate variable resources, and respond to grid conditions without having the limitations regarding rate-based approaches that struggle to account for startup and shutdown emissions and conditions.

Mass-based approaches will help states utilize other flexibility tools, like averaging, trading, and using lower-GHG fuels in a more straightforward and least-cost way. This will allow for numerous other flexibilities to be utilized as well, including the ability to link existing state-based programs, as discussed *infra* in these comments, as well as straightforward incorporation of mass-based limitations into unit-specific permits. Mass-based approaches will allow consistency and seamless integration with existing state programs that measure compliance based on mass emissions, while still achieving the program goals of net reductions in greenhouse gas emissions. EPA should explicitly authorize mass-based approaches to accommodate these additional flexibilities.

2. EPA should explicitly authorize states to use mass-based compliance for new sources.

EPA also should affirmatively allow for mass-based compliance options for new units. NSPS are traditionally set on an efficiency rate basis; for EGU GHG standards, these are expressed in pounds of CO_2 per hour. Allowing companies to translate the rate-based standard into a mass-based tonnage limitation would provide significant operational flexibility for units that cycle frequently—e.g., that ramp "up and down," operate at various loads, or have frequent startups and shutdowns to meet grid demands—which are becoming more essential and more common as

[259] *See* EEI Whitepaper, attached as Appendix B.

greater amounts of variable renewable resources interconnect to the grid. Further, cycling degrades individual unit efficiency since units operate more efficiently at higher load profiles when compared to continued cycling. Instead of requiring units to meet a continuously applicable rate, which limits their ability to integrate newer and cleaner resources, allowing companies to translate the BSER rate into a mass-based tonnage limit would provide for environmental integrity, offer more straightforward compliance options, and support utility planning based on known unit constraints via carbon dioxide tonnage limits. While such approaches would provide less environmental protection in the context of traditional air pollutants, such concerns are not relevant for GHGs, which are well-mixed in the atmosphere once emitted.[260]

EPA should also consider that operating efficiency is also correlated to a combined cycle CTs ambient conditions. Highly efficient operations are not available under all ambient conditions and vary based on the location of a CT. EPA should also consider degradation of efficiency over time. An additional benefit would be ease of incorporating these units into state-based trading schemes, as discussed *supra*, to the extent states would like to utilize such an approach.

B. Trading and Averaging Must Be Included in Any Final Guidelines and Should Be Encouraged as a Compliance Pathway.

EPA proposes to allow states to include an array of compliance flexibilities in compliance plans, including mass- and rate-based approaches, along with ability for states to use trading and averaging for compliance. Specifically, EPA notes that states can consider using mass- and rate-based trading programs in a way that "preserves the stringency of" the emissions limits that are

[260] *See* EEI's November, 2022 submission to EPA's non-regulatory docket. States routinely use mass-based limits when permitting new NGCCs under the PSD Program.

based on the identified BSER, and that these approaches should be consistent with other EPA trading programs, like the NOx Budget Trading Program, the Good Neighbor Rule, and others. *See* 88 *Fed. Reg.* at 33,393.

EPA notes that states should consider ways to ensure that any emissions budget does not overestimate the required budgets, including via a dynamic budgeting mechanism. *See id*. The Agency also notes that states could consider banking and/or averaging, as appropriate, which could help to incentivize unit retirements in advance of certain retirement deadlines. EPA proactively takes comment on whether to allow trading and averaging approaches as part of these guidelines. *See id*. at 33,395-96.

EPA should note in any final rule that trading and averaging are proven, well-understood approaches to compliance with environmental requirements and should affirmatively allow for these approaches to be included in state compliance plans. Allowing states to adopt a mass-based approach would also dovetail with the ability to utilize trading programs, and EPA should affirmatively note that both approaches are authorized. EPA should also consider developing a model trading program for states without the resources to develop their own plans or provide guidance to states about factors to consider when developing trading and averaging schemes as part of state plan development. Additional guidance or a model rule that states could adopt will assist with states developing plans in the two-year window provided for the state plan development process, and EPA should strive to release that guidance in conjunction with—or shortly after—any final rule. At a minimum, EPA should convene technical workshops with interested stakeholders regarding the development of any trading regimes by states, to allow for increased coordination and collaboration through the development of state plans.

EPA has ample authority to permit states to use these approaches. Trading is not inconsistent with the recent Supreme Court decision in *West Virginia*. In that case, the Supreme Court suggested that if an overall cap (as defined by BSER) is based on "the application of particular controls and sources could have complied by installing them," emissions credit trading may be permissible as a compliance measure. *West Virginia,* Slip Op. at 21-22.

This also would be consistent with positions that EPA has taken in previous rules, in which the Agency has argued for significant compliance flexibility as a legal matter. The Agency's 1995 rule promulgating municipal waste combustor (MWC) emissions guidelines which allowed state plans the *option* to average emissions from units within a large MWC plant and to trade emissions credits between MWC plants. [261] In doing so, however, EPA set emission limits for averaging that were about 10 percent lower than if these limits applied to an individual plant.

In 2005, EPA issued the Clean Air Mercury Rule (CAMR) under CAA section 111(d), capping mercury emissions from coal-fired power plants. There, EPA first determined that technological systems were available to control mercury, but that it would take multiple years to install such controls across the existing fleet. CAMR's cap-and-trade system (allowing at least some affected sources to avoid installing technological controls) was based on EPA's determinations that such a

[261] *See Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources; Municipal Waste Combustors*, 60 *Fed. Reg.* 65,387 (Dec. 19, 1995).

system would: (a) constitute a "standard"; (b) reflect the degree of emissions limitation achievable; and (c) for coal-based EGUs, constitute BSER. *See* 70 *Fed. Reg.* at 28,616-17. Under CAMR, states had the option of adopting "substantially similar" regulations, but if they adopted other standards, EPA indicated that it would review the state plans pursuant to the 40 C.F.R. 60.24(h)(2)-(5).[262]

Further, as part of the briefing surrounding both the CPP and the ACE Rule, the D.C. Circuit's 2021 decision in *American Lung Association* found that EPA's limitation in the ACE Rule on the compliance measures that sources could use to comply with the states' standards of performance was arbitrary. *American Lung Association*, 985 F.3d 914, 957. EPA had categorically excluded two specific measures from the states' consideration: averaging and trading, and biomass co-firing. The Agency's concern was that compliance measures that are not source-specific could result in "asymmetrical regulation[,]" meaning the stringency of standards could vary across sources.[263] The D.C. Circuit found these concerns unpersuasive.

Because the court held that the EPA erred by concluding that CAA section 111(d) unambiguously required that BSER be source specific, the court noted that it must "necessarily reject the ACE Rule's exclusion … of compliance measures it characterizes as non-source-

[262] This criterion was subsequently deleted from the C.F.R. following vacatur of CAMR. The D.C. Circuit in *New Jersey v. EPA,* 517 F. 3d 574 (D.C. Cir. 2008), however, did not reach the merits of EPA's interpretation of its CAA section 111(d) authority; rather, the court determined that EPA had improperly "de-listed" the source category from CAA section 112, thus invalidating EPA's attempt to regulate under section 111.
[263] *See Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating units; Revisions to Emission Guidelines Implementing Regulations*, 84 *Fed. Reg.* at 32,520 (July 8, 2019) at 32,556.

specific." *Id.* at 957. The court also noted that even if EPA might reasonably limit compliance measures in specific situations based on its determination of the best system for reducing particular types of emissions with localized consequences, the statute imposes no requirement that such limitations be uniform across the regulation of different pollutants—in effect, there is no requirement for "symmetry" in regulation between standard setting and compliance. "Regardless of any policy-based reasons the EPA offers for limiting compliance measures, then, its decision to exclude averaging and trading and biomass co-firing is foreclosed by its legally erroneous starting point." *Id*.

None of these provisions were addressed directly by the Supreme Court's *West Virginia* decision, which focused exclusively on the major questions doctrine and focused mostly on the authority underlying the BSER determination made by the agency in the Clean Power Plan. As a result, that decision does not limit EPA's authority to offer states and affected sources broad compliance flexibility within an existing unit context. EPA should affirmatively and proactively offer states the ability to utilize trading and averaging approaches and should provide states with latitude to implement those approaches in a manner consistent with the need for both reliable system operations and the overall emissions reductions expected from a state plan under the final existing source guidelines.

C. Dual Path Options Should be Available for All Existing Sources and EPA Should Further Develop This Approach.

EPA explains, and as discussed above in section II of these comments, under the emissions guidelines for existing coal-based steam generating units in the Proposed 111 Rule states would place affected coal-based EGUs into one of four subcategories based on the time horizons over which those EGUs elect to operate. *See* 88 *Fed. Reg.* at 33,403. The Agency explains further that these subcategories are static—that is, affected EGUs would not be able move between subcategories absent a plan revision. *See id.*[264] However, EPA does solicit comment on a dual-path approach for existing coal-based EGUs. Under such an approach, if included in any final rule, existing coal-based EGUs could submit two different standards of performance to EPA to be included in its compliance plan. *See id.* at 33,405. For example, for an affected coal-based steam unit that wants the option to be part of either the long-term or imminent-term subcategory, the state plan would include an enforceable standard of performance based on implementation of CCS and associated requirements, including increments of progress; as well as an enforceable requirement to permanently cease operations before January 1, 2032, and a standard of performance based on routine operation and maintenance. *Id.*

EPA should, at a minimum, further develop this dual-path approach and include it in any final rule, which would allow for states and sources to take full advantage of EPA's proposed subcategories. Compliance and operations decisions regarding EGUs are complex and involve multiple steps over which owners and operators may have varying levels of control, including integrated requirements to decommission a unit, procure replacement generation, meet capacity requirements, and—in the event of a unit working to comply with several of the compliance pathways chosen by EPA, including potentially the installation of CCS—procurement, design, and installation of control technology, including the need to permit and test any new technology. A proposed path may seem viable during the state plan development phase, but soon after can become unworkable or infeasible. A dual-path approach would allow owners/operators and states

[264] As discussed further *infra*, EPA should consider providing greater flexibility for units to move between subcategories during the compliance period based on a variety of factors.

additional time to make these difficult and complex decisions, while also providing additional flexibility to account for potential changes in circumstances, including delays in procuring, or more expedited arrival of, replacement generation, or reliability considerations. Accordingly, EPA should include dual-path optionality in the final rule.

The Agency also should allow existing coal-based EGUs the opportunity to select a dual-path approach for units that might retire as part of one of the proposed subcategories, but also should permit these units the option to convert completely to steam-gas units that comply with the steam-gas rate limitations proposed by EPA. This would allow units to either retire or convert, resulting in significant emission reductions under either approach, consistent with EPA's rationale for providing dual-path approaches.

D. EPA Should Alter Its Proposed Approach to Increments of Progress to be Consistent with Providing Appropriate Flexibility to States and Units.

EPA is proposing to adopt emission guideline-specific implementation of the five generic increments specified in the CAA section 111(d) implementing regulations. These five increments of progress are: (1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency; (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification; (3) Initiation of on-site construction or installation of emission control equipment or process change; (4) Completion of on-site construction or installation of emission control equipment or process change; and (5) Final compliance. 88 *Fed. Reg.* 33,388. EPA also proposes that state plans must include specified enforceable increments of progress as required elements for coal-based EGUs that use natural gas co-firing to meet the standard of performance for the medium-term existing coal-based steam generating subcategory and for natural gas-based combustion turbine EGUs that use hydrogen blending to meet the standard of performance. *Id*.

EPA has clear authority to require increments of progress under the statute and its own regulations; however, EPA should not be overly prescriptive in setting those increments of progress so that the only method of implementing or complying with those increments for the medium-term coal-based subcategory or hydrogen pathway for combustion turbines is how units must comply with EPA's specific BSER. As noted *supra*, the D.C. Circuit's decision in *American Lung Association* notes that EPA could offer significant compliance flexibility to states and units and was not required to have sources implement the specific BSER prescribed by EPA. *American Lung Association* 985 F.3d at 942-43, 96. As proposed, the increments of progress—especially (3) Initiation of on-site construction or installation of emission control equipment or process change, and (4) Completion of on-sites construction or installation of emission control equipment or process change—seem to denote that sources in these subcategories *must* implement EPA's BSER to comply with the increments. EPA should note that sources do not have to meet every single increment of progress, especially if those sources are part of a broader mass-based, trading, averaging, or other compliance approach that does result in an emission limitation being placed on an individual unit. Such an approach would be consistent with offering additional flexibility to sates and units, as well as *American Lung*.

The Agency also notes that it is not proposing increments of progress for either the imminent- or near-term subcategories for coal-fired steam generating units, or for oil- or natural gas-fired steam generating units. The proposed BSERs for these affected EGUs are routine operation and maintenance. *See* 88 *Fed. Reg.* 33,388. Given that these units are utilizing routine operation and maintenance as BSER, such an approach is warranted and valid. EPA should finalize this approach.

E. EPA Should Provide Additional Guidance Regarding Setting Unit-Specific Baselines.

In Section XII(D)(1)(a) of the preamble to the Proposed 111 Rules, EPA describes its proposed method for states to determine the baseline emissions performance, which is a critical step in determining the presumptive standards for existing EGUs. *See* 88 *Fed. Reg.* 33,240, 33,375 (May 23, 2023). Once a state determines a unit-specific baseline, it will then "apply" the BSER to that unit based on which BSER is applicable to that unit, resulting in a unit-specific emissions rate.

While states have the obligation to set unit-specific emissions limitations for each existing affected fossil-based generator, EPA proposes presumptive methods for establishing emissions limitations for certain subcategories of these units, and state plans that opt to use this methodology to calculate emissions rates would be presumptively approvable. The proposed methodologies both account for historic unit-specific operations—on the assumption that past performance is indicative of future performance—and EPA's proposed BSER for the relevant subcategory. After identifying the affected EGUs in the state, EPA proposes that the state would then use the corresponding methodology for the given subcategory to calculate and then apply the presumptively approvable standard of performance for each affected EGU. The Agency notes that the proposed approach would provide a "uniform" way to determine unit-specific standards while allowing unit owners and operators to be able to reasonably approximate the emissions limitations that would apply to units prior to the development of state plans. *See* 88 *Fed. Reg.* 33,358.

EPA's proposed methodology is that a state will use the CO_2 mass emissions and corresponding electricity generation data for a given affected unit from any continuous eight-quarter period, from 40 C.F.R. part 75 reporting, within the five years immediately prior to the date the final rule is published in the Federal Register. EPA expects states to utilize the most representative eight-quarter period of data from those five years. *See id*. EPA will evaluate the choice states' determination of what constitutes representative data when reviewing state plan submissions. However, the Agency notes that it intends to defer to a state's reasonable exercise of discretion as to which 8 quarter period is representative. *See id*. at 33,375. For example, a state establishing baseline emission performance in the year 2023 would start by evaluating the CO_2 emissions and electricity generation data for each of its affected EGUs from 2018 through 2023. The state would choose a continuous eight-quarter period that it deems to be the best representation of the operation for each affected EGU. *See id*.

Using these eight quarters of data, the state would then divide the total CO_2 emissions (in the form of pounds) from that continuous time period by the total gross electricity generation (in the form of MWh) over that same time period. This result is baseline CO_2 emission performance in lb CO_2 per MWh. *See id*. States would then multiply that baseline rate by the emissions reductions EPA has determined is achievable via the application of the BSER for the relevant subcategory to determine the presumptively approvable emissions limit for that unit. *See id*. For example, if an existing natural gas combined cycle unit had a baseline emissions rate of 1000 lb CO_2/MWh, the resulting emissions limitation (effective starting in 2035) would be 110 lb CO_2/MWh, reflecting EPA's determination that carbon capture and sequestration (CCS) at a 90 percent capture rate would result in an 89 percent reduction in emissions (1000 x .11 = 110). These are baseline calculations and are not necessarily the way compliance is demonstrated.[265]

EPA also notes that, consistent with CAA section 111(d), states retain the ability to deviate from EPA's proposed methodology to apply more stringent standards. *See id*. However, EPA believes that the instances in which a state may need to use an alternate baseline-setting methodology will be limited to anticipated changes in operation, such as circumstances in which historical emissions performance is not representative of future emissions performance.[266] Where such changes result in a less stringent standard of performance, states must use the remaining useful life (RULOF) mechanism to determine the appropriate emissions limitation, which is discussed at length *infra* in these comments.[267] *See* 88 *Fed. Reg.* at 33,381.

The flexibilities EPA provides around setting unit specific baselines are well founded. The latitude provided by EPA both for states to determine which eight quarters are best representative and to use another methodology if they choose will allow for more accurate baseline determinations for EGUs. However, to simplify how the methodology is administered and ensure

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[265] EPA proposes that: coal or gas units applying CCS at a 90 percent capture rate results in approximately an 89 percent reduction in emissions rate; coal units that are co-firing with 40 percent natural gas results in an 18 percent reduction in emissions rate; gas units blending hydrogen at 30percent by volume results in a 12% reduction in emissions rate; gas units blending hydrogen at 96 percent by volume results in an 89 percent reduction in emissions rate. EPA does not delineate the expected emissions rate reduction from a 20 percent capacity factor restriction for coal units.

[266] For example: a state decides that an EGU in the medium-term coal-fired subcategory should co-fire 50 percent natural gas instead of 40 percent.

[267] RULOF is discussed in more detail in Section VI(H), *infra*, and also *supra* in Section II regarding EPA's authority to utilize retirement-abased subcategories.

consistency and predictability for state and unit owners/operators, in the final rule or through guidance, EPA should provide several examples states can use as templates for making these determinations. Some of these are included in the Proposed Rule, but additional examples and variations should be included in any final rule. This will ensure that unit owners and operators have a better sense of the manner in which states may exercise their discretion in making these determinations.

Further, EPA should provide additional clarity surrounding how to address baseline calculations for coal-based units that are already co-firing with natural gas or have existing capacity factor restrictions as these units do not fit perfectly into the proposed methodology, which assumes that units have not implemented any restrictions that impact their emissions profile. EPA should provide additional clarity and specific guidance for how to address and account for these variations from EPA's assumed baseline methodology.

F. EPA Should Provide More Flexibility in Implementing Its Proposed Remaining Useful Life and Other Factors (RULOF) Provisions When Assessing State Plans.

EPA's approach to states' ability to engage in RULOF analyses as part of their obligation to set standards for existing units is inflexible and does not comport with the role afforded states under section 111(d)(2).[268] EPA is obligated, therefore, to provide more flexibility for states to consider

[268] As discussed in section II, EPA should cite section 111(d)(2)'s authorization for states to consider remaining useful life and other factors as an alternative rationale to support the legality of the proposed retirement subcategories for existing coal-based units, which would be in line with a more flexible and expansive approach to the RULOF requirements in the statute. These proposed subcategories are an appropriate exercise of EPA's statutory authorization to distinguish between classes, types, and sizes of units when setting standards; but, they also represent a presumptively approvable approach to a state's exercise of its discretion to consider remaining useful life and other factors when setting standards for these existing units. EPA

using RULOF to modify the presumptive standards for an affected facility. EPA can assess the validity of the RULOF analysis and resulting standard when determining whether to approve a state implementation plan. To ensure that states can consider RULOF when setting standards for existing units, EPA should clarify in any final guidelines that states are not limited in the ways that EPA proposes, but instead are free to make such demonstrations as appropriate. In addition, EPA also should provide guidance on how states could rely on cost assumptions and source-specific considerations that may differ from approaches EPA has taken.

1. EPA must provide more flexibility to states to consider RULOF when setting standards for existing units.

EPA proposes that a state's invocation of RULOF when setting a standard for any existing unit would be required to be based on one or more of three circumstances—(1) unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility or technical infeasibility of installing necessary control equipment; and (3) other facility-specific circumstances that are fundamentally different from the information considered in determining the BSER—and that there must be "fundamental differences" between the EPA's determined BSER and the circumstance of affected EGU. *See* 88 *Fed. Reg.* at 33,382.

While these criteria are generally reasonable, their proposed application is both unreasonably stringent and requires further guidance. EPA may "not anticipate that states would be likely to demonstrate the need to invoke RULOF based on a particular coal-fired EGU's remaining useful life," and may believe that the circumstances for properly invoking RULOF "will be rare," but

should adopt this approach and also adopt a more expansive individual-unit RULOF approach as well.

EPA must consider a wide range of approaches for a state's proposed use of RULOF. *Id.* at 33,383-84.

EPA also proposes that states wanting to invoke RULOF must also consider cost in terms $/ton of CO_2 reduced and $/MWh electricity generated. *See* 88 *Fed. Reg.* at 33,382. EPA should be less prescriptive. While EPA may have considered $/ton of CO_2 reduced and $/MWh electricity generated in determining BSER, an identical requirement for states in crafting plans is not justified or necessary since states can consider the unique circumstances of each unit and the attendant costs, as long as each state plan provides a justification of the costs it considers as part of invoking RULOF for a specific source. Instead, EPA can note that such costs metrics can be helpful in supporting a standard that is based on a state's RULOF assessment, but EPA cannot deem that any deviation from this cost metric is fatal for the resulting standard.[269] Ultimately, EPA should examine a state's invocation of RULOF in a more holistic sense and consider why the state is proposing a different standard than those deemed presumptively approvable by EPA for an affected EGU.

If a state relies on "unreasonable cost of controls" in support of invoking RULOF, EPA proposes to require that states must demonstrate the facility cannot reasonably apply the BSER to achieve

[269] Moreover, EPA's reliance on the cost of carbon abatement is not a relevant or appropriate metric for determining BSER, nor is it relevant for a RULOF determination. Owners/operators of affected units, and states, need to consider the cost of the potential controls relative to the remaining useful life in determining whether it is reasonable to apply the BSER in determining a standard of performance or to invoke RULOF. The cost of carbon abatement is not an appropriate substitute for the actual cost impacts on a per unit basis. It can be useful for comparative analysis, but it bears little relationship to the costs that companies and their customers may have to bear to achieve compliance.

the emissions limitation determined by EPA, including that there must be a "fundamental difference" between EPA's BSER and the circumstance of affected EGU. EPA seeks comment on whether it should provide further guidance for determining when costs are "fundamentally different" from EPA's BSER determination. *See id*. EPA outlines some of the considerations taken into account in determining the BSER, including the physical possibility and technical feasibility of applying that system, the costs of a system of emission reduction, the non-air quality health and environmental impacts and energy requirements associated with a system of emission reduction and the extent of emission reductions from a system. *See id.* EPA further notes that "many of the factors [it] considers in its BSER determination," which would be the same or similar to the factors a state would consider in invoking RULOF, "are reflected in the cost considerations" for determining the standards of performance. EPA also provides examples of costs, including for CCS and natural gas co-firing for coal-based EGUs, that it evaluated in determining the proposed standards of performance. *See id*.

While this guidance generally may be helpful to states, it is nonetheless incomplete and largely provides examples of how difficult EPA believes it should be to demonstrate the required fundamental difference in cost. EPA should provide additional guidance on how states can show that the costs of controls is unreasonable, including examples of what would be considered an adequate demonstration of different costs from EPA's BSER determination for an affected EGU. EPA should also eliminate the modifier "fundamental," as it is not defined and is intended to limit states' exercise of RULOF to set different standards for certain existing units. EPA can assess the sufficiency of any cost differences demonstration based on the record before it in any proposed state implementation plan. EPA should avoid prejudging the outcome of its own assessment in this way.

The other two circumstances EPA cites under which invocation of RULOF could be based—physical impossibility or technical infeasibility of installing necessary control equipment, and other facility-specific circumstances that are fundamentally different from the information considered in determining the BSER—are reasonable and applied logically. For example, "facility-specific" circumstances could include the situation where replacement generation is not available in time for the affected facility to retire as scheduled. EPA provides helpful examples of how these circumstances could be applied to an affected EGU in considering the use of CCS, or to an affected combustion turbine in considering the amortization period for controls when deciding to cease operations and make that closure enforceable. *See id*. at 33,383. EPA also correctly proposes to allow states to use RULOF to provide a different compliance deadline for sources that can meet the standard of performance but not by the final compliance date under these guidelines. As discussed elsewhere in these comments, states should be able to use RULOF to adjust compliance deadlines, including the compliance deadlines included in EPA's presumptively approvable proposed retirement subcategories.

2. EPA should provide additional guidance to states on potentially approvable RULOF approaches.

EPA provides additional guidance as to potential specific invocations of RULOF by states when setting standards of existing units. EPA proposes that states invoking RULOF for affected coal-based units in the long-term coal-based retirement subcategory be required to evaluate natural gas co-firing as a potential source-specific BSER. States invoking RULOF for affected long-term (and medium-term) coal-based EGUs must evaluate different levels of natural gas co-firing unless they have demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. *See* 88 *Fed. Reg.* 33,384. Additionally, if an EGU in this subcategory can implement CCS but cannot achieve the degree of emission limitation prescribed by the BSER, EPA proposes that the state evaluate CCS with a source-specific degree of emission limitation. *See id.* For natural gas-based units choosing the CCS or hydrogen blending pathways, states would first have to demonstrate that the affected EGU cannot reasonably participate in the other pathway and meet that pathway's presumptive standard. "If a unit can comply it must do so." *Id.* at 33,385. For natural gas-based units opting for the CCS compliance pathway, EPA proposes that if a unit cannot reasonably comply with either of the performance standards—unless a state has demonstrated that it is physically impossible or technically infeasible for a unit to implement CCS—that the state must evaluate CCS with lower rates of carbon capture as a potential BSER. If CCS with lower rates of capture is not the BSER, then states would be required to consider comprehensive turbine upgrades, and finally smaller scale efficiency improvements. *See id*. For natural gas-based units in the hydrogen pathway that cannot reasonably comply with the performance standards for either category, EPA would require that states first analyze lower percentages of hydrogen co-firing, followed by comprehensive turbine upgrades and, lastly, smaller scale efficiency improvements. *See id*. While these requirements for specific instances in which a state might invoke RULOF, the Agency should also allow states more flexibility for determining source-specific BSER and calculating a standard of performance for affected EGUs.

Rather than limiting states' ability to invoke RULOF in these scenarios, EPA instead should characterize these as presumptively approvable approaches. This will provide states with greater flexibility in developing state plans and evaluating the invocation of RULOF for affected EGUs while ensuring that states take the necessary steps for determining an applicable standard of performance for affected EGUs.

This flexibility is consistent with other aspects of EPA's proposed approach to RULOP. For example, EPA proposes that states invoking RULOF for affected long-term and medium-term coal-based units must evaluate different levels of natural gas co-firing if an affected EGU cannot reasonably co-fire 40 percent natural gas unless the state has demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. Similarly, states seeking to invoke RULOF for affected CTs must evaluate CCS with lower rates of carbon capture or hydrogen co-firing as a potential BSER. *See* 88 *Fed. Reg*. at 33,385. Such an approach to applying RULOF is reasonable, and EPA should allow states to take a flexible approach in evaluating what might be an appropriate level of co-firing.

3. EPA's proposed additional requirements for sources invoking RULOF are appropriate.

EPA also proposes three additional provisions for states seeking to apply less stringent standards of performance pursuant to RULOF. One requires state plans to consider the potential pollution impacts, and benefits of control, to communities most affected by and vulnerable to emissions from the affected EGU. In addition, state plans that include a less stringent standard of performance pursuant to RULOF must meet all other applicable requirements of subpart Ba and the proposed guidelines, including the use of site- and source-specific information when possible. The proposed rule would also allow states to adopt and enforce standards of performance more stringent than required by an applicable emissions guideline. *See id*. at 33,386-87. EPA's proposed implementation of the other three provisions for invoking RULOF are reasonable and are in line with the Administration's Justice40 and related environmental justice initiatives.

G. Gas-Steam Units Require Additional Flexibilities.

EPA's proposed BSER for existing natural gas-fired steam generating units is "routine methods of operation and maintenance" and its proposed emissions limitation for these units is "no increase in emission rate (lb CO_2/MWh-gross)," presumptive unit limitations of either 1,300 lb CO_2/MWh, or 1,500 lb CO_2/MWh based on unit capacity factor. For low load existing natural gas-fired steam generating units, EPA neither proposes BSER nor emissions limitations. These standards are well founded and should be finalized; allowing these units to continue to serve their vital grid function while retaining the emissions benefit of prior conversion to utilizing natural gas from coal is critical for system reliability and affordability. EPA's approach on gas-steam units is the correct one.

EPA should also provide additional clarity to make the standards for gas-steam units maximally useful for states and members. EPA can provide additional clarity on applicability between categories for units based on utilization. EPA should also clarify that units can utilize the presumptive unit limitations in lieu of the no increase in emission rate approach. The Agency should state that it is either the presumptive *or* the no increase in emission rate unit-specific standard. This flexibility is well-grounded in EPA's traditional approaches discussed *supra* in this section and should be included.

Further, as described in these comments *supra*, the electric industry is in the process of a clean energy transformation. EPA recognizes this reality in the Proposed Rule by offering subcategories for retiring coal-based units. As part of the clean energy transformation, EEI's member companies also are continuing to retire certain natural gas-based units. EPA should develop and finalize retirement-based subcategories for these existing natural gas steam units, similar to those for coal-based units, in any final rule.

EPA should also be explicit in any final rule that coal-based units in retirement subcategories that later choose not to retire, but rather, completely convert to utilizing natural gas may transition to the standards for natural gas-based units. Unforeseen future circumstances—including potential reliability needs—may require that coal-based units slated for retirement instead convert to using natural gas rather than completely retire. EPA should account for these potential situations in any final rule by providing gas-steam units additional flexibilities.

H. Allowing States Additional Time to Submit Plans, and the Ability to Revise Plans After Submittal and During the Compliance Period, Is Essential.

In the preamble to the Proposed Rule, EPA notes that it expects to finalize the proposed standards for exiting units by June 2024. States will have 24 months to develop plans and will be required to submit these plans no later than June 2026. *See* 88 *Fed. Reg.* 33,401. EPA notes that it will adjust this deadline to reflect the actual date that standards are finalized; regardless of that date, states will have 24 months to develop and submit plans. States will have to meet a number of requirements as they develop plans, including requirements for public hearings, provide supporting documentation, and other completeness requirements. EPA notes that this is an increase in time from the current regulatory requirement for states to submit plans within 9 months of a final existing source guideline, and the Agency's December 2022 proposal to allow for up to 15 months for states to submit plans under proposed changes to the section 111 implementing regulations. *See id*.

EPA also acknowledges that, despite states' best efforts to accurately reflect the plans of owners/operators regarding affected EGUs at the time of state plan submission, such plans may subsequently change. *See* 88 *Fed. Reg.* 33,403. The Agency, therefore, reiterates that states have the authority and discretion to submit revised state plans to EPA for approval under 40 C.F.R. 60.23(a)(2), 60.28(a). *See id.*

EPA is justified in providing states with additional time to develop and submit plans to EPA beyond the nine months allowed by the generic section 111 implementing regulations and the 15 months in the proposed updates to those implementing regulations. The Agency should allow for at least the 24 months proposed for states to develop and submit plans given all the required steps—some of which are described above—to apply individual, unit-specific emissions rates to the vast number of sources covered by the proposed existing source guidelines in the Proposed 111 Rules. However, it is unclear if this is enough time for all states to develop and submit plans given the tremendous workload successful plan development requires, and EPA should either provide more time for initial plan development or provide significant mechanisms to extend the submission deadline for state plans. To the extent that states are unable to fully submit a plan to EPA for approval within those 24 months—but are working to develop and submit a plan to EPA—the Agency should develop and finalize a mechanism to provide an additional 12 months to finalize and submit a plan, and such a mechanism should be based on concrete steps that can be triggered automatically through specific, easy to understand and demonstrate criteria. EPA should explicitly consider what milestones will be required for states that need this additional time, which could include plans being out for comment, or state legislative changes that must be completed, and/or other tangible, specific events or requirements. This is appropriate given the potentially large number of existing coal- and natural gas-based units in some states.

Continuing to allow states the flexibility to revise plans after initial submittal, as already provided in the regulations, will help states and owners/operators of EGUs address new and unforeseen circumstances, including reliability, load growth, and technology deployment. At a minimum, and to ensure efficient and effective processes, EPA should commit to reviewing and making decisions on revised state plans expeditiously. EPA also should consider allowing states to reclassify units based on new and emerging events or circumstances without needing to go through a formal or total plan revision. This would increase the efficiency and efficacy of state plans but would also have another practical effect: namely the state plan revision and EPA approval process, even done as expeditiously as possible, is time consuming. Implementing some of the choices that will be included in state plans, especially given the lead times for permitting changes or installation of control technology, or natural gas co-firing capabilities, will require significant lead times. As decisions and circumstances change throughout the period after plans are filed, responding to potentially changing circumstances without the burden of additional regulatory time through a plan revision will benefit states, units, and EPA by avoiding time consuming and resource-intensive processes.

I. EPA Should Seek to Approve Existing State Programs as Much as Possible.

In the preamble to the Proposed 111 Rules, EPA explains that many states have adopted binding policies and programs under their own authorities that have significantly reduced, and will continue to reduce, CO_2 emissions from EGUs. *See* 88 *Fed. Reg.* at 33,396. These programs include multi-state and regional programs, such as the Regional Greenhouse Gas Initiative (RGGI).[270]

The scope and approach of EPA's Proposed 111 Rules can differ significantly from the range of policies and programs employed by states to reduce power sector CO_2 emissions, notably applying to a narrower subset of EGUs within the broader electric power sector. However, there still may be significant cross-over between the Proposed Rule and myriad state programs. In any final rule, EPA should signal it intends to approve appropriate existing state programs in a manner that avoids potential regulatory duplication. This would increase efficiency, reduce duplicative and/or potentially conflicting regulations between the state and federal level, and improve cost-effectiveness for owners/operators and customers. To the extent that existing state programs, even if they are set up differently and utilize alternative mechanisms for compliance and enforceability, can achieve equivalent reductions as those that would be achieved by unit-specific standards, satisfying the broader emissions reductions goals of CAA section 111, EPA should seek to approve those programs. This includes states that use a variety of other low-GHG "drop in" or replacement fuels in turbines, including biogas, renewable natural gas, ammonia, and other types of low-GHG fuels that provide significant life cycle carbon benefits while allowing companies to continue to utilize existing and new turbines to provide grid services. States should be able to utilize them as part of state plans since several states utilize these fuels as part of their existing frameworks.

[270] RGGI, https://RGGI.org (2023).

At a minimum, EPA should clarify which elements of existing state plans may be presumptively approvable, or what additional analysis and justification states would need to provide in order to have EPA approve a state plan including such programs. EPA also can provide additional avenues for existing programs to be approvable by providing additional compliance flexibilities more generally—including explicitly authorizing the use of mass-based approaches, trading, averaging, and others—to the states as discussed *supra*.

J. EPA Should Provide Clarity Regarding the Definition of System Emergency.

EPA proposes to amend the definition of system emergency in 40 C.F.R part 60, subpart TTTT and the proposed 40 CFR part 60, subpart TTTTa. That definition includes a provision that electricity sold during hours of operation when a unit is called upon to operate due to a system emergency is not counted toward the percentage electric sales subcategorization threshold. *See* 88 *Fed. Reg.* at 33,333. In the past, EPA concluded that an exclusion was necessary to provide flexibility, to maintain system reliability, and to minimize overall costs to the sector. *See* 80 *Fed. Reg.* 64,612. EPA notes that the intent of that the local grid operator would determine which EGUs are essential to maintain grid reliability, and it solicits comment on whether to amend the definition of system emergency to clarify how the intent of the grid operator standard would be implemented. *See id*.

The current regulatory definition of system emergency is that any "abnormal system condition" that the RTO/ISO or control area administrator determines requires immediate automatic or manual action to "prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system" and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load. The emissions from units that are called on during these “abnormal system condition” would not count towards the compliance calculation for any individual unit, per EPA. 88 *Fed. Reg*. 33,333-34.

EPA should keep this provision and provide additional specificity as to what constitutes an “abnormal system condition.” EPA should consider using an emergency alert level 2, which is when an RTO/ISO or local balancing authority requests emergency energy from all resources and has activated its emergency demand response program. During an emergency alert level 2, consumers are urged to conserve energy to help preserve grid reliability. This level precedes alert levels 3 and 4, which occur when a grid operator is unable to meet minimum reliability reserve requirements and then rotating power outages begin occurring to preserve grid reliability broadly, respectively. All units operating when an emergency alert level 2 is declared are working to prevent the abnormal system condition included in EPA’s definition, and EPA should affirmatively note that those emissions should not negatively impact a unit’s compliance.

Further, since emergency alert levels impact the entire grid, EPA should allow this definition for all existing coal- and natural gas-based units; when a grid operator or balancing authority calls on units under an emergency alert level 2, it does not discriminate on which units will be called on; as a result, EPA should ensure that all types of units, not just Subpart TTTT or Subpart TTTTa units have the ability to access this provision in the regulations. Such an approach would help allow units and system operators additional certainty in responding to any reliability events or issues.

VI. EPA Should Clarify Applicability Requirements Across All Three Rulemakings.

EPA should clarify applicability across all three substantive rulemakings to provide specific direction regarding which set of standards could apply to units. The requested clarifications are discussed below.

A. EPA Must Clarify Applicability for Existing Coal-Based EGUs.

For existing coal-based units, EPA appears to allow states and unit owners/operators choose among the various retirement subcategories. However, once a selection is made, and the retirement comments are made federally enforceable via its inclusion in an approved state plan, it is not clear how changes to the planned retirement date could be effectuated. EPA should clarify how units might move between categories to address changing conditions to accommodate both earlier and later retirements.

As a corollary, and as discussed *supra*, EPA should simplify the increments of progress requirements to maximize the potential for units to move between subcategories. There is the possibility that the increments of progress and/or milestone requirements, as proposed, could limit the ability to change subcategory classification.

EPA also proposes an applicability definition of "coal-fired steam generating unit" in proposed section 60.5880b holding that the existing source guidelines apply to any unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during the three calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after December 31, 2029. This look back provision for units to be "coal-fired steam generating units" based on their heat input in years 2027- 2029 may be overly restrictive, as units that could convert to steam-gas units or utilize alternative fuels might be able to do so prior to 2030. EPA's proposed definition, however, essentially mandates that those conversions occur by 2027 (or maybe 2028, depending on unit operations) to avoid being classified as a coal-fired steam generating units. This may impede units from reducing emissions by switching fuels and could act as an incentive to continue the use of coal as opposed to investing in the development of other fuels, like natural gas or biomass. EPA should make it clear that this applicability element does not apply to any unit that makes such a conversation prior to 2030.

B. EPA Must Clarify Applicability for New and Existing Natural Gas-Based Turbines.

The Agency also should clarify applicability requirements for new natural-gas based units, particularly between intermediate and low-load units, but also across all three standards phases. As discussed, *supra*, the capacity factor restriction requirements in the Agency's proposed NSPS for gas-based units is a complex, unit-specific inquiry based on heating value and overall capacity factor. Given the widely varying requirements in terms of emissions rates and potentially phased standards for new gas-based units, EPA needs to provide clarity around how units are determined to be low load, intermediate load or base load. In particular, the Agency should provide clarity regarding the demarcation between the low and intermediate load natural gas-based units, since intermediate-load units would be subject to potential phased standards including hydrogen blending while the low-load units would not have the same requirements. *See* 88 *Fed. Reg.* 33,244. As currently proposed, it is not clear how applicability of sources would function as a practical matter with compliance—e.g., applicability for each subcategory is determined on an annual basis on a unit-by-unit analysis, while compliance with EPA's standard for new units is measured on a 12-month rolling average. EPA should address this discrepancy and provide clarity regarding how applicability and compliance can be synchronized in order for sources to practically comply with EPA's standards.[271]

Finally, EPA should clarify to which existing natural gas-based units the Agency's proposal applies. EPA proposes that the existing source guidelines would apply to "large (*i.e.,* greater than 300 MW), frequently operated (*i.e.,* with a capacity factor of greater than 50 percent), existing … stationary combustion turbines." *Id*. at 33,245. EPA should state that the determination of whether a unit is subject to regulation under the proposed standards is based on actual utilization greater than 50 percent capacity factor, and not a unit's ability to operate at capacity factors of at least 50 percent. If applicability is based on ability to operate at capacity factors of at least 50 percent, the proposed standards would apply to a much larger subset of units as ability to operate is much greater than actual operations. EPA's intent appears to have been to take a more limited approach to applicability and should thus make the requested clarification as it is consistent with EPA's approach.

More importantly, EPA must specify whether the determination of the applicable subcategory for an existing natural gas-based turbine is a one-time test or whether there would there be an ongoing obligation to evaluate the annual capacity factor and potentially reclassify a unit if the capacity factor changes such that a different subcategory would apply. Constant re-evaluation

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[271] EPA also proposes to exempt EGUs "not capable of combusting natural gas (e.g., not connected to a natural gas pipeline)" as part of its proposal at 40 C.F.R. section 60.5509(b)(8). This exemption is well founded and warranted, especially for EEI members that cannot be connected to a natural gas system, like those in isolated or island locations. EPA should retain and finalize this provision.

would be labor intensive for unit owners/operators and the state air quality regulators who would be required to make such assessments. It also would provide little operating certainty. Accordingly, EPA should take the approach that applicability determinations are final once made or, at minimum, should leave such determination up to the discretion of the state regulator.

VII. Conclusion.

EEI Looks forward to working with EPA to finalize a defensible and implementable set of section 111 rulemakings. The Proposed 111 Rules are an important piece of the regulatory framework that can either support or hinder the power sector's continuing clean energy transformation. EPA must ensure that the Proposed 111 Rules work on their own, work with each other, work with the rest of EPA's holistic approach to regulation, and—critically—work within the entire regulatory, legislative and economic context within which the power sector operates at the federal and state levels. EEI appreciates the engagement with EPA staff regarding this rulemaking. Questions on these comments may be directed to Alex Bond (202-508-5523).

December 20, 2023

The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave, N.W.
Washington, DC 20460

Re: EPA's Supplemental Proposal on Clean Air Act Section 111 Rules for Power Plants. Docket No. EPA-HQ-OAR-2023-0072.

Dear Administrator Regan:

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) supplemental notice of proposed rulemaking (Supplemental Notice) for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (Proposed 111 Rules). 88 *Fed. Reg.* 80,682 (Nov. 20, 2023). Notably, the Agency is seeking comment on "whether to include mechanisms to address potential reliability issues" with respect to EPA's Proposed 111 Rules. *Id*. Reliability mechanisms should be included in the Final 111 Rules. These should provide paths to compliance with GHG emissions limitations for units whose operations may be essential for the reliability of the energy grid. EEI's comments outline such paths.

EEI members are united in their commitment to get the energy they provide as clean as they can as fast as they can, while keeping reliability and affordability front and center, as always, for the customers and communities they serve. Across the nation, EEI members are leading a clean energy transformation, making significant progress to reduce GHG emissions, while also creating good-paying jobs and an equitable clean energy future.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the agency's full suite of climate and environmental regulations for power plants. Please contact Alex Bond at abond@eei.org (202-508-5523) with any questions.

Sincerely,

Emily Sanford Fisher
Executive Vice President, Clean Energy
General Counsel & Corporate Secretary

COMMENTS FROM THE EDISON ELECTRIC INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S SUPPLEMENTAL NOTICE OF PROPOSED RULEMAKING ON NEW SOURCE PERFORMANCE STANDARDS FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS; EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING FOSSIL-FUEL FIRED ELECTRIC GENERATING UNITS; AND REPEAL OF THE AFFORDABLE CLEAN ENERGY RULE

Docket No. EPA-HQ-OAR-2023-0072

December 20, 2023

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) supplemental notice of proposed rulemaking (Supplemental Notice) for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (Proposed 111 Rules). 88 *Fed. Reg.* 80,682 (Nov. 20, 2023).[1] EPA's Supplemental Notice requests comment on an Initial Regulatory Flexibility Analysis following the completion of a Small Business Advocacy Review. Notably, the Agency is seeking comment on "whether to include mechanisms to address potential reliability issues" with respect to EPA's Proposed 111 Rules. *Id*.

[1] EEI filed extensive comments on to the Proposed 111 Rules in this Docket on August 8, 2023, in response to the proposal that was noticed in the *Federal Register* on May 23, 2023. *See* 88 *Fed. Reg*. 33,240. These comments in response to the Supplemental Notice should be read in conjunction with those comments.

EEI is the association that represents all U.S. investor-owned electric companies. EEI's member companies provide electricity for nearly 250 million Americans and operate in all 50 states and the District of Columbia. The electric power industry supports more than seven million jobs in communities across the United States. EEI's member companies invest more than $140 billion each year, on average, to make the energy grid smarter, cleaner, more dynamic, more flexible, and more secure; to diversify the nation's energy mix; and to integrate new technologies that benefit both customers and the environment.

I. Introduction and Executive Summary.

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This clean energy transition already has resulted in significant GHG emissions reductions, as EPA has recognized, and more than 40 percent of our nation's electricity now comes from clean, carbon-free sources. EEI's member companies are committed to getting the energy they provide as clean as they can as fast as they can, while keeping customer reliability and affordability front and center.

Across the industry, electric companies are investing in a broad range of carbon-free technologies and approaches, with the goal of demonstrating these technologies so that they can help further reduce power sector emissions when they satisfy industry performance requirements and are affordable for customers. Electric companies and EPA agree on the long-term clean energy vision for the sector that is embodied in the Proposed 111 Rules: electric companies have reduced and will continue to reduce GHG emissions and will use emerging technologies to reduce emissions from new and existing fossil-based generation.

Grid reliability is and will continue to be a top priority for EEI's member companies and their customers. The last few years have seen extreme summer and winter conditions that have challenged the reliability of the grid, raising concerns about the retirement of dispatchable, 24/7 generation, the speed with which new generating resources can be interconnected, the need to expand the capacity of the grid, the clean energy and energy infrastructure supply chain, and increased demand for electricity as a result of economic growth, domestic manufacturing, and electrification. Regardless of any final EPA regulations addressing GHG emissions from the new and existing fossil generating fleet, the clean energy transition is not going to be easy.

Challenges do not mean that this transition is impossible or that our larger goals for a resilient, equitable, affordable clean energy future should change. What these challenges do mean, however, is that we will need to work with and across a myriad of stakeholders to solve them, be prepared for progress to be bumpy on occasion, and be willing to be flexible. The investor-owned electric companies are committed to working with EPA, state regulators, the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), customers, environmental groups, and others to make the clean energy transition successful.

EPA need not address every potential reliability challenge associated with the clean energy transition via a mechanism included in the Final 111 Rules. Reliability tools and mechanisms should be included in the Final 111 Rules and should be focused on the particular challenges that arise from the structure of those Rules. In its simplest form, this means that EPA should provide paths to compliance with GHG emissions limitations for units whose operations may be essential for the reliability of the energy grid. To accomplish this, EPA may need to provide more flexibility to amend state compliance plans to allow units to change compliance pathways more easily and efficiently. EPA also may need to create a process whereby grid reliability experts can provide input to EPA about potential challenges, in support of requests for compliance flexibility for reliability-critical units. However, potential reliability-related challenges unrelated to the structure of the Proposed 111 Rules can and should be addressed by other stakeholders and those charged with maintaining reliability.

As discussed in these comments in more detail, EPA also should finalize reliability tools and mechanism in conjunction with expanded compliance flexibilities for states and units that can help obviate the need to deploy reliability-specific mechanisms while supporting the ability of units to comply with EPA's final guidelines.

These comments also update EEI's August 2023 comments to note developments regarding the deployment of carbon capture and storage (CCS) and hydrogen technologies, and request that EPA seek additional data regarding the operations of the existing natural gas-based turbines to inform the development and finalization of standards for those units.

II. EEI's Member Companies Continue To Lead The Clean Energy Transition

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This transformation is being driven by a wide range of factors, including relatively lower prices for natural gas, particularly as compared to historic high prices; increased deployment of renewable energy resources, energy efficiency measures, and demand-side management; technological improvements; changing customer, investor, and owner expectations; federal and state regulations and policies; legislation, including the Infrastructure Investment and Jobs Act[2] (IIJA) and Inflation Reduction Act of 2022[3] (IRA); and the increasing use of distributed energy resources. Across the industry, electric companies are investing in a broad range of affordable, carbon-free technologies and approaches with the goal of finding the most cost-effective ways to deliver resilient clean energy.

The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly clean.[4] In 2022, for the first time, renewable energy sources[5] surpassed coal as a generation resource: 22.6 percent of total generation at utility-scale facilities in the United States came from renewable sources compared to 19 percent from coal-based generation.[6] In total, more than 40 percent of America's electricity came from clean carbon-free resources in 2022, including nuclear energy, hydropower, solar, and wind,[7] putting

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[2] Pub. L. No. 117-58.

[3] Pub. L. No. 117-169.

[4] *See* U.S. Energy Information Administration (EIA), Today in Energy: Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022 (Mar. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55960&src=email; *See also* EIA, Electric Power Monthly: Data for February 2023—Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2013-February 2023 (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01.xlsx; *and* EIA, Electric Power Monthly: Data for February 2023—Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors) (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01_a.xlsx.

[5] Renewables here include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, hydroelectric conventional, solar thermal, photovoltaic energy, solar, and wind. *See* EIA, Electric Power Monthly, Table 1.1, *supra*, n.3.

[6] *See id*.

[7] *See id.*

clean resources at parity with natural gas generation, which provided approximately 40 percent of the country's total electricity generation in 2022.

As part of the move toward resilient clean energy, electric companies are deploying more energy storage, which is a key asset that helps integrate increasing amounts of renewables into the energy grid while also enhancing resilience and reliability. Electric companies are the largest users and operators of the approximately 32 gigawatts (GW) of operational storage in the country—representing 93 percent of active energy storage projects.[8]

Going forward, renewable and clean energy technology deployments will continue. EIA predicts that declining capital costs for solar panels, wind turbines, and battery storage, along with government support such as that provided through the IRA, will make these technologies increasingly cost-effective compared to the alternatives when building new power generating capacity.[9] EIA projects that renewable generation in the United States will more than triple by 2050, with both wind and solar responsible for most of the growth.[10]

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[8] Compiled from the following proprietary sources: Wood Mackenzie Power & Renewables/American Clean Power Association, *U.S. Energy Storage Monitor* (2022); Dep't of Energy, *Energy Storage Database* (2022); Hitachi Energy, *The Velocity Suite Database* (2022).

[9] *See* EIA, Annual Energy Outlook 2023 (AEO 2023) 9 (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.

[10] *See* AEO 2023—Table 16. Renewable Energy Generating Capacity and Generation: Electric Power Sector: Generation: Total (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=16-AEO2023&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.25-16-AEO2023~&ctype=linechart&sid=ref2023-d020623a.25-16-AEO2023~ref2023-d020623a.64-16-AEO2023&sourcekey=0.

The changes in the mix of resources used to generate electricity have profoundly decreased the sector's carbon dioxide (CO_2) emissions, the primary GHG emissions associated with electricity production. EIA's preliminary full-year estimates for 2022 find that electric power sector CO_2 emissions were 36 percent below 2005 levels, as low as they were almost 40 years ago.[11] These reductions will continue.[12] Further, 50 EEI member companies have announced voluntary, forward-looking carbon reductions goals, 41 of which include a net-zero by 2050 or earlier equivalent goal, and member companies routinely increase the ambition or speed of their goals or altogether transform them into net-zero goals to reflect changing expectations about the cost and availability of renewable generation and other clean energy resources.

In addition, the electric power industry has significantly reduced emissions of traditional air pollutants, such as mercury, HAPs, sulfur dioxide (SO_2), and nitrogen oxides (NOx). As of 2022, SO_2 and NOx emissions have declined 95 and 88 percent, respectively, since 1990.[13] In addition, mercury emissions have declined by 95 percent since 2010,[14] and total HAPs—including all acid gas emissions—declined by 96 percent between 2010 to 2017.[15] EEI's member companies see a clear path to continued emissions reductions over the next decade using current technologies,

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[11] *See* EIA, Monthly Energy Review, Environment, Table 11.6—Electric Power Sector (Mar. 2023), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

[12] *See* AEO 2023 at 4.

[13] *See* EPA, Power Plant Emissions Trends (Feb. 2023), https://www.epa.gov/power-sector/power-plant-emission-trends.

[14] *See* EPA, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, page 2-7 (Dec. 2011), https://www.epa.gov/sites/default/files/2015-11/documents/matsriafinal.pdf.

[15] *See* 84 *Fed. Reg.* 2,670, 2,689 (Feb. 7, 2019).

including nuclear energy, natural gas-based generation, energy demand efficiency, energy storage, and deployment of new renewable energy—especially wind and solar[16]—as older coal-based and less-efficient natural gas-based generating units retire.[17] These technologies will continue to enable significant, cost-effective carbon reductions.

In the long term, reaching net-zero carbon emissions also will require the deployment of next-generation, carbon-free, 24/7, dispatchable technologies not currently available commercially. Supported by the clean energy tax incentives included in the IRA and the grant funding available via the IIJA, electric companies are partnering with technology developers, academic institutions, investors, philanthropists, each other, and other stakeholders to develop, demonstrate, and deploy these new clean energy technologies. These include long-duration energy storage, CCS, advanced nuclear and renewable generation, and clean fuels (like hydrogen, renewable natural gas, and ammonia). Developing and deploying a broad range of advanced clean energy technologies will further expedite the transition of the electric power sector to one that is low- or non-emitting while keeping electricity affordable and reliable for customers.

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[16] Once built and when the resource is available, wind and solar are the least cost resources to operate to meet electricity demand because they have zero fuel costs. Over time, the combined investment and operating cost advantage increases the share of zero-carbon electricity generation. *See* AEO 2023 at 5.

[17] EIA notes that coal-based generation capacity will decline sharply by 2030 to about 50 percent of current levels (from about 200 GW to 100 GW) with a more gradual decline thereafter. *See* AEO 2023 at 13.

III. EPA Should Include Both Reliability-Specific Mechanisms And Additional Compliance Flexibilities In The Final Rules.

In the Supplemental Notice, EPA solicits comment on whether it should include "a specific mechanism or mechanisms to address grid reliability needs that may arise" as final CAA section 111 rules are implemented. *See* 88 *Fed. Reg.* at 80,684. Specifically, EPA seeks comment on:

- Tools and mechanisms already available to balancing authorities, RTOs, ISOs, and other reliability authorities to address reliability challenges;
- Circumstances and conditions that should be accounted for in a mechanism or mechanisms to address reliability concerns, including (i) concerns driven by events, such as extreme weather, unexpected generator outages, and unanticipated transmission line disruption; and (ii) concerns driven by supply chain or construction delays or disruptions for new generation, transmission lines, or other infrastructure as well as delays in permit issuance for controls required to meet the standards of performance;
- The technical form and structure of such a mechanism or mechanisms, such as an extension of the compliance date or a temporary, alternative standard of performance, and supporting details describing whether such a mechanism or mechanisms should be automated to enable extensions;
- Detailed descriptions of other reliability mechanisms or ways to address commenters' reliability concerns, including phase-in considerations for small entities;
- What information would be ample and appropriate, but not overly burdensome, to substantiate the need for and use of such a mechanism or mechanisms, including any appropriate documentation from balancing authorities, RTOs, or ISOs (the EPA specifically solicits comment on approaches that would minimize potential documentation burden); and,
- Lessons learned from the architecture of any previously proposed or finalized reliability mechanisms and the use of the mechanism in practice.

See id. at 80,684. EPA is correct to focus on specific mechanisms it can include in any final CAA section 111 rules to help address reliability considerations. When including such mechanisms in any final rules, EPA must specifically explain how such solutions fit within the Agency's legal and policy framework.

EPA need not address every potential reliability challenge via a mechanism included in the Final 111 Rules. As a general matter, EPA should take into consideration existing tools and efforts—as well as their benefits and limitations—when crafting a reliability mechanism. These existing tools are discussed, *infra,* in section C. Moreover, EPA's efforts to include reliability mechanisms should be focused on the particular challenges that arise from the structure of the Proposed 111 Rules. Other potential reliability-related challenges unrelated to the Proposed 111 Rules can and should be addressed by other stakeholders and those charged with maintaining reliability.

EPA's task is therefore to ensure that the Final 111 Rules themselves can be implemented without adverse impacts to reliability and do not complicate ongoing solutions as those the Proposed 111 Rules are finalized and states submit plans. This task is complex given that EPA's framework in the Proposed 111 Rules provides both opportunities and challenges from a reliability and compliance perspective—and that is before considering the inherent uncertainties about the various forms that compliance will take in future years. Importantly, EPA's subcategories for coal-based units will provide notable additional certainty for grid planners and others charged with maintaining the reliability of the grid because they will provide concrete information about the expected time horizons for when specific units are going to retire and no longer provide services to the grid. This will allow for future planning to replace those assets in an orderly fashion. However, at the same time, as units are placed into (or opt into, as the case may be) various subcategories, whether individual unit compliance decisions will create reliability challenges for the larger energy grid will become clearer. In that event, a change to the unit's status might be needed to address critical reliability considerations. Accordingly, it is essential that any reliability tools that EPA develops in the Final 111 Rules are flexible enough to address future scenarios about which no one, including the Agency, FERC, the balancing authority, and the unit owner/operator, has sufficient clarity today. These tools, therefore, should be viewed as insurance policies for a changing grid.

In the development of such tools, EPA should be focused on compliance flexibility. The provision of additional compliance flexibility for states and units can help to limit the need for the use of any reliability mechanism, as well as the impact of extreme reliability events, by providing states and units with additional regulatory pathways and tools for compliance—as discussed *infra* in Section B. However, when reliability situations cannot be addressed via these tools, EPA must have a mechanism available to provide units with a pathway to comply with the section 111 rules and also run to meet system reliability obligations. As noted, EEI's members are committed to both reducing emissions and providing reliable and affordable power. Reliability mechanisms to address both acute and non-acute circumstances would provide unit owner/operators the chance to do both while ensuring they remain in compliance with their unit-specific obligations under EPA's 111 framework.

Ultimately, EPA must design a reliability mechanism that can be responsive to reliability considerations while providing a clear path for unit compliance, be adaptive to evolving scenarios, and be targeted to address specific reliability-based considerations that arise due to the section 111 framework and process. Suggestions and considerations for achieving these goals are discussed *infra* in Section A.

A. EPA Should Include a Reliability Mechanism Targeted at Critical Situations That Are Not Acute But Still Must Be Addressed Quicker Than the State Planning Process Contemplates.

EPA should develop and include a mechanism in the Final 111 Rules to allow for environmental compliance during situations when units must run to ensure system reliability, but which may not be acute emergency scenarios that more appropriately would be addressed via orders under Federal Power Act (FPA) section 202(c). Often, these types of scenarios revolve around the potential for resource adequacy shortfalls—e.g., delays in replacement generation or increases in demand over a multi-year basis that was unanticipated that result in a deficiency of resources to cover reliability obligations and necessary reserve margins—or a need for additional energy requirements to replace the energy provided by the retiring asset.[18] In these instances, the reliability challenges might require resources to increase their generation above forecasted levels or to delay a planned retirement until other assets (including transmission assets) are brought into service. These scenarios often are time limited but may extend beyond the 90-day window envisioned by FPA 202(c)—discussed more *infra*—to remedy supply chain constraints, permitting delays, and other roadblocks to deploying replacement or additional generation assets that could enable units to either retire or return to forecasted operational levels consistent environmental compliance obligations. These factors also often are outside the control of the unit owner or operator. Of further note, many of these scenarios are unpredictable by their very nature, and EPA will need to design a tool flexible enough to address a multitude of potential compliance-related scenarios that could arise.

[18] Many of these concerns were raised in the recent Technical Conference held by FERC on November 9, 2023. *See* https://www.ferc.gov/news-events/events/2023-annual-reliability-technical-conference-11092023.

Numerous EEI members have raised concerns about whether the Proposed 111 Rules are sufficiently flexible to address reliability concerns, based on real world examples. One example of this type of situation comes from EEI member Alliant Energy. Alliant announced in June 2022 that it would delay the retirement of its coal-based Edgewater Generating Station and Columbia Energy Center to 2025 and 2026, respectively, from their announced 2022-2023 retirement commitments, partially in response to additional requirements and reliability concerns raised by the Midcontinent Independent System Operator (MISO) regarding a potential energy shortage in the summer of 2023 and partially due to concerns regarding the lead time required to bring on over 1,100 megawatts of new solar generation in Wisconsin. Following the retirement of those assets, Alliant would have retired all of its coal-based assets in Wisconsin by the middle of 2026, consistent with the company's Clean Energy Blueprint.[19] As the company noted in its announcement, shifting the retirement dates for both coal-based units in Wisconsin helps ensure that the grid can weather multiple uncertainties while continuing to add cleaner, renewable energy to the grid in the MISO footprint. Notably the decision to delay the unit retirements consistent with the concerns raised by MISO occurred under a year before the scheduled retirement of the units.

Alliant was able to move these retirement dates to address reliability concerns without the use of FPA 202(c) because their retirement is voluntary, and delay did not implicate violations of any environmental or GHG emissions limits. But, once the Section 111 Rules are finalized, units subject to compliance requirements may not be able to change retirement dates in a timely fashion to respond to the changing needs of the energy grid unless EPA creates mechanisms to

[19] *See* https://www.alliantenergy.com/alliantenergynews/newscenter/23-generationupdate.

allow for revision to state plans in response to such concerns without unreasonable delay. As documented extensively in comments to EPA by states and other entities, the state plan process will take significant time. States not only need to enact needed policy, legislative, and regulatory changes, but they also need to engage in significant public participation and analysis before they can submit a plan to EPA. As currently proposed, a similarly intensive process would be required to alter any plan that has been approved by EPA.

EEI member PacifiCorp has had a similar experience. Two coal-based units at PacifiCorp's Naughton plant in Kemmerer, Wyoming recently shifted from a planned, but voluntary, retirement in 2025 to instead convert to utilizing natural in 2026. This change was based in part on the need to bolster reliability for PacifiCorp's system and the region. Under the Coal Combustion Residuals (CCR) rulemaking, both Naughton units are required to cease burning coal by December 31, 2025. As PacifiCorp evaluated how the planned retirement of the two units would impact reliable, dispatchable energy generation in the area and the region, it determined that converting the two Naughton units to natural gas was necessary and prudent to address considerable reliability challenges. Because the retirement of the two units was voluntary, PacifiCorp was able to shift from retirement to conversion to provide the much-needed, reliable energy generation resources while still meeting its commitment to cease burning coal.

Another example is the New York State Department of Environmental Conservation's (NYSDEC's) Part 227-3, Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple

Cycle and Regenerative Combustion Turbines, commonly known as the "Peaker Rule."[20] That rule, which is part of the EPA-approved state implementation plan (SIP) for New York State, authorizes the New York Independent System Operator (NYISO) to identify a unit as a "reliability source" if the unit is required to temporarily resolve a bulk power system reliability need, or a local transmission owner to do the same for a local reliability need. *See* 6 NYCRR § 227-3.6(a).[21] Once the NYISO or transmission owner has provided the NYSDEC with a unit's designation as a reliability source, that unit can operate outside of the applicable emissions limit until a permanent solution to the reliability need has been placed online or for up to two years. *Id.* at § 227-3.6(b). After this initial period, there can be an extension of the compliance deadline for up to another two years, if the reliability authority concludes that the reliability need still exists, the unit continues to address that need, and a permanent solution is in progress. *Id.* During this period, the unit's other NOx emissions limits (like under the NOx Reasonably Available Control Technology (RACT) program) continue to apply. Similar to Alliant's situation, NYISO or transmission owner can use the Peaker Rule's mechanisms to address their reliability concerns today, since they are not subject to an existing state plan under CAA section 111.

Other EEI members face a variety of other related reliability challenges, including but not limited to concerns regarding the amount of hydropower resources available to meet peak load; localized grid challenges due to load constraints and other geographic limitations; cross-border transmission and resource integration limitations and complications; lack of supportive infrastructure; and interconnection delays for new resources. These are all factors that can impact

[20] https://www.nyiso.com/documents/20142/39103148/NYC-Reliability-Solution-Fact-Sheet.pdf/169f336c-730f-6bd3-67c2-22037fcee56f?t=1700503745709.

[21] For incorporation into the New York State SIP, *see* 86 *Fed. Reg.* 43,956.

compliance for fossil-based units and necessitate alteration of the reduction pathways that may be included in state plans.

Further, the potential for delays is not limited exclusively to EGUs and retirement dates. Distribution transformers, which convert power to a useable voltage for use in homes and businesses, have become a bottleneck. Ongoing supply chain challenges and unprecedented demand for grid components has led to significant supply constraints on distribution transformers. Prior to the COVID-19 pandemic, lead time for distribution transformers—the time it takes to order and receive a new component—was less than one year on average. Today, due to complexities and inefficiencies in the supply chain, lead times exceed two years and are growing. Record demand for these products, the lack of available skilled labor to produce them, and challenges acquiring various components and materials which go in them are causing real-world problems: new building and housing construction projects have been stalled and utilities are unable to modernize the grid and help communities recover quickly from disasters. Further, lack of distribution transformers can delay necessary grid upgrades to incorporate additional clean energy in an efficient, effective, and timely manner. These challenges also may require revision to state plan approaches and deadlines.

But, it is not currently clear that such revisions to state plans will be possible or, if possible, sufficiently expedient. Concerns about the timing of state plan revisions are bolstered by the Agency's experience in the SIP process, as states often submit new SIPs and update existing SIPs to address the National Ambient Air Quality Standards (NAAQS). This process often takes several years, while states undertake their own administrative processes to update their plans, and because EPA must undergo its own complex process to approve updates to state plans. These processes require significant resource commitment and time before plans are approved and enforceable so that affected entities can move forward with implementation.[22]

In the context of EPA's section 111 rules for the power sector, the time constraints inherent to the state plan process, therefore, can present a significant barrier to addressing reliability events within the context of EPA's proposed framework in a way that gives owner/operators of generation, grid operators, states, and regulators confidence that these scenarios can be effectively addressed. This is especially relevant given that—as described above—there exist scenarios that present reliability-based challenges that likely will have to be addressed outside the FPA 202(c) context but need to be addressed faster than the state plan revision process can capture given the time-consuming nature of that process.

To some extent, because these reliability issues largely will turn on the operation of existing units, EPA's focus in creating a reliability mechanism should be a focus on creating a workable and efficient state plan revision process. In the Alliant example, the relevant units likely would have needed to move from one retirement subcategory into a later subcategory. Their ultimate path to compliance—closure—would remain unchanged, but the exact timing of that closure would need to be updated in the state plan. And, consistent with reliability needs, moving between existing closure subcategories should not require extensive process. If a unit is moving between already-defined retirement subcategories and the owner/operator accepts the full

[22] As discussed *infra*, states can also include mechanisms in their own state plans absent a presumptively approved approach from EPA allowing units to shift between subcategories.

requirements of those subcategories, which can include, for example, capacity factor limitations or standards that reflect co-firing obligations, then the state plan should be able to be updated via notice to EPA and EPA should make clear that it will approve such updates without additional analysis or documentation requirements.[23]

As EPA examines how to make the state plan revision process more responsive these kinds of compliance changes, EPA should ensure that both unit owner/operators and states can initiate the revision process. As discussed *infra* in Section B, a key element of this approach will be to eliminate or suspend the proposed increments of progress requirements to allow for units to shift between subcategories more seamlessly and allow for continued operations to address reliability concerns as they arise.

Once EPA creates a plan revision mechanism that is streamlined and consistent with possible changing reliability needs, EPA will need a process to help the states and the Agency understand the potential reliability challenge that could warrant a change to state plans beyond simply moving between retirement subcategories and how best to address those concerns while also seeking to minimize emissions.[24] For example, these would be situations in which an existing

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[23] If a unit could have opted into a later retirement subcategory at the time that the state plans were first developed, there should be no limitation on its ability to shift into that category in the future should circumstances warrant. Without such flexibility, all units rationally would choose the latest retirement subcategory to preserve operational flexibility. To incent retirements as early as practicable, EPA should allow changes between the defined subcategories without limitation. As discussed later, this will require EPA to eliminate or suspend the proposed increments of progress requirements. As discussed *supra* and *infra*, states can also enable this type of flexibility under their own authority under CAA section 111.

[24] As EPA establishes a reliability mechanism in the Final 111 Rules, EEI and its members are committed to working with states and the Agency to continue to resolve and address these issues;

natural gas-based turbine needs to exceed capacity factor limitations for some period of time, or a unit slated for closure needs to extend its retirement deadline beyond that provided by the latest retirement subcategory. Again, the goal is to provide units options to avoid having to operate such that they violate GHG emissions limits. EPA is not charged with solving the reliability challenge, but with providing a pathway to avoid compliance penalties for units that are needed to provide reliable power to customers.[25]

Here, EPA can build upon previous efforts to provide compliance pathways to units that need to operate beyond compliance deadlines. In the Mercury and Air Toxics (MATS) rulemaking under CAA section 112, EPA designed a reliability-specific process by which it would exercise enforcement discretion and provide a fifth year to units for compliance when reliability warranted such an extension of the compliance timeline.[26] There are valuable elements to the

EPA should also make proactive efforts to continue this type of essential stakeholder outreach once it finalizes the rules.

[25] These proposed reliability approaches do not directly address the compliance challenges that could arise if new or existing units are attempting to deploy either CCS or hydrogen blending to comply but are not able to do so on EPA's proposed timelines because the necessary infrastructure is delayed, access to necessary inputs is constrained, or the technology is not performing consistently at compliance-levels. EPA will need to design processes to address these compliance challenges as well, even if they are not explicitly reliability related. In the final rules, EPA should address how it will exercise enforcement discretion or otherwise modify requirements, particularly for new units that are directly regulated by EPA, to address these kinds of compliance challenges.

[26] The 2011 Office of Enforcement and Compliance Assurance memo outlining this process is attached as Appendix A. The CAA section 112 context is different from the CAA section 111 context in ways that are relevant but should not prevent EPA from looking to the framework MATS compliance provides, since section 111 does not bind EPA to a statutorily mandated compliance timeline. Therefore, unit owners and operators need not rely on enforcement discretion to provide compliance timing flexibility to address reliability concerns, which gives EPA additional flexibility to rely on several of the process steps contained in the memo, if not the underlying legal rationale.

MATS approach that EPA should use here, particularly the documentation and administrative process needed to access any reliability mechanism.

Specifically, EPA should consider requiring unit owner/operators, states, or grid operators (RTO/ISOs or Balancing Authorities) to submit the following administrative steps to access any reliability mechanism, which are identified below and should be included in the Final 111 Rules as a presumptively approvable option for state plans:

- Written notice to a planning entity or planning authority—defined as a state air office, balancing authority, public utility commission and EPA Regional Office for regulated states and defined as a state air office, RTO/ISO and EPA Regional Office for states with wholesale power markets—within a reasonable period of time of learning of a potential reliability concern that might require relief under a reliability mechanism due to a variety of factors, including but not limited to lack of timely replacement generation, supply chain considerations outside of the unit operators control, lack of supporting transmission or other required energy infrastructure;

- Documentation, including appropriate supporting analysis or modeling, of the reliability risk if the unit or units were not in operation, which demonstrates that the unit or units are critical to maintaining reliability, that the scenario was not predicted with a high degree of certainty at the time of a final plan submission and that without relief the unit or units would (1) result in the violation of at least one of the reliability criteria required to be filed with FERC, or (2) cause reserves to fall below the required system reserve margin;

- Written concurrence with that analysis by the planning entity or planning authority for the area where the unit or units are located, where practicable;

- Copies of any written comments from third parties directed to, and received by, the unit owner/operator or planning authority in favor of, or opposed to, accessing the reliability mechanism for the unit or units;

- Quarterly updates to the planning entity or planning authority, EPA and all interested parties regarding whether the underlying reliability issue can be resolved through the use of the reliability mechanism, or whether a plan revision may be required; and,

- Consistent with the CAA's RULOF provisions, a proposal for operational limits and/or work practices to minimize or mitigate any emissions to the extent practicable during any operation not in full compliance with the 111 rules, when applicable and not resolved by the reliability mechanism and any available compliance flexibilities.

In adopting this framework for the Final 111 Rules, EPA should also note that it intends to, when appropriate, consult with FERC and/or other entities with relevant reliability expertise as part of any review of the use of such a reliability mechanism.[27]

Regarding potential relief offered under the reliability mechanism, EPA should tailor such relief based on the situation and by the type of unit—coal- or natural gas-based. For example, and as appropriate:

- For coal-based units that are part of a retirement-based subcategory, the reliability mechanism could extend the retirement date of a specific unit or units to address critical reliability needs to the end of the immediately preceding subcategory, or for a period not to extend past a set number of years;

- For coal-based units that are not part of a retirement-based subcategory, an extension of compliance until a unit can be projected to install the necessary control technology, including consideration of potential future capacity factor restrictions for an equivalent number of years on a situationally specific basis if appropriate and potentially to be addressed in a future plan revision;

- For gas-steam units, a one-year grace period to achieve the emissions rate of the higher subcategory, where applicable;

- For natural gas-based turbines, an up-to-three-year lifting or raising of the capacity factor requirements above the finalized threshold that would make any existing source gas rule applicable to those units, including consideration of potential future capacity factor restrictions for an equivalent number of years on a situationally specific basis and potentially to be addressed in a future plan revision;

- For natural gas-based turbines, an extension of an averaging period of up to one or three years, whichever is required, to allow for the unit to average more appropriately and manage reliability-based energy requirements; and,

- For new, base load natural gas-based turbines, an extension of compliance until a unit can be projected to install the necessary control technology, including consideration

[27] The involvement of FERC and/or other entities as part of this process ensures that a unit or units that are participating in any reliability mechanism or specific relief are properly scrutinized and that EPA is consulting with parties that have the appropriate reliability expertise.

of potential future capacity factor restrictions for an equivalent number of years on a situationally specific basis and potentially to be addressed in a future plan revision.

EPA should include a mechanism that has these types of relief available, and it should be included as a presumptively approvable option for states to include in plans. Such an approach would provide unit owner/operators, states and reliability entities with additional confidence that both compliance with EPA's final rule and system reliability can be addressed and maintained.

B. EPA Should Provide a Reliability Mechanism Along with Additional Compliance Flexibilities—Rather Than in Lieu of Those Flexibilities.

As noted in EEI's August 2023 comments, EPA must design final standards for all regulated units that allow for compliance. Key design elements that EPA incorporated into the Proposed 111 Rules—which include the use of subcategories and significant compliance flexibility for states and units—should be finalized consistent with the technical, legal, and policy recommendations set forth in these comments and those filed by EEI in August 2023.

EPA also should consider expanding the proposed design and compliance flexibilities and making other important changes to the proposed standards to support compliance. Final 111 Rules should:

- Set achievable, efficiency-based standards for new natural gas-based units, consistent with EEI's February 2023 recommendation to the Agency that these units be "capable" of future retrofit to install CCS or blend hydrogen when those technologies are demonstrated and available at costs that are affordable for customers;

- Allow states to recognize changes to how existing units will be operated in the future and the emissions benefits of retiring existing units through appropriate subcategories—for both existing coal- and natural gas-based EGUs;

- Affirmatively allow states to adopt mass-based compliance approaches for both new and existing units;

- Provide states with additional flexibility on the timing for state plan development and submittal to EPA, including the streamlining or elimination and suspension of increments of progress that can limit unit operational flexibility;

- Allow states to develop other decarbonization reduction pathways in their state specific plans, taking into account how each state is unique in electricity demand, short-term load growth, long-term load growth and at what pace, and many states have already developed prescribed approaches to address these issues; and,
- Provide units with dual-pathway approaches to state plan compliance, which recognize that planning for new technologies during the short window for state plan development will be challenging, provide a less prescriptive approach to the increments of progress to support these more flexible approaches, and allow for other innovative GGH emissions reduction approaches.

These key program design elements and compliance flexibilities, along with the others discussed in these comments, will enable states and electric companies to implement final standards that are achievable, reliable, and affordable.

Crucially, additional flexibility in compliance will enable units to account more for electric reliability considerations and, in practice, likely limit the need for states and units to utilize the Final 111 Rules' specific reliability mechanisms themselves. EPA should therefore ensure that it finalizes approaches that authorize states to explore additional compliance flexibilities in conjunction with any reliability-specific mechanisms. As a result, EPA must offer both additional flexibilities *and* a reliability specific mechanism to support states and unit owner/operators while providing for reliable electric service and environmental certainty.

C. Some Near-Term and Urgent Reliability Considerations Can Be Addressed by Existing Tools and EPA's Own Proposed Regulations, With Appropriate Modifications.

There are also other tools available to EPA and other Agencies. Some urgent and immediate reliability concerns can be addressed under section 202(c) of the Federal Power Act (FPA). FPA section 202(c) authorizes the Department of Energy (DOE or Department) to "require by order" the "temporary connection of facilities, generation, delivery, interchange, or transmission of electricity" in the event of a war in which the U.S. is engaged or "when an emergency exists by reason of sudden increase in the demand for electric energy, or a shortage of electric energy, or of facilities for the generation or transmission of electric energy…or other causes." 16 U.S.C § 824a(c)(1).[28] In general, an order pursuant to FPA 202(c) can be issued by the Secretary for up to 90 days. Under the FAST Act amendments, the Secretary need not consult with EPA before issuing this first order. However, for any subsequent orders (up to two additional 90-day periods are permitted), DOE must consult with EPA or the relevant environmental regulator and include any limitations that regulator deems necessary to minimize violations of environmental standards. *See* 16 U.S.C. § 824a(c)(4). In practice, DOE has responded to initial requests for 202(c) orders expeditiously, often in a matter of days or, in extreme emergency conditions, hours.[29] Given this precedent and the intent of 202(c), this mechanism is clearly understood to apply to acute reliability challenges, and is used during specific, discrete, and urgent to emergent scenarios. This is demonstrated by the limited use of 202(c) orders—less than 20 times over the past 23 years, sometimes with orders addressing follow on and/or related reliability events. Those instances are documented on DOE's website.

[28] This authority was retained by the Secretary of Energy and not transferred to the Federal Power Commission—the precursor to the Federal Energy Regulatory Commission (FERC) — when it was created. In 2015, the FAST Act amended section 202(c) to provide limited relief from environmental liabilities incurred by entities when complying with an order from the Secretary under this section. *See* 16 U.S.C. § 824a(c)(3) and (4). An order under section 202(c) can be issued to any owner or operator of facilities used to generate, transmit, or distribute electricity. This owner or operator can be a public or private entity. *See* 10 C.F.R. § 205.370. The definition of an "emergency" first focuses on an "*unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown of facilities for the generation, transmission or distribution of electric power" and finds that "such events can be the result of weather, act of God, or other *unforeseen* occurrences not reasonable within the power of the affected entity to prevent…" 10 C.F.R § 205.371 (emphasis added).

[29] *See* ERCOT 202(c) order, February 14, 2021.

The benefit of 202(c) orders is that they permit units that are reliability critical to run, even if such operations may conflict with environmental regulations. These orders, therefore, are useful to address grid emergencies, but are definitionally (and appropriately) limited in terms of scope and duration. Nevertheless, 202(c) orders are one tool to address reliability concerns in certain scenarios, and to ensure that units that may need to run to address these concerns are able to do so.

Section 202(c) is not the only available tool to address environmental compliance during urgent and emergent reliability situations. EPA has also proposed to amend the definition of system emergency in 40 C.F.R part 60, subpart TTTT and the proposed 40 CFR part 60, subpart TTTTa as part of the Proposed 111 Rules. That definition includes a provision that electricity sold during hours of operation when a unit is called upon to operate due to a system emergency is not counted when determining whether a unit has surpassed the threshold, denominated in terms of the percentage of electric sales, for membership in certain regulatory subcategories. *See* 88 *Fed. Reg.* at 33,333. In the past, EPA has concluded that such an exclusion was necessary to provide flexibility, to maintain system reliability, and to minimize overall costs to the sector. *See* 80 *Fed. Reg.* 64,612. EPA notes that the local grid operator would determine which EGUs are essential to maintain grid reliability, and it solicits comments on whether to amend the definition of system emergency to clarify how that would be implemented. *See* 88 *Fed. Reg.* at 33,333.

The current regulatory definition of system emergency is any "abnormal system condition" that the RTO/ISO or control area administrator determines requires immediate automatic or manual action to "prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system" and therefore calls for maximum generation resources to operate in the affected area or for the specific affected EGU to operate to avert loss of load. The emissions from units that are called on during these "abnormal system condition" would not count towards the compliance calculation for any individual unit. 88 *Fed. Reg*. 33,333-34.

As noted in EEI's August 2023 comments to the Agency, EPA should include this provision in the final rules and provide additional specificity as to what constitutes an "abnormal system condition." There are existing levels of energy emergency alerts (EEAs) as defined by the North American Electric Reliability Corporation (NERC) that are issued when grid operating conditions require available resources to generate at maximum levels to address system reliability. There are three separate EEA levels—1, 2 and 3—which are arranged in ascending order of emergency and need, with EEA 1 being issued when an area foresees or experiences conditions where all available resources are already committed, up to EEA 3 being issued when an area foresees (or has implemented) firm load obligation interruption. Reliability entities respond to EEA levels with increasing levels of generation requirements and emergency measures, as well.

EPA should consider using *at least* an EEA level 2, which is when an RTO/ISO or local balancing authority requests emergency energy from all resources and has activated its emergency demand response program.[30] During an EEA level 2, consumers are urged to

[30] EPA should also consider whether using EEA level 1 as the trigger for this provision given that these alerts are called by grid operators for functionally the same types of issues as higher alert levels.

conserve energy to help preserve grid reliability, and these events are intended to provide for unit operations that work to avoid serious reliability events. This level precedes alert level 3, which occurs when a grid operator is unable to meet minimum reliability reserve requirements and then rotating power outages begin occurring to preserve grid reliability broadly. All units operating when an emergency alert level 2 is declared are working to prevent the abnormal system condition included in EPA's definition, and EPA should confirm that those emissions should not negatively impact a unit's compliance. EEA level 2 events are usually in response to discreet events—e.g., a cold snap, hurricane, extreme heat, or storm event, or malfunction or other failure—and thus emissions associated with those events are likely to be both a) time limited and b) have the potential to meaningfully impact compliance for the affected units.

Further, since emergency alert levels impact the entire grid, EPA should use this definition for all coal- and natural gas-based units that may be required to run to avoid loss of load or other reliability events; when a grid operator or balancing authority calls on units under an emergency alert level 2, it calls on those units necessary to maintain reliability, regardless of fuel type, location, or other factors; as a result, EPA should ensure that all types of units, not just Subpart TTTT or Subpart TTTTa units, have the ability to access this provision in the regulations. Such an approach would help allow units and system operators additional certainty in responding to any reliability events or issues. EPA should finalize such an approach to help address urgent reliability scenarios within the framework of EPA's proposed 111 rules.

D. EPA Should Ground the Creation of Any Reliability Mechanisms in the Agency's Remaining Useful Life And Other Factors (RULOF) Statutory Authority.

CAA section 111(d)(1)(B) allows the Administrator to take into consideration, "among other factors, the remaining useful life of the existing source to which any standard applies." EPA should note that the utilization of any reliability-specific mechanism would be squarely authorized given the language in section 111(d)(1)(B). Many of the units that could or would take advantage of such a provision would already be part of the subcategories that EPA has already designed to take into account the remaining useful life of sources that are in each subcategory—which is sensible since to be eligible for the imminent-, near- or medium-term subcategory, a unit must have an enforceable shutdown commitment, and would have a standard different from the one applied to long-term units. Further, the RULOF language in the statute exists and states may avail themselves of it regardless of whether a unit is part of an EPA-identified subcategory, and EPA should note that this authority is reserved for the states and also allows state plans to include reliability specific mechanisms independently of any EPA-approved approach. This language squarely authorizes EPA to set an alternative standard for these types of units if needed—and reliability considerations squarely fall in the "other factors" language in section 111(d)(1(B).

This approach would also be consistent with EPA's recently finalized Section 111(d) implementing regulations for state plans, which EPA states are intended to "improve flexibility and efficiency in the submission, review, approval, revision, and implementation of state plans." 88 *Fed. Reg.* 80,480 (Nov. 17, 2023). Importantly, this compliance flexibility also reflects the "core principle of cooperative federalism" embedded in the CAA. *Miss. Comm'n on Envt'l. Quality v. EPA*, 790 F.3d 138, 156 (D.C. Cir. 2015); *Am. Lung Ass'n*, 985 F.3d at 420 (reiterating "the importance of allowing States maneuvering room under the cooperative federalism scheme"). Further, given the D.C. Circuit's decision in *American Lung Association* noting that EPA could offer significant compliance flexibility to states and units and was not required to have sources implement the specific BSER prescribed by EPA, the Agency is well within its statutory authority to offer a reliability-specific provision to states and units in any final rule. 985 F.3d at 942-43, 963.

The Agency should also note that it is relying on the RULOF authority inherent in the statute for this reliability mechanism while also working to finalize an expanded version of the RULOF provisions it put forward in the Proposed 111 Rules, consistent with EEI's August, 2023 comments. This is essential since the RULOF justification for the reliability mechanism would operate once a state has an approved plan, and the RULOF authority is also clearly useful, as EPA noted in its proposal, for states to consider as they work to develop their state plans before submitting them to EPA for approval. EPA should also work to ensure that this mechanism also works in conjunction with the other rulemakings it is finalizing as part of the holistic approach to power sector regulation, consistent with this legal authority to be flexible and the Agency's desire for coordinated decision-making.

IV. EPA Should Also Take Notice of Additional Technical Developments For The Rulemaking Record.

It is imperative that EPA design final standards for all regulated units that allow for compliance, since standards that allow for units to comply also help to address reliability considerations. Several recent developments that have occurred since EEI's August 2023 comments regarding EPA's proposed determinations that CCS and "low-GHG hydrogen" are the best system of emissions reduction are worth the Agency's note. As discussed below, these developments include (1) permitting-related and other delays or cancelations of proposed CO_2 pipeline projects and delay of an important federal program; (2) institution of an EPA Inspector General evaluation into the efficacy of the EPA Class VI well program for injection and storage of carbon dioxide in geologic formation; and (3) DOE's selection of the Regional Clean Hydrogen Hubs.

These developments support the contention in the August 2023 comments that neither technology is adequately demonstrated under the CAA and that EPA's proposed timing fails to account for the significant regulatory and infrastructure developments needed for both CCS and low-GHG hydrogen systems to support achievability throughout the electric sector of standards based on these technologies. In addition, the Energy Futures Initiative Foundation recently released a report analyzing the infrastructure that would be required to support the Proposed 111 Rules, which concludes that the need for major infrastructure deployments in the next decade could limit implementation.[31]

A. Recent Project Cancelations and Delays, Along with Challenges to the Federal Permitting Regime, Highlight Challenges with EPA's Assumptions About the Timing and Availability of Critical CO_2 Infrastructure in Support of the Proposed 111 Standards.

EEI and its members are working to develop, deploy and demonstrate CCS projects, since CCS, although location dependent, remains an essential emerging technology to address emissions throughout the power sector. CO_2 transportation from the point of capture to storage facilities or

[31] Energy Futures Initiative Foundation, *How Much, How Fast? Infrastructure Requirements of EPA's Proposed Clean Power Plant Rules* (Oct. 2023), https://efifoundation.org/foundation-reports/how-much-how-fast-infrastructure-requirements-of-epas-proposed-power-plant-rules/. For example, the report finds that "[w]ith 90% capture rates set by EPA's proposal, there would be 150 MTPA of captured CO_2 in 2035 and roughly 170 MTPA by 2042." *Id.* at 42. Importantly, "[d]eveloping and permitting enough CO_2 pipelines and geologic storage capacity to support EPA's proposal likely requires new policies and regulations that align the capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements. Permitting CCS projects is a highly uncertain process that can take years in ideal conditions [ ]. The CCS value chain covers multiple sectors—each with different regulatory systems with little federal coordination—creating complex permitting needs." *Id.* at 45. Further, "[l]arge amounts of dedicated renewables (115 GW in 2035, 850 GW by 2042) are needed to power electrolyzers (capacities of 37 GW in 2035, 275 GW in 2042) for clean hydrogen production [ ]. To put this into context, there is about 230 GW of wind and solar capacity on the grid today." *Id.* at 50. In addition, "more than 11,000 miles of new hydrogen pipelines (transmission and distribution) and more than 5,000 compressed hydrogen storage sites (50 tons capacity each) will be needed by 2035." *Id.* at 6.

markets for end-use is an integral component of the CCS system that would be needed to support electric sector use of CCS while preserving reliability and affordability. In the Proposed 111 Rules, EPA lists a number of CO_2 pipelines that have been announced, noting that they are "likely to be developed" and have been in the planning stage for several years. *See* 88 *Fed. Reg.* at 33,366. However, as EEI noted in its August comments and as experience since then has proven, "likely to be developed" does not mean "has been, or will be, developed," and does not provide assurances to EGU owners and operators that there will be CO_2 transportation available to ensure compliance with the proposed standards.

In fact, since EEI filed its comments on the Proposed 111 Rules in August of 2023, one of the CO_2 pipelines that EPA cites as support for its arguments has been postponed, another has moved to withdraw its application and plans to refile in 2024, and a third has been cancelled entirely. Together, these three projects—the Midwest Carbon Express CO_2 Pipeline Project, the Mt. Simon Hub, and the Heartland Greenway Project—would have spanned six states, represented approximately 3,650 miles of new dedicated CO_2 pipeline, and accounted for an over 68 percent increase in U.S. CO_2 pipeline infrastructure. *See* 88 *Fed. Reg.* at 33,293-94. These three projects also account for approximately 94 percent of the miles of the planned or announced new CO_2 pipeline that EPA notes in its GHG Mitigation Measures for Steam EGUs Technical Support Document, included in and used to support the Proposed 111 Rules.

Notably, developers of these projects have cited permitting challenges as the rationale for their decisions to delay, withdraw, or cancel. Recent trends underscore that this critical component of a CCS system will continue to face strong opposition from across the political spectrum and from a range of stakeholders.[32] Given these concerns, the availability of necessary infrastructure on the timeline that the Proposed 111 Rules would require remains a concern.[33]

1. The Midwest Carbon Express CO_2 Pipeline Project Has Been Denied Necessary Permits.

The Midwest Carbon Express CO_2 Pipeline Project is an approximately 2,067-mile proposed project that would cross North Dakota, South Dakota, Nebraska, Minnesota, and Iowa. In the Proposed 111 Rules, EPA stated that this project planned a 2024 in-service date. However, based on recent statements, the project has delayed its in-service date until 2026.[34] This project has faced significant permitting challenges. On August 4, 2023, the North Dakota Public Service Commission (NDPSC) denied the project's October 27, 2022, permit application for the

[32] Soraghan, M., *CO_2 pipelines: The new populist Republican target*, EnergyWire (Sept. 21, 2023), https://www.eenews.net/articles/co2-pipelines-the-new-populist-republican-target/ (noting "[p]roject developers have suffered notable losses lately in the Republican states at the core of the carbon capture push," while "[m]uch of the groundwork for the opposition … has been laid by liberal groups. . . [t]hey've been joined by many conservative landowners made wary by past pipeline projects . . . and infuriated that the pipelines will cut across their farms and ranches.").

[33] It is worth noting that release of a DOE funding opportunity announcement (FOA), expected Q4 2023, has been delayed for the Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA) Program: Future Growth Grants under the Infrastructure Investment and Jobs Act (IIJA). U.S. Dep't of Energy, Notice of Intent: Bipartisan Infrastructure Law - Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA) Program: Future Growth Grants (Section 40304) (Aug. 25, 2023), https://www.fedconnect.net/FedConnect/default.aspx?ReturnUrl=%2Ffedconnect%3Fdoc%3DDE-FOA-0003079%26agency%3DDOE&doc=DE-FOA-0003079&agency=DOE. In addition, this $2.1 billion program is intended to support shared infrastructure projects, including pipelines, rail transport, ships and barges, and ground shipping, that connect anthropogenic sources of CO_2 with endpoints for its storage or utilization. DOE has issued a notice of intent indicating that it now anticipates the FOA will be released in Q1 2024.

[34] *See, e.g.*, Tomich, J., *Developer scuttles plans for Midwest CO2 pipeline*, GreenWire (Oct. 20, 2023), https://www.eenews.net/articles/developer-scuttles-plans-for-midwest-co2-pipeline/.

approximately 320 miles of pipeline that would be sited in North Dakota.[35] The project filed a request for rehearing with the NDPSC on September 7, 2023, noting changes to its proposed route to address concerns that intervenors had raised and providing additional studies, clarifications, and information. In response, the NDPSC plans to hold a hearing to allow the project the opportunity to demonstrate that it has cured the deficiencies identified in the August 4 order.

On September 11, 2023, the South Dakota Public Service Commission (SDPSC) denied the project's February 7, 2022, certificate application for the approximately 495 miles of the project that would be sited in that state. On October 13, 2023, the SDPSC closed the Midwest Carbon Express project's docket. The project has noted its intent to refine its proposal and reapply for a permit, though the timing of that reapplication and the duration of the resulting permitting process remain unclear.

With respect to the remaining states, the project's applications for the approximately 28 miles of pipeline that would be sited in Minnesota[36] and for the approximately 687 miles that would be sited in Iowa[37] remain pending as of the date of these supplemental comments. In Nebraska,

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[35] SCS Carbon Transport LLC, *Findings of Fact, Conclusions of Law, and Order*, NDPSC Dkt. No. PU-22-391 (Aug. 4, 2023).

[36] Summit Carbon Solutions, LLC, *Route Permit Application for the Summit Carbon Solutions Otter Tail to Wilkin Project in Wilkin and Otter Tail Counties, Minnesota*, MNPUC Dkt. 22-422 (Sept. 12, 2022).

[37] Summit Carbon Solutions, LLC, *Petition for Hazardous Liquid Pipeline Permit*, IUB Dkt. HLP-2021-0001 (Jan. 28, 2022).

there is no state level agency with primary jurisdiction over CO_2 pipeline permitting—as a result, permitting decisions are left to individual counties. As of its last report, the project has secured easement agreements for more than 50 percent of the pipeline route in Nebraska, though it is unclear what the ultimate outcome for the Nebraska portion of the project will be.

2. The Mt. Simon Hub Has No Clear Path to Obtain Necessary Permits Without Improvements to the Federal Safety Regime for CO_2 Pipelines.

In the Proposed 111 Rules, EPA included the Mt. Simon Hub among the "number of CO_2 pipeline projects in the United States that are likely to be developed to meet growing demand for CO_2 and increased interest in CO_2 utilization and sequestration." GHG Mitigation Measures for Steam EGUs Technical Support Document at 28-29. This 280-mile project would include facilities in Illinois and Iowa. On November 20, 2023, the project announced[38] that it filed to withdraw its certificate application pending before the Illinois Commerce Commission (ICC) for the 166 miles of CO_2 pipeline that would be cited in Illinois, including 33 above ground facilities.[39] This withdrawal followed testimony from ICC staff indicating their intent to recommend that the ICC deny the project's application. The withdrawal and resubmission of its application in Illinois likely will impact the projects anticipated late 2025 in-service date.

Importantly, while an ICC Gas Engineer in the Energy Engineering Program of the Safety & Reliability Division agreed that the project developer is "fit, willing, and able to construct and operate" the project, he further explained that "it is my opinion that the current construction

[38] Press Release, Wolf Carbon Solutions U.S. to Refile Mt. Simon Hub Permit Application in Illinois in Early 2024 (Nov. 20, 2023), https://wolfcarbonsolutions.com/wp-content/uploads/2023/11/WOLF_MediaStatement_11_20_2023.pdf.

[39] Wolf Carbon Solutions US LLC, Application for Certificate Authority, ICC Dkt. No. 23-0475, at 3 (June 16, 2023), https://www.icc.illinois.gov/docket/P2023-0475/documents/339033.

guidelines for CO_2 pipelines do not adequately address public safety and new [Pipeline and Hazardous Materials Safety Administration or] PHMSA regulations may render the proposed route non-compliant."[40] Consequently, regardless of the outcome for the Mt. Simon Hub, CO_2 pipeline projects may continue to face significant regulatory hurdles beyond their control as state regulators with siting authority question the sufficiency of current PHMSA regulations and as PHMSA continues its efforts to update its regulations. On that point, PHMSA announced in 2022 that it would initiate a rulemaking to update its CO_2 pipeline safety regulations. PHMSA plans to publish a Notice of Proposed Rulemaking in June 2024, but has not set a date for a final rule.[41] The delay in this rulemaking likely will have a continuing impact on the timeline for the permitting and construction of CO_2 pipelines.

3. The Heartland Greenway Project Has Been Canceled.

The Proposed 111 Rules also cite the Heartland Greenway pipeline project, an approximately 1,300-mile CO_2 pipeline that would have spanned South Dakota, Nebraska, Minnesota, Iowa, and Illinois and carried carbon dioxide emissions from more than 20 industrial plants. Earlier this year, the SDPSC denied the project's certificate application and the project faced significant opposition and challenges before the Iowa Utilities Board as well. On October 20, 2023, the company issued a press release explaining that "[g]iven the unpredictable nature of the

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[40] Direct Testimony of Brett Seagle, ICC Dkt. No. 23-0475, lines 292-94 (Oct. 24, 2023), https://www.icc.illinois.gov/docket/P2023-0475/documents/343441.

[41] *See* Congressional Research Service, Insight: Carbon Dioxide (CO_2) Pipeline Development: Federal Initiatives, IN12169 (Jan. 2, 2023), https://crsreports.congress.gov/product/pdf/IN/IN12169#:~:text=In%20response%20to%20these%20criticisms,date%20for%20a%20final%20rule.

regulatory and government processes involved, particularly in South Dakota and Iowa, the Company has decided to cancel its pipeline project."[42]

As noted, these three projects represent a significant portion of proposed CO_2 pipeline infrastructure. Their delay and cancellation, respectively, as a result of permitting challenges cast further doubt on the timing and extent of the CO_2 pipeline infrastructure that is a necessary component of the CCS system used as BSER in the Proposed 111 Rules. In addition, these examples demonstrate that EPA's assumptions about the timing of the development and deployment of CO_2 infrastructure are not grounded in the record or the experience of actual pipeline projects. At minimum, EPA has significantly underestimated the siting and permitting challenges that these projects have and will face.

B. EPA's Inspector General is Evaluating the Class VI Well Permitting Process; It is Not Clear How This Will Impact Permitting for CO_2 Storage.

On November 15, 2023, EPA's Office of the Inspector General sent a letter to EPA's Office of Water explaining that it plans to evaluate the Agency's Underground Injection Control Class VI Well Program for CO_2 injection.[43] The objective is to "determine whether the EPA has used available resources, including funding appropriated by the Infrastructure Investment and Jobs Act, to improve permitting of Class VI wells under its Underground Injection Control Program . . . [and] to identify how the EPA either has used or plans to use $5 million in annual Infrastructure

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[42] Press Release, Navigator CO_2, Heartland Greenway Project Update (Oct. 20, 2023), https://navigatorco2.com/press-releases/heartland-greenway-project-update.

[43] U.S. Envt'l Protection Agency, Letter from EPA Inspector General to EPA Office of Water (Nov. 15, 2023), https://www.epaoig.gov/sites/default/files/document/2023-11/notification_memo_uic_class_vi.pdf.

Investment and Jobs Act funding from fiscal year 2022 through 2026 to improve Class VI well permitting." Anticipated benefits of this evaluation include "increased assurance that the EPA is making effective use of available resources to . . . efficiently manage the influx of permit applications."

While efforts to enhance the efficiency of the Class VI well permitting program are positive and should be pushed forward, it is unclear what the outcome of the Inspector General's evaluation will be and whether there will be impacts on pending Class VI applications that would delay CCS projects.

C. Significant Additional Hydrogen Pipeline Infrastructure Will be Needed to Connect the Regional Clean Hydrogen Hubs and Enable the "Low-GHG" Hydrogen Economy Necessary to Support Achievability Throughout the Electric Sector.

EPA's interest in hydrogen as a technology to reduce power sector emissions is well-founded and is shared by EEI's member companies. EEI and its members are working to make clean hydrogen commercially available at scale. We are engaged in pilot and demonstration projects across the clean hydrogen value chain, including participating in approximately half of the Regional Clean Hydrogen Hub (H2Hubs) proposals that DOE encouraged to submit full applications and being part of each of the seven H2Hubs that were selected for award on October 13, 2023; we are working with agencies and the National Laboratories to help advance clean hydrogen technology, delivery, and safety; and we are designing the power generation facilities of the future to be hydrogen capable.

However, electric companies also recognize that the U.S. is in the nascent stages of development of the clean hydrogen fuel that will be necessary to support hydrogen blending across the economy and throughout the U.S. power sector in a manner that preserves reliability and affordability. Not only is hydrogen blending in the power sector not adequately demonstrated at present, but to progress from the current hydrogen market at the necessary scale to support reliable hydrogen blending in the power sector, a number of barriers must be overcome. Midstream infrastructure buildout is among these.

In the Proposed 111 Rules, EPA cited the H2Hubs as support for its reliance on low-GHG hydrogen. *See, e.g.,* 88 *Fed. Reg.* at 33,309 ("Given the growth in the hydrogen sector and Federal funding for the H2Hubs, which will explicitly explore and incentivize hydrogen distribution, the EPA therefore believes that hydrogen distribution and storage infrastructure will not present a barrier to access for new combustion turbines opting to co-fire with 30 percent low-GHG hydrogen by volume in 2032 and to co-fire with 96 percent low-GHG hydrogen by volume in 2038."). At least three of the H2Hubs that received awards on October 13, 2023, are in states with limited existing natural gas pipeline infrastructure. Therefore, regardless of whether existing natural gas pipelines can be retrofitted to carry hydrogen, these H2Hubs will require significant pipeline buildout to support a hydrogen system that would enable achievability throughout the electric sector. In addition, the H2Hubs that were selected are in states that are mainly along the borders of the United States. As a result, while the H2Hubs program may promote development of pipeline infrastructure to transport hydrogen, additional development beyond the H2Hubs program will be needed to support midstream infrastructure buildout across the center of the United States, much of the southeast, and the Northeast.

The H2Hubs program has significant potential to catalyze the development of a U.S. clean hydrogen economy, and DOE's efforts on H2Hubs are necessary first steps. However, barriers to hydrogen development remain and raise questions about the timing and scope of the hydrogen system that will be necessary to support achievability *throughout* the electric sector, which EPA should take note of as it works to finalize the Proposed 111 Rules.

V. EPA Should Conduct An Information Collection Request (ICR) For The Existing Natural Gas Turbine Fleet.

As EEI described in it's August 2023 comments, the existing natural gas-based turbine fleet is diverse, from a size, technology, efficiency, emissions, and operations perspective, which makes developing a working regulatory scheme to address these units under CAA section 111(d) challenging. EPA's approach to regulating existing natural gas-based turbines—covering those combined cycle units that have a nameplate capacity equal to or greater than 300 MW and operate at a capacity factor of greater than 50 percent—would benefit from additional analysis and data to support reasoned decision making. One issue that EPA should affirmatively address is the significant role that existing natural gas-based turbine generation plays in overall system reliability and the technical and practical challenges associated with retrofitting existing natural gas-based units.

As the fleet continues to transition, dispatchable resources like natural gas-based turbines will continue to play a critical and evolving role in integrating increasing amounts of renewable generation and providing essential reliability services to allow for the ongoing retirement of the coal-based generation fleet while preserving customer affordability. Until emissions-free dispatchable resources become available at commercial scale, existing natural gas-fired units need to be retained to support grid reliability. Natural gas-based turbines are significantly more flexible than coal-based units given their ability to ramp quickly, especially as compared to other dispatchable units, including nuclear units and coal-based units—e.g., they are able to come online quickly and provide power to the grid much faster while also being able to ramp down as needed. This fast-ramping ability both minimizes emissions related to start up and shut down and also helps to avoid emissions by supporting the integration of variable renewable generating resources.

Some units may operate at significant capacity factors—greater than 80 percent—for long periods of time to respond to system considerations, such as when a coal-based unit is retired and other resources might not be fully online, resulting in highly efficient generation from an emissions rate perspective.[44] Other units might instead respond to intermittent system needs, operating at capacity factors of less than 15 percent while still providing essential reliability services and helping to reduce overall system emissions. Further complicating matters, units that operate at high or low (or even in between) capacity factors for long stretches are not guaranteed to remain in that mode while demand for their energy and other services changes continuously in response to system needs. Units are obligated to respond when called upon based on these system needs, which will change further in coming years as the generation mix of the grid continues to evolve.

[44] In general, the emissions rate of an individual unit is more efficient (resultingly, lower) when it run at higher capacity factors. Units that operate at lower capacity factors have concomitantly higher, less efficient emissions rates despite having fewer mass emissions of CO_2.

Many of these units likely will be required to operate differently in response to the changing grid mix and the resulting changes in system needs.[45] These changes will have a significant impact on the emissions and emissions rates associated with these units. This includes the potential for: units switching between operational modes (e.g., simple v. combined cycle) to respond to voltage demands; units in specific locations running more or less often to respond to generation intermittency, transmission congestion or new transmission coming online changing the dynamics of the operating grid; and the aging of the existing gas turbine fleet, which will continue as the fleet transition continues. Each of these scenarios will result in a significant impact on the efficiency rates and the CO_2 profile of existing gas-based turbines and the associated efficiency rates for those units. Consequently, the sheer diversity of the types of units and the range of possible operating characteristics of the existing turbine fleet makes determining an implementable BSER for these units extremely difficult.

EPA should address these salient issues in its analysis of the feasibility of the proposed standards, which would be effective far into the future. As noted in EEI's August 2023 comments, the Agency should re-propose or significantly supplement its proposal for existing natural gas to develop additional flexibilities that can help reduce emissions from the existing natural gas fleet while integrating additional renewables on to the grid in a reliable and affordable way for customers. This also would provide necessary additional record material to underpin EPA's analysis and regulatory approach. One goal of such an action would be to avoid potential unintended consequences of the current proposed approach, which include limiting the

[45] *See, e.g.*, Eric Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Final report (Princeton University, Oct. 2021), https://netzeroamerica.princeton.edu/the-report.

operations of the most efficient units in the existing fleet, particularly during peak demand and extreme events, without significant reductions in emissions.

Fundamentally, one of the issues that EPA and the regulated sector will need to solve to help craft workable standards for existing natural gas-based turbines is to better understand how those units are likely to operate in the future in order to provide a regulatory scheme that can both reduce emissions and meet system reliability needs as the clean energy transition. In order to do so, EPA should utilize the authority under CAA section 114 to issue an information collection request (ICR) to obtain additional data on both the current and future operation of the existing gas turbine fleet. Issuing an ICR expeditiously would show continued progress between the Agency and stakeholders on this important concern. An ICR would also help EPA bolster its record on the proposed existing gas guidelines. Electric companies would work diligently to respond to such a request on an expedited timeframe to ensure that the Agency had necessary data available to it as it works to address emissions from the existing natural gas-based turbine fleet. EPA should do so.

VI. Conclusion.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the Agency's full suite of climate and environmental regulations for fossil-based power plants. We look forward to engaging with EPA and stakeholders on these issues as the Agency works to finalize the Proposed 111 Rules. Please contact Alex Bond at abond@eei.org (202-508-5523) if you have any questions regarding EEI's comments.

APPENDIX A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

December 16, 2011

MEMORANDUM

SUBJECT: **The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard**

FROM: **Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance** Cynthia Giles

TO: **Regional Administrators (EPA Regions I-X)**
Regional Counsel (EPA Regions I-X)
Regional Enforcement Division Directors (EPA Regions I-X)
Air Division Directors (EPA Headquarters and Regions I-X)

I. STATEMENT OF POLICY

It is the EPA's obligation to ensure compliance with environmental laws designed to protect public health and welfare. Where there is a conflict between timely compliance with a particular requirement and electric reliability, the EPA intends to carefully exercise its authorities to ensure compliance with environmental standards while addressing genuine risks to reliability in a manner that protects public health and welfare.

Pursuant to Section 112 of the Clean Air Act ("CAA"), the EPA finalized national emission standards for hazardous air pollutants ("NESHAP") from electric generating units ("EGUs") in December 2011. These standards, commonly known as the "Mercury and Air Toxics Standards" ("MATS"), adopt emission limits on mercury, acid gases and other toxic pollutants for affected coal and oil-fired EGUs. Many existing sources will comply with the MATS by controlling their emissions, while others (typically older, smaller, less efficient units) may choose to cease operations rather than install control technologies.

The EPA believes that all affected sources will be able to comply with the MATS within the compliance period specified by Section 112(i)(3) of the CAA (including, as applicable, any extensions permitted under Section 112(i)(3)(B)) (the "MATS Compliance Date"). The EPA's analysis projects only a modest level of retirements, and the Agency does not anticipate that such retirements will lead to resource constraints that would adversely affect electric reliability.

Nonetheless, the EPA acknowledges that there may be isolated instances in which the deactivation or retirement of a unit or a delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability that cannot be predicted or planned for with specificity at the present time. In such instances, sources could find themselves in the position of either operating in noncompliance with the MATS or halting operations and thereby potentially impacting electric reliability.

The EPA is issuing this policy memorandum to describe its intended approach regarding the use of Section 113(a) administrative orders ("AOs") with respect to sources that must operate in noncompliance with the MATS for up to a year to address a specific and documented reliability concern. This enforcement policy is limited in application to units that are critical for reliability purposes. Some sources will be able obtain a broadly available one-year extension pursuant to Section 112(i)(3)(B). A source that qualifies for a one year extension from its permitting authority may also qualify for an AO at the end of its extension, provided that it falls within the terms of this policy. The EPA believes that there are likely to be few, if any, cases in which it is not possible to mitigate a reliability issue within four years, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under this policy.

This policy does not address situations where a reliability critical unit needs more than one year to come into compliance after the MATS Compliance Date. The policy also does not address delays in installations of controls and/or other instances of noncompliance with the MATS for units that are not reliability critical. The EPA intends to handle such scenarios as it has in the past, by assessing each situation on a case-by-case basis, at the appropriate time, to determine the appropriate enforcement response and resolution.

As set forth below, in light of the complexity of the electric system and the local nature of many reliability issues, the EPA will, for purposes of using its Section 113(a) AO authority in this context, rely for identification and/or analysis of reliability risks upon the advice and counsel of reliability experts, including, but not limited to, the Federal Energy Regulatory Commission ("FERC"), Regional Transmission Operators ("RTOs"), Independent System Operators ("ISOs") and other Planning Authorities as identified herein, the North American Electric Reliability Corporation ("NERC") and affiliated regional entities, and state public service commissions ("PSCs") and public utility commissions ("PUCs"). The EPA will work with these and other organizations, as appropriate, to ensure that any claims of reliability risks are properly characterized and evaluated.

The EPA is committed to achieving compliance with the MATS while ensuring electric reliability.

The policies established in this document supplement other applicable policies, and are intended to assist government personnel in determining the appropriate response to noncompliance. These policies and procedures are not intended to, nor do they, constitute a rulemaking by the EPA. These policies and procedures do not create a right or a benefit, substantive or procedural, that is enforceable at law or in equity by any person. The EPA reserves the right to act at variance with these policies and to change them at any time without public notice. Further, nothing in this document should be construed to affect the EPA's analysis of, or reaction to, an imminent and substantial endangerment to human health.

II. SUMMARY OF LEGAL REQUIREMENTS AND AUTHORITIES

Section 112 of the CAA establishes compliance deadlines for existing sources to meet standards promulgated under that provision, such as those included in the MATS rule.[1] Specifically, Section 112(i)(3)(A) provides:

> After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard.
>
> *See, also* 40 CFR 63.9984.

The CAA and its implementing regulations provide specific conditions under which extensions may be granted to this three year compliance period and under which other compliance time periods may apply. *See, e.g.,* Section 112(i)(3)(B), (4)-(6). In particular, Section 112(i)(3)(B) provides:

> The Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls.

Section 113 of the CAA authorizes the Administrator to bring enforcement actions against sources in violation of CAA requirements, seeking injunctive relief, civil penalties and, in certain circumstances, other appropriate relief. The EPA also has the discretion to agree to negotiated

[1] Except as otherwise provided under Section 112(i)(3)(B), the MATS requires compliance within three years of the effective date, the statutory maximum.

resolutions including, for example, expeditious compliance schedules with enforceable compliance milestones.

III. THE EPA'S ENFORCEMENT RESPONSE TO BRING RELIABILITY-CRITICAL UNITS INTO COMPLIANCE

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly years in advance of the date when a violation may occur. The Agency is doing so now with respect to the MATS to provide confidence with respect to electric reliability. EGUs may be needed to operate to maintain the reliability of the electric grid when they would prefer, or could be required, to halt operations temporarily (until controls can be installed) or indefinitely (through deactivation of a unit). This policy describes the EPA's intended enforcement response in such instances. The policy is informed, as are our enforcement actions in general, by the need to find an appropriate balance between critical public interests, bearing in mind the resources and process time required for any enforcement response.

Some sources may take all steps necessary to comply with the MATS, but may nevertheless be needed to operate in noncompliance with the MATS to address concerns with electric reliability. In the event that such sources are interested in receiving a schedule to come into compliance while operating, the EPA intends, where necessary to avoid a serious risk to electric reliability, and provided the criteria set forth herein are met, to issue an expeditious case-specific AO to bring a source into compliance within one year. *See* Section 113(a). Any such AOs would be issued on or after (not before) the MATS Compliance Date and would be limited to units that are required to run for reliability purposes that (A) would otherwise be deactivated, or (B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay.[2]

The Agency is cognizant that early planning will play a key role in allowing for the identification, and timely mitigation, of any potential reliability issues. The EPA expects that owners/operators will begin compliance planning early, and will provide early notice of their compliance plans to the appropriate reliability entities. We further expect that entities with responsibility for reliability planning and coordination will develop and maintain system-wide reliability plans for the units within their purview, and that this regional reliability planning will provide early identification of units that are critical for reliability purposes. Early notice and planning can discourage delays in coming into compliance, encourage timely action to avoid or mitigate reliability concerns, and minimize the need for issuance of AOs of the type described herein.

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[2] The EPA does not intend to seek civil penalties for violations of the MATS that occur as a result of operation for up to one year in conformity with an AO issued in connection with this policy, unless there are misrepresentations in the materials submitted in a request for an AO.

The EPA also recognizes the need for advance planning with regard to the future availability of any reliability critical EGUs to operate as needed to maintain electric reliability. Accordingly, although an AO cannot be issued under Section 113(a) prior to the MATS Compliance Date, the EPA intends – where the owner/operator has timely submitted a complete request and has provided appropriate cooperation – to give the owner/operator as much advance written notice as practicable of the Agency's plans with regard to such an AO.

To qualify for an AO in connection with this policy, an owner/operator should, at a minimum, take the following steps.[3, 4]

A. Provide early notice of compliance plans. Within one year after the effective date of the MATS, an owner/operator should provide written notice of its compliance plans, with regard to each EGU it owns or operates, that identifies (a) the units it plans to deactivate and the anticipated dates of deactivation and (b) the units for which it intends to install pollution control equipment or otherwise retrofit and the anticipated schedule for completion of that work, to the Planning Authority for the area in which the relevant EGU or EGUs are located.[5]

B. Timely request an AO for a unit that may affect reliability due to deactivation. In addition to the elements identified in III(A) above, for a unit that is required to run for reliability purposes that would otherwise be deactivated:

   1. An owner/operator should, no less than 180 days prior to the MATS Compliance Date, submit electronically to (a) the Director of the Air Enforcement Division in the EPA's Office of Enforcement and Compliance Assurance, and (b) the Regional Administrator of the EPA Region in which the EGU is located, with a copy to FERC, at an office of its designation, (collectively, "AO Request Recipients") a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to each of the elements specified in III(D) below.

   2. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to (a) the Planning Authority, (b) any state PUCs/PSCs with regulatory jurisdiction with

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[3] The EPA will evaluate each request for an AO for a unit that is required to run for reliability purposes on a case-by-case basis.

[4] Any notice, request or other submission discussed in this memorandum should conform to the standard business practice of the receiving entity for the submission of information, including any requirements governing submission of Confidential Business Information and/or other confidential information.

[5] Planning Authority is the entity defined as such in the "Glossary of Terms Used in NERC Reliability Standards," available at: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf, or any successor term thereto approved by FERC, and includes, in relevant jurisdictions, RTOs and ISOs.

regard to the relevant EGU,[6] (c) any state, tribal or local environmental agency with permitting authority under Titles I and V of the CAA, and any tribal environmental agency that does not have such authority, with jurisdiction over the area in which the EGU is located (collectively, "AO Notice Recipients").

C. Timely request an AO for a unit that may affect reliability due to delays related to the installation of controls. In addition to the elements identified in III(A) above, for a unit that that is required to run for reliability purposes that, due to factors beyond the control of the owner/operator, has a delay in installation of controls or needs to operate because another unit has had such a delay:

1. An owner/operator should, within a reasonable time of learning of a delay that it believes may result in a unit being unable to comply by the MATS Compliance Date, provide to the Planning Authority for the area in which the relevant EGU or EGUs are located, written notice of the units impacted by the delay, the cause of the delay, an estimate of the length of time of the delay, and the timeframe during which it contemplates operation in noncompliance with the MATS.

2. An owner/operator should, within a reasonable time of learning that it is critical to reliability to operate a unit described in the preceding paragraph in noncompliance with the MATS after the MATS Compliance Date, submit electronically to the AO Request Recipients a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to as many of the elements specified in III(D) below as it is possible to provide at that time.

3. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to the AO Notice Recipients.

D. Submit a complete request for an AO. The following elements should be included in a request for an AO in connection with this policy:[7]

1. Copies of the early notice provided to the Planning Authority pursuant to III(A) or an explanation of why it was not practicable to have provided such notice and a demonstration that such notice was provided as soon as it was practicable.

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[6] PUCs/PSCs may also wish to obtain the information identified in III(A), either by requesting that an owner/operator over which the PUC/PSC has jurisdiction provide such information directly, or by requesting such information from the relevant Planning Authority.

[7] The EPA may request additional information from the unit owner/operator. The speed with which the EPA evaluates a request and its ultimate response will be related to the timeliness, completeness, and quality of the submittal.

2. Written analysis of the reliability risk if the unit were not in operation, which demonstrates that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability, and that failure to operate the unit would: (a) result in the violation of at least one of the reliability criteria required to be filed with FERC, and, in the case of the Electric Reliability Council of Texas ("ERCOT"), with the Texas PUC,[8] or (b) cause reserves to fall below the required system reserve margin.

3. Written concurrence with the analysis in III(D)(2) by, or a separate and equivalent analysis by, the Planning Authority for the area in which the relevant EGU or EGUs are located, or, in the alternative, a written explanation of why such concurrence or separate and equivalent analysis cannot be provided, and, where practicable, any related system wide analysis by such entity.

4. Copies of any written comments from third parties directed to, and received by, the owner/operator in favor of, or opposed to, operation of the unit after the MATS Compliance Date.

5. A plan to achieve compliance with the MATS no later than one year after the MATS Compliance Date, and, where practicable, a written demonstration of the plan to resolve the underlying reliability problem and the steps and timeframe for implementing it, which demonstrates that such resolution cannot be effected on or before the MATS Compliance Date.

6. An identification of the level of operation of the unit that is required to avoid the documented reliability risk in III(D)(2) and, consistent with that level, a proposal for operational limits and/or work practices to minimize or mitigate any HAP emissions to the extent practicable during any operation not in full compliance with the MATS.

In evaluating a request for an AO submitted in contemplation of this policy, although the EPA's issuance of an AO is not conditioned upon the approval or concurrence of any entity, the EPA intends to consult, as necessary or appropriate on a case-by-case basis, with FERC and/or other entities with relevant reliability expertise.

[8] Because ERCOT oversees intrastate transmission of electricity solely within Texas and does not provide for interstate transmission, ERCOT files reliability criteria with the Texas PUC.

THE BUCKEYE INSTITUTE

Comment on EPA's Proposed Rule for New and Existing Fossil Fuel-Fired Power Plants

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The Buckeye Institute
Caesar Rodney Institute
Frontier Institute
John Locke Foundation
Mackinac Center for Public Policy

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Abbreviation Definitions

BSER – Best System of Emission Reduction
CAA –Clean Air Act
CCS – Carbon Capture and Sequestration
CO2 – Carbon Dioxide
DOE –Department of Energy
EGU – Electricity Generating Unit
EOR –Enhanced Oil RecoveryEPA – United States Environmental Protection AgencyMT – Metric Tonnes
MW – Megawatt
MWe – Megawatt-equivalent
NETL – National Energy Technology Laboratory
SaskPower – Saskatchewan Power Corporation
SCC –Social Cost of Carbon
WAG – Water-Alternating-Gas

Glossary

Capture rate –the rate at which a CCS plant can remove CO2 from treated flue gas. Capture rate does not equate to total emissions from a plant.

CO2-EOR – an Enhanced Oil Recovery method whereby CO2 is injected into a mature well, typically using a WAG process, to recover 30-70 percent of the residual oil stored in an oil formation's small rock cavities.

Enhanced Oil Recovery (EOR) – a series of methods and used to extend the productive life of a mature oil field, typically by injecting gases, such as ethane, nitrogen, and CO2, into a well in a WAG configuration.

Flue gas – the emissions from a coal or natural gas fired EGU.

Treated Flue Gas – the amount of flue gas subjected to treatment by a CCS, rated in MWe.

Introduction

There are many flaws with the Environmental Protection Agency's (EPA) proposed rule for limiting emissions from sources of greenhouse gas. Chief among them is the EPA's recommendation of carbon capture and sequestration (CCS) systems as the best systems of emission reduction (BSER) for coal-fired electricity generating units (EGUs) that intend to operate beyond 2039. In more than two decades, no government funded CCS pilot program or commercial-scale facility has adequately demonstrated the BSER. This means that the EPA's BSER is not viable and therefore cannot be a "best" system of emission reduction. Concerningly, forcing compliance with EPA's BSERs will likely exacerbate an impending energy security and reliability crisis by dissuading utilities from investing in reliable baseload sources of electric power, and pigeon-holing them to adopt intermittent—and consequently unreliable—renewable power sources.

The EPA's proposal to adopt CCS as a BSER, and its standard for states to meet based on CCS, are arbitrary, capricious, and an abuse of discretion. The EPA justifies its standard by providing examples of CCS facilities that do not meet the agency's proposed standard. The sources for the EPA's examples do not demonstrate what the EPA claims. Further, the EPA ignores important aspects of implementing CCS systems.

Despite ample evidence proving CCS has never met the Clean Air Act's (CAA) criteria for "adequate demonstration" of a BSER, the EPA is not offering any other BSER for existing coal-fired-EGUs "other than CCS with 90 percent capture."[1]

The EPA has presented CCS as a burgeoning, cost-effective, and fully functional technology capable of mitigating the majority of all coal-fired power plants' emissions. But no existing CCS plant has managed to achieve the proposed BSER's required 88.4 percent reduction in total carbon dioxide (CO_2) emission via a 90 percent CO_2 capture rate from a full CCS system – which the EPA's BSER would functionally require. And the EPA misreported, misrepresented, and misinterpreted its primary examples of commercial CCS facilities attaining a 90 percent capture rate.[2] Although every plant demonstrated the ability to capture CO_2 from flue gas emissions, every plant failed to achieve the minimum emissions reduction target that the EPA set for the proposed BSER. No CCS facility has demonstrated a consistent ability to sequester 90 percent of total greenhouse gas emissions.

Figure 1 shows the EPA's view—or at least hope—of CCS's current technological capability based on a hypothetical CCS process designs presented in a National Energy Technology Lab (NETL) report.[3] Figure 2 shows the actual capture rate and total emissions mitigation achieved by SaskPower's Boundary Dam Unit 3's CCS facility in 2022. The EPA cites the SaskPower Boundary Dam as the best-case example of current CCS technology. SaskPower's demonstrated capture rate

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[1] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.
[2] *Ibid.*
[3] Tommy Schmitt et al., **Cost and Perforamnce Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.

is far below what the EPA has claimed, and well below the BSER's proposed 88.4 percent emission reduction.

Figure 1: EPA REQUIRED EMISSION REDUCTION PLAN

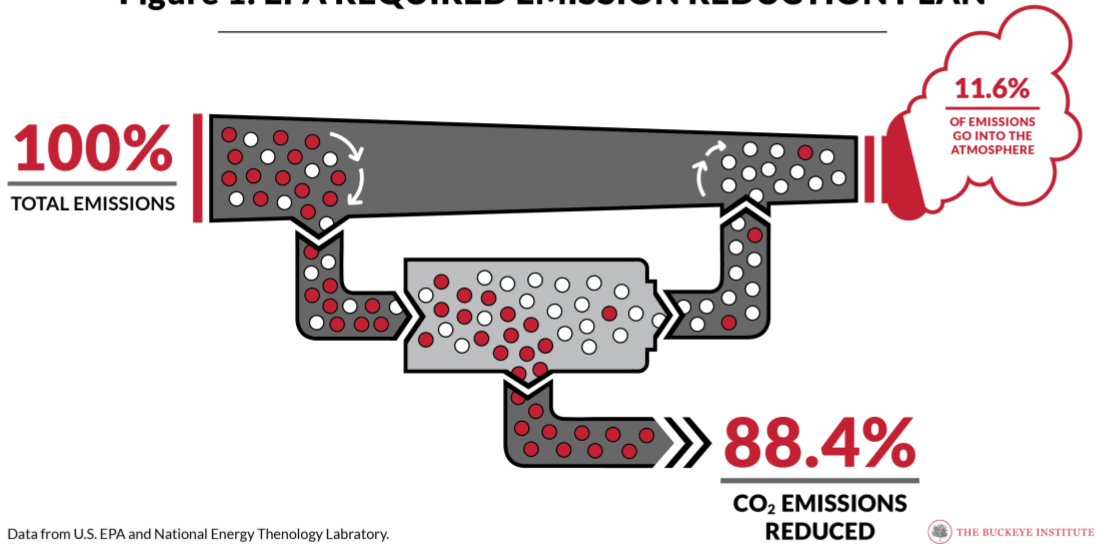
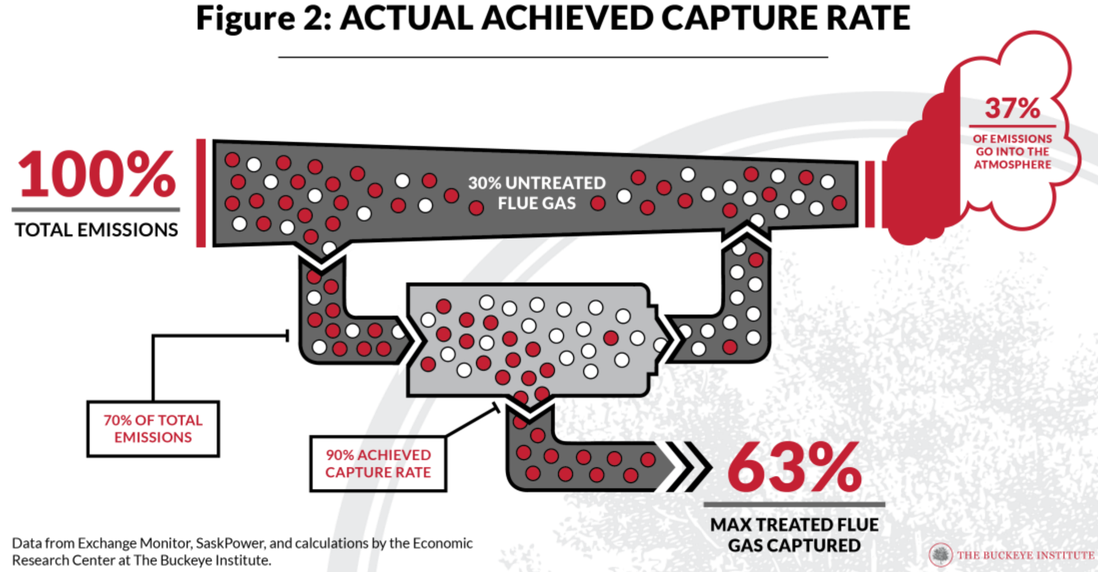


Figure 2: ACTUAL ACHIEVED CAPTURE RATE



The EPA's arbitrary standard does not reflect what CCS has achieved or is scientifically capable of achieving. Yet, the EPA will require all existing long-term coal fired EGUs to implement these costly retrofits.

Additionally, the EPA has also set a BSER for existing natural gas and oil fired EGUs. These new emission rate caps placed on baseload EGUs threaten to worsen grid reliability and trigger an energy security crisis in America. Last year, Americans saw electricity rates increase 15.8 percent, the greatest year-over-year rate increase in two decades.[4] The EPA's proposed restrictions on coal and natural gas fired power plants that provide over 80 percent of America's electric power, present a problem for meeting increased power demand. Utilities will be dissuaded from investing in baseload sources of power dependent on fossil fuels and pigeonholed into using intermittent sources of renewable power to meet America's ever-growing energy needs.

The EPA's Regulatory Impact Analysis failed to adhere to defensible and sound procedures for quantifying costs and benefits. Instead, the agency cherry-picked a range of real discount rates for use in unreliable integrated planning models when calculating the social cost of carbon (SCC) and estimating compliance costs. By discounting the SCC at 2.5, 3, and 5 percent at the 95th percentile of climate damage estimates, the EPA failed to adhere to OMB Circular A-4's guidelines for discounting by omitting the prescribed real discount rate of seven percent. Similarly, the EPA did not discount the national electricity sector's compliance costs at Circular A-4's required discount rates of three and seven percent. Instead, the EPA selected a single discount rate—3.76 percent—to estimate compliance costs in its integrated planning model. By using lower discount rates to estimate the social cost of carbon and the compliance costs, the EPA vastly overstates the benefits of the new regulations while severely understating compliance costs.

In its current form, the proposed rule will jeopardize America's energy security by making cheap power scarce and markedly increasing power costs for all Americans, rich and poor alike. America's poor and minority communities, however, will be the most impacted by higher utility rates, which are tantamount to a regressive tax.

I. The EPA's Proposed BSER.

The EPA's proposed rule requires all existing coal plants to comply with the standards based on the agency's established BSER. The BSER instructs all existing coal plants to retrofit their EGUs with CCS technologies with a minimum capture rate of 90 percent or reduce total CO2 emissions by 2030—a mere seven years from now. Coal plants that do not—or cannot—comply with the proposed rule's BSER will be required to implement 40 percent natural gas co-firing and submit a plan to shut down coal-fired generating units by 2032.[5] Based on a NETL report, the EPA asserts that a 90 percent capture rate will result in an overall reduction of coal plant emissions by 88.4 percent. The EPA has set 88.4 percent emission reduction as the minimum emission reduction target and has provided CCS as the only "demonstrated" technology capable of meeting this target.

All CCS facilities cited by EPA used an amine-based solution to absorb CO2 from flue gas emissions. The process for capturing CO2 from flue gas is energy intensive, consuming more energy than what an EGU can produce. Ali et al. (2023) states that "the current energy penalty level of CO2 chemisorption is still unbearable if a full-scale CO2 removal process is to be

[4] U.S. Bureau of Labor Statistics, **12-month percentage change, Consumer Price Index, selected categories – Electricity**, (Last visited June 27, 2023).
[5] U.S. Environmental Protection Agency, **New Source Performance… and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

implemented for… coal-fired power plant[s].”[6] CCS plants use most of their energy to compress flue gas and heat treating the amine-solution to release the trapped CO_2.[7]

CCS facilities consume a lot of power to scrub CO_2 from flue gas. The electric power used in the processes can either be drawn directly from the attached coal-fired EGU or produced by an ancillary generator. When the CCS facility is integrated with the EGU, it results in a parasitic load that reduces overall power output,[8] which can raise electricity rates for consumers in the region near the coal-fired EGU. The immense energy inputs required to sequester CO_2 at a large-scale makes it physically impossible for a CCS facility integrated into an EGU to attain and sustain a 90 percent capture rate without consuming more energy across the CO_2 sequestration lifecycle than is produced by the coal fired-EGU. Non-integrated CCS facilities will need to draw from a reliable and dispatchable power source, *e.g.*, natural gas, nuclear, or coal fired power.

The EPA cited three coal fired facilities utilizing CCS as primary evidence for the BSER. None of the cited CCS facilities, however, achieved a consistent 90 percent capture rate on a significant portion of the emissions covered by the regulation. No commercial CCS facility has successfully met the EPA’s requirement to reduce total emissions by 88.4 or continuously sustain a 90 percent capture rate over a long-term period.

II. The Proposed Rule’s Technical Problems.

The proposed rule’s defects begin with misquoted sources and extend to inconsistent standards and irrelevant concepts that confuse and mislead.

a. Incorrect Citations and Misquotations.

As evidence to establish the BSER, the EPA stated that SaskPower’s Boundary Dam Unit 3’s CCS facility demonstrated the “commercial-scale… of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically PC plants) [and] has shown the ability to capture 90 percent of the CO_2 in the flue gas stream.”[9] The proposed rule’s justification for this assertion—the 2022 NETL report—never stated that the plant achieved a 90 percent rate of capture.[10] A single data point taken from Figure 7 in Giannaris’ report implies that a 90 percent capture rate of Unit 3’s total emissions was achieved once in 2015 for a single day. The remaining data in the time series shows that Boundary Dam has never sustained a 90 percent capture rate.[11] The proposed rule also cites the 2022 NETL report to provide the 88.4 percent emission reduction

[6] Emad Ali, Mohamed K. Hadj-Kali, Salim Mokraoui, Rawaiz Khan, Meshal Aldawsari, Mourad Boumaza. “**Exergy analysis of a conceptual CO_2 capture process with an amine-based DES**,” *Green Processing and Synthesis* Volume 12, Issue 1, February 16, 2023.
[7] Tom Yelland, **The Role of Solvents in Carbon Capture**, CarbonClean.com, August 17, 2021.
[8] **CO_2 Capture Technologies, Post Combustion Capture (PCC)**, Global CCS Institute, January 2012.
[9] Tommy Schmitt et al., **Cost and Perforamnce Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[10] Stavroula Giannaris et al., **SaskPower’s Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability**, 15th International Conference on Greenhouse Gas Control Technologies, March 2021.
[11] *Ibid.*

standard. But the NETL report misrepresented Giannaris' report when citing it as a justification for the following claim: "Commercial-scale demonstration of solvent-based post-combustion CO_2 capture systems at power generation facilities… has shown the ability to capture 90 percent of the CO_2 in the flue gas stream."[12] SaskPower's Boundary Dam Unit 3 was only able to achieve a 90 percent capture rate by reducing the intake of untreated flue gas. Reducing the plant's flue gas intake resulted in a de-rating of the CCS plant's effective target to a maximum capture rate of 65 percent of total emissions, which the plant has yet to demonstrate.[13] The EPA has failed to accurately cite a scientific study as primary evidence for its BSER and must therefore change its standard to reflect what the scientific report stated or provide new scientific evidence that supports, clarifies, contextualizes, or qualifies the claim that Boundary Dam Unit 3 achieved its targeted capture rate.

b. Inconsistent Baseline for Reporting Reduction in Carbon Capture.

One of E.O. 12866's objectives is to make the regulatory review process "more accessible and open to the public."[14] Undermining this objective, the metric Megawatt equivalent (MWe) is a confusing metric and a poor choice for rating a CCS system's CO_2 capture capabilities. Unaccompanied by an EGU's generation capacity, fuel type, and total daily emissions, MWe is a useless measure of CCS capture that has been misunderstood and inconsistently reported. Indeed, even the EPA has shown its misunderstanding by its inconsistent use of MWe throughout the proposed rule. Without a quantitative metric, it is impossible to measure the efficacy of CCS.

A watt is a unit[15] equal to 1 Joule per second and used to measure instantaneous power. A watt hour (Wh) is the measure of continuous electrical energy needed to power a device. Typically, lightbulbs and small household appliances have energy requirements rated in watt hours. A Megawatt (MW) is a million watts and represents power equal to 1,000,000 Joules per second. Because power plants generate a lot of electric power, their capacity is typically given in Megawatts. Unlike MW, Megawatt-equivalent (MWe) is not a unit that measures the rate of energy flow per unit of time. Instead, MWe can have many different meanings depending on the context.

In America, CCS facilities use MWe to qualitatively describe their nameplate capture capacity. Every MW generated at a coal-fired power plant releases a quantity of emissions. MWe measures the emissions released by the coal plant per MW produced. For example, A CCS facility rated at one MWe captures the emissions released by the coal plant per one MW of power generated.

MWe is a poor metric for several reasons. First, MWe can easily be confused with MW. MW measures power generated. Worse yet, megawatt electric, which measures the electric power produced by a boiler, uses the same abbreviation, MWe, to differentiate electric MW and MW

[12] Tommy Schmitt et al., **Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[13] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
[14] E.O. 12866
[15] **What is a Megawatt**, Nuclear Regulatory Commission (Last visited June 29, 2023).

thermal generated by the heat engine.[16] Consequently, MWe can be and has been interpreted as a unit for measuring a CCS plant's power consumption and total emissions mitigated. Second, CCS facilities rated in MWe only describe emissions captured at the coal plants they are attached to and are not a uniform method of emission reduction. Coal plants do not uniformly emit CO_2. Emissions can vary drastically between coal-fired power plants depending on the type of coal used, the efficiency of the boiler, turbine, and the cooling process. Thus, a 25 MWe CCS facility at one coal plant may be less effective at a different coal plant, making it an inconsistent metric for rating a CCS facility's capture rate. Third, MWe on its own does not convey information about total generation capacity or the operational schedule of the coal plant, which determines emission intensity and is an important detail for measuring effectiveness of the CCS facility. Without the coal plant's generation capacity or active capacity, MWe does not convey any information about the measured capture rate. Using MWe to represent capture capacity overstates the measured capture rate of most plants. Most CCS facilities target a 90 percent capture rate from a stream of flue gas. At a 25 MWe CCS facility, the plant only offsets 22.5 MWe of emissions. MWe's shortcomings make it an unhelpful and inconsistent metric for comparisons between CCS systems.

Due to the similarities to MW and inconsistent reporting, MWe is also a confusing metric for those unfamiliar with the terminology of CCS plants. MWe can be interpreted as any one of the following: the power rating of the CCS plant, the thermal energy in the waste flue gas stream, the parasitic load of an integrated CCS plant, or as the emissions mitigated per MW of power. These varied interpretations inevitably cause misunderstandings and distort or omit important information about the CCS facility.

Even when used and understood correctly, MWe says nothing about the CCS facility's actual achieved CO_2 capture rate or the percentage of total emissions mitigated from the coal plant. Reporting a CCS facility's maximum capture potential in MWe without the generation capacity of the EGU it is attached to, as the EPA did at Petra Nova and Plant Barry, is misleading and ultimately says nothing about the total emissions captured by the plant.

The EPA inconsistently used MWe throughout the proposed rule when describing the capture rate of several CCS facilities. The EPA described Petra Nova as a "240 MW-equivalent capture facility," and Plant Barry as a "25-MW CCS project." But subsequent scientific studies conducted by Mitsubishi (the patent holder of the KM-CDR™ process used at both plants) consistently use MWe as a rate for capture capacity.[17] Although the EPA correctly reported Petra Nova's capture capacity in MWe, it incorrectly reported Plant Barry's 25 MWe as a 25 MW capture facility. This error can be interpreted several ways: Plant Berry draws a parasitic load of 25 MW or Plant Barry is capable of mitigating 25 MWe of emissions from a flue gas slipstream. The EPA then

[16] **Megawatts electric**, Energy Education, University of Calgary (Last visited: July 18, 2023).
[17] Osamu Miyamoto, Cole Maas, Tatsuya Tsujiuchi, Masayuki Inui, Takuya Hirata, Hiroshi, Tanaka, Takahito Yonekawa, and Takashi Kamijo, **KM CDR Process™ Project Update and the New Novel Solvent Development**, Energy Procedia, November 18, 2016 ; Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.

indiscriminately switches between MWe and MW when describing capture capacity of several proposed CCS projects.

To prevent future confusion and to determine if CCS is a viable technology, the EPA should consider adopting a metric other than MWe. The new metric should be easily understandable, reportable, and comparable to total emissions and better assess the performance of the CCS facility. For example, The Saskatchewan Power Corporation (SaskPower) uses daily CO_2 capture in metric tonnes (MT) as a reporting metric for their captured CO_2 emissions. Average daily CO_2 capture rate offers several benefits over MWe. First, average daily CO_2 capture can be easily understood when reported by itself. Second, average daily capture presents a clear picture of the total emissions captured by the CCS plant on a daily basis. This number can trivially be divided by total plant emissions to assess the day-to-day performance of the plant. Third, daily capture rate creates a continuous stream of emissions data that can easily be aggregated and audited by the public to assess the performance of the CCS facility month-to-month, quarter-to-quarter, or year-to-year. Average daily capture rate simplifies the reporting of CO_2 captured by a CCS plant and makes it easier to assess the performance of a CCS facility.

Several NETL reports have used pounds of CO_2 per megawatt hour (lb/MWH) to measure CCS efficacy.[18] But although it is a superior metric to MWe, MW/ton of CO_2 can vary from site to site depending on fuel type and efficiency of the CCS plant.

The EPA needs to consistently report the capture capacity of the CCS facilities used to justify its BSER and adopt a more transparent metric that adequately describes a CCS facility's actual performance rather than its projected emission mitigation capacity, which, as will be demonstrated, has rarely been consistently achieved.

III. The Proposed Rule is Arbitrary, Capricious, and an Abuse of Discretion.

The laws of physics always trump the laws of man. The proposed rule demands the opposite.

Under the Administrative Procedure Act, agency action, findings, and conclusions must be held unlawful and set aside if found to be arbitrary, capricious, an abuse of discretion, contrary to constitutional power, or otherwise not in accordance with law.[19] Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors that Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.[20] Additionally, the agency must "examine the relevant data and articulate a satisfactory explanation for its action

[18] **Eliminating the Derate of Carbon Capture Retrofits**, National Energy Technology Laboratory, May 31, 2016; Tommy Schmitt et al., **Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity**, National Energy Technology Laboratory, October 14, 2022.
[19] 5 U.S.C § 706(2).
[20] *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins.*, 463 U.S. 29, 30 (1983).

including a rational connection between the facts found and the choice made."[21] And as part of the required analysis for determining the BSER, the EPA must consider only viable technologies.[22]

Instead of following these prescribed norms, the proposed rule has not considered important aspects of the problem, it has not fairly examined the relevant data, has determined that an unproven—even speculative—technology is the "best system" for emissions reduction, and has based its Section 111(d) standard on the unproven technology's theorized emissions reductions. These theoretical emissions reductions cannot be achieved by the state plans in any way other than attempting to use the unproven technologies or shutting down plants entirely.

a. The Proposed Rule's CSS Examples Violate the CAA § 111(a)(1) Criteria.

i. Plant Barry

Prior to 2011, the Southern Company partnered with Mitsubishi Heavy Industries to attach a small 25 MWe CCS pilot facility to the James M. Barry Electric Generating Plant's (Plant Barry) Unit 5, a 770 MW capacity coal fired EGU in Alabama.[23] Plant Barry's auxiliary CCS plant commenced operation in 2011, and had a maximum capture capacity of a mere 550 MT of CO2 per day, enough to offset just three percent of Unit 5's total CO2 emissions.[24] Plant Barry's CCS plant was the only CCS facility cited by the EPA that consistently achieved and sustained a stable capture rate of 90 percent, but it showed that very small-scale CCS was possible.[25] This limited success did not demonstrate, however, that it was possible to achieve the EPA's 88.4 percent emissions reduction target. And given the small size of Plant Barry's CCS facility, it is certainly not representative of large-scale CCS facilities capabilities.

ii. SaskPower's Boundary Dam Unit 3 CCS Facility

The EPA cites SaskPower's Boundary Dam Unit 3's CCS facility as a successful demonstration of meeting the BSER's 90 percent capture rate and overall 88.4 percent emissions reduction target.[26] But that claim is factually inaccurate.

The CCS facility attached to SaskPower's Boundary Dam Unit 3 entered service in October 2014. After eight years of operation, the CCS facility has failed to consistently achieve its maximum designed capture rate. Mechanical and equipment failures stemming from design oversights forced the plant to reduce its operation capacity. The plant's annual capture rate is below 60

[21] *Id.* at 43.
[22] *See* 42 U.S.C. § 7411 (requiring BSER to be "adequately demonstrated").
[23] **Carbon Capture and Sequestration (CCS) Demonstration Project**, Southern Company, (PowerPoint presentation, August 21, 2009); Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.
[24] **MHI Carbon Capture Technology to be Demonstrated in United States on Southern Company Coal-Fired Power Plant**, Mitsubishi Heavy Industries press release, May 22, 2009.
[25] Michael A. Ivie II et al., "**Project Status and Research Plans of 500 TPD CO2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry**" *Energy Procedia*, Volume 37, (2013) p. 6335-6347.
[26] U.S. EPA, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

percent, evidence that the CCS technology cannot meet the EPA's desired standards and so cannot be the BSER.

Between 2008 and 2014, Unit 3's generation capacity was upgraded from 139 MW to 160 MW and retrofitted with a CCS facility. The CCS facility would draw a parasitic load of 50 MW of power directly from Unit 3. The CCS facility's 50MW load reduced Unit 3's power generation capacity by 31 percent from 160 MW to 110 MW of net generation capacity.[27] The CCS facility's parasitic draw negated the additional 21 MW gained by upgrading Unit 3's generation capacity, and further reduced Unit 3's power output by an additional 29 MW, which is enough energy to continuously meet power demand for 21,750 homes.[28] By integrating the CCS facility directly into Unit 3, SaskPower reduced the amount of electricity to the grid, which doubled the wholesale power price.[29]

Unit 3's CCS plant was designed as a "full" CCS system[30] to treat 100 percent of Unit 3's flue gas emissions for 90 percent of CO2. The projected daily capture was 3,200 MT of CO2 out of Unit 3's estimated daily emissions of 3,600 MT of CO2. [31] Unit 3's CCS facility, however, only achieved its targeted 90 percent capture rate for several days in 2015 and never sustained it over a long period of time.

Attempts to run the CCS system at its designed capture rate of 90 percent over total emissions caused frequent equipment failures. Though intended to treat 100 percent of flue gas emissions, designers failed to account for fly ash from the coal plant entering the system and choking the SO2 and CO2 absorbers.[32] The fly ash contaminated and compromised the "health" of the amine solution, which severely impeded the rate of CO2 capture.[33] Repairing and cleaning the equipment required multiple months-long outages. Additional equipment failures, such as the repeated failures in the facility's CO2 compressor motor, also resulted in long downtime.[34]

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[27] J.E. Cichanowicz, "**2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation**," (January 2022); Wesley Peck, John A. Hamling, Neil Wildgust, Charles D. Gorecki, **What Parasitic Load? a New Paradigm for Ccus**, *2019 Carbon Management Technology Conference*, July 18, 2019; Abby L. Harvey, **Two Years of Operation at Boundary Dam**, Exchange Monitor: presented at Carbon, Capture, Utilization & Storage Conference, 2016 (Last visited June 26, 2023).
[28] **Understanding electricity**, California Independent System Operator (Last visited June 26, 2023).
[29] Stefani Langenegger, **Sask. Carbon capture plant doubles the price of power**, CBC News, June 17, 2016.
[30] U.S. EPA, **Basis for Denial of Petitions to Reconsider the CAA Section 111(b) Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Generating Units**, April 2016.
[31] **SaskPower Boundary Dam 3 Project Update & Some Lessons Learned**, Cansolv Technologies Inc., March 2013; Abby L. Harvey, **Two Years of Operation at Boundary Dam**, Exchange Monitor: presented at Carbon, Capture, Utilization & Storage Conference, 2016 (Last visited June 26, 2023).
[32]Brent Jacobs et al., "**Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities**," 16th International Conference on Greenhouse Gas Control Technologies (November 2022).
[33] J.E. Cichanowicz, "**2021 Status of Carbon Capture Utilization and Sequestration for Application to Natural Gas-Fired Combined Cycle and Coal-Fired Power Generation**," (January 2022).
[34] Carlos Anchondo, **CCS 'red flag?' World's sole coal project hits snag**, E&E News, January 10, 2022.

To mitigate equipment failures, Unit 3's CCS plant's flue gas intake needed to be downgraded from a "full" CCS system. The intake of flue gas was reduced to 70 percent of the CCS plant's designed intake capacity. Only after Unit 3's CCS facility was de-rated did the CCS facility achieve a capture rate of 90 percent CO2—but only of the 70 percent of the CO2 emissions.[35] Capture of 90 percent rate of the 70 percent of emissions reduced the CCS plant's maximum capture rate to about 65 percent of total emissions.[36] But even at the lower capture rate, the CCS facility still underperforms targets, mitigating only 57 percent of total emissions in 2021. The derating and continued under-performance of the CCS plant caused SaskPower to miss emission reduction targets.[37]

According to SaskPower, Unit 3's CCS facility was only able to capture 749,035 MT out of a designed annual capture capacity of 1,100,000 MT.[38] This puts the CCS facility's capture rate at 74 percent, well below the 90 percent of treated flue gas that the EPA claims. Out of the estimated 1,314,000 MT of CO2 emitted from Unit 3, the CCS facility was only able to capture 57 percent of total emissions (see Figure 2), well below the proposed 88.4 percent requirement.

October 2022 marked the plant's eighth year of operation. Over those eight years, the plant has only captured five million tonnes of CO2, three million tonnes short of its intended mark. Unit 3's real capture rate has been 62.5 percent of its designed capacity over its operational life[39] and has not demonstrated a satisfactory carbon capture sequestration rate to justify the EPA's proposed BSER.

iii. Petra Nova

In May 2010, NRG Energy Inc. (NRG) entered a cooperative agreement with the Department of Energy to build Petra Nova,[40] a CCS facility that would be retrofitted onto Washington A. Parish Electric Generating Station's Unit 8. Unit 8 is a lignite-fired coal boiler with a generation capacity

[35] Brent Jacobs et al., "**Reducing the CO2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities**," 16th International Conference on Greenhouse Gas Control Technologies (November 2022).
[36] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
[37] **SaskPower Annual Report 2021-2022**, SaskPower, March 31, 2022; Karin Rives, **Only still-operating carbon capture project battled technical issues in 2021**, S&P Global Market Intelligence, January 6, 2022.
[38] **BD3 Status Update: Q4 2022**, SaskPower.com, January 23, 2023.
[39] **Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 26, 2023).
[40] **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

of 654 MW.[41] Petra Nova was designed to capture 90 percent of emissions sourced from a 240 MWe flue gas slip stream diverted from Unit 8.[42]

Using the Mitsubishi's KM-CDR™ process piloted at Plant Barry, Petra Nova was initially designed as a 60 MWe capture plant.[43] But plans to monetize captured CO2 by selling it to on-going CO2-EOR operations in the West Ranch Oil Field required larger economies of scale.[44] If Petra Nova was going to be commercially viable, the plant would need to be scaled up to 240 MWe, a factor of 4x the original design and well above Plant Barry's capture quantity.

When operating at full capacity, Petra Nova could theoretically sequester 36 percent of Unit 8's total emissions. Petra Nova's performance, however, suffered design flaws and equipment deficiencies that severely reduced its capture rate during its early years of operation. Additionally, Petra Nova was powered by a dedicated natural gas-fired turbine that emitted CO2, which effectively negated a substantial portion of the CO2 it was designed to sequester. The emissions from the natural gas turbine offset as much as 25 percent of the sequestered CO2.[45]

To prevent a parasitic load from reducing plant generation efficiency like at SaskPower's Unit 3, Petra Nova's designers did not integrate Petra Nova with Unit 8, but instead used an ancillary natural gas-fired turbine rated at 78 MW as a dedicated power source. Petra Nova drew all 35 MW of its power from the generator and sold all excess power to the grid.[46] This avoided placing a parasitic load on Unit 8 and prevented Petra Nova from removing 35 MW of electric power – enough for 26,250 homes – from the grid.[47] Ironically, Petra Nova was a CCS facility completely powered by a fossil fuel EGU.[48]

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41 **Petra Nova is one of two carbon capture and sequestration power plants in the world**, U.S. Energy Information Administration, October 31, 2017; **Plant Barry CO2 Capture Project**, Mitsubishi Heavy Industries, LTD., October 2015; **Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 26, 2023).

42 Scott DiSavino, **Fire shuts NRG Texas coal power unit during hot spell, all personnel safe**, Reuters, May 09, 2022; **Petra Nova Parish Holdings: W.A. Parish Post-Combustion CO2 Capture and Sequestration Project**, NETL.DOE.gov (Last visited June 26, 2023).

43 Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020.

44 *Ibid.*

45 Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020; **Petra Nova Is One of Two Carbon Capture and Sequestration Power Plants in the World**, U.S. Energy Information Administration, October 31, 2017; Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

46 Greg Kennedy, **W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report)**, U.S. Department of Energy Office of Scientific and Technical Information, March 31, 2020.

47 **Understanding electricity**, California Independent System Operator (Last visited June 26, 2023); Osamu Miyamoto, Cole Maas, Tatsuya Tsujiuchi, Masayuki Inui, Takuya Hirata, Hiroshi Tanaka, Takahito Yonekawa, and Takashi Kamijo, ***KM CDR Process™ Project Update and the New Novel Solvent Development***, Energy Procedia, November 14-18, 2016.

48 Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

Petra Nova's target capture rate was 1.4 million MT out of a possible 1.6 million MT of CO2 per year, roughly 40 percent of Unit 8's total emissions.[49] Operating at the targeted capacity factor of 85 percent, Petra Nova was rated to sequester 5,200 MT of CO2 per day.[50] Like SaskPower's Unit 3 CCS facility, however, Petra Nova encountered operational challenges and frequent equipment breakdowns.[51] Houston's high summer temperatures complicated the plant's water cooling process, which hurt the CCS facility's performance. Operating the plant at full capacity during the summer stressed the system and risked equipment failures to meet the area's surging power demand for air conditioning.[52] Petra Nova also suffered from non-weather-related equipment failures, including leaks from heat exchangers and calcification, which caused its flue gas blower to vibrate.[53] Technical problems ultimately led to 367 days of outages, nearly a third of Petra Nova's operational life.[54]

The proposed rule states that Petra Nova, "successfully captured 92.4 percent of the CO2 from the slip stream of flue gas processed with 99.08 percent of the captured CO2 sequestered by EOR."[55] But Petra Nova never achieved its maximum capture rate, and according to a report from the Institute for Energy Economics and Financial analysis, "Emission data for Parish Unit 8 reported to the EPA suggests the actual CO2 capture rate was substantially lower than 90%, perhaps as low as 65% to 70%. And the average capture rate does not include emissions from the gas-fired combustion turbine used to power the facility. Adding those emission lowers the overall on-site capture rate to… 55% to 58%."[56] And when considering total emissions from the W.A. Parish generating station, Petra Nova captured an even smaller percentage. In 2018, Petra Nova only captured 1.017 million MT of CO2 out of the 14.6 million MT emitted by the entire plant—a mere six percent of total emissions.[57]

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[49] NRG Energy, **Petra Nova - WA Parish Generating Station**, nrg.com, accessed June 1, 2017; **Petra Nova, World's Largest Post-Combustion Carbon-Capture Project, Begins Commercial Operation**, Office of Fossil Energy and Carbon Management press release, January 11, 2017; **Plant Barry CO2 Capture Project**, Mitsubishi Heavy Industries, LTD., October 2015; **Petra Nova - W.A. Parish Project**, Office of Fossil Energy and Carbon Management press release, January 10, 2017.

[50] **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

[51] Valerie Volcovici and Timothy Gardner, **Biden's power plant proposal poses huge test for carbon capture**, *Reuters*, May 12, 2023.

[52] **W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report**, NETL, March 31, 2020.

[53] Oakley Shelton-Thomas, **Carbon Capture: Billions of Federal Dollars Poured Into Failure**, Food and Water Watch, September 27, 2022.

[54] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

[55] U.S. Environmental Protection Agency (EPA), **New Source Performance… and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

[56] Suzanne Mattei and David Schlissel, **The ill-fated Petra Nova CCS project: NRG Energy throws in the towel**, Institute for Energy Economic and Financial Analysis, October 05, 2022.

[57] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

Because Petra Nova was only ever designed to capture 36 percent of Unit 8's emissions at maximum capacity, and because it failed to reliably sustain a 90 percent capture rate over a long period of time, Petra Nova fails to meet the EPA's criterion of an 88.4 percent total emission reduction and does not justify CCS as a BSER.

b. CCS is Only Viable with DOE Grants and Subsidies.

The Department of Energy's (DOE) gamble on CCS technology has sent billions of taxpayer dollars chasing an elusive green dividend. Most projects that received funding from DOE in the last decade were never completed. Petra Nova was the only coal capture project that was built, but it ultimately failed to generate positive environmental benefits and cash flow. Similarly, SaskPower received 240 million CAD (US $195 million) from Canadian taxpayers.[58] But Boundary Dam Unit 3's CCS facility never profited from the commercial sale of captured CO2. In fact, CCS cost Boundary Dam millions of dollars when the CCS plant failed to deliver CO2 promised to Cenovus for Enhanced Oil Recovery. Were it not for the $50/tonne CO2 carbon tax imposed by the Canadian government, Boundary Dam's CCS plant would have been a complete failure.

Over the past decade, DOE has spent hundreds of millions of taxpayer dollars on CCS facilities. According to a Government Accountability Office (GAO) report on Carbon Capture and Storage, "DOE provided nearly $684 million to eight coal projects, [which resulted] in one operational facility"[59]—Petra Nova. However, Petra Nova ultimately shutdown due to the high cost of producing CO2 for Enhanced Oil Recovery (CO2-EOR) operations. The DOE cancelled funding agreements with four projects. The remaining $488.7 million was spread between five incipient projects that never progressed beyond paper-napkin sketches.[60]

Additionally, the GAO found that the "DOE's process for selecting coal projects and negotiating funding agreements increased the risks that DOE would fund projects unlikely to succeed."[61] The GAO concluded that the DOE's senior leadership, "did not adhere to cost controls designed to limit its financial exposure on funding agreements for coal projects… [the DOE] spent nearly $[488.7] million on the definition and design of four unbuilt facilities – almost $300 million more than planned for those projects."[62] That is a nearly 200 percent cost overrun before even starting construction.

Cost overruns at proposed CCS facilities have been well documented and devastating for utility consumers. The Kemper project was kickstarted in 2007 by Southern Power Company's

[58] **Boundary Dam Integrated Carbon Capture and Storage Demonstration Project**, Government of Canada, January 5, 2016.
[59] United States Government Accountability Office, ***Report to Congressional Committee on Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects***. Government Accountability Office, December 2021.
[60] United States Government Accountability Office, ***Report to Congressional Committee on Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects***, Government Accountability Office, December 2021.
[61] *Ibid.*
[62] *Ibid.*

subsidiary, Mississippi Power Company, which was conceived as an integrated gasification plant with an attached CCS facility capable of capturing 65 percent of total emissions from the lignite coal fuel source.[63] The DOE fed Kemper's fiscal furnace by adding $382 million in grant funding.[64] Originally, the Kemper project was estimated to cost $2.4 billion, but quickly ballooned 212.5 percent to $7 billion and ultimately was terminated. The facility was fitted for natural gas-fired generation.[65] To recover the costs of the failed project, the Mississippi state legislature authorized Southern Power to raise consumer power rates by 41 percent, roughly $37 per household per month.[66]

Congress has since rewarded the DOE's behavior with a near blank check. The Energy Act of 2020 offered the DOE $7 billion over five years (2020-2025) to examine CCS projects at natural gas-fired power plants and industrial plants.[67] The Inflation Reduction Act (IRA) has offered an additional $12 billion in funding and billions more in tax credits for yet unproven CCS facilities.[68]

Direct Air Carbon (DAC) capture is a largely unproven method of CCS. Currently, Occidental Petroleum is building the nation's first such commercial scale facility in Ector County, Texas. DAC is a yet unproven technology with high estimated CO2 capture costs. Current cost estimates for captured CO2 range well above $100 - $335 per tonne of CO2.[69] Captured CO2 will be too expensive for utilization and the cost of capture is well above the existing tax credits. Whether this facility will generate revenue remains to be seen. The project has secured a 10-year tax abatement from Ector County despite rural Texas counties depending on property tax revenue to fund education and municipal services. The loss of tax revenue from this parcel of land is an injustice that deprives a majority Hispanic community[70] of resources to fund education and local infrastructure. The EPA's BSER encourages unproven facilities like these to squander taxpayer dollars on unproven technology and prompt coal plants to try unproven DAC facilities in poor, rural counties just to mitigate emissions.

c. The Water Use Impact Analysis Underestimates Required Water Use.

Section VII.F.3.v.iii.(C) of the proposed rule cites increased water use as a potential impediment for CCS adoption. According to the EPA, CCS technology increases an EGU's combined cycle water

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[63] Richard Esposito, **The Kemper Project IGCC Project Overview**, SECARB Stakeholders' Briefing, May 2010.
[64] James Conca, **The Largest Clean Coal Power Plant In America Turns To Natural Gas**, Forbes, July 11, 2017.
[65] David Schlissel, **IEEFA U.S.: Southern Company Demolishes Part of the $7.5 Billion Kemper Power Plant in Mississippi**, Institute for Energy Economics and Financial Analysis, October 14, 2021.
[66] Ian Urbina, **Piles of Dirty Secrets Behind a Model 'Clean Coal' Project**, *The New York Times*, July 5, 2016; Rebecca Smith, **Coal-Fired Power Plant Loses Steam: Mississippi utility withdraws as backer of electricity project as costs soar**, *The Wall Street Journal*, May 22, 2015.
[67] **DOE's Carbon Capture and Storage (CCS) and Carbon Removal Programs**, Congressional Research Service, April 4, 2022.
[68] Charles Harvey, Kurt House, **Every Dollar Spent on This Climate Technology Is a Waste**, MIT Civil and Environmental Engineering, August 17, 2022.
[69] International Energy Agency, **Direct Air Capture: A Key Technology for Net Zero**, 2022.
[70] U.S. Cencus, **QuickFacts: Ector County, Texas: Population Estimates**, July 1, 2022, Texas (Last Visited: July 20, 2023).

usage from 190 gallons to 290 gallons, increasing water usage over 50 percent.[71] Other sources indicate that the water requirements of carbon sequestration can double the per kilowatt water usage of a coal plant.[72] But the proposed rule asserts—with no supporting evidence—that all coal-fired EGUs can implement dry cooling to negate extra water requirements. Dry cooling, however, requires low ambient temperatures making it impractical for plants in hot or drought prone areas. Houston's Petra Nova, for example, used 1.49 billion gallons of water in addition to Unit 8's water consumption. High temperatures at the plant created problems that led to outages or the de-rating of the CCS plant.[73] If dry cooling will not work for the CCS plants, then it cannot work for power plants. Furthermore, very few EGUs rely solely on dry cooling technologies—and for good reason—but the proposed rule offers them as a unilateral solution without properly assessing how such a requirement would affect hot and drought prone regions.

d. Enhanced Oil Recovery.

Enhanced Oil Recovery (EOR) operations were a significant driver of early CCS technology. Today, proponents of CCS view CO2-EOR as a ready-made market for CO2 sourced from coal projects. Although the EPA acknowledges the important role that CO2-EOR will play in commercializing and sequestering captured CO2, the BSER stopped short of including it as a method—and rightly so. The success of a CCS project is determined by regional CO2 markets, geography, and plant-type. But in eschewing CO2-EOR, the EPA has overlooked the fact that commercial CO2 captured by coal projects is economically uncompetitive in every regional CO2 market. Due to strong competition from easily sourced natural and industrial CO2, it is unlikely that there will ever be an economic case for plants to adopt CCS voluntarily sans generous tax credits. The EPA's BSER will saddle coal plants with expensive facilities that will be unable to defray their maintained costs with the revenue stream generated by the sale of CO2 for EOR.

An oil field's productive life has three phases: primary, secondary, and tertiary recovery. Tertiary recovery can produce 30 – 60 percent of a field's original oil in place depending on the methods used and the price of oil.[74] CO2-EOR is one of several tertiary oil recovery methods used by petroleum landmen.[75] But CO2-EOR usually requires high oil prices to be economically viable. The inputs to CO2-EOR can raise the final production costs of a barrel of crude oil by $20 – $30 per barrel.[76] This makes CO2-EOR one of the most expensive methods of EOR, and uncompetitive

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[71] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.

[72] Samuel K. Moore, **The Water Cost of Carbon Capture: Coal Power's Carbon Savior Could Double Its Water Woes**, IEEE.org, May 28, 2010; Rosa, L., Reimer, J.A., Went, M.S. et al. **Hydrological limits to carbon capture and storage**, *Nature Sustainability,* Volume 3 (2020) p. 658–666.

[73] Joe Smyth, **Petra Nova carbon capture project stalls with cheap oil**, Energy and Policy Institute, August 6, 2020.

[74] **Enhanced Oil Recovery**, Department of Energy (Last visited Jun 28, 2023)

[75] Sean T. McCoy and Edward S. Rubin, "**The Effect of high Oil prices on EOR project economics**" *Energy Procedia*, Volume 1, Issue 1 (February 2009) p. 4143 - 4150

[76] **Oil prices drive projected enhanced oil recovery using carbon dioxide**, U.S. Energy Information Administration, July 30, 2014.

with cheaper superior methods like ethane flooding.[77] Additionally, CO2-EOR's economic viability also depends entirely on the availability and regional price of CO2.

Over the last 70 years, geography has been, and remains, the greatest influence on determining whether manmade or naturally sourced CO2 is used in CO2-EOR operations. CO2-EOR was field tested in 1964 when a CO2 slug and carbonated water were injected into a pilot well in Mead Strawn Field.[78] After CO2-EOR was proven feasible, high oil prices in the 1970s spurred landmen to find sources of CO2.[79] By 1972, several industrial gas processing facilities were providing dense quantities of captured CO2 to CO2-EOR operations in the Permian Basin.[80] By the late 1970s, several pipeline projects were planned to tap Colorado's large deposits of natural CO2.[81] By 1982, several of these pipelines were completed, carrying natural CO2 to EOR projects in the Permian basin. Today, 70 to 80 percent of all CO2 used in EOR comes from natural deposits[82] and over 90 percent of naturally sourced CO2 is almost exclusively used in the Permian Basin.[83] The remaining 20 – 30 percent of CO2 for EOR is nearly exclusively captured from industrial gasification plants, natural gas refineries, ethanol plants and predominantly used in the Rocky Mountains and Midcontinent regions where natural deposits of CO2 are either difficult to access or scarce.[84] In place of natural CO2 deposits, industrial sources of CO2 can consistently offer dense quantities of CO2 that are easier to capture, process, and sell to vendors. Coal CCS projects have attempted to breach into both markets and have largely failed because sourcing CO2 in low-concentration from flue gas cannot economically compete in any region or with any other source of CO2.

[77] Steven T. Anderson, Steven Cahan, **Estimating market conditions for potential entry of new sources of anthropogenic CO2 for EOR in the Permian Basin**, U.S. Geological Survey, Publications Warehouse, November 30, 2019.

[78] James P. Meyer, ***Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology***, Contek Solutions - American Petroleum Institute, November 24, 2004; Tuo Huang, Xiang Zhou, Huaijun Yang, Guangzhi Liao, Fanhua Zeng, "**CO2 flooding strategy to enhance heavy oil recovery**" Petroleum, Volume 3, Issue 1 (March 2017) p. 68-78.

[79] Matthew Fry, Adam Schafer, et al., **Capturing and Utilizing CO2 from Ethanol**, working paper, State CO2-EOR Deployment Work Group, December 2017; **A Brief History of CO2 EOR, New Developments and Reservoir Technologies for CO2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[80] Matthew Fry, Adam Schafer, et al., **Capturing and Utilizing CO2 from Ethanol**, working paper, State CO2-EOR Deployment Work Group, December 2017; **A Brief History of CO2 EOR, New Developments and Reservoir Technologies for CO2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[81] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

[82] **Enhanced Oil Recovery**, Department of Energy, energy.gov (Last visited Jun 28, 2023); **A Brief History of CO2 EOR, New Developments and Reservoir Technologies for CO2 EOR in Conjunction with Carbon Capture, Utilization and Storage (CCUS)**, Melzer Consulting, (PowerPoint Presentation, December 8-10, 2020; Christophe McGlade, **Can CO2-EOR really provide carbon-negative oil?**, International Energy Agency, April 11, 2019.

[83] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999; Christophe McGlade, **Can CO2-EOR really provide carbon-negative oil?**, International Energy Agency, April 11, 2019; Matthew Wallace, Lessly Goudarzi, Kara Callahan, Robert Wallace, "**A Review of the CO2 Pipeline Infrastructure in the US**." *NETL*, April 21, 2015.

[84] A. Amarnath, ***Enhanced Oil Recovery Scoping Study***, Electric Power Research Institute, October 1999.

SaskPower intended for Boundary Dam Unit 3's CCS facility to produce enough CO2 that captured CO2 could compete with CO2 captured from the Dakota gasification facility in North Dakota. But Boundary Dam's frequent equipment failures meant that Unit 3 was unable to meet the contractually obligated sales of CO2 to Cenovus, the operator of the Weyburn oil field.[85] By the end of 2015, SaskPower owed 12 million CAD ($9 million USD) to Cenovus for failing to deliver promised CO2 for EOR.[86] In 2016, SaskPower had to renegotiate its contract with Cenovus to avoid a $91 million (CAD) failure to deliver penalty.[87] Ultimately, Boundary Dam Unit 3 was unable to provide CO2 at the prevailing market price of $25/MT.[88] The renegotiated price resulted in Cenovus paying the market rate for CO2, while the plant's high operating costs remained the same.

Even regions that lacked access to large natural deposits and industrial sources of CO2 could not justify sourcing CO2 from coal projects for EOR operations. At Plant Barry, captured CO2 was piped 12 miles and sequestered in a geologic formation in the Citronelle Oil Field above an active CO2-EOR pilot operation.[89] Although captured CO2 from Unit 5 was not used in CO2-EOR, Plant Barry's operators planned to scale the CCS facility to capture and commercialize one MT of CO2 emissions by selling captured CO2 to CO2-EOR operations in the Citronelle oil field.[90] These plans never materialized due in part to the poor regional economics of sourcing CO2 from flue gas emissions. Petra Nova originally planned to supply enough cheap CO2 to revitalize Hilcorp's West Ranch Oil Field. But when the plant was operating, Petra Nova did not supply enough CO2 to sustain EOR operations.[91] The cost of its CO2 was estimated at $60/tonne.[92] When oil prices collapsed in 2020, operators could no longer afford to purchase Petra Nova's expensive and unreliable CO2.

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[85] David Schlissel, **Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late**, Institute for Energy Economics and Financial Analysis, April 2021.
; ***EO 12866_GHG EGU New Sources 2060-AT56 TSD Reliability of Currently Available CCS Final Rule_20201214***, the Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, December, 2020.

[86] Fraser, D.C. **SaskPower renegotiated contract to avoid $91.8M penalty**, Regina Leader-Post, June 13, 2016;

[87] The Canadian Press. **SaskPower pays out $12M to Cenovus for not providing captured carbon dioxide**. CTV News, October 26, 2015.

[88] Geoff Leo, **Carbon Capture plant Delay Costing SaskPower Millions**, CBC News, October 26, 2015.

[89] U.S. Department of Energy, **Alabama Injection Project Aimed at Enhanced Oil Recovery, Testing Important Geologic CO2 Storage**, Office of Fossil Energy and Carbon Management, March 1, 2010.

[90] Richard A. Esposito, Jack C. Pashin, Denise J. Hills, Peter M. Walsh, "**Geologic assessment and injection design for a pilot CO2-enhanced oil recovery and sequestration demonstration in a heterogeneous oil reservoir: Citronelle Field, Alabama, USA**" *Environmental Earth Science*, Volume 60, (March 2010) p. 431-444; Konstantinos Theodorou, **Carbon Dioxide Enhanced Oil Recovery from the Citronelle Oil Field and Carbon Sequestration in the Donovan Sand, Southwest Alabama**, dissertation, the University of Alabama at Birmingham, 2013; **Plant Barry Fact Sheet: Carbon Dioxide Capture and Storage Project**, MIT.edu (Last visited June 23, 2023); **Southeast Regional Carbon Sequestration Partnership Citronelle Project**, NETL.DOE.gov (Last visited June 23, 2023); **Operations Initiated at Southern Company's Carbon Capture Project**, EnergyOnline.com (Last visited June 23, 2023).

[91] Florian Martin, **Low Oil Prices Lead to Shutdown of Much-Hyped Carbon Capture System Outside Houston**, Houston Public Media, August 3, 2020.

[92] Dennis Wamsted and David Schlissen, **Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign**, Institute for Energy Economics and Financial Analysis, August 2020.

Petra Nova, Boundary Dam's Unit 3, and the cancellation of Plant Barry, are prime examples of flue gas captured CO2's failure to deliver CO2 at a competitive price to EOR operations. By the DOE's own estimates, the cost of capturing CO2 from flue gas needs to decline by 50 percent.[93] Even these estimates are likely pollyannish. To spur investment in CCS technology the IRA has significantly increased the 45Q tax credit. Congress has increased the 45Q tax credit for CO2 sequestered through CO2-EOR by more than 70 percent, from $35/tonne to $60/tonne, to match what the DOE believes is the break-even price.[94] There is no guarantee that these tax credits will continue, but as all CCS plants have shown, without them, CCS is not economically feasible.

The EPA has proposed several methods of permanent geological sequestration that require a massive and costly build out of a CO2 midstream infrastructure and unproven methods of geological sequestration. For example, the EPA recommends disposing of captured CO2 by injecting it into coal seams even though it recognizes that this process remains theoretical and has not been tested.

The EPA's BSER tacitly promotes squandering financial resources pursuing the uneconomical development of CO2 capture facilities that will never have a positive return on investment. Should Congress decide to repeal these tax credits, all CCS coal and natural gas projects will lose their only stream of reliable revenue as their captured emissions will never be able to compete with CO2 sourced from natural deposits or industrial sources.

e. Discount Rate.

Discounting future benefit streams and compliance costs is an integral part of any benefit-cost analysis. In the net present value model, discount rates estimate the value of money received in the future by converting its value into dollars. It is important for regulators to accurately and consistently discount future benefits received and costs stemming from a regulation, so that policy makers have a complete picture.[95] In the proposed rule, the EPA properly discounted future benefits and compliance costs using the Office of Management and Budget (OMB) Circular A-4's prescribed real discount rates of 3 percent and 7 percent. But the EPA calculated the social cost of greenhouse gases (SC-GHGs) and compliance costs using much lower discount rates. These estimates were obtained using integrated planning models (IMPs) that fail to meet OMB A-4's threshold for being "sound and defensible."[96] The EPA used an IMP to calculate the social cost of carbon at five, three, and 2.5 percent at the 95th percentile of environmental damages. For calculating compliance costs, the EPA used one real discount rate of 3.76 percent.[97] The EPA's bifurcated discount rates grossly understate the private sector's compliance costs and vastly

93 Ryser, Jeffrey. **DOE hopes to see carbon capture costs cut 50%; NETL says it has stored 10 million mt of CO2**. S&P Global, June 10, 2020.

94 **Section 45Q Credit for Carbon Oxide Sequestration**, International Energy Agency, April 14, 2023.

95 David C. Tryon, Alex M. Certo, Zachary D. Cady, and Trevor W. Lewis, **Comment on Proposed OMB Circular A-4**, The Buckeye Institute, June 6, 2023.

96 **OMB Circular A-4**, Regulatory Analysis, September 17, 2003.

97 U.S. EPA, **Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units… and Repeal of the Affordable Clean Energy Rule**, May 23, 2023.

overestimate the future benefits stream. This is unsurprising considering that federal agencies routinely and significantly understate the cost of their regulations.[98]

The three discount rates selected by the interagency working group (IWG) in 2010 centered around the 3 percent estimate of the consumption interest rate published in OMB's Circular A-4 in 2003. That guidance was based on the real rate of return on 10-year Treasury Securities over the prior 30 years (1973 through 2002), which averaged 3.1 percent. Over the past four decades there has been a substantial and persistent decline in real interest rates driven by decreases in the equilibrium real interest rate (Bauer and Rudebusch 2020).

OMB A-4's guidelines for regulatory analysis instruct regulators to "monetize quantitative estimates whenever possible… [by using] sound and defensible values or procedures… and ensure that key analytical assumptions are defensible."[99] The EPA and the IWG have used several integrated planning models to obtain the SC-GHGs. But the IPMs used are so inconsistent in calculating values that results are neither sound nor defensible.

Dr. Kevin Dayaratna, Chief Statistician at the Heritage Foundation, has demonstrated that the models the EPA used to estimate various SC-GH fail to produce consistent and reliable results.[100] When Dr. Dayaratna put the real discount rate of 7 percent into the IPMs, he found that the SC-GHG declines substantially and is even positive in some cases – implying that greenhouse gas emissions carry positive societal benefits. The EPA's IPM's inability to produce a consistent SC-GHG at higher discount rates implies that the models undergirding the IPMs are indefensibly inconsistent, and the derived results should be considered unsound.[101] And the EPA's inconsistent discounting treatment is not limited to estimating the SC-GHG. When discounting compliance costs of adopting CCS at fossil fuel-fired EGUs in the IPM, the EPA selected a single discount rate - 3.78 percent, well below the seven percent required by OMB A-4. Given the numerous mechanical and economic challenges encountered by Boundary Dam, Petra nova, and the Kemper Project, discounting at 3.78 percent is wholly inappropriate and vastly understates the financial risk of CCS retrofits and new fossil fuel-fired power plants. The EPA's inconsistent handling of discount rates within its own planning models should cast doubt on the empirical results presented in the benefit-cost-analysis.

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[98] Casey B. Mulligan, **Burden is Back: Comparing Regulatory Costs between Biden, Trump, and Obama**, June 2023 (estimating EPA's 2021 rule for light-duty vehicle emissions at "a cost of $309 billion, which is about 70 percent more than the EPA reported").
[99] **OMB Circular A-4**, Regulatory Analysis, September 17, 2003.
[100] Kevin Dayaratna, **Why "Social Cost of Carbon" Is the Most Useless Number You've Never Heard of**, The Heritage Foundation, March 2, 2021; Kevin Dayaratna and David Kreutzer, **Unfounded FUND: Yet Another EPA Model Not Ready for the Big Game**, Heritage Foundation, April 29, 2014; Kevin Dayaratna and David Kreutzer, **Loaded DICE: An EPA Model Not Ready for the Big Game**, November 21, 2013; Patrick J. Michaels and Kevin D. Dayaratna, **The Scientific Case for Vacating the EPA's Carbon Dioxide Endangerment Finding: The Hazard of Unreliable Models Guiding Policy**, Competitive Enterprise Institute, Issue Analysis No. 3, April 17, 2020.
[101] Kevin Dayaratna and David Kreutzer, **Unfounded FUND: Yet Another EPA Model Not Ready for the Big Game**, Heritage Foundation, April 29, 2014; Kevin Dayaratna, **Why "Social Cost of Carbon" Is the Most Useless Number You've Never Heard of**, Heritage Foundation, March 2, 2021.

f. Conclusion: The Proposed BSER for Long-Term Coal-Fired EGUs is Arbitrary, Capricious, and an Abuse of Discretion.

The EPA's proposed BSER and Section 111(d) standard fail the arbitrary, capricious, and abuse of discretion test.

First, in determining that CCS is the BSER, the proposed rule relied on the fact that forcing plants to implement CCS would advance the development of CCS technology. This is a factor "which Congress has not intended [the agency] to consider."[102] Second, the proposed rule "offered an explanation for its decision that runs counter to the evidence before" it.[103] The EPA's own sources confirm that its examples of "successful" CCS facilities have entirely failed to achieve a consistent capture rate at a level that satisfies the proposed standard. Third, the proposed rule ignores the GAO reports demonstrating the infeasibility of the CCS facilities, and thus "it ignores important considerations or relevant evidence" without justification.[104] Fourth, the proposed rule's convoluted explanation for its exemplar CCS facilities has not "reasonably considered the relevant issues and reasonably explained the decision."[105] Fifth, discounting compliance costs at 3.8 percent runs counter to evidence showing that CCS facilities do not work on a large scale.[106] All of the EPA's examples of "successful" CCS facilities had significant difficulties implementing CCS and the EPA must account for those difficulties at all other regulated plants. This implies that retrofitting existing power plants with CCS facilities puts immense financial risk on the power plant operator to comply with the regulation and warrants the use of a higher discount rate when estimating compliance costs in the IPM. Sixth, the water use impact analysis runs counter to the evidence and does not consider the additional water needed for CCS. The EPA's unilateral dry cooling solution to the extra water problem does not adequately account for hot or dry environmental constraints. Seventh, the only CCS facilities that have had even limited success were linked to CO_2-EOR operations, and the EPA's other proposed solutions of geologic sequestration, mass scale saline formation, and coal-seam injection remain theoretical. Finally, the proposed rule risks successful legal challenges because the EPA "entirely failed to consider an important aspect of the problem,"[107] namely, that CCS is only viable with DOE grants and subsidies. If Congress or the DOE eliminate these grants and subsidies, the proposed rule will shutter power plants.

Not only is the proposed rule's BSER an unproveable system, but the section 111(d) standard is based on a capture rate that has never been consistently achieved at scale. Thus, state plans must

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[102] *State Farm Mut. Auto. Ins. Co.*, 463 U.S. at 43; 42 U.S.C. § 7411 (CAA 111(a)(1)) ("the best system of emission reduction [ ] (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) . . . .").
[103] See BNSF Ry. Co. v. Fed. R.R. Admin., 62 F.4th 905, 910 (5th Cir. 2023).
[104] *Rancheria v. Jewell*, 776 F.3d 706, 714 (9th Cir. 2015)
[105] *Abbott v. Biden*, No. 22-40399, 2023 WL 3945847, at *5 (5th Cir. June 12, 2023).
[106] Genuine Parts Co. v. Env't Prot. Agency, 890 F.3d 304, 313 (D.C. Cir. 2018) ("It was arbitrary and capricious for EPA to rely on portions of studies in the record that support its position, while ignoring cross sections in those studies that do not.").
[107] *State Farm Mut. Auto. Ins.*, 463 U.S. at 30.

adopt a system that does not work or force power plants to shut down as there is no alternative to meet the standard. As the U.S. Supreme Court noted in *West Virginia v. EPA*, "[o]f course, EPA has never ordered anything remotely like that, and we doubt it could."[108]

IV. The Proposed Standard for Non-continental Gas- and Oil-fired Power Plants Risks Electricity Crises in Hawaii.

The EPA has requested comment on section XII.D.1.b.vi, non-continental intermediate and baseload oil-fired power, "that is defined by 0 to 2 standard deviations in annual emission rate (using the 5-year period of data) above the baseline emission performance, or that is 0 to 10 percent above the baseline emission performance."[109] Any regulation on non-continental oil-fired power plants will decrease dispatchable baseload power generation and substantially raise electricity rates in Hawaii, which will disproportionately impact Hawaii's poor and indigenous populations.

To avoid causing a supply and affordability crisis in Hawaii, the EPA should set no emissions limitation for non-continental oil-fired baseload and intermediate power stations. Over 80 percent of Hawaii's electric power is generated by oil-fired power plants.[110] Although Hawaii has prime geography for including some renewable power sources into its energy mix,[111] its distance from the mainland and the Merchant Marine Act of 1920 have raised the cost of building renewable energy sources and stalled the state's energy transition, leaving oil-fired power as the only reliable energy source for meeting existing and growing electric power demand for the foreseeable future.

Having a single reliable energy source puts Hawaii's grid in a precarious condition and means that even small reductions in generation capacity can raise electricity prices dramatically. In September 2020, for example, Hawaii's legislature passed Senate Bill 2629, requiring Hawaii's only coal plant on Oahu to shut down by 2022.[112] The plant complied and electricity prices immediately increased seven percent as the supply of baseload power declined and was replaced with more expensive oil-fired power plants.[113]

Hawaii has tried to fill the gap in power generation with lithium battery packs to store energy generated by the limited renewable infrastructure. But Hawaiian power companies estimate only 30 percent of the battery's energy will come from renewables, with the rest derived from oil-fired power.[114] Setting an emission limit on Hawaii's dominant source of electricity for baseload and

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[108] *W. Virginia v. EPA*, 142 S. Ct. 2587, 2612 n. 3 (2022).
[109] U.S. Environmental Protection Agency, **New Source Performance... and repeal of the Affordable Clean Energy Rule**, May 23, 2023.
[110] U.S. Energy Information Administration, **US Energy Atlas with Total Energy Layers** (Last Visited: Jun 26, 2023).
[111] U.S. EIA, **Hawaii Profile Analysis**, March 16, 2023.
[112]U.S. EIA, **Hawaii Profile Analysis**, March 16, 2023; **Electricity Generation; Coal; Prohibition**, 2020(Hawaii S.B. No. 2629), Act 23.
[113] Jason Lindquist, **Can't Help Falling In Love - Hawaii Finds The Move Away From Fossil Fuels Is Easier Said Than Done**, RNB energy, June 1, 2023.
[114] *Ibid*.

peak generation while the state struggles with its energy transition will condemn Hawaiians to higher electricity rates. As studies have shown, higher electricity rates are an inequitable, regressive tax that falls disproportionately hard on the poor.[115] The higher electricity prices will hurt Hawaii's indigenous community the most, 15.5 percent of whom live in poverty.[116] The proposed rule increases the cost of electricity primarily—and unjustly—on low-income and indigenous Hawaiians.

The EPA should delay indefinitely setting emission limitations on non-continental oil-fired power plants. More importantly, the EPA should learn from Hawaii's misguided decision to forcibly close its last coal-fired plant and recognize the crises that follow when regulators artificially curb coal- and gas-fired generators.

V. The Proposed Standard for Baseload Natural Gas Plants Will Exacerbate an Electricity Crisis.

The EPA's proposed "BSER of routine methods of operation and maintenance and a degree of emission limitation of no increase in emission rate" will handicap fossil fuel powered operators to expand capacity to meet America's growing energy consumption needs. Additionally, existing natural gas plants will need to adopt either CCS technologies or low-greenhouse gas (GHG) hydrogen by 2035. The EPA's proposed inclusion of energy attribute certificates to certify low-GHG hydrogen is yet another arbitrary regulatory deterrent for utilities to expand natural gas generated electricity. Complying with these BSERs risks exacerbating an impending energy security crisis by dissuading investment in reliable and dispatchable baseload power and encouraging utilities to adopt intermittent sources of renewable electricity.

Capping the emissions rate at natural gas power plants, America's leading source of low-carbon energy, places an artificial limitation on expanding America's leading source of affordable power. Requiring future sources of natural gas to use hydrogen co-firing will increase the cost of residential electricity as existing plants will need costly retrofits and an expensive hydrogen midstream infrastructure. Additionally, most hydrogen is produced as a byproduct of natural gas refining. Hydrogen produced through electrolysis is only as clean as the energy used to produce it. CCS is not economically viable at natural gas plants due to the low concentrations of CO2 in the flue gas.[117]

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[115] Rea S. Hederman Jr., Michael E. Reed, and Trevor Lewis, ***The Economic Impact of A Potential New Clean Power Plan on Ohio and California***, The Buckeye Institute, April 12, 2023; F. Noel Perry, Colleen Kredell, Marcia E. Perry, Stephanie Leonard, **Paying for Electricity in California, How Residential Rate Design Impacts Equity and Electrification**, Next10, September 22, 2022.

[116] ***Demographic, Social, Economic, and Housing Characteristics for Selected Race Groups in Hawaii***, Research and Economic Analysis Division of the Department of Business, Economic Development & Tourism, March, 2018.

[117] Kazuya Goto, Katsunori Yogo, Yakyuki Higashii, "**A review of efficiency penalty in a coal-fired power plant with post-combustion CO2 capture**" Applied Energy, Volume 11 (November 2013) p. 710--720.

On May 4, 2023, four Federal Energy Regulation Commission (FERC) commissioners told the Senate Committee on Natural Resources and Energy that America was headed for an electricity reliability crisis.[118] Commissioner Mark Christie summarized the causes of the crisis as follows:

> The core of the problem is this: Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the addition of intermittent resources, primarily wind and solar, but the far too rapid subtraction of dispatchable resources, especially coal and gas.[119]

Coal accounts for nearly 20 percent of all electric power generated in America. When West Virginia Senator Joe Manchin asked the commissioners if America's power grid could maintain reliability if coal "pulled . . . off right now," all four commissioners agreed that it could not.[120] And removing coal from the national grid overnight would especially impact regions that depend heavily on coal for electric power. Appalachian states, like West Virginia and Kentucky, depend on coal for more than 65 percent of their electric power.[121] As Commissioner James Danly commented: "it is simply impossible to keep the system running entirely with unreliable intermittent generation."[122] Yet, the EPA's proposed rule would do exactly that by capping emissions at fossil fuel-fired power plants and pigeonholing future power generation to solely intermittent renewable sources.

Natural gas is cheaper and burns cleaner than coal, and replacing coal with natural gas could reduce power plant emissions in Appalachia's coal country. But limited pipeline capacity prevents that from happening. As Wyoming Senator John Barrasso observed during the May 4, testimony, "[i]n 2022, the least interstate natural gas pipeline capacity was added since [the energy information administration] began data collection in 1995."[123] Last year, the United States added a mere 897 million cubic feet per day of permanent interstate pipeline capacity from just five pipeline projects.[124] Permitting delays and cancelations have prevented large parts of the West Coast, New England, and Midwest, from accessing cheap natural gas. Expanding pipeline capacity would not only facilitate coal country's transition to cheaper natural gas, but it would also reduce methane emissions at wellheads. As FERC Commissioner Christie observed, expanding pipeline capacity is crucial for replacing shuttering coal plants: "We are not building a transportation capacity for gas units. Gas units increasingly are the ones that were being called upon to be the balancing resources when coal is retired prematurely, but if you can't get gas to the generating

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[118] U.S. Congress, Senate, Committee on Energy and Natural Resources, ***Full Committee Hearing to Conduct Oversight of FERC***. 118th Cong., 1st sess., May 4, 2023.
[119] ***Full Committee Hearing to Conduct Oversight of FERC***: **Testimony before the Committee on Energy and Natural Resources**, 118th Cong. (2023) (statement of Mark C. Christie, FERC commissioner).
[120] *Ibid.*
[121] Nikos Tsafos, **Phasing Out Coal from U.S. Electricity Increasingly a Regional Challenge**, CSIS, May 24, 2021.
[122] U.S. Congress, Senate, Committee on Energy and Natural Resources, ***Full Committee Hearing to Conduct Oversight of FERC***. 118th Cong., 1st sess., May 4, 2023.
[123] *Ibid.*

units, they can't run."[125] But the proposed rule's errant restrictions on emissions from natural gas fired power plants hinder the expansion of natural gas pipelines, ironically hindering expediting decarbonization of several regions living in energy isolation. Renewable power will not be able to meet these regional energy needs without natural gas generation. And without a cheap replacement for coal-fired electricity, Americans will pay more for the energy they consume.

Conclusion

The EPA has failed to adequately demonstrate CCS technology as a BSER for emission reduction under the CAA and fails Section 111(d)'s legal standard. The proposed rule leaves coal plant operators with functionally one option: shut down before 2040. The EPA's unwelcomed restrictions on natural gas risk dissuading investment in a cheap source of low-cost energy and pigeonholing producers into adopting expensive and unreliable intermittent sources of renewable power. States that have overbuilt renewable sources of power, like Texas and California, have had problems balancing power demand and power supply. This has led to power shortages, greater risk of brown- and blackouts, and households paying expensive surge prices for electricity. In its current form, the EPA's proposed rule promotes an unsustainable energy policy.

[125] *Ibid.*

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Sent: Friday, August 4, 2023 11:49 AM
To: A-AND-R-DOCKET
Cc: Darren Foster; Joel Cherry; Cole Goertz
Subject: Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule

Follow Up Flag: Follow up
Flag Status: Flagged

In the Proposed Rule for the *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, there is a reference to SaskPower's Boundary Dam Unit 3 CCS Facility '*successfully demonstrating the commercial-scale feasibility of 90 percent capture rates'*. As the owner and operator of this facility, we are providing the following correction to the emissions performance of the Boundary Dam Unit 3 CCS Facility.

- SaskPower's CCS facility was the first of its kind, and we have acknowledged the technical issues encountered at the facility, such as amine degradation resulting from fly ash ingress. We have consistently made modifications during the past eight years to stabilize operations, improve reliability and maximize capacity.
- SaskPower's CCS facility is not capturing 90 per cent of emissions from Boundary Dam Unit 3, though that is its nameplate capacity. Our CCS facility has only operated at full nameplate capacity for a few days shortly after it was commissioned.
- To maintain long-term reliable operation, only a portion of the total flue gas from BD3 can be processed by the CCS facility. The portion that cannot be processed through the CCS facility is released to the atmosphere.
- Recent performance has shown that the CCS facility can capture at least 90% of the CO_2 from the partial flue gas stream it processes.
- To ensure a higher level of overall equipment reliability and process efficiency, SaskPower has optimized the CO_2 capture rate at a target of 65 to 70 per cent of total Boundary Dam Unit 3 emissions on an ongoing basis.

If you have any questions, or would like further information, please contact Jeff Jickling at (306)566-2374 or jjickling@saskpower.com.

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APPENDIX D

DECLARATION OF RYAN ADELMAN

1. I am the Vice President of Power Supply at Idaho Power Company ("Idaho Power"). As Vice President of Power Supply, I am responsible for overseeing Idaho Power's maintenance, operations, and compliance of Idaho Power's generation fleet, including compliance with the Clean Air Act and any permitting required for Idaho Power's generating resources. I also oversee real-time operations of the transmission grid and the origination of new sources of generation. I provide this declaration in support of a motion to stay the rule promulgated on May 9, 2024 by the U.S. Environmental Protection Agency ("EPA" or "Agency"), entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39,798 (May 9, 2024) ("Final Rule").

2. This declaration is based on my personal knowledge of facts and analysis conducted by my staff.

3. I have been responsible for overseeing the teams who are responsible for the operations, maintenance, and compliance associated with Idaho Power's generation fleet. During my time at Idaho Power, I have been responsible for

compliance-driven projects and the management of design and construction of our only combined cycle natural gas plant.

4. My utility career spans over 20 years with Idaho Power, holding project management, leadership, and executive positions.

5. I graduated from the University of Idaho with a Bachelor of Science degree in civil engineering. I also received a Master of Business Administration degree from Boise State University in 2018.

IDAHO POWER OPERATIONS

6. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and capacity with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon.

7. Customer and load growth continues to increase rapidly across Idaho Power's service area. After its customer base grew 2.4% in 2023, Idaho Power currently serves approximately 636,000 residential, business, and agricultural customers in the area. Idaho Power forecasts growth of 5.5% annually through 2028.

8. Approximately 535,000 of Idaho Power's customers are residential. Idaho Power's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, health care, government, and education. Idaho Power also provides irrigation customers with

electric utility service to operate irrigation pumps during the agricultural growing season.

9. Idaho Power employes approximately 2,100 full-time employees.

10. In 2019, Idaho Power became one of the first regulated electric utilities in the nation to establish a goal of achieving 100 percent clean energy by 2045 and did so without a regulatory mandate. Today, more than half of Idaho Power's energy capacity comes from carbon-free sources, as its generation mix consists of a diverse portfolio of energy resources, including hydroelectric (36.8%); wind (9.8%); solar (5.4%); geothermal, biomass, and other renewable resources (2.3%); coal (13.0%); natural gas (15.4%); and long-term purchases of wind, solar, and other renewable resources (17.5%).

11. Idaho Power operates 17 hydropower projects located on the Snake River and its tributaries. Together, these hydropower facilities provide a total nameplate capacity of 1,818 MW and have averaged total annual generation of approximately 7.6 million MWh over the last 30 years.

12. Idaho Power co-owns two coal-fired power plants located in Wyoming and Nevada. By 2030, Idaho Power intends to convert the coal-fired units at these facilities into natural gas-fired units. Earlier this year, two of the four units at the Jim Bridger facility located in Wyoming were converted from coal to natural gas.

13. In addition to the converted units, Idaho Power also operates three natural gas-fired power plants in Idaho. One utilizes combined-cycle combustion turbines while the other two use simple-cycle combustion turbines.

14. In recent years, Idaho Power has incurred, on average, approximately $1.3 billion annually in the form of fuel, maintenance, and other operating expenses, as well as over $500 million annually in capital expenditures. Its impact on Idaho's economy is substantial.

FINAL RULE CONTROL REQUIREMENTS AND IDAHO POWER COMPLIANCE PATHWAYS

15. The Final Rule, under Section 111 of the Clean Air Act, imposes greenhouse gas emission control requirements for existing coal-fired boilers, existing natural gas-fired boilers, and new stationary combustion turbines.

16. For new and modified gas-fired combustion turbines, the Final Rule creates three subcategories based on the unit's utilization relative to its potential electric output. "Low load" units are those that sell 20% or less of their potential electric output. They must comply with a standard of performance based on lower emitting fuels. "Intermediate load" units, which sell 20-40%, must comply with a standard based on high-efficiency simple cycle turbine technology. "Base load" units, which sell more than 40%, must comply with a multi-phase standard of performance. Phase I starts immediately and is based on highly efficient combined-cycle generation. Phase II requires 90% capture of carbon dioxide using carbon

capture and sequestration ("CCS") by January 1, 2032, along with continued use of highly efficient combined-cycle generation.

17. The Final Rule may have a substantial impact on Idaho Power's operations.

18. As discussed above, Idaho Power has seen significant growth in the number of customers in its service area in recent years. Over the twelve months ended March 31, 2024, Idaho Power's customer count grew by 2.4%, and Idaho Power forecasts annual growth of 5.5% over the upcoming 5-year period, largely driven by two major projects currently under construction in its service territory. This does not take into account the potential for substantial load growth due to numerous data center inquiries.

19. To meet the demand caused by this significant load growth, Idaho Power forecasts needing to add approximately 350 MW of peak capacity for 2026-27, 138 MW of peak capacity for 2028, and at least 400 MW of additional capacity in 2029. Idaho Power is currently in the process of issuing an RFP for 2028 resources. Idaho Power intends to issue another RFP later this year for significant amounts of new generation to meet energy demand for 2029 and beyond. These forecasts have been updated after the issuance of Idaho Power's 2023 Integrated Resource Plan, which examines the company's need for additional electricity over

the next 20 years and the resources that will best meet that need while balancing reliability, cost, environmental responsibility, efficiency, and risk.

20. Idaho Power must turn to the lowest cost, least-risk option available to meet that new demand for additional energy.

21. Idaho Power has been developing significant transmission resources through its Boardman to Hemmingway Transmission Line Project ("B2H"), which began permitting in 2008; however, long-term delays in the permitting process have limited the company's ability to put B2H into service in a timely manner, meaning that Idaho Power must look to other resources to meet our growing energy demand.

22. One possible pathway is for Idaho Power to procure new natural gas-fired units. If Idaho Power determines that natural gas-fired units are the solution to its growing demand, it must act now to start building natural gas-fired units for that resource to come online in time to meet Idaho Power's generation needs. Idaho Power must identify a site and acquire it (2-3 months), determine air permitting needs (18-24 months), and build the resource (2-3 years). The process in total will take 4-5 years, which is just in time to get the resource built and online to address the capacity shortfalls projected by the company's most recent load and resource forecasts, based upon large load growth, new customers, and existing resources.

23. The Final Rule significantly complicates this pathway with its requirement of CCS by 2032 for new base load units. It is not feasible for Idaho

Power to implement CCS on those new units in that timeframe. While Idaho Power could operate any new units at a baseload capacity factor during Phase I—for the few years between 2029 and 2032—it would have to severely underutilize them in Phase II so that they stay in the low or intermediate load categories that are not burdened by a CCS mandate. If Idaho Power went forward with combined cycle units, therefore, it would have to build more of them and then underutilize each unit to stay below the 40% threshold for the base load category. Needless to say, that compliance pathway would entail unnecessary expense and waste—as it would result in building more units and operating them less efficiently rather than building fewer units and operating them more efficiently.

24. Another possible pathway Idaho Power is also considering is to build new simple cycle turbines or gas-fired reciprocating engines. Both simple cycle turbines and reciprocating engines are generally less efficient and more costly for the customer per unit of power produced than combined cycle turbines, but if new natural gas combined cycle units are artificially constrained to less than 40% of their capacity beginning in 2032 under the Final Rule, then simple cycle turbines and/or reciprocating engines may make more economic sense than the more capital-cost intensive combined cycle units. Because reciprocating engines are less efficient than larger simple cycle turbines, they also result in higher emissions per megawatt.

25. Idaho Power's ability to pursue this second compliance pathway is further complicated by the Final Rule's stringent requirements for intermediate load units, which make constructing new simple cycle units inefficient and costly. These requirements are very stringent, and it is unclear when vendors will be able to guarantee performance for simple cycle units that would meet these intermediate load requirements.

26. Due to the near-term need to construct new dispatchable capacity to meet growing demand, the long lead time required to bring new generation online, and the regulatory filings that must be filed well in advance, Idaho Power cannot wait until the challenges to the Final Rule reach a final conclusion before deciding how to proceed. Instead, the company will have to make decisions among the possible compliance pathways that are difficult to reverse and incur expenses proceeding down a compliance pathway in the next 24 months, which may ultimately cause Idaho Power to lose much-needed time.

27. These costs will impact Idaho Power and its customers. As a regulated utility subject to the jurisdiction and regulation of the Oregon Public Utility Commission ("OPUC") and the Idaho Public Utilities Commission ("IPUC"), costs incurred by Idaho Power that are deemed prudent by the OPUC and IPUC are ultimately included in the rates charged to Idaho Power's customers. Any timely-

made expenditure to comply with the Final Rule in good faith will be paid by either Idaho Power or its customers, even if EPA's Final Rule is later overturned.

28. Adding more pressure to the timeline is that, prior to beginning construction, Idaho Power will also need to: (1) seek approval from the OPUC through its RFP process and the IPUC through its Certificate of Public Convenience and Necessity process, which typically takes a total of 2-4 years; and (2) submit new or modified air permit applications, which Idaho Power estimates takes between 1-2 years.

29. Idaho Power's timing issues are further complicated by Oregon's resource procurement rules that must be followed for any resource over 80 MW with a duration of five years or more. This process can take 19-36 months. The process involves OPUC, stakeholder, and independent evaluator oversight of Idaho Power's resource procurement process. The IPUC requires Idaho Power to follow the Oregon resource procurement process. If the successful resource procured under the Oregon competitive bidding rules is one that was submitted by Idaho Power, the company must obtain a Certificate of Public Convenience and Necessity in Idaho, which adds an additional 6-12 months. For Idaho Power to comply with these requirements, the company must start this process now in order to bring resources online to meet forecasted load growth in 2029.

INFEASIBILTY OF CCS BY 2032

30. Installing and having operational CCS on Idaho Power's new gas units by 2032 is infeasible.

31. The Department of Energy ("DOE") has laid out a timeline demonstrating that CCS projects take 14.5 years from the date of their funding award to become operational. Included in DOE's timeframe is a planning phase (up to 1.5 years); siting, permitting, and financing phase (up to 3 years); building and integration (up to 6 years); and ramp-up and operations (up to 4 years): U.S. Department of Energy: Office of Clean Energy Demonstrations, Bipartisan Infrastructure Law Carbon Capture Demonstration Projects Program, Funding Opportunity Announcement Number: DE-FOA-0002962, at 12, available at https://oced-exchange.energy.gov/Default.aspx#FoaId151b5065-5838-46ba-9a23-b188d2086a39. Yet January 1, 2032, the Final Rule's requirement for operating with CCS with 90% capture for new base load combined cycle turbines, is less than 8 years away. Accordingly, Idaho Power has only about half the time the Department of Energy forecasts that a company needs to have operational CCS—and any new natural gas-fired units have not even been built yet.

32. One complication that adds more time to this already lengthy timeline is that Idaho Power does not have ready access to a CO_2 pipeline network, which is necessary for CCS to operate. To my knowledge, there are no current plans for permitting or building a CO_2 pipeline at or near Idaho Power's service territory.

Without pipeline transport availability, CCS cannot happen unless a facility is fortuitously located above a sequestration unit.

33. Additionally, permitting for and construction of the necessary pipeline system is a lengthy process, and there is no guarantee that those obstacles to constructing the pipelines could be overcome at all.

34. Another issue is that injecting CO_2—another necessary part of the CCS process—also requires permits that take a long time to obtain. To my knowledge, there are no injection sites currently in use in Idaho. If Idaho Power elects to pursue base-load natural gas combined cycle units, in order to comply with the Final Rule's 2032 deadline, Idaho Power would need to immediately begin assessing whether injections sites are available for development by the compliance deadline.

35. If Idaho Power were to pursue CCS, it may have to explore in hopes of discovering new sequestration sites that are not too distant from its new units. Even if it did, it would then have to obtain title to the sites, build the necessary injection infrastructure, and obtain the required permits. This process could take several years, assuming that suitable sites could even be found in the first place.

36. Exacerbating all of these issues is that the Final Rule applies to all power plants throughout the United States. For that reason, power companies across the country would all be going through these steps at the same time. That will result in unprecedented demand for CCS resources and equipment, increased costs, and a

massive influx in permitting applications being submitted, further straining an already overly burdened review process. All of that introduces greater uncertainty into the timelines and would likely result in additional delays.

37. In sum, because it would take well over a decade to install CCS a combined cycle natural gas turbine, it is not feasible to do so by the Final Rule's 2032 Phase II commencement.

COMPLIANCE PATHWAYS AND IRREPARABLE HARM

38. Assuming there were no CCS requirement, Idaho Power would have the option of constructing natural gas turbines as needed for our growth and could operate them at base load for the foreseeable future. But that option is unavailable to Idaho Power because of the infeasible CCS requirement.

39. Because CCS is not a feasible option, Idaho Power must evaluate whether it would (i) construct combined cycle turbines that would operate at base load during Phase I and low and intermediate load during Phase II; (ii) construct simple cycle turbines or potentially some gas-fired reciprocating engines that would operate at low and intermediate load during both Phases I and II; or (iii) employ some combination of those approaches. Idaho Power must begin the planning process for any of these approaches now in order to meet forecasted demand growth in 2029 and beyond, given the extended timeline required to bring new resources online.

40. In addition to the construction timelines discussed above in paragraph 22, new units must also navigate the grid interconnection queue before they begin providing power to customers. That can take up to 4 years as a result of the new FERC Order No. 2023, 184 FERC ¶ 61,054 (2023).

41. Putting that all together, bringing a new unit online requires 4 years *at minimum*, and may require up to 9 years.

42. Accordingly, to ensure that new natural gas-fired units are online and providing power to customers by 2029, Idaho Power must begin the planning for new electric generating units immediately, with much work to happen and costs to be incurred over the next 24 months.

43. If Idaho Power elects to build new gas generation, it would incur approximately $8 million to $15 million in costs over the next 24 months.

44. Idaho Power would also have to enter into contracts for the construction of the new units in the next 24 months, which could include cancellation fees and termination penalties that would apply even if a court later vacates EPA's Final Rule.

45. In sum, to meet the needed demand by 2029, Idaho Power must make critical decisions and financial commitments now if the company chooses to move forward with new natural gas-fired units. If the company moves toward new natural gas, it must decide now whether to build more efficient combined cycle units and then either hope that the Final Rule gets vacated or operate those expensive

investments less efficiently after 2032; or whether to choose less-efficient simple cycle units or gas-fired reciprocating engines, which may impact operations going forward. Each path creates significant, irreparable harms and would result in the expenditure of millions of dollars in the next 24 months.

CONCLUSION

46. For the reasons described above, Idaho Power and potentially its customers are facing substantial irreparable harm during the next 24 months from the Final Rule.

I, Ryan Adelman, declare under penalty of perjury that the foregoing is true and correct. Executed this 24th day of May, 2024.

Ryan N. Adelman

DECLARATION OF ERIK BAKKEN

1. I am the Senior Vice President of Energy Resources and Chief Sustainability Officer of Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric"), (TEP and UNS Electric collectively as "Companies"), which are wholly owned direct and indirect subsidiaries of the Arizona-based parent company, UNS Energy Corporation ("UNS Energy").

2. As Senior Vice President of Energy Resources and Chief Sustainability Officer, I am responsible for the Companies' power generation operations, renewable development, system control and transmission planning. I also oversee environmental compliance, sustainability strategy, and policy advocacy. I provide this declaration in support of a motion to stay the rule promulgated on May 9, 2024 by the U.S. Environmental Protection Agency ("EPA" or "Agency"), entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39,798 (May 9, 2024) ("Final Rule").

3. This declaration is based on my personal knowledge of the facts and the analysis conducted by my staff.

4. I have been responsible for overseeing a number of areas, including Land Resources, Corporate Environmental Services, Transmission Development, Renewable Development, Power Plant Operations, and System Control Operations since I joined the Companies in 2000. During my time at the Companies, I have been responsible for a number of diverse projects, including transmission siting, development and construction of over 1,000 megawatts of renewable energy and battery energy storage, carbon capture and sequestration ("CCS") feasibility analyses (including sequestration viability), and the Companies' energy transition to a net zero carbon aspirational goal in 2050.

5. My career spans over 20 years. Before joining the Companies, I was employed by the Arizona Chamber of Commerce and the Arizona State Legislature House of Representatives. At those entities, I was responsible for policy development and advocacy.

6. I graduated with a Bachelor of Arts Degree in Political Science from Arizona State University in 1995 and a law degree in 2000 from the University of Arizona.

TEP AND UNS ELECTRIC OPERATIONS

7. Under the Arizona-based parent company of UNS Energy, TEP serves more than 447,000 customers in and around Tucson across 1,155 square miles, while UNS Electric provides electric service to about 103,000 customers in Mohave

County in northwest Arizona and in Santa Cruz County in southeast Arizona across 8,000 square miles.

8. TEP employs approximately 1,740 full-time employees. UNS Electric employs approximately 152 full-time employees.

9. In recent years, TEP and UNS Electric together have invested approximately $600 million annually in capital expenditures and $500 million annually in operating and maintenance expenses, which has had a substantial impact on Arizona's economy.

10. TEP and UNS Electric together contribute approximately $200 million annually in sales, use, and property taxes. The taxes it pays to the communities where its facilities operate are an indispensable source of government revenue for those localities, including their local public schools and libraries.

11. As of December 31, 2023, TEP had 3,101 MW of nominal generation capacity split between natural gas, coal, and renewable generation sources. UNS Electric maintains 300 MW of generation split between natural gas and renewable generation sources. TEP serves as the balancing authority on behalf of itself and UNS Electric and is responsible for managing system reliability for both the TEP and UNS Electric systems.

FINAL RULE CONTROL REQUIREMENTS AND COMPLIANCE PATHWAYS

12. The Final Rule, under Section 111 of the Clean Air Act, imposes greenhouse gas emission control requirements for existing coal-fired boilers, existing natural gas-fired boilers, and new stationary combustion turbines.

13. For new and modified gas-fired combustion turbines, the Final Rule creates three subcategories based on the unit's utilization relative to its potential electric output. "Low load" units are those that generate 20% or less of their potential electric output. They must comply with a standard of performance based on lower emitting fuels. "Intermediate load" units, which generate 20% to 40% of their potential output, must comply with a standard based on high-efficiency simple cycle turbine technology. "Base load" units, which generate more than 40% of their potential output, must comply with a multi-phase standard of performance. Phase I starts immediately and is based on highly efficient combined-cycle generation. Phase II requires 90% capture of carbon dioxide using CCS by January 1, 2032, along with continued use of highly efficient combined-cycle generation.

14. The Final Rule will have a substantial impact on the Companies' operations.

15. TEP plans to retire its last 903 MW of coal-fired generation with the retirement of Units 1 and 2 at TEP's Springerville Generating Station ("Springerville") in 2027 and 2032, respectively, and Units 4 and 5 at the co-owned

Four Corners Power Plant in 2031. The retirement of Springerville Unit 1 in 2027 will result in the loss of about 387 MW of coal-fired generation. The retirement of Units 4 and 5 at the Four Corners Power Plant in 2031 will result in the loss of about 110 MW of coal-fired generation. Finally, the retirement of Springerville Unit 2 will result in the loss of about 406 MW. This generating capacity must be replaced prior to the retirement dates mentioned above.

16. Additionally, load growth has created an urgent need for new generation resources in the Desert Southwest. For example, TEP projects that peak energy demand on the Companies' systems will increase from 2,382 MW in 2024 to 2,800 MW by 2038.

17. UNS Electric also plans to increase its generation to meet increased demand in the region. Currently, UNS Electric is heavily dependent on wholesale market purchases in a region that is short on resource capacity in the summer. UNS Electric's 2023 resource plans contemplate adding approximately 250 MW of new natural gas generation capacity. UNS Electric plans to serve over 100 MW of additional new mining load starting in 2029.

18. Importantly, the Companies' current projections do not incorporate the drastic spike in potential demand seen across the country, including in the Companies' service territory as of late 2023. The Companies share the growing consensus in the electric industry that the nation can expect to see substantial growth

in new drivers of electric demand: data centers, larger industrial loads in advanced manufacturing industries, and electrification. For context, TEP has been contracted to study its ability to serve more than 2,000 MW of additional high load factor loads for potential customers. If the loads under study result in projects like those being developed in states such as Mississippi and Indiana, TEP's peak energy demand in 2038 would be over 4,800 MW. This means the Companies must do more than merely replace the capacity lost to retirements, it will be required to actually increase its total generation above its current planned level of generation resources to account for the growing demand.

19. Based on TEP's and UNS Electric's 2023 Integrated Resource Plans ("IRPs"), the Companies plan to meet future load obligations with a combination of renewables, battery storage, and natural gas. Absent the new limitations in the Final Rule and based on revised commercial and industrial load ("C&I") growth projections in these service territories, TEP and UNS Electric would consider building new natural gas combined cycle ("NGCC") units to meet these C&I demands. NGCC units are seen as the most efficient and cost-effective natural gas technology to meet these high load factor C&I loads.

20. The Final Rule significantly complicates that plan, however. Its requirement of CCS on new base load units by 2032 is the main problem. It is not feasible for TEP and UNS Electric to implement CCS on those new units in that

short timeframe. The Companies could operate the NGCC units as planned during Phase I, but would have to severely underutilize them in Phase II so that the NGCC units stay in the low or intermediate load categories that are not burdened by a CCS mandate. Under the Final Rule, if NGCC is constrained to a 40% capacity factor, the Companies would have to build additional NGCC capacity in order to serve its future load requirements and then underutilize the resources to stay below the 40% threshold for the base load category. Needless to say, that compliance pathway would entail unnecessary expense and waste—as it would result in building more natural gas units and operating them less efficiently rather than building fewer units and operating them more efficiently.

21. A second compliance pathway that TEP and UNS Electric could consider is to build fewer or no NGCC and instead produce that power through new simple cycle units. Simple cycle units are less efficient and would cost approximately 40% more on a dollar per megawatt basis compared to NGCC resources.

22. A third compliance pathway could involve adding considerably more renewable energy resources and battery storage capacity to meet the baseload demand requirements of customers. Renewables and battery storage would be more costly for the customer per unit of power produced than NGCC or simple cycle units operating as base load resources. Additionally, renewables and battery storage as

standalone base load resources do not offer the same reliability benefits (*i.e.*, grid stability) as natural gas-fired units. Renewables and battery storage are invertor-based technologies, and battery storage typically only provides 4-hours of available capacity when fully charged versus the on-demand capacity that is available 24-hours a day with natural gas resources.

23. Due to the impending retirements of the coal units, the need to construct new capacity in the near future to meet growing demand, the long lead time required to bring new generation online, and the regulatory filings that must be filed well in advance, TEP and UNS Electric cannot wait until the challenges to the Final Rule reach a final conclusion before deciding how to proceed. Instead, they will have to make effectively irreversible decisions among the possible compliance pathways and potentially incur unrecoverable costs proceeding down a compliance pathway in the next two months as the Companies look to submit interconnection requests and secure queue positions to procure major equipment for new natural gas generation.

24. The irreparable harm from attempting to comply with the Final Rule would have a significant cost and reliability impact for TEP, UNS Electric, and their customers. As a regulated utility subject to the jurisdiction and regulation of the Arizona Corporation Commission ("ACC"), costs incurred by TEP and UNS Electric that are deemed prudent by the ACC are ultimately included in the rates

charged to their customers. Accordingly, any timely-made expenditure to comply with the Final Rule in good faith will be incurred by the Companies, as applicable, and ultimately included in customer rates, subject to ACC approval. If the Final Rule is later vacated, these expenditures may not be recoverable through customer rates as they could be deemed by the ACC to be imprudent investments given there would be no regulatory justification for installing CCS.

INFEASIBILTY OF CCS BY 2032

25. Installing and having operational CCS on TEP's and UNS Electric's new gas units is infeasible.

26. The Department of Energy ("DOE") has laid out a timeline demonstrating that CCS projects take 14.5 years from the date of their funding award to become operational. Included in DOE's timeframe is a planning phase (up to 1.5 years); siting, permitting, and financing phase (up to 3 years); building and integration (up to 6 years); and ramp-up and operations (up to 4 years): U.S. Department of Energy: Office of Clean Energy Demonstrations, Bipartisan Infrastructure Law Carbon Capture Demonstration Projects Program, Funding Opportunity Announcement Number: DE-FOA-0002962, at 12, available at https://oced-exchange.energy.gov/Default.aspx#FoaId151b5065-5838-46ba-9a23-b188d2086a39. Yet January 1, 2032, the Final Rule's requirement for operating with CCS with 90% capture for new base load combined cycle turbines, is less than 8

years away. Accordingly, TEP and UNS Electric have only about half the time the DOE says it needs to have operational CCS—and their new natural gas-fired units have not even been built yet.

CCS – Capture Timeline

27. Just the "capture" piece of CCS would take years. TEP and UNS Electric would have to hire an engineering team immediately to begin that process. Each engineering phase can only proceed once the necessary regulatory and internal approvals are also completed. Strategy and scoping would take up to a year, followed by up to six months for a pre-feasibility study. A pre-Front End Engineering and Design ("FEED") study would take six months, and a FEED design would take 24 months.

28. Before TEP and UNS Electric could proceed beyond a FEED design, financing authority and internal approvals would likely need to be secured. Given the exorbitant cost of a capture project receiving the necessary internal and regulatory approvals would take up to 6 months or more. Before TEP and UNS Electric could begin construction, they would need to go through a lengthy permit-amending process. Based on TEP's and UNS Electric's experience, modifying a Title V operating permit would take approximately 30 to 33 months. Finally, assuming there are no regulatory delays, financing issues, or labor availability issues, TEP and UNS Electric can commence construction, which requires approximately

another 36 months. Then commissioning and the beginning of full operation would take at least 6 months.

29. In sum, just the capture piece of CCS would take close to 10 years. Accordingly, TEP and UNS Electric would have to begin that work immediately.

CCS – Transport Timeline

30. A further complication that adds more time to this already lengthy timeline is that TEP and UNS Electric do not have ready access to a CO_2 pipeline network, which is necessary for CCS to operate. Pipeline transportation is the only feasible means of transporting the captured CO_2 to the sequestration location. However, there is currently no CO_2 pipeline capacity in Arizona, and none is readily available near TEP and UNS Electric's units. Without pipeline transport availability, CCS cannot happen unless a facility is fortuitously located above a sequestration unit.

31. Permitting for and construction of the necessary pipeline system could take a minimum of 4 to 5 years, and there is no guarantee that the obstacles to constructing the pipelines could be overcome at all.

CCS – Injection and Storage Timeline

32. Injecting CO_2—another necessary part of the CCS process—also requires permits that take a long time to obtain. The Arizona Geological Survey has undertaken a survey to identify an appropriate geologic sequestration unit. It has

found some formations that may have appropriate characteristics, and these units must now have wells drilled to evaluate whether the characteristics are actually appropriate for sequestration. The Arizona Geological Survey is seeking funds to complete this work, and the first test well in Arizona that could potentially support underground storage in one formation (likely the Harquahala basin) is planned to be completed in two to three years. One other site is being considered for natural gas storage, but neither basin has been proven as a viable site for carbon sequestration, to this point. TEP and UNS Electric are actively engaged in these efforts through programs like DOE's CarbonSAFE Phase II program and other CCS development activities.

33. If TEP and UNS Electric were to pursue CCS, they would therefore have to explore in hopes of discovering new sequestration sites that are not too distant from its new units. Even if they did, they would then have to obtain title to the sites, build the necessary injection infrastructure, likely enter into multi-party agreements and obtain the required permits. Just the permitting part of that process alone could take 5 to 6 years. And there is no guarantee that suitable sites can be found nearby.

CCS – Full Timeline

34. Putting that all together, it likely would take more than decade to install CCS on TEP's and UNS Electric's potential new NGCC, especially since many

aspects of work on the three facets of CCS (*i.e.*, capture, transport, and storage) cannot necessarily be pursued simultaneously. Accordingly, that work could not be completed by Final Rule's 2032 Phase II commencement.

35. Exacerbating these issues is that the Final Rule applies to all power plants throughout the United States. For that reason, power companies across the country would all be going through these steps at the same time. That would result in unprecedented demand for CCS resources and equipment and a massive influx in permitting applications being submitted, further straining an already overly burdened review process. All of that introduces greater uncertainty into the timelines and would likely result in additional delays.

36. In short, CCS is not a viable option for TEP and UNS Electric given the 2032 compliance deadline.

NATURAL GAS RESOURCES IDENTIFIED AS LEAST COST RESOURCES IN THE COMPANIES' 2023 RESOURCE PLANS

37. The Companies' 2023 IRPs resource portfolios identified the need for 650 MW of new natural gas resources. These resource portfolios were shown to balance both reliability and affordability for customers while achieving an 80% reduction in carbon dioxide emissions by 2035.

38. NGCC plants without CCS can be constructed at an approximate cost of $1,388/kW. Once constructed, an NGCC operating at a baseload capacity factor of 75% and $4.00/mmBtu natural gas pricing has a leveled cost of energy of

approximately \$57.50/MWh. Limiting NGCC plants to a 40% capacity factor (because CCS is infeasible) would reduce the total energy production of the plant by approximately 53% and result in a levelized cost of energy of approximately \$83.50/MWh and would require the Companies to invest hundreds of millions of dollars more in additional generation resources in order to maintain the same reliability requirements for its customers.

COMPLIANCE PATHWAYS AND IRREPARABLE HARM

39. Assuming there were no CCS requirement, TEP and UNS Electric would construct NGCC at an approximate cost of \$720,000,000 and would operate them as base load resources for the foreseeable future. That is the most efficient option and will result in the lowest cost to customers. But that option is unavailable to TEP and UNS Electric because of the infeasible CCS requirement.

40. Because CCS is not a feasible option, this means TEP and UNS Electric must decide now whether they will (i) construct NGCC that will operate at base load during Phase I and low and intermediate load during Phase II; (ii) construct simple cycle turbines that will operate at low and intermediate load during both Phases I and II; (iii) install enough renewable energy and storage capacity to meet future baseload demand requirements; or (iv) employ some combination of the approaches.

41. Both NGCC and simple cycle units take approximately 4 to 7 years to develop and construct.

42. Renewable and battery storage projects take approximately 3 to 4 years to develop and construct.

43. Regardless of the type of new resource built, all must navigate the grid interconnection queue study process before it may proceed with construction of a project. This process can take several years, as TEP and UNS Electric, and other transmission providers are in the midst of implementing new reforms to the interconnection procedures contained within their Open Access Transmission Tariff as mandated by the Federal Energy Regulatory Commission.

44. Accordingly, to ensure that new natural gas-fired units (and potentially renewables and battery storage as well) are online and providing power to customers by the time of the planned retirements of TEP's coal units starting in 2027, the Company must begin the process of designing, building, and interconnecting new natural gas-fired units immediately, with much work to happen and costs to be incurred over the next 24 months.

45. Over the next 24 months, the Companies plan to make commitments of approximately $280,000,000 in natural gas-fired resources that will be at risk if the Final Rule is not stayed.

46. TEP and UNS Electric would also have to enter into binding contracts for the design and construction of new natural gas-fired resources in the next 24 months. These contracts may include cancellation fees and termination penalties that

would apply even if a court later vacates EPA's Final Rule. Termination penalties typically equate to 10-25% of the project cost and are unrecoverable in the regulatory environment.

47. Furthermore, delays in construction result in lost contracts, delays in installation, and cost overruns that can double the total installed cost of new natural gas-fired resources. For TEP and UNS Electric to meet its future reliability and system load growth projections, the Companies need to initiate design and procurement services immediately. Furthermore, permitting has become increasingly lengthier and construction services are extremely limited.

48. In sum, to meet the needed resource capacity demands by 2028, TEP and UNS Electric must make effectively irreversible decisions and financial commitments now for its new natural gas-fired resources. They must decide now whether to (i) build more efficient combined cycle units and then either hope that the Final Rule gets vacated or operate those expensive investments at a lower capacity factor that results in higher costs for customers; (ii) incur higher capital costs regardless of what happens with the challenges to the Final Rule by building all simple cycle units and renewables and battery storage; or (iii) employ a combination of both approaches. Any of those paths will lock TEP and UNS Electric into a potentially sub-optimal course and result in the expenditure of many millions of dollars in the next 24 months and will significantly impact customer rates.

CONCLUSION

49. For the reasons described above, TEP, UNS Electric, and potentially their customers are facing substantial irreparable harm during the next 24 months from the Final Rule.

I, Erik Bakken, declare under penalty of perjury that the foregoing is true and correct.

Executed this 24th day of May, 2024.

Erik Bakken
Vice President of Energy Resources
and Chief Sustainability Officer
Tucson Electric Power Company
and UNS Electric, Inc.

DECLARATION OF MATTHEW BULPITT

1. I am the Vice President, Power Development for Entergy Services, LLC. As Vice President, Power Development, I am responsible for management oversight responsibility for the development and execution of decarbonization projects and technology to support the needs of the Entergy Corporation's Operating Companies, including renewable power plant development and construction. I am also responsible for leading broad initiatives, such as the potential deployment of post-combustion carbon capture technology in natural gas power plants, to support the planning of Entergy Corporation's future generation portfolio to meet Entergy's customers' demands and its own long-term corporate emissions commitments. I provide this declaration in support of a motion to stay the rule promulgated on May 9, 2024 by the U.S. Environmental Protection Agency ("EPA" or "Agency"), entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39,798 (May 9, 2024) ("Final Rule").

2. This declaration is based on my personal knowledge of facts and analysis conducted by Entergy.

3. During my early time at Entergy, I held various roles in Entergy's Capital Projects organization supporting the development and execution of two new combined cycle natural gas power plants in Louisiana and Texas. I subsequently held the role of Director, Commercial Operations in the System Planning & Operations ("SPO") organization within Entergy Corporation, where I was responsible for managing the procurement of long-term generation resources (one year or longer), including power plant acquisitions, renewable resource acquisitions, and power purchase agreements on behalf of the Entergy Corporation Operating Companies. In March 2021, I became the Director of Power Development, and in May 2022, I assumed my current role as Vice President of Power Development. I am responsible for the development and construction of decarbonization capital projects, maintaining the company's technical, cost, and schedule view of carbon-free power generation technology, including solar, wind, battery storage, hydrogen, and carbon capture, and conducting detailed engineering studies to evaluate deploying new decarbonization technologies, such as carbon capture, in Entergy Corporation's existing and planned power plants.

4. I graduated from LeTourneau University with a Bachelor of Science degree in Electrical Engineering. I also graduated from the US Navy's Bettis Reactor Engineering School with a master's-level certificate in nuclear engineering, and graduated from Old Dominion University with a Master's degree in Engineering

Management. I also have been a licensed Professional Engineer in Texas since November 2015. Prior to joining Entergy, I served on active duty in the US Navy's Naval Nuclear Propulsion Program from November 2002 to June 2008, and worked for the US Navy directly as a government civil servant in the US Navy's Naval Nuclear Propulsion Program from June 2008 to August 2015. During my years of active duty and civil service, I held several engineering project management positions for the design and construction of nuclear power plant instrumentation and control systems, propulsion plant instrumentation and control systems, and electric plant power generation and distribution systems for nuclear powered submarines and aircraft carriers.

ENTERGY OPERATIONS

5. Entergy Corporation's utility operating companies in Arkansas, Louisiana, Mississippi, and Texas, together provide power to more than 3 million customers. As used herein, the term "Entergy" refers to Entergy Services, LLC and encompasses the utility services provided by the operating companies.

6. Entergy provides capacity and energy-related services in a balanced and environmentally responsible manner. Entergy's fleet includes 28 active natural gas, oil, hydroelectric, and coal generating facilities with a combined capacity of nearly 19,000 megawatts. The Entergy nuclear fleet produces approximately 5,000 megawatts. Entergy also has approximately 3,100 megawatts of renewable energy

projects that are either operational or have been announced and approved, and it is in the process of soliciting additional renewable resources through various requests for proposal processes.

7. In 2019, Entergy Corporation set a goal to achieve net-zero greenhouse gas emissions by 2050 and, by 2030, to reduce its CO_2 emission rate (including both owned and purchased power) by 50% relative to the 2000 rate. In 2022, Entergy Corporation set an additional goal to achieve 50% carbon-free (nuclear + renewable) generating capacity by 2030.

8. Part of these efforts include Entergy's investment in two projects that are the cutting edge of emissions control technology. One is the Orange County Advanced Power Station ("OCAPS"), a 1,215-megawatt facility in Orange, Texas. OCAPS will be a dual-fuel combined cycle facility that utilizes combustion turbines capable of co-firing hydrogen and natural gas. Entergy Texas (one of the utility operating companies) broke ground on OCAPS in early 2023.

9. The other project of note is a pioneering effort at demonstrating carbon capture, transport, and storage ("CCS") at an existing gas power plant. In December 2023, Entergy Louisiana (one of the utility operating companies) was selected as an awardee for the U.S. Department of Energy's Office of Clean Energy Demonstrations Carbon Capture Demonstration Projects Program Front-End Engineering Design ("FEED") Studies. The project, which began in January 2024,

is in the process of developing a FEED analysis for a CCS project at Entergy's Lake Charles Power Station ("Lake Charles"), which is Entergy's 1,000-megawatt combined cycle combustion turbine in Westlake, Louisiana. CCS is an emerging emissions control technology, and this facility will help to establish its feasibility at large-scale power plants. Entergy believes that CCS potentially could be installed and operational for *certain* new combined cycle combustion turbine ("CCCT") plants within its fleet by 2032, though the technology, and importantly the needed transportation and storage infrastructure, simply cannot be ready for all new CCCTs by that time. Assuming the technology is proven to be successful, Entergy anticipates deploying CCS at all new CCCT plants when the infrastructure can be completed to support the capture, transportation, and sequestration of carbon dioxide. Due to significant differences in existing infrastructure and geology, however, Entergy expects that it will take longer, potentially substantially so, than 2032 to have the necessary infrastructure in place in all four states where it serves.

10. Entergy's service areas in Texas and Mississippi are facing significant load growth in the near-term. In Texas, the demand is both industrial—centered in and around Port Arthur—and residential—centered in and around the greater Houston area. Entergy projects a need to increase generating capacity by over 40% over the next four years. In Mississippi, Amazon Web Services recently announced a $10 billion investment, which will require over 1 GW of new natural gas and solar

generation to support. To respond to AWS's investment, Entergy Mississippi will need to invest between $2 and $3 billion in new generation resources.

11. To provide additional capacity needed for sharply increasing demand across its service area, Entergy has submitted permit applications for new natural gas combined cycle units in Port Arthur, Texas (the "TX Plant") and Greenville, Mississippi (the "MS Plant"). The TX Plant and MS Plant (together, the "Plants") each will be constructed with one combustion turbine, one supplemental fired heat recovery steam generator, and one steam turbine.

12. Entergy employs approximately 12,000 people and has, since 2018, delivered more than $100 million in economic benefits each year to local communities through philanthropy, volunteerism, and advocacy.

FINAL RULE CONTROL REQUIREMENTS AND IMPACTS ON ENTERGY

13. The Final Rule, under Section 111 of the Clean Air Act, imposes greenhouse gas emission control requirements for existing coal-fired boilers, existing natural gas-fired boilers, and new stationary combustion turbines anticipated to operate above a threshold capacity level.

14. EPA's promulgation of the Final Rule will have a substantial impact on Entergy's operations with respect to its planned new CCCTs.

15. The Final Rule requires CCS with a 90% capture of CO_2 by 2032 for the base load subcategory for new combustion turbines, *i.e.*, new CCCTs.

16. Entergy's owned coal-fired generation represents 2,368 megawatts of peak summer capacity.[1] In keeping with its planning principle to balance affordability, reliability, and sustainability and in recognition of the advanced age of our coal assets, Entergy plans to cease combustion of coal at its remaining coal units by 2030.

17. Entergy's TX Plant and MS Plant are examples of investments underlying Entergy's continued portfolio transformation, which includes ceasing coal combustion at remaining units and retiring less efficient legacy gas assets while also allowing Entergy to keep pace with significant demand growth.

18. Before the Final Rule was promulgated, Entergy planned on permitting, constructing, and operating the TX Plant and the MS Plant as base load combined cycle units with hydrogen capability and carbon capture deployment as soon as practicable. However, whether it would be practicable to complete the installation by 2032 is uncertain at best; indeed, it is uncertain whether CCS technology even can capture carbon dioxide at the rate required by the EPA, and there is very little existing infrastructure to transport and store captured carbon dioxide, particularly in Mississippi. Despite these serious uncertainties, Entergy must immediately reallocate money, labor, and other resources to concurrently develop, permit, construct, and install operational CCS in conjunction with the construction of the

[1] As reported on EIA form 860 (2022).

Plants themselves. In other words, instead of building the Plants first and potentially adding CCS second when the technology and infrastructure can be built, tested, and ready, Entergy is going to have to do everything at once if it has any chance of meeting the 2032 deadline.

19. Assuming it is required to self-provide CCS, Entergy estimates that compliance with the Final Rule by 2032 for the Plants would cost in excess of $2 billion, with substantial costs to be incurred over the next 24 – 36 months while the litigation is pending.[2]

20. These costs will impact not only Entergy but also, importantly, its customers. As a regulated utility subject to the jurisdiction and regulation of several state utility commissions, prudently incurred costs are eligible for recovery in the rates charged to Entergy's customers; by definition, these would encompass costs to comply with new EPA regulation. Accordingly, assuming prudent investment in compliance costs, these costs will be paid by customers regardless of whether (1) the EPA rule survives legal challenge; and (2) the technology ultimately proves to be cost-effective and able to capture carbon at the rate required by the EPA. Once the costs are paid, there is no mechanism under federal law to reimburse customers (or

[2] This assumes a self-build structure. The amount spent by Entergy could vary by commercial structure and payment milestones if there are viable options to self-providing CCS.

Entergy), thus causing irreparable harm of potentially billions of dollars to Entergy and its customers.

COMPLIANCE TIMELINE FOR CCS ON THE TX AND MS PLANTS

21. Installing and having operational CCS on the TX and MS Plants by 2032 is extremely challenging at best and infeasible at worst. Immediate commencement and an aggressive timeline are the only way Entergy could possibly have any chance of meeting the Final Rule's January 1, 2032 deadline given the lengthy lead time required for installing CCS. Even with that, it may not be possible for Entergy to install CCS on the TX and MS Plants by the deadline, and there is no way to predict whether the needed transportation and sequestration infrastructure can be in place by that time, especially in Mississippi, even if the capture technology could be installed timely. Despite the lack of commercially proven capture technology at the level required by the EPA and the absence of transportation and sequestration infrastructure, simply to have even a hope of meeting the 2032 deadline, Entergy would need to commence work within the next six months.

22. The Department of Energy ("DOE") has laid out a timeline demonstrating that CCS projects take 14.5 years from the date of their funding award to become operational. Included in DOE's timeframe is a planning phase (up to 1.5 years); siting, permitting, and financing phase (up to 3 years); building and integration (up to 6 years); and ramp-up and operations (up to 4 years): U.S.

Department of Energy: Office of Clean Energy Demonstrations, Bipartisan Infrastructure Law Carbon Capture Demonstration Projects Program, Funding Opportunity Announcement Number: DE-FOA-0002962, at 12, available at https://oced-exchange.energy.gov/Default.aspx#FoaId151b5065-5838-46ba-9a23-b188d2086a39. This timeline comes from the very funding opportunity that was awarded to Lake Charles. Yet January 1, 2032, the Final Rule's requirement for operating with CCS with 90% capture for new base load combustion turbines, is less than 8 years away. Accordingly, Entergy has only about half the time the Department of Energy says it needs to have operational CCS.

23. Before Entergy could begin construction, it would need to go through a lengthy permit application-amending process of two permits that Entergy, to date, does not possess. Based on Entergy's experience, modifying a Prevention of Significant Deterioration (PSD) permit application to incorporate the additional air emission sources from a carbon capture facility and incorporate the CCS impacts on a generating unit would take approximately 3-4 months and add approximately 2-3 months of review time by the state permitting agency. Alternatively, Entergy could allow its pending permit applications to remain as-is and permit the carbon capture facility separately. Doing so would take approximately 12-27 months from initial application development to expected final permit issuance. In addition to PSD permits, addition of a carbon capture facility at a site where wetlands are present

would likely require additional Section 404 permitting with the US Army Corps of Engineers. Incorporation of a capture facility into a Section 404 application in development would take approximately 3-6 additional months. Environmental permitting also would be required for the transportation and sequestration infrastructure needed to transport and store the carbon dioxide after it is captured. While some of this infrastructure exists or is under development in portions of Entergy's territory in Texas and Louisiana, this is not the case for portions of Entergy's territory in Arkansas and Mississippi. Because much of this infrastructure first must be designed and funding secured, there is no basis to conclude that the infrastructure will be in place in 2032 when the CCS requirement becomes effective.

24. In addition to environmental permitting, regulatory approvals must be obtained for the TX Plant before it can be constructed.[3] Regulatory approvals for new power plants typically take at least six months and often closer to one year to complete. It is entirely unclear whether, at this time, regulators will approve the cost to install CCS at the TX Plant (or in the case of the MS Plant, would approve that at a later time as a prudently-incurred cost) because of its estimated cost and the uncertainties around the ability of the technology to meet EPA's standards and the

[3] As a result of special legislation enacted earlier this year to support the economic development opportunity afforded by Amazon Web Services, Entergy Mississippi need not obtain pre-approval to construct the plant, though it must seek approval for cost recovery at the appropriate time.

need to develop and construct significant transportation and sequestration infrastructure.

25. Finally, assuming there are no regulatory impediments, internal delays, financing issues, or labor issues, Entergy can commence procurement and construction, which requires another 36 to 48 months, possibly longer, following regulatory and permitting approvals, before commissioning.

26. In sum, just the capture piece of CCS conservatively would take at least six years, likely longer given the first-of-kind nature presented by utility-scale CCS for an entire industry. Accordingly, Entergy would have to begin that work immediately.

27. Injecting CO_2 for storage—another necessary part of the CCS process—also requires permits that take a long time to obtain. While the State of Louisiana recently gained primacy for the Class VI program (wells used for geologic sequestration of CO_2), EPA Regions 6 and 4 are the permitting authority for Texas and Mississippi. Neither EPA Region 6 nor Region 4 have issued a single final Class VI permit. In fact, neither region has yet to even complete technical review of a single Class VI application, including on an application Region 6 received in May 2022. U.S. EPA, *Underground Injection Control (UIC) Class VI Permit Tracker*, last updated May 10, 2024, available at https://www.epa.gov/uic/current-class-vi-projects-under-review-epa. Based on Entergy's knowledge and experience, the

process can take up to three years from start to finish, assuming EPA is able to work through its existing backlog.

28. Entergy or a project partner may also have to conduct property and geologic searches to identify potential pore space for CO_2 sequestration and then develop those sites. While there is some sequestration infrastructure existing and under development in southeast Texas, there currently is little such infrastructure in Northern Mississippi.

29. Exacerbating all of these issues is that the Final Rule applies to all power plants throughout the United States. For that reason, power companies across the country would all be going through these steps at the same time. That would result in unprecedented demand for CCS resources and equipment, which is unlikely to be able to be met and would result in significantly higher costs due to demand than if a longer, and more reasonable, time frame was allowed for CCS. Further, the massive influx in permitting applications would strain further an already overly burdened review process. All of that introduces greater uncertainty into the timelines and would likely result in additional delays—which only further emphasizes the need to start this process immediately.

COST OF INSTALLING CCS ON THE TX AND MS PLANTS

30. Since Entergy must begin work immediately if it moves forward with the CCS compliance option, it would be required to incur significant costs over the

next 24 to 36 months, potentially hundreds of millions if it is required to self-provide the carbon capture. Those expenditures could not be reversed if the Final Rule is later vacated.

CONCLUSION

31. For the reasons described above, Entergy and potentially its customers are facing substantial harm during the next 24 to 36 months from the Final Rule.

I, MATTHEW BULPITT, declare under penalty of perjury that the foregoing is true and correct. Executed this 24th day of May, 2024.

Matthew Bulpitt
Vice President, Power Development
Entergy Services, LLC

DECLARATION OF ROBERT BURCH

1. I am the Vice President of Utility Technical Services of the Oklahoma Gas and Electric Company ("OG&E"). As Vice President of Utility Technical Services, I am responsible for the design and execution of major projects and delivering new assets to the company. I am also responsible for the company's Environmental Operations group, which has the responsibility of permitting new facilities. Additionally, I oversee OG&E's Fleet and Facilities Services operations. I provide this declaration in support of a motion to stay the rule promulgated on May 9, 2024 by the U.S. Environmental Protection Agency ("EPA" or "Agency"), entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39,798 (May 9, 2024) ("Final Rule").

2. This declaration is based on my personal knowledge of facts and analysis conducted by my staff.

3. I have been responsible for overseeing OG&E activities related to power generation and major projects since I joined the company in 2012. During my time at OG&E, I have been responsible for a number of diverse projects, including

new generation projects, air quality control projects, major transmission line projects, and substation projects.

4. My career spans over 39 years. Before joining OG&E, I was employed by three other electric utility companies, a specialty chemicals refinery, and a nationwide food manufacturing company. At those companies, I held a number of positions of responsibility including engineering, project management, maintenance, and operations. Many of those positions included various management and executive responsibilities. Most recently, I was Director of Engineering for Duke Energy's Edwardsport Integrated Gasification Combined Cycle generation station located in Edwardsport, Indiana. My major duties included technical management of engineering staff engaged in design, facility permitting, and sub project management. I also was involved with studies related to potential carbon capture and sequestration, including studies related to test wells to determine storage potential of the geologic strata.

5. I graduated with a Bachelor of Science degree in Mechanical Engineering from Rose-Hulman Institute of Technology.

OG&E OPERATIONS

6. OG&E is the largest electric utility in Oklahoma, serving nearly 900,000 customers across 30,000 square miles in Oklahoma and western Arkansas. OG&E is a member of the 14-state Southwest Power Pool ("SPP") integrated market

which serves more than 17.5 million people over 546,000 square miles throughout the midwestern United States.

7. OG&E employs approximately 2,329 full-time employees.

8. In recent years, OG&E has spent approximately $2.7 billion annually in the form of taxes, fuel, maintenance, and other operating and capital expenditures, and its impact on gross state product and gross domestic product is substantial.

9. OG&E is the largest ad valorem taxpayer in Oklahoma, contributing approximately $90 million annually. The millions of dollars in ad valorem taxes it pays to the communities where its facilities operate are an indispensable source of government revenue for those localities, including their local public schools and libraries.

10. OG&E's customer service territory includes Oklahoma's state capital and most populous city, Oklahoma City, as well as some of the largest industrial customers in the region and two military bases. OG&E's consumer base spans rural and remote areas serving disadvantaged communities. Much of OG&E's service territory is subject to extreme weather, including extended periods of frigid temperatures and extended periods of triple-digit temperatures. These conditions challenge all fuel generation types, including renewables. Maintaining a diverse generation fleet is particularly important given these severe weather challenges.

11. OG&E is committed to providing energy-related services in a balanced and environmentally responsible manner. Currently, OG&E maintains 7,116 megawatts of generation—split between 9 fossil-fuel fired power plants, 6 solar farms, and 3 wind farms. This fuel diversity allows OG&E to maintain system reliability and affordable rates for its consumers.

FINAL RULE CONTROL REQUIREMENTS AND OG&E COMPLIANCE PATHWAYS

12. The Final Rule, under Section 111 of the Clean Air Act, imposes greenhouse gas emission control requirements for existing coal-fired boilers, existing natural gas-fired boilers, and new stationary combustion turbines.

13. The Final Rule purports to offer four options for existing coal-fired boilers: (1) fully convert to natural gas by the end of 2029; (2); permanently retire by 2032; (3) convert to co-firing 40% natural gas by 2030 and retire by 2039; or (4) if operating on or after January 1, 2039—install carbon capture and sequestration ("CCS") with a 90% capture of carbon dioxide by January 1, 2032. These requirements would apply to OG&E's Sooner 1, Sooner 2, Muskogee 6, River Valley 1, and River Valley 2 coal units (collectively, the "Coal Units"). Each of the Coal Units is currently scheduled to retire after 2039.

14. The Coal Units, together, generate 1,880 megawatts.

15. The Final Rule likewise requires CCS with a 90% capture of CO_2 by 2032 for the base load subcategory for new combustion turbines.

16. EPA's promulgation of the Final Rule will have a substantial impact on OG&E's operations.

17. OG&E has evaluated compliance options for each Coal Unit. To maintain its retirement schedules, each Coal Unit would be subject to a 90% capture CCS requirement starting on January 1, 2032. As detailed below, this compliance option is not feasible.

18. Because OG&E cannot meet the CCS requirement, OG&E is left with three options at each Coal Unit: (1) fully convert to natural gas by December 31, 2029; (2) co-fire 40% natural gas by January 1, 2030, and then retire by January 1, 2039; or (3) retire by January 1, 2032. Regardless of the compliance path OG&E chooses, significant decisions need to be made and significant resources need to be expended within the next 24 months. For that reason, each pathway leads to significant expenditures and/or irrevocable commitments by OG&E within that timeframe.

19. These costs would impact not only OG&E, but potentially also its customers. As a regulated utility subject to the jurisdiction and regulation of the Oklahoma Corporation Commission ("OCC" or "Commission"), costs incurred by OG&E that are deemed prudent by the OCC are ultimately included in the rates charged to OG&E's customers. Any timely-made expenditure to comply with the Final Rule in good faith will be paid by either OG&E or its customers. These

expenditures cannot be recovered for OG&E or its customers if the Final Rule is later vacated.

20. OG&E estimates that compliance with the Final Rule would cost at least $4 billion in capital costs for the capture piece alone—which is over half of OG&E's parent company's total market capitalization of approximately $7 billion—as well as over $150 million in annual operating and maintenance costs. These capital and operating and maintenance costs do not include similar costs that would be required to construct, operate, and maintain additional generating capacity to offset the approximately 30% increase in auxiliary load needed to operate the CCS system.

21. The steps OG&E takes to attempt to comply with the Final Rule must be submitted to the State of Oklahoma to be included in its state plan. Oklahoma must submit its plan to the EPA by May 11, 2026, which is less than 24 months away. Prior to submitting its plan to the State, OG&E (1) would seek preapproval from the Commission, a process that typically takes at least 240 days; and (2) in some instances, would need to submit permit applications for construction of new equipment, which is another time-consuming process, taking as long as 12-18 months per site.

22. OG&E's actions to comply with the Final Rule also cannot be made in a vacuum. EPA "announced a suite of final rules" on April 25, 2024, among them,

effluent limitation guidelines ("ELG Rule") and updates to the Mercury and Air Toxics Standards ("MATS"). OG&E is also facing potential impacts from the Agency's 2023 Good Neighbor Rule. These rules will impact OG&E's near-term decisions regarding whether to retire Muskogee 6 or whether to commit significant additional capital to retrofitting this facility by 2034.

COMPLIANCE TIMELINE FOR INSTALLING CCS ON COAL UNITS

23. Installing and having operational CCS on all of the Coal Units by 2032 is infeasible. However, because each Coal Unit is not scheduled to retire until after January 1, 2039, OG&E has evaluated what actions it would need to take, starting now, to even come close to having timely CCS on its Coal Units.

24. Immediate commencement and an aggressive timeline are the only way OG&E could possibly have any chance of meeting the Final Rule's January 1, 2032 deadline given the lengthy lead time required for installing CCS. Even with that, it may not be possible for OG&E to install CCS by the deadline. If OG&E decides to install CCS controls on its Coal Units, it would need to begin that process almost immediately and would begin to incur costs within the next 6 months.

25. The Department of Energy ("DOE") has laid out a timeline demonstrating that CCS projects take 14.5 years from the date of their funding award to become operational. Included in DOE's timeframe is a planning phase (up to 1.5 years); siting, permitting, and financing phase (up to 3 years); building and

integration (up to 6 years); and ramp-up and operations (up to 4 years): U.S. Department of Energy: Office of Clean Energy Demonstrations, Bipartisan Infrastructure Law Carbon Capture Demonstration Projects Program, Funding Opportunity Announcement Number: DE-FOA-0002962, at 12, available at https://oced-exchange.energy.gov/Default.aspx#FoaId151b5065-5838-46ba-9a23-b188d2086a39. Yet January 1, 2032, the Final Rule's requirement for operating with CCS with 90% capture for the Coal Units, is less than 8 years away. Accordingly, OG&E has only about half the time the Department of Energy says it needs to have operational CCS.

CCS – Capture Timeline

26. Just the "capture" piece of CCS would take years. OG&E would have to hire an engineering team immediately to begin that process which would consist of successive feasibility studies and various levels of Front-End Engineering and Design ("FEED") studies. Each engineering phase can only proceed once the necessary regulatory and internal approvals are also completed.

27. A typical project development timeline requires a pre-feasibility study to review the site and assess the feasibility of adding CCS to the existing facility and would take 4-6 months to complete. A FEED study would then be conducted in conjunction with the CCS technology provider identified at the conclusion of the feasibility study and would take 12-18 months. Following the FEED study, OG&E

would need to go through a 9-12 month contracting period to engage major vendors, at which point OG&E's engineering and procurement efforts would take another 12-18 months. Construction of the facility can only begin after engineering and procurement, assuming all environmental permits and approvals have been obtained.

28. Construction itself will take approximately 36 months, followed by a 6-9 month start-up and commissioning period.

29. OG&E would need to seek preapproval from the Commission before proceeding beyond a FEED design or undertaking large expenditures for purchasing capture equipment and labor. It may also need preapproval for FEED costs. The preapproval process typically takes at least 240 days but would likely take longer given the complexity and costs associated with CCS.

30. Before OG&E could proceed beyond a FEED design, it must also secure financing as well as internal approvals. OG&E would need to develop a financing plan based on the FEED design capture technology, consult with banks and rating agencies, and then seek internal board approval, but only after seeking (and receiving) preapproval from the state. The combined process of receiving preapproval and then securing financing and obtaining internal approvals to proceed beyond a FEED design would take approximately 12-15 months.

31. If OG&E is unable to get preapproval from the Commission, securing financing may be impossible. Even with preapproval, financing for a CCS project may still be difficult or impossible to obtain given its nature.

32. Before OG&E could begin construction of the capture system, it would need to go through a lengthy permitting and permit-amending process. Following the FEED study and preliminary design of the carbon capture system, a construction air permit application would be submitted to the Oklahoma Department of Environmental Quality ("ODEQ") requesting authorization to commence construction and initial operation of the facility. A construction air permit would be required to account for all new and modified emissions and emissions sources associated with the capture facility and to establish emission limits and monitoring requirements. Based on OG&E's experience, obtaining a construction permit would take 12-18 months following completion of the FEED study and assuming that the design of the capture system does not change during the engineering and procurement phases of the project.

33. Other environmental permits and approvals that would be required for the carbon capture facility include, but are not necessarily limited to, permits for increased cooling water requirements and water consumption, cooling water and wastewater treatment and discharge, and construction-related activities affecting sensitive environmental resources such as wetlands or other waters of the United

States. Assuming all permits are identified and permit applications submitted in a timely manner, these permits could be obtained concurrent with the construction air permit; however, unforeseen circumstances and permitting delays could extend the permitting timeline.

34. Finally, assuming there are no regulatory hiccups, internal delays, financing issues, or labor issues, OG&E can commence construction, which requires another 36 months before a 6-9 month start-up and commissioning period, during which OG&E must complete any testing and necessary adjustments before it can guarantee successful operation. Construction and commissioning of multiple CCS units would need to be staggered so that all of the Coal Units are not offline at the same time, thereby lengthening the total timeline.

35. In sum, just the capture piece of CCS would take up to 10 years. Accordingly, OG&E would have to begin that work immediately.

CCS – Transport Timeline

36. A further complication that adds more time to this already lengthy timeline is that OG&E's Coal Units do not have ready access to a CO_2 pipeline network, which is necessary for CCS to operate. The CO_2 pipelines that do already exist in Oklahoma are not built to serve OG&E's existing generating resources and are not in close proximity to the Coal Units. Furthermore, these existing pipelines do not terminate at storage facilities. A substantial amount of new pipe would need

to be sited and laid to ensure OG&E could transport CO_2 captured at a generating resource.

37. Significant time and resources would have to be expended to identify and evaluate alternative pipeline routes, negotiate with numerous landowners to secure necessary rights-of-way, and acquire all permits. Acquisition of the rights-of-way and permitting the new pipeline would trigger a time-consuming permitting process and potential opposition. Permits would be required for impacts to wetlands and other waters of the United States, would require compliance with section 7 of the Endangered Species Act and section 106 of the National Historic Preservation Act, and would require consultation with numerous federal and state agencies including the U.S. Fish and Wildlife Service, State Historical Preservation Office, and Oklahoma Department of Wildlife Conservation.

38. In order to plan for this new piping, additional FEED studies would need to be conducted to determine the necessary routing and design. As part of this process, pipeline rights-of-way or easements must be obtained from landowners which could be a contentious and expensive process that may include the use of condemnation. These FEED studies would need to be complete in order to support the permitting process that can be time-consuming and carries a high likelihood of potential opposition.

39. Furthermore, given the location of the Coal Units, any pipeline would likely cross federal or tribal land, triggering the National Environmental Policy Act ("NEPA") review process. The NEPA review process would add significant time and expense to the pipeline permitting process and would extend beyond the pipeline to include all connected actions including the carbon capture system and sequestration field. Although the Fiscal Responsibility Act amendments to NEPA established deadlines for the preparation and review of environmental assessments ("EAs") and environmental impact statements ("EISs"), the NEPA review process would take at least 2 years to complete and the lead agency could, in consultation with OG&E, extend the deadline as necessary to complete the required assessments. Construction of the pipeline could not commence until the NEPA review process is complete.

40. Assuming that the permits could be obtained, and potential opposition overcome—which is not guaranteed—this pipeline permitting and construction process would take many years to complete assuming that NEPA applies.

CCS – Injection and Storage Timeline

41. Injecting CO_2—another necessary part of the CCS process—also requires permits that take a long time to obtain. EPA Region 6 is the permitting authority for Oklahoma for the Class VI (wells used for geologic sequestration of CO_2) program and has yet to issue a single final Class VI permit. In fact, Region 6

has yet to even complete technical review of a single Class VI application, including on an application Region 6 received in May 2022. U.S. EPA, *Underground Injection Control (UIC) Class VI Permit Tracker*, last updated May 10, 2024, available at https://www.epa.gov/uic/current-class-vi-projects-under-review-epa. Based on OG&E's knowledge and experience, the administrative processing of a Class VI application can take many years. And that does not take into consideration the possibility of judicial review or the wide variation in this timeline.

42. Concurrent to and in conjunction with the permitting process, OG&E would need yet another FEED study to determine the availability and capability of sufficient geologic storage for its Coal Units. Initial site screening and feasibility assessments would take 3-4 months. Those facilities would at the very least need to be sufficient to store the potential CO_2 generated from those facilities until their retirement dates, which are all beyond 2039. These dates also have a high likelihood of being extended if CCS is installed in order to recover the at least $4 billion in capital investment required to install such systems.

43. OG&E is not aware of any commercial CO_2 sequestration facilities in the proximity to the Coal Units. Even if there were such facilities, they would not forgo the need for OG&E to at least conduct the sequestration FEED. OG&E would need to ensure that sufficient geologic storage exists and is available to support the at least $4 billion investment for the capture equipment alone. Solely relying on a

third-party entity introduces the risk of either unavailability of the storage should that entity cease operations or, at a minimum, exposes OG&E customers to potential lack of cost control for storage if there are a limited number of third-party options available.

44. While a sequestration FEED may take 18-24 months, that timeline is compounded because a final FEED would need to rely on a number of test wells in order to verify sufficient porosity exists to support long term sequestration and storage.

CCS – Full Timeline

45. Exacerbating all of these issues is that the Final Rule applies to all power plants throughout the United States. For that reason, power companies across the country would all be going through these steps at the same time. That would result in unprecedented demand for CCS resources and equipment, including securing access to geologic storage, and a massive influx in permitting applications being submitted, further straining an already overly burdened review process. All of that introduces greater uncertainty into the timelines and would likely result in additional delays—which only further emphasizes the need to start this process immediately.

46. Putting that all together, it likely would take well over a decade to install CCS on OG&E's Coal Units and have fully operational CO_2 transportation

and storage, especially since all aspects of work on the three facets of CCS (*i.e.*, capture, transport, and storage) cannot necessarily be pursued simultaneously. That means that OG&E would have to begin that process immediately. Even if OG&E began the CCS process today, it simply could not meet the Final Rule's compliance deadline unless it were significantly extended.

COST OF INSTALLING CCS ON COAL UNITS

47. If OG&E moves forward with the CCS compliance option, it would be required to spend over $12-15 million per coal site (Sooner, Muskogee, and River Valley) in the next 24 months, for a total of $36-45 million. These near-term costs would be borne by OG&E in the first instance and then potentially by its customers.

48. Additionally, modifying the Coal Units to equip them with CCS would require OG&E to replace approximately 30% of the Coal Unit's power due to the parasitic nature of operating CCS. In other words, operating CCS will reduce each Coal Unit's capacity by approximately 30%. That lost capacity must be replaced by a new resource which will impose additional costs on OG&E's customers.

CCS – Capture Cost

49. Regarding capture, discussed in paragraphs 26 to 35, OG&E would need to hire an engineering firm to begin strategy and scoping immediately. Over the next 24 months, an engineering firm would also need to complete a pre-feasibility study, pre-FEED study, and begin a FEED design. All in, the cost to get

this far along in the capture process would be $12-15 million for a single coal site (between $2 million and $5 million for pre-feasibility and pre-FEED activities, and $10 million for the FEED design), for a total cost of $36-45 million for the three coal sites.

50. To support the engineering work to physically assess the ability of the Coal Units to be retrofitted with CCS, OG&E would incur costs entering binding engineering contracts within the next 24 months. Should a court later vacate EPA's Final Rule, these contracts may very well include cancellation fees and termination penalties.

51. OG&E also would have to enter binding contracts for buying and installing the CCS equipment. OG&E would need to add amine capture equipment at a cost of approximately $1 billion per Coal Unit. Should a court later vacate EPA's Final Rule, these contracts may very well include cancellation fees and termination penalties, which must be paid.

CCS – Transportation Cost

52. OG&E would also incur costs in the next 24 months related to the necessary pipeline infrastructure. Because OG&E's Coal Units do not have ready access to a CO_2 pipeline network, OG&E would likely need to build out this infrastructure from scratch.

CCS – Injection and Storage Cost

53. For storage, OG&E is not aware of any commercially available CO_2 sequestration sites near, or within a reasonable proximity to, OG&E's service territory. OG&E would need to identify, test, and develop viable sequestration sites. Given the compressed timeframe for having fully operational CCS, OG&E would need to begin this process immediately.

54. OG&E must conduct property and geologic searches to identify potential pore space for CO_2 sequestration and must pay private landowners to allow OG&E personnel access to the overlying surface property. OG&E personnel or contractors must conduct seismic testing to determine test well sites to be drilled in order to analyze potentially viable pore space.

55. OG&E must negotiate with the owners of the subsurface pore space to secure an easement, lease, or other real property interest in the potential sequestration site. Given OG&E's federal mandate to install and operate CCS, any owner of the pore space is incentivized to hold out for a top-of-the-market price from OG&E for that real property interest.

56. OG&E must conduct land option, public information, and stakeholder activities associated with a CO_2 pipeline within the next 24 months. OG&E must engage in an extensive and resource-intensive permitting process with Region VI of the EPA within the next 24 months.

57. Currently, no legislative or regulatory framework exists in Oklahoma to address the development and operation of Class VI wells. OG&E would have to expend time and resources to coordinate with the Oklahoma legislature to ensure such legislation is enacted prior to OG&E's operation of CCS equipment.

58. OG&E would also have to incur cost paid to landowners to secure access to these geologic areas so they would be available when needed, either from the onset of a CCS requirement, or should a third-party vendor become unavailable due to business cessation or cost issues.

59. Given the lengthy timeline regarding injection and storage, OG&E would need to begin and start incurring costs on these activities in the next 24 months.

COMPLIANCE TIMELINE FOR FULL CONVERSION OF COAL UNITS

60. If OG&E instead decides to convert certain Coal Units to run purely on natural gas and no longer retain the capability to fire coal by December 31, 2029, it would need to begin that process almost immediately and would begin to incur costs within the next 6 months. At least a full year is required for OG&E to complete any necessary engineering and replacement-resource procurement work, prepare a preapproval filing with the Commission, and then receive preapproval. The conversion process then requires approximately 36-48 months and would only begin after OG&E secures preapproval.

61. Conversion is not currently a feasible option for OG&E's two River Valley units that employ circulating fluidized bed technology, but if OG&E opts to fully convert some of its other Coal Units, OG&E must notify the State of Oklahoma by early 2025, so that the conversion can be included in the state plan.

62. Moreover, OG&E would need to acquire permits for each full coal-to-gas conversion. These permits must be acquired prior to OG&E's state plan submission for Oklahoma. OG&E would seek preapproval from the Commission prior to submitting that information to Oklahoma, which will take at least 240 days. Accordingly, OG&E would need to start the preapproval process almost immediately to ensure completion prior to submitting its information to the State in early 2025.

63. Stretching out the timeline even further, OG&E likely would have to begin planning and communicating to affected personnel before the end of 2024 to ensure that its employees at the Coal Units are not blindsided by the news of the impending conversion.

64. Adding further delays is that converting from coal to gas requires a minimum of a 12-week outage. If OG&E were to convert three of its Coal Units (Sooner 1, Sooner 2, and Muskogee 6) on similar timeframes, approximately 1,500 MW would be taken off the grid. Those units would also need to be online during

the peak summer and winter seasons. The result is that OG&E would have to stagger its conversions over the course of approximately 18-24 months.

65. OG&E would need to begin work immediately to achieve conversion of those three units by the December 31, 2029 deadline. Engineering and procurement activities would need to start in 2024 to support the regulatory approval process and the Oklahoma state plan filing with EPA.

COSTS OF FULL CONVERSION OF COAL UNITS

66. Fully converting the three Coal Units that can be converted to natural gas would cost in excess of $100 million. Those costs would include replacement burners, pipe gas, and potentially fan wheels, fan motors, and/or transformers. To determine the precise path for conversion, OG&E would need to immediately contract for engineering reports on each Coal Unit. Of these costs, approximately $1 million per unit would be incurred over the next 24 months.

67. The workforce at the Coal Units, a total of approximately 250 full-time employees, would need to be made aware of the conversions. Approximately 130 of those full-time employees could lose their jobs upon a full conversion to natural gas. In an effort to retain key personnel prior to the conversion, OG&E would need to offer retention bonuses.

68. Even with retention bonuses, OG&E would face morale and attrition issues from a workforce that would know that their ranks would soon be reduced by over half.

COMPLIANCE TIMELINE FOR COFIRING-AND-RETIREMENT OF COAL UNITS

69. If OG&E decides to convert certain Coal Units to co-fire 40% natural gas by January 1, 2030 and then retire them by the January 1, 2039 deadline, it would need to begin that process almost immediately and would begin to incur costs within the next 6 months. At least a full year is required for OG&E to complete any necessary engineering and replacement-resource procurement work, prepare a preapproval filing with the Commission, and then receive preapproval. The conversion process then requires approximately 36-48 months and would only begin after OG&E secures preapproval.

70. Accordingly, OG&E would need to start engineering and procurement activities in 2024 to support the regulatory approval process and the Oklahoma state plan filing with EPA to secure compliance by the January 1, 2030 deadline.

71. Converting the Coal Units to co-fire 40% natural gas would require a similar timeline to that described in paragraphs 60 to 65.

72. Since OG&E would also have to retire these units by January 1, 2039, it would need to secure the approximately 1,500 MW of replacement capacity by 2039. OG&E does not currently have excess capacity within its system. In order to

meet capacity needs and comply with SPP's Planning Reserve Margin, retiring a unit would require OG&E to replace that unit's capacity with equal or greater replacement capacity.

COST OF COFIRING-AND-RETIREMENT OF COAL UNITS

73. If OG&E moves forward with the cofiring-and-retirement compliance option, it would be required to spend approximately $1 million per Coal Unit in the next 24 months for units converted to co-fire. The total cost for co-firing OG&E's three Coal Units would be in excess of $100 million. These costs would be borne by OG&E in the first instance and then potentially by its customers.

74. Unit retirements could also impact ad valorem tax assessments for OG&E's facilities, which would reduce resources available for investing in important community benefits.

RETIREMENT OF THE COAL UNITS BY 2032

75. If OG&E opts to fully retire its Coal Units, it would need to replace that 1,880 MW of lost capacity. OG&E likely would have to retire at least its River Valley Coal Units for any compliance scenario involving full conversion or conversion to co-firing, and may elect to retire other Coal Units as well.

76. If not for the CCS requirement for base load gas in the Final Rule, OG&E likely would build new natural gas combined cycle combustion turbine units to make up a significant amount of that lost capacity and for grid reliability. That

would be the most efficient route that would result in the lowest cost to the customer. But the Final Rule's requirement of CCS for base load gas units makes that infeasible by 2032. That is due to the same complications and complexities that CCS introduces that were discussed above in paragraphs 23-46.

77. For that reason, OG&E instead likely would have to utilize simple cycle combustion turbines in the intermediate- and low-load subcategories to help replace the capacity OG&E would be forced to retire. Given the significant amount of replacement capacity needed, this would result in a less efficient and more costly option than would otherwise be required if combined cycle combustion turbines were an option.

78. Generating units in the intermediate- and low-load subcategories would impose yearly capacity factor limitations. These limitations could impact grid reliability in years with exceptionally warm summers or cold winters during which dispatchable resources would need to be called more frequently.

79. Based on current information, OG&E likely would use those simple cycle combustion turbines to make up half of the lost capacity and use solar power to make up the other half.

80. In order to prevent a dangerous loss of capacity between retirement of the Coal Units and replacement, OG&E would need to begin the process for

permitting, constructing, and bringing online the replacement capacity in sync with its accelerated retirement schedules.

81. At least a full year is required for OG&E to complete any necessary engineering and replacement-resource procurement work, prepare a preapproval filing with the Commission, and then receive preapproval. Following preapproval, building out 900 MW in intermediate load combustion turbine generation would take between 48-60 months depending on project development maturity, generation interconnection status and regulatory approvals. The total costs for these gas units would run into the hundreds of millions of dollars. Of those costs, OG&E would expect to incur $5 million in the next 24 months. Similarly following preapproval, building out 900 MW in solar resources would take between 48-60 months depending on project development maturity, generation interconnection status and regulatory approvals.

82. OG&E needs approximately seven acres for each MW of photovoltaic, single axis tracking solar generation. The total costs for those new solar resources would run into the hundreds of millions and potentially billions of dollars.

83. Additionally, a retirement decision would require OG&E to notify its employees well in advance of notifying the State, for the same reasons discussed in paragraph 63 for a full conversion. Before the end of 2024, OG&E would have to inform the approximately 250 full-time Coal Unit employees of their unit's

retirement. OG&E also has contractors full-time on-site, as well as a significant number of temporary contractors hired during maintenance periods. While approximately 30-40 of these employees would be retained in positions with the replacement generation, the vast majority of these employees would lose their jobs.

84. In addition to the monetary costs and personnel impacts, the Final Rule would also effectively lock OG&E into the less efficient and more costly path of using only simple cycle turbines. That would inflict harm on OG&E and its customers for decades to come.

IMPACTS ON THE NATION'S GRID

85. SPP is already at risk of electric supply shortfalls due to declining reserve margins "as a result of increasing peak demand and declining anticipated resources." North American Electric Reliability Corporation, 2023 Summer Reliability Assessment, May 2023, at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

86. SPP itself "questions the feasibility of implementing the carbon capture and sequestration process by the [Final Rule's] deadline." Press Release, Southwest Power Pool, May 20, 2024.

87. The Final Rule's stringent constraints on both existing and new generation will only exacerbate that problem, as it leaves OG&E and other

generators will be left with a dwindling list of suboptimal generation options. As the SPP Chief Operating Officer stated, the Final Rule "presents serious complications for SPP and our members that may be insurmountable." *Id.*

CONCLUSION

88. For the reasons described above, OG&E and potentially its customers are facing substantial harm during the next 24 months from the Final Rule.

I, Robert Burch, declare under penalty of perjury that the foregoing is true and correct. Executed this 24th day of May, 2024.

Robert Burch
Vice President of Utility Technical Services
Oklahoma Gas and Electric Company