

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2011-0660; FRL-9654-7]

RIN 2060-AQ91

Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The United States EPA is proposing new source performance standards for emissions of carbon dioxide (CO₂) for new affected fossil fuel-fired electric utility generating units (EGUs). The EPA is proposing these requirements because CO₂ is a greenhouse gas (GHG) and fossil fuel-fired power plants are the country's largest stationary source emitters of GHGs. The EPA in 2009 found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGUs greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 pounds of CO₂ per megawatt-hour (lb CO₂/MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology. Because of the economics of the energy sector, the EPA and others project that NGCC will be the predominant choice for new fossil fuel-fired generation even absent this rule. In its base case analysis, the EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this proposal through 2030. New coal-fired or pet coke-fired units could meet the standard either by employing carbon capture and storage (CCS)¹ of approximately 50% of the CO₂ in the exhaust gas at startup, or through later application of more effective CCS to meet the standard on average over a 30-year period. The 30-year averaging option could also provide flexibility for owners and operators of coal or pet coke units implementing CCS at the outset of

the unit's operation that were designed and operated to emit at less than 1,000 lb CO₂/MWh to address startup concerns or short term interruptions in their ability to sequester captured carbon dioxide. The EPA is not proposing standards of performance for existing EGUs whose CO₂ emissions increase as a result of installation of pollution controls for conventional pollutants, or for proposed EGUs, which are referred to here as transitional sources, that have acquired a complete preconstruction permit by the time of this proposal and that commence construction within 12 months of this proposal. As a result, those sources would not be subject to the standards of performance proposed in today's rule.

DATES: *Comments.* Comments must be received on or before June 12, 2012. Under the Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after April 13, 2012, a comment to the OMB is best assured of having its full effect if the OMB receives it by May 14, 2012.

Public Hearing. The EPA will hold public hearings on this proposal. The dates, times, and locations of the public hearings will be announced separately. Oral testimony will be limited to 5 minutes per commenter. The EPA encourages commenters to provide written versions of their oral testimonies either electronically or in paper copy. Verbatim transcripts and written statements will be included in the rulemaking docket. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela Garrett, Sectors Policies and Programs Division (C504-03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541-7966; email: garrett.pamela@epa.gov. Persons wishing to provide testimony should notify Ms. Garrett at least 2 days in advance of the public hearings. The public hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. The EPA officials may ask clarifying questions during the oral presentations, but will not respond to the presentations or comments at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. For updates and additional information on the public hearings, please check the EPA's Web site for this rulemaking,

<http://www.epa.gov/airquality/carbonpollutionstandards>.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2011-0660, by one of the following methods:

At the Web site <http://www.regulations.gov>: Follow the instructions for submitting comments.

At the Web site <http://www.epa.gov/oar/docket.html>: Follow the instructions for submitting comments on the EPA Air and Radiation Docket web site.

Email: Send your comments by electronic mail (email) to a-and-r-docket@epa.gov, Attn: Docket ID No. EPA-HQ-OAR-2011-0660.

Facsimile: Fax your comments to (202) 566-9744, Attn: Docket ID No. EPA-HQ-OAR-2011-0660.

Mail: Send your comments to the EPA Docket Center, U.S. EPA, Mail Code 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Attn: Docket ID No. EPA-HQ-OAR-2011-0660. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St. NW., Washington, DC 20503.

Hand Delivery or Courier: Deliver your comments to the EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Room 3334, Washington, DC, 20460, Attn: Docket ID No. EPA-HQ-OAR-2011-0660. Such deliveries are accepted only during the Docket's normal hours of operation (8:30 a.m. to 4:20 p.m., Monday through Friday, excluding legal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include agency name and docket ID number (EPA-HQ-OAR-2011-0660). The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at <http://www.regulations.gov>, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through <http://www.regulations.gov> or email. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404-02), Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA-

¹ Throughout this preamble, we refer to 'carbon capture and storage' or CCS. By this, we mean the use of a technology for separating and capturing CO₂ from the flue gas or syngas stream with subsequent compression and transportation to a suitable location for long term storage and monitoring. Many references refer to CCS as 'carbon capture and sequestration'. In this preamble, 'storage' and 'sequestration' mean the same thing and the words are used interchangeably.

HQ-OAR-2011-0660. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD-ROM that you mail to the EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

The EPA requests that a separate copy of your comments also be sent to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**). If the comment includes information you consider to be CBI or otherwise protected, a copy of the comment that does not contain the information claimed as CBI or otherwise protected should be sent.

The www.regulations.gov Web site is an "anonymous access" system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through <http://www.regulations.gov>, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the <http://www.regulations.gov> index. Although listed in the index, some information is not publicly available (e.g., CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in <http://www.regulations.gov> or in hard copy at the EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave.

NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Air Docket is (202) 566-1742. Visit the EPA Docket Center homepage at <http://www.epa.gov/epahome/dockets.htm> for additional information about the EPA's public docket.

In addition to being available in the docket, an electronic copy of this proposed rule will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: <http://www.epa.gov/ttn/oarpg/>. The TTN provides information and technology exchange in various areas of air pollution control.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243-01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541-4003, facsimile number (919) 541-5450; email address: fellner.christian@epa.gov or Dr. Nick Hutson, Energy Strategies Group, Sector Policies and Programs Division (D243-01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541-2968, facsimile number (919) 541-5450; email address: hutson.nick@epa.gov.

SUPPLEMENTARY INFORMATION: Acronyms. A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

AB Assembly Bill
AEP American Electric Power
AEO Annual Energy Outlook
ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing of Materials
BACT Best Available Control Technology
BDT Best Demonstrated Technology
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt Hour
Btu/lb British Thermal Units per Pound
CAA Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CDX Central Data Exchange

CEDRI Compliance and Emissions Data Reporting
CEMS Continuous Emissions Monitoring System
CH₄ Methane
CHP Combined Heat and Power
CO₂ Carbon Dioxide
CSAPR Cross-State Air Pollution Rule
DOE Department of Energy
DOT Department of Transportation
ECMPS Emissions Collection and Monitoring Plan System
EERS Energy Efficiency Resource Standards
EGU Electric Utility Generating Units
EIA Energy Information Administration
EO Executive Order
EOR Enhanced Oil Recovery
EPA Environmental Protection Agency
FR Federal Register
GHG Greenhouse Gas
H₂ Hydrogen Gas
HAP Hazardous Air Pollutant
HFC Hydrofluorocarbon
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
kg/MWh Kilogram per Megawatt-hour
kJ/kg Kilojoules per Kilogram
kWh Kilowatt Hour
lb CO₂/MMBtu Pound of CO₂ per Million British Thermal Unit
lb CO₂/MWh Pound of CO₂ per Megawatt-hour
lb CO₂/yr Pound of CO₂ per Year
lb/lb-mole Pound per Pound-Mole
MATS Mercury and Air Toxic Standards
MW Megawatt
MWe Megawatt Electric
MWh Megawatt-hour
N₂O Nitrous Oxide
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NAS National Academy of Sciences
NETL National Energy Technology Laboratory
NGCC Natural Gas Combined Cycle
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
O₂ Oxygen Gas
OMB Office of Management and Budget
PC Pulverized Coal
PFC Perfluorocarbon
PM Particulate Matter
PM_{2.5} Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
RCRA Resource Conservation and Recovery Act
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
SBA Small Business Administration
SCC Social Cost of Carbon
SCR Selective Catalytic Reduction
SF₆ Sulfur Hexafluoride
SIP State Implementation Plan
SNCR Selective Non-Catalytic Reduction

SO₂ Sulfur Dioxide
 SSM Startup, Shutdown, and Malfunction
 Tg Teragram
 Tpy Tons per Year
 TSD Technical Support Document
 TTN Technology Transfer Network
 UIC Underground Injection Control
 UMRA Unfunded Mandates Reform Act of
 1995
 U.S. United States
 USGCRP U.S. Global Climate Research
 Program
 VCS Voluntary Consensus Standard
 WWW Worldwide Web

Organization of This Document. The information presented in this preamble is organized as follows:

- I. General Information
 - A. Executive Summary
 - B. Does this action apply to me?
- II. Background
 - A. Statutory Background for This Rule
 - B. Overview of Climate Change Impacts From GHG Emissions
 - C. GHGs From Fossil Fuel-Fired EGUs
 - D. Litigation Directly Leading to This Rule
 - E. Coordination With Other Rulemakings
- III. Summary of the Proposed Requirements for New Sources
 - A. What is the affected source?
 - B. What emissions limitations must I meet?
 - C. What are the startup, shutdown, and malfunction requirements?
 - D. What are the continuous monitoring requirements?
 - E. What are the emissions performance testing requirements?
 - F. What are the continuous compliance requirements?
 - G. What are the notification, recordkeeping, and reporting requirements?
- IV. Rationale for the Proposed Standards: New Sources
 - A. How did the EPA establish the emission limits?
 - B. How did the EPA determine the other requirements for the proposed standards?
- V. Implications for PSD and Title V Programs
 - A. Overview
 - B. Implications for PSD Program
 - C. Implications for Title V Program
- VI. Discussion of Modified Sources
 - A. CAA Section 111 Requirements
 - B. Timing for Promulgation of Standards of Performance for Modifications
- VII. Impacts of the Proposed Action
 - A. What are the air impacts?
 - B. What are the energy impacts?
 - C. What are the compliance costs?
 - D. How will this proposal contribute to climate change protection?
 - E. What are the economic and employment impacts?
 - F. What are the benefits of the proposed standards?
- VIII. Request for Comments
- IX. Statutory and Executive Order Reviews
 - A. Executive Order 12866: Regulatory Planning and Review, and Executive Order 13563: Improving Regulation and Regulatory Review
 - B. Paperwork Reduction Act
 - C. Regulatory Flexibility Act as Amended by the Small Business Regulatory

Enforcement Fairness Act of 1996,
 5 U.S.C. 601 *et seq.*
 D. Unfunded Mandates Reform Act of 1995
 E. Executive Order 13132: Federalism
 F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
 G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
 H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
 I. National Technology Transfer and Advancement Act
 J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

I. General Information

A. Summary

1. Executive Summary

In this rulemaking, the EPA proposes to limit GHG emissions from new fossil fuel-fired power plants by limiting CO₂ emissions. The proposed rule is undertaken pursuant to section 111 of the Clean Air Act, which establishes a several step process for the EPA and the States to regulate air pollutants from stationary sources. Under section 111, the EPA must regulate emissions from new sources in the source category by issuing a standard of performance, which is 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 * * * cost [and other factors]) * * * has been adequately demonstrated.”

In today’s action, the EPA is proposing to combine electric utility steam generating units (boilers and IGCC units, which are currently included in the Da category) and combined cycle units that generate electricity for sale and meet certain size criteria (which are currently included in the KKKK category), into a new category for new sources (the TTTT category) for the purposes of GHG emissions. The EPA is proposing standards of performance that require that all new fossil fuel-fired EGUs meet an electricity-output-based emission rate of 1,000 lb CO₂/MWh of electricity generated on a gross basis. This proposed standard is based on the demonstrated performance of natural gas combined cycle (NGCC) units, which are currently in wide use throughout the country, and are likely to be the predominant fossil fuel-fired technology for new generation in the future.

New coal-, coal refuse-, oil- and petroleum coke-fired boilers and IGCC units should also be able to meet this standard by employing carbon capture and storage (CCS) technology. While a coal unit with CCS may be more expensive to construct than NGCC generation, for reasons explained below, we expect the difference to decrease over time as CCS becomes more mature and less expensive.

We include in today’s proposed rulemaking a 30-year averaging compliance option under which affected coal- and pet coke-fired sources could comply with the 1,000 lb CO₂/MWh standard on a 30-year average basis. Coal- and pet coke-fired EGUs that use this compliance alternative must meet an immediate performance standard of 1,800 lb CO₂/MWh (gross) on a 12-month annual average basis, which can be achieved by a “supercritical” efficiency level, during the period before installation of CCS. By no later than the beginning of the 11th year, the facility would be required to meet a reduced CO₂ emission limit of no more than 600 lb CO₂/MWh (gross) on a 12-month annual average basis for the remaining 20 years of the 30-year period, such that the weighted average CO₂ emissions rate from the facility over the 30-year time period would be equivalent to the proposed standard of performance of 1,000 lb CO₂/MWh.

Today’s proposal to require an emission rate of 1,000 lb CO₂/MWh meets the requirements for a “standard of performance,” as defined under CAA section 111(a)(1). This proposed standard is based on the degree of emission limitation achievable through natural gas combined cycle generation. NGCC qualifies as the “best system of emission reduction” (BSER) that the EPA has determined has been adequately demonstrated. New natural gas-fired EGUs are less costly than new coal-fired EGUs, and as a result, our Integrated Planning Model (IPM) model projects that for economic reasons, natural gas-fired EGUs will be the facilities of choice until at least 2020, which is the analysis period for this rulemaking.

Indeed, our IPM model does not project construction of any new coal-fired EGUs during that period. This state of affairs has come about primarily because technological developments and discoveries of abundant natural gas reserves have caused natural gas prices to decline precipitously in recent years and have secured those relatively low prices for the near-future. We emphasize that, in light of a number of economic factors, including the increased availability and significantly lower price

of natural gas, energy industry modeling forecasts uniformly predict that few, if any, new coal-fired power plants will be built in the foreseeable future.

We recognize that some owners/operators may nevertheless seek to construct new coal-fired capacity. This may be beneficial from the standpoint of promoting energy diversity, and today's proposal does not interfere with construction of new coal-fired capacity. At present, while CCS would add considerably to the costs of a new coal-fired power plant, there are sources of funding available to support the deployment of CCS, including a limited number of government demonstration programs. Even if companies decide to construct a few new coal-fired power plants under any circumstance, those few may well have access to those government programs. We expect that the costs of CCS will decline in the future as CCS matures and is utilized more widely.

For purposes of today's action, the EPA does not have a sufficient base of information to develop a proposal for the anticipated relatively few affected sources that may be expected to take actions that would constitute "modifications" (as defined under the EPA's NSPS regulations) and therefore be subject to requirements for new sources. As a result, the EPA is not proposing requirements for NSPS modifications.

The EPA is aware that approximately 15 proposed EGUs have received CAA permitting authority approval for their preconstruction permits, but may not have "commenced construction" by the date of today's proposed rulemaking. For this proposed rule, these sources that, as of the date of this proposal, have a PSD permit and are poised to commence construction within the very near future are referred to as "transitional sources." In today's proposed rulemaking, the EPA is not proposing a standard of performance for transitional sources, which we define as sources that have been issued a PSD permit by the date of proposal (including sources that have approved permits that are in the process of being amended, if those sources are intending to install CCS as evidenced by participating in any of the DOE CCS funding programs, either loan guarantee or grant programs) and that commence construction within 12 months of the date of publication of this proposal in the **Federal Register**. Upon finalization of this rulemaking without a standard of performance applicable to these sources, they will not be treated as new sources subject to the specific limitations set forth in the final new source standards.

Our IPM modeling, using Energy Information Administration (EIA) reference case assumptions, projects that there will be no construction of new coal-fired generation without CCS by 2030. Under these assumptions, the proposed rule will not impose costs by 2030. We also examined a scenario with both increased future natural gas prices and increased future electric demand. In this sensitivity case, we saw small amounts of coal-fired generation being built in 2030. Even under this sensitivity analysis with small amounts of new coal generation under conditions of high natural gas prices and simultaneously high electricity demand in 2030, we do not project that this proposed rule will impose notable costs upon sources.

We seek comments on all aspects of this proposal and identify a number of aspects of the proposal on which comments are specifically requested.

B. Overview and Outline

1. Overview

In this rulemaking, the EPA proposes to limit GHG emissions from new fossil fuel-fired power plants by limiting CO₂ emissions. In 2009, the EPA issued a finding that GHG air pollution may reasonably be anticipated to endanger Americans' public health and welfare, now and in the future, by contributing to climate change. Fossil fuel-fired power plants emit more GHG emissions than any other stationary source category in the United States, and among new GHG emissions sources, the largest individual sources are in this source category. This rulemaking proposes federal standards of performance for new fossil fuel-fired power plants that can be met with existing technology.

Note that in this preamble, while we refer to these sources, interchangeably, as power plants, steam generating units, affected sources, fossil fuel-fired electric generating units, covered EGUs, or, simply, EGUs, the proposed standards apply to only those sources identified in Section III.A. as the affected source category.

2. Why is the EPA proposing this rule?

This proposed rule reflects the EPA's common-sense approach to reducing CO₂ and other GHG emissions, which by causing climate change, pose a serious threat to public health and welfare. The EPA is focusing first on reducing emissions from the largest emitters through measures with reasonable costs. The EPA is proposing to control CO₂ pollution from fossil fuel-fired power plants because they are responsible for

approximately 40 percent of all U.S. anthropogenic CO₂ emissions.² Individual new coal-fired power plants are among the largest individual new sources of GHGs. Furthermore, design and technology choices, such as NGCC, exist that can be readily and cost-effectively used to reduce GHG emissions from new fossil fuel-fired power plants. Thus, this proposed rule is a rational first step to control GHG emissions from the largest-emitting stationary sources under CAA section 111.

a. The Serious Threat of Climate Change to the Public's Health and Welfare. Climate change, including global warming, is a significant threat to the global environment. The National Research Council (NRC) of the National Academies³ stated in a 2011 report, "Each additional ton of greenhouse gases emitted commits us to further change and greater risks. In the judgment of the [NRC] Committee on America's Climate Choices, the environmental, economic, and humanitarian risks of climate change indicate a pressing need for substantial action to limit the magnitude of climate change and to prepare to adapt to its impacts."⁴

Action to reduce emissions is warranted because, as the EPA stated in its 2009 Endangerment Finding,⁵ GHGs endanger the public health and public welfare of current and future generations. The anthropogenic buildup of GHGs in the atmosphere is very likely (90 to 99 percent probability) the cause of most of the observed global warming over the last 50 years.⁶ Based on the Endangerment Finding and its underlying technical support document (TSD),⁷ reasons to reduce GHG emissions include the following:

² Or 32.4% of all anthropogenic GHG emissions; from information in Table 2-1 from "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009," U.S. Environmental Protection Agency, EPA 430-R-11-005, April 2011.

³ The National Academies comprise the National Academy of Sciences, National Academy of Engineering, Institute of Medicine and National Research Council.

⁴ National Research Council (2011) *America's Climate Choices*, Committee on America's Climate Choices, Board on Atmospheric Sciences and Climate, Division on Earth and Life Studies, The National Academies Press, Washington, DC.

⁵ EPA, "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act" (74 FR 66,496; Dec. 15, 2009). <http://epa.gov/climatechange/endangerment.html>.

⁶ Endangerment Finding at 74 FR 66,518, which notes that the 2007 conclusion of the Intergovernmental Panel on Climate Change was re-confirmed by the June 2009 assessment by the U.S. Global Change Research Program.

⁷ EPA, "Technical Support Document for Endangerment and Cause or Contribute Findings for
Continued

- The key effects of climate change observed to date and projected to occur in the future include, but are not limited to, more frequent and intense heat waves, more severe wildfires, degraded air quality, heavier and more frequent downpours and flooding, increased drought, greater sea level rise and storm surge, more intense storms, harm to water resources, continued ocean acidification, harm to agriculture, and harm to wildlife and ecosystems.

- These effects are anticipated to result in premature deaths, illnesses, damage to property and infrastructure, and other harm to people's welfare in the U.S.

- Those "most vulnerable" to climate related health effects, such as children, the elderly and the poor—and future generations—face disproportionate risks.⁸

- Human-induced climate change impacts have the potential to be far-reaching and multidimensional, though not all risks and potential impacts can be quantified.⁹

- A supporting consideration is that climate change impacts in certain regions of the world (potentially leading, for example, to food scarcity, conflicts or mass migration) may exacerbate problems that raise humanitarian, trade and national security issues for the United States.¹⁰

The TSD further notes that some risks, such as the extinction of many species, would be irreversible.¹¹ Also, the TSD points to research on the potential for "abrupt changes" ¹² which have uncertain or low probability but high potential impact. The NRC has said abrupt changes are an important consideration because, if triggered, they could occur so quickly and unexpectedly that human or natural systems would have difficulty adapting to them.¹³ Examples include severe drought in subtropical areas, release of

large amounts of GHGs stored in the sea floor and frozen Arctic soils, and rapid disintegration of Greenland ice sheet or collapse of the West Antarctic ice sheet leading to many feet of sea level rise.¹⁴

The special characteristics of GHGs make it important to take initial steps to control the largest emissions categories without delay. Unlike most traditional air pollutants, GHGs persist in the atmosphere for time periods ranging from decades to millennia, depending on the greenhouse gas. Greenhouse gases will continue to accumulate in the atmosphere at higher and higher concentrations each year unless substantial reductions in global greenhouse gas emissions are achieved. The NRC notes that emissions reduction choices made today matter in determining the level of impacts experienced not just over the next few decades, but in the coming centuries and millennia.¹⁵ Also, the longer that the U.S. and other countries take to reduce emissions, the greater the future emissions reductions that will be required to limit global temperature increase to any given level.

This proposed rule to limit GHG emissions from the largest U.S. stationary source category will contribute to the emissions reductions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against projected climate change impacts and risks. Reducing GHG emissions reduces the impacts and risks articulated in the Endangerment Finding and TSD.

b. The High Level of GHG Emissions from Fossil-Fuel-Fired Power Plants and the Opportunities to Reduce these Emissions. Fossil fuel-fired power plants comprise the largest category of stationary source GHG emissions in the U.S. These sources account for approximately 40 percent of total U.S. anthropogenic CO₂ emissions, based on 2009 data.¹⁶ Among all stationary sources of GHG emissions, fossil-fuel-fired power plants generally constitute the largest individual sources.

Furthermore, a range of options are available to reduce emissions of new power plants. For economic reasons,

most new power plants being built in the U.S. today are either natural gas-fired or are powered by renewable sources of energy, such as wind and solar, and therefore generally produce significantly fewer CO₂ emissions than uncontrolled coal-fired power plants. Natural gas combustion inherently emits less CO₂ than coal combustion and the technology of choice for generating electricity with natural gas, stationary combined cycle gas turbines, is also more efficient. Almost all the stationary combined cycle gas turbines built in the U.S. in the last five years can meet the proposed standard of 1,000 lb CO₂/MWh. New coal-fired power plants can install CCS technology and can thereby limit their CO₂ emissions per MWh generated to levels similar to, or even lower than, those of natural gas-fired combined cycle plants without CCS. New coal-fired power plants with CCS are being permitted and built today, albeit usually with considerable financial assistance from the federal government.

c. Alignment with Industry's Other CAA Obligations. Establishing the overall regulatory requirements for GHG emissions from new fossil fuel-fired power plants at this time is efficient because the EPA has recently issued regulations to limit criteria and hazardous air pollutants from these sources. Aligning the timing of these GHG rules with the rules for criteria and air toxics pollutants gives the industry more regulatory certainty, will facilitate the industry's investment decisions, and will help inform its compliance decisions to meet all of its CAA obligations.

d. Promotion of Energy Diversity. This proposed rule is consistent with the President's goal to ensure that "by 2035 we will generate 80% of our electricity from a diverse set of clean energy sources—including renewable energy sources like wind, solar, biomass and hydropower, nuclear power, efficient natural gas and clean coal."¹⁷ The proposed rule will assist the deployment of CCS technology for new coal-fired power plants and reinforce incentives for the use of efficient natural gas-fired generation. Regulatory uncertainty may be hindering the development and deployment of CCS, as evidenced by American Electric Power (AEP)'s recent deferral of a large-scale CCS retrofit demonstration project on one of its coal-fired power plants because the State's utility regulators would not approve CCS without a

Greenhouse Gases under Section 202(a) of the Clean Air Act, Dec. 9, 2009." Both the **Federal Register** Notice and the TSD for Endangerment and Cause or Contribute Findings are found in the public docket established for the endangerment rulemaking, Docket No. EPA-OAR-2009-0171 and at <http://epa.gov/climatechange/endangerment.html>.

⁸ Endangerment Finding, 74 FR 66498.

⁹ Endangerment Finding, 74 FR 66497.

¹⁰ Endangerment Finding, 74 FR 66535.

¹¹ Endangerment TSD, p. 136.

¹² Endangerment TSD, p. 75–78. The U.S. Climate Change Science Program defined "abrupt change" as a "large-scale change in the climate system that takes place over a few decades or less, persists (or is anticipated to persist) for at least a few decades, and causes substantial disruptions in human and natural systems." Synthesis and Assessment Product (SAP) 3.4: Abrupt Climate Change (2008).

¹³ Endangerment TSD, p. 75, citing National Research Council (2002).

¹⁴ Endangerment TSD, pp. 76–78.

¹⁵ National Research Council (NRC) (2011). Climate Stabilization Targets. Committee on Stabilization Targets for Atmospheric Greenhouse Gas Concentrations; Board on Atmospheric Sciences and Climate, Division of Earth and Life Sciences, National Academy Press. Washington, DC.

¹⁶ Or 32.4% of all anthropogenic GHG emissions; from information in Table 2–1 from 'Inventory of U. S. Greenhouse Gas Emissions and Sinks: 1990–2009', U. S. Environmental Protection Agency, EPA 430-R-11-005, April 2011.

¹⁷ "Blueprint for a Secure Energy Future", March 30, 2011.

regulatory requirement to reduce CO₂.¹⁸ The standard established in this proposal would help create the regulatory certainty that CCS is the path forward for new coal-fired generation.

3. Legal Proceedings Leading up to This Rulemaking

In April 2007, the U.S. Supreme Court ruled, in *Massachusetts v. EPA*,¹⁹ that GHGs meet the definition of “air pollutant” in the CAA. This decision clarified that the authorities and requirements of the CAA, including section 111, apply to GHG emissions.

As a result of this decision, the EPA obtained a voluntary remand from the U.S. Court of Appeals for the District of Columbia Circuit (the “Court”) to reconsider the EPA’s actions in a 2006 rulemaking for EGUs under CAA section 111, in which the EPA had promulgated standards for criteria air pollutants, but had declined to regulate GHG emissions. In part in response to threatened litigation over the EPA’s failure to act on the remand, the EPA agreed to propose today’s action to regulate GHG emissions from new fossil fuel-fired EGUs.

4. Legal Basis for CAA Standards for Fossil-Fired Power Plants

a. General Legal Requirements. Clean Air Act section 111 establishes a several step process for the EPA and the States to regulate air pollutants from stationary sources. First, the EPA must list categories of stationary sources that cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Then, the EPA must regulate emissions from new sources in the source category by issuing a standard of performance, which is 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 * * * cost [and other factors]) * * * has been adequately demonstrated.” New sources include

new construction, and, as discussed below, modifications to existing sources as well as reconstructed sources.

Standards of performance for new sources are often referred to as new source performance standards (NSPS).

b. Cause-or-Contribute-Significantly Finding for Fossil Fuel-Fired Power Plants and Endangerment Finding for GHG Air Pollution. The EPA is authorized to regulate GHGs from power plants based on earlier actions concerning endangerment. Before today’s rulemaking, the EPA listed different types of fossil fuel-fired EGUs as source categories that caused or contributed significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Specifically, the EPA listed electric utility steam generating boilers, including coal-fired boilers, and initially regulated them in subpart D of its regulations under CAA section 111. Subsequent regulation of utility boilers has been under subpart Da. The EPA listed stationary combustion turbine engines and initially regulated them under subpart GG. The stationary combustion turbine engine portions of combined cycle facilities were also regulated under subpart GG. Heat recovery steam generators (HRSG) associated with combined cycle facilities with duct burners were regulated under either subpart Da or one of the industrial boiler regulations, depending on the specific characteristics of the HRSG. To minimize the compliance burden for owners/operators of combined cycle facilities some monitoring harmonization was done, but the two subparts were still applicable. In 2005, the EPA proposed subpart KKKK as a replacement for subpart GG and specifically covered the entire combined cycle facility under subpart KKKK such that only a single set of requirements would apply. In that same year, the EPA proposed to include Integrated Gasification Combined Cycle (IGCC) facilities under the applicability of subpart Da. The EPA is authorized to promulgate the rulemaking proposed today—which would establish standards of performance for CO₂ emissions from EGUs currently in the Da and KKKK source categories—because the EPA has already determined that both those source categories cause or contribute significantly to air pollution that may reasonably be expected to endanger public health or welfare. Clean Air Act section 111 does not require the EPA, as a prerequisite to regulating any particular air pollutant, to issue an endangerment finding or a

cause-or-contribute-significantly finding for that air pollutant from that source category.

As an alternative, the EPA is considering whether CAA section 111 should be interpreted to require that the EPA base its regulation of CO₂ emissions from EGUs on two findings: (i) A finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare; and (ii) a finding that CO₂ emissions from EGUs cause or contribute significantly to that air pollution. If section 111 were so interpreted, the EPA believes that (a) the 2009 Endangerment Finding, along with the EPA’s 2010 action denying petitions to reconsider that finding (which action reviewed scientific developments after the Endangerment Finding) would fulfill any requirement to make the endangerment finding concerning GHG air pollution; and (b) the large amount of CO₂ emissions from EGUs clearly exceeds the low applicability threshold upon which the EPA would make the cause-or-contribute-significantly finding.

As another alternative, the EPA is also considering whether CAA section 111 should be interpreted to require that the EPA base its regulation of CO₂ emissions from EGUs on a rational basis for protection of the public health or welfare. If section 111 were so interpreted, the EPA believes that (i) its 2009 Endangerment Finding and 2010 denial of petitions to reconsider, by themselves, and particularly in conjunction with the National Academy of Sciences’ assessment reports issued since then, coupled with (ii) the fact that EGUs are the largest stationary source emitters of CO₂, provide a rational basis for regulating CO₂ emissions from EGUs. There is no reason to revisit the 2009 Endangerment Finding given recent scientific findings that strengthen the scientific conclusion that GHG air pollution endangers public health and welfare.²⁰

5. Summary of Today’s Proposed Requirements To Reduce GHG Emissions From New Fossil Fired Power Plants, and Rationale for Those Requirements

a. Summary of Proposed Revisions to Categories and Requirements for New Sources

i. Revisions to Categories of EGUs. In today’s action, the EPA is proposing to

¹⁸ In a July 17, 2011, press release, AEP’s chairman said, “We are placing the project on hold until economic and policy conditions create a viable path forward * * * We are clearly in a classic ‘which comes first?’ situation. The commercialization of this technology is vital if owners of coal-fueled generation are to comply with potential future climate regulations without prematurely retiring efficient, cost-effective generating capacity. But as a regulated utility, 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. The uncertainty also makes it difficult to attract partners to help fund the industry’s share.”

¹⁹ 549 U.S. 497 (2007).

²⁰ These recent scientific findings are described in section II of this notice, titled “Background.” See subsection II.B.3., “Climate Impacts Detailed in Recent NRC Assessments.” The legal options introduced here are presented in detail below in section IV.A.2, “Endangerment and Cause-or-Contribute-Significantly Finding.”

combine electric utility steam generating units (boilers and IGCC units, which are currently included in the Da category) and combined cycle units that generate electricity for sale and meet certain size criteria (which are currently included in the KKKK category), into a new category for new sources (the TTTT category) for the purposes of GHG emissions. Today's proposed rulemaking would not affect NSPS requirements for criteria air pollutants, simple cycle turbines or EGUs located in non-continental areas.²¹ It also would not affect biomass-fired boilers (including those that sell electricity to the grid) that co-fire with less than 250 MMBtu/h of any fossil fuel (biomass boilers currently subject to subpart Db, the Industrial-Commercial-Institutional Steam Generating Unit NSPS).

ii. Control Requirements for New Sources. The EPA is proposing standards of performance that require that all new fossil fuel-fired EGUs meet an electricity-output-based emission rate of 1,000 lb CO₂/MWh of electricity generated on a gross basis. This proposed standard is based on the demonstrated performance of natural gas combined cycle (NGCC) units, which are currently in wide use throughout the country, and are likely to be the predominant fossil fuel-fired technology for new generation in the future.

New coal-, coal refuse-, oil- and petroleum coke-fired boilers and IGCC units should also be able to meet this standard by employing CCS technology. There are currently a number of coal- and pet coke-fired EGU projects under development that include CCS. While a coal unit with CCS may be more expensive to construct than NGCC generation, for reasons explained below, we expect the difference to decrease over time as CCS becomes more mature and less expensive.

We include in today's proposed rulemaking a 30-year averaging compliance option under which affected coal- and pet coke-fired sources could comply with the 1,000 lb CO₂/MWh standard on a 30-year average basis. Coal- and pet coke-fired EGUs that use this compliance alternative must meet an immediate performance standard of 1,800 lb CO₂/MWh (gross) on a 12-month annual average basis, which can be achieved by a "supercritical" efficiency level, during the period before installation of CCS. By no later than the beginning of the 11th year, the

facility would be required to meet a reduced CO₂ emission limit of no more than 600 lb CO₂/MWh (gross) on a 12-month annual average basis for the remaining 20 years of the 30-year period, such that the weighted average CO₂ emissions rate from the facility over the 30-year time period would be equivalent to the proposed standard of performance of 1,000 lb CO₂/MWh.

We seek comment on this compliance option and on reasonable variations on the framework we propose to establish, and in particular on a mechanism for establishing practicably enforceable short term limits during the 30-year period. The potential approaches here include (1) requiring the owner/operator to identify and obtain approval of, at the time of construction, an alternative 30-year emission trajectory to the 10- and 20-year limits described immediately above; and (2) specifying the emission rate for each year during the 30-year period consistent with meeting a 30-year average emission rate of 1,000 lb CO₂/MWh. Such an option would provide coal-fired sources that intend to use a reduction technology, such as CCS, significant flexibility in how that reduction technology is implemented. They could install the technology as part of the original project but use some or all of the initial ten year period to optimize the system. Such flexibility could be particularly useful to early adopters (i.e., "first movers") of the technology. Alternatively, they could delay installation of the technology for a period of up to ten years to take advantage of advancements in the technology that could reduce costs and enhance performance. Under CAA section 111(b)(1)(B), the EPA is required to conduct a review of the new source standards in eight years and we intend at that time to review the availability and cost of CCS. As proposed, this 30-year averaging compliance option is available only to new coal- and pet coke-fired EGUs. We do not believe that it is necessary for NGCC units, as they should be able to meet the proposed performance with no need for add-on technology. We also solicit comment on the need to extend the applicability for the 30-year averaging compliance option to other fossil fuels beyond just coal and pet coke.

b. *Rationale.* Today's proposal to combine the relevant parts of the Da and KKKK categories is authorized under CAA section 111(b)(1)(A) because that provision authorizes the EPA, after drawing up the list of affected source categories, to "revise" that list from time to time. Combining the relevant parts of the categories, as the EPA proposes to do, is one method to "revise" the list.

Moreover, the EPA's action to combine the relevant parts of the categories is reasonable because with the combination, all new fossil fuel-fired electricity generating units that meet specified minimum criteria will be subject to the same requirements, and therefore will be treated alike because they serve the same function, that is to serve baseload or intermediate demand. The EPA is not including stationary simple cycle turbines in this rule because they generally operate differently than the other units covered by today's rule. The units covered by today's rule are generally used to serve baseload or intermediate demand, while simple cycle turbines are generally used much less often (and thus have lower GHG emissions) and are generally used to meet peak demand rather than base or intermediate load requirements.

Today's proposal does not apply to new sources in non-continental areas, which include Hawaii and the territories. This is because non-continental areas do not have available pipeline quality natural gas and, accordingly, a natural-gas-fired plant that could comply with the 1,000 lb CO₂/MWh may not be feasible. At present, we do not have information to identify what types of new power plants may be constructed in those areas. Those types of power plants may range from liquified natural gas (LNG)-, to oil-, to coal-fired to renewables. Our lack of more specific information precludes us from proposing, at this time, a standard for new sources in non-continental areas.

Today's proposal to require an emission rate of 1,000 lb CO₂/MWh meets the requirements for a "standard of performance," as defined under CAA section 111(a)(1). This proposed standard is based on the degree of emission limitation achievable through natural gas combined cycle generation. NGCC qualifies as the "best system of emission reduction" (BSER) that the EPA has determined has been adequately demonstrated because NGCC emits the least amount of CO₂ and does so at the least cost. We propose that a NGCC facility is the best system of emission reduction for two main reasons. First, natural gas is far less polluting than coal. Combustion of natural gas emits only about 50 percent of the CO₂ emissions that the combustion of coal does per unit of energy generated. Second, new natural gas-fired EGUs are less costly than new coal-fired EGUs, and as a result, our Integrated Planning Model (IPM) model projects that for economic reasons, natural gas-fired EGUs will be the facilities of choice until at least 2020,

²¹ Thus, today's rulemaking does not affect the Da and KKKK categories for conventional pollutants and does not affect the KKKK category for simple cycle turbines.

which is the analysis period for this rulemaking. Indeed, our IPM model does not project construction of any new coal-fired EGUs during that period. This state of affairs has come about primarily because technological developments and discoveries of abundant natural gas reserves have caused natural gas prices to decline precipitously in recent years and have secured those relatively low prices for the near-future. Importantly, because the IPM modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance in today's rulemaking — which is based on the emission rate of a new NGCC unit — does not add costs. In addition, compared to coal-fired EGUs, natural gas-fired EGUs have fewer nonair quality health and environmental impacts. This is true under not only a set of base-case assumptions, but also under a sensitivity considering significantly higher gas prices.

The just-described reasons are sufficient as a legal matter to justify today's proposed actions to combine source categories and establish the 1,000 lb CO₂/MWh standard. Such a standard could also be met today by new coal-fired units using CCS. In addition, we propose to include the compliance alternative of allowing new coal- and pet coke-fired power plants to meet the 1,000 lb CO₂/MWh standard over a 30-year period so that plant developers can take advantage of future advancements cost savings in CCS technology that could lower its cost. This compliance alternative allows owners/operators to install CCS when the unit is first constructed but also provides the operational flexibility that may be necessary to optimize the performance and to have additional time to address any startup challenges related to issues such as business arrangements related to the sale or storage of the captured CO₂.

We recognize that, in light of a number of economic factors, including the increased availability and significantly lower price of natural gas, energy industry modeling forecasts uniformly predict that few, if any, new coal-fired power plants will be built in the foreseeable future. For these economic reasons, and independent of this proposed standard, the fossil fuel-fired electricity generating industry has been trending towards increased use of natural gas and decreased use of coal for new generating capacity. Today's proposed action is consistent with that trend; but, at the same time, today's proposal is not intended to affect that apparent trend.

We recognize that some owners/operators may nevertheless seek to construct new coal-fired capacity. This may be beneficial from the standpoint of promoting energy diversity, and today's proposal does not interfere with construction of new coal-fired capacity. In the first instance, a new coal-fired power plant may be able to meet the 1,000 lb CO₂/MWh standard by installing CCS at the time of construction. At present, while CCS would add considerably to the costs of a new coal-fired power plant, there are sources of funding available to support the deployment of CCS, including a limited number of government demonstration programs.²² Even if companies decide to construct a few new coal-fired power plants under any circumstance, those few may well have access to those government programs.

The proposed 30-year averaging compliance option adds additional flexibility for new coal- and pet coke-fired power plants by allowing them to construct and begin operations without CCS, and then to install and operate CCS at some time in the future, as long as they install CCS within ten years and operate it in a manner that allows them to meet the 1,000 lb CO₂/MWh standard, on a weighted average basis, over the 30-year period.

We expect that the costs of CCS will decline in the future as CCS matures and is utilized more widely. Today's action, if finalized, would promote utilization and further development of CCS by making it clear that CCS would be necessary for new coal-fired power plants to meet the performance standard. The prospect of declining CCS costs, in conjunction with the possibility of continued availability of additional funding mechanisms (e.g. demonstration funding such as Department of Energy (DOE) grants, tax credits (for investment and/or EOR), State incentives such as clean energy standards), and sale of other usable products such as CO₂, sulfur and hydrogen based products, indicates that CCS may well be sufficiently accessible in the near term to the few coal-fired power plants that are expected to commence construction. Thus, the 30-year averaging compliance option, along with the potential opportunities for funding to implement CCS immediately, helps to alleviate any concerns that

²² A number of the sources that EPA has identified as transitional sources have received some form of DOE financial assistance to demonstrate CCS. In addition, several additional projects have received funding but have not yet received air permits. Beyond these projects, prospects for additional federal funding are dependent on the overall budget process.

today's action could restrict new coal-fired construction.

It should be noted that we are not required to justify the 30-year averaging compliance option on grounds that it qualifies as the "best system of emission reduction" adequately demonstrated, and we are not stating in this action whether that compliance alternative does or does not qualify as such. Thus, it is not necessary to determine that our expectation that costs will go down meets the standards for determining that CCS is "adequately demonstrated." Rather, to reiterate, the 30-year averaging compliance option, along with the opportunity to implement CCS to meet the 1,000 lb CO₂/MWh standard immediately upon startup, make CCS an available option for the limited number of new coal-fired power plants that may construct to serve the policy goals of promoting energy diversity, as well as other policy objectives.²³ Indeed, by clarifying that, in the future, new coal-fired power plants will need to implement CCS, this rulemaking eliminates uncertainty about the status of new coal and may well enhance the prospects for new coal-fired generation.

In addition, there may also be other potential compliance options available that were not considered in this proposal. In the analysis for today's proposal, the EPA did not include unique treatment of CO₂ emissions from biologically-based material, otherwise called biogenic CO₂ emissions.²⁴

In 2011, the EPA prepared and submitted the draft Accounting Framework for Biogenic CO₂ Emissions from Stationary Sources (http://www.epa.gov/climatechange/emissions/biogenic_emissions/study.html). The draft Framework includes both a detailed examination of the scientific and technical issues related to accounting for biogenic CO₂ emissions from stationary sources, and a proposed method to account for a stationary source's onsite CO₂ emissions, taking the biological cycling of carbon into consideration, in a scientifically and technically rigorous manner. The independent Science Advisory Board (SAB) has convened a Biogenic Carbon

²³ EIA analysis (AEO 2012 early release) shows that "coal remains the dominant energy source for electricity generation."

²⁴ Biologically-based material is defined as non-fossilized and biodegradable organic material originating from modern or contemporaneously grown plants, animals or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Emissions Panel (<http://yosemite.epa.gov/sab/sabproduct.nsf/0/2F9B572C712AC52E8525783100704886?OpenDocument>) to conduct a peer review of the draft Framework. The peer review report will be finalized later in 2012.

The SAB's peer review of the EPA's discussion on the science related to the impacts of biogenic CO₂ is not yet finalized and the EPA looks forward to the SAB's conclusions later in 2012. Given that the SAB's peer review is ongoing, the EPA is not suggesting specific methods of accounting or otherwise making particular proposals for treatment of biogenic CO₂ emissions in any stationary source program, including NSPS. As more information, including the SAB peer review, becomes available, the EPA will consider its options and move forward as warranted.

c. *Requirements and Rationale for NSPS Modifications for GHGs.* For purposes of today's action, the EPA does not have a sufficient base of information to develop a proposal for the affected sources that may be expected to take actions that would constitute "modifications" (as defined under the EPA's NSPS regulations) for GHGs and therefore be subject to requirements for new sources. As a result, the EPA is not proposing requirements for NSPS modifications for GHGs.²⁵

The EPA's current regulations define an NSPS "modification" as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, but specifically exempt from that definition pollution control projects, which are projects that entail the installation of pollution control equipment or systems. Based on current information, most of the projects that we believe EGUs are most likely to undertake in the foreseeable future that could increase the maximum achievable hourly rate of CO₂ emissions would constitute pollution control projects. In many cases, those projects would involve the installation of add-on control equipment required to meet CAA requirements for criteria and air toxics air pollutants. These increases in CO₂ emissions would generally be small and would occur as a chemical byproduct of the operation of the control equipment. In other cases, those projects would involve equipment changes to improve efficiency to meet the requirements of a future 111(d) rulemaking for existing sources and

would have the effect of increasing a source's maximum achievable hourly emission rate (lb CO₂/hr), even while decreasing its actual output based emission rate (lb CO₂/MWh). Because all of these actions would be treated as pollution control projects under the EPA's current NSPS regulations, they would be specifically exempted from the definition of modification.

Our base of knowledge concerning NSPS modifications has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for NSPS modifications for GHGs at this time.

In addition, the sources that took these actions vary widely one from another, and the types of actions were disparate. In light of this, as noted, we do not have adequate information as to the types of actions that qualify as modifications, the amount of increase in CO₂ emissions they cause, the types of control measures, or the costs and effectiveness of control measures, on which to base a proposed standard of performance. Therefore, in today's action, we are not proposing a standard of performance for modifications. We note that the statute contemplates that in circumstances such as these (where section 111(d) is implicated), sources not subject to the new source standards would be treated as existing sources subject to section 111(d).

In today's action, we solicit comment on the types of modifications power plants may undertake and the appropriate control measures. Depending on the information we develop, we may issue proposed standards of performance in the future.

d. *Requirements for Transitional sources.* The EPA is aware that approximately 15 proposed EGUs have received CAA permitting authority approval for their preconstruction permits, but may not have "commenced construction" by the date of today's proposed rulemaking.

A few of these sources have taken additional action preparatory to commencing construction. For this proposed rule, these sources that, as of the date of this proposal, have a PSD permit and are poised to commence construction within the very near future are referred to as "transitional sources." We are aware that approximately six of these sources have plans to implement CCS to some degree.

CAA section 111 provides by its terms that sources that have not "commenced

construction" before the date of proposed standards for new sources will be subject to the NSPS when they do commence construction. The EPA's regulations define "commenced construction" as, in general, undertaking a continuous program of construction or entering into a binding contract to do so. 40 CFR 60.2.

Commenters²⁶ have pointed out that absent different treatment, transitional sources will be subject to the same requirements that apply to new sources that did not obtain their permit before the date of proposal. These commenters have suggested that today's proposed rule should treat transitional sources differently, especially in light of the substantial redesign that meeting such the proposed standard would have and the impact that redesign would have on the schedule for a project that was nearly ready to commence construction. The transitional sources at issue are coal-fired EGUs that, absent special treatment, would be subject to the standard of performance proposed in this rulemaking.

In today's proposed rulemaking, the EPA is not proposing a standard of performance for transitional sources, which we define as sources that have been issued a PSD permit by the date of proposal (including sources that have approved permits that are in the process of being amended, if those sources are intending to install CCS as evidenced by participating in any of the DOE CCS funding programs, either loan guarantee or grant programs) and that commence construction within 12 months of the date of publication of this proposal in the **Federal Register**. Upon finalization of this rulemaking without a standard of performance applicable to these sources, they will not be treated as new sources subject to the specific limitations set forth in the final new source standards. These sources would remain obligated, by the terms of their permits, to construct and operate in accordance with their permits. In addition, these sources will be treated as existing sources and would be subject to any requirements that a State promulgates to meet its obligations under section 111(d). Sources that do not commence construction within 12 months of the date of this proposed action will be subject to this standard of performance for new sources.

²⁵ Note that any analysis of the cost and feasibility of CCS that EPA has undertaken for purposes of this proposal has focused solely on new sources. In today's action, EPA has not undertaken any analysis of the cost or feasibility of CCS for existing units that undergo modifications.

²⁶ As mentioned elsewhere, the EPA held a series of listening sessions and allowed for a period of additional comment after announcing it was moving forward with development of new source performance standards for GHGs emitted from fossil fuel-fired EGUs. The term "commenters" here refers to those who commented during the listening sessions or during the subsequent comment period.

e. *Requirements for Reconstructed Sources, and Rationale.* The EPA's CAA section 111 regulations provide that reconstructed sources are to be treated as new sources and, therefore, subject to new source standards of performance. The regulations define reconstructed sources as, in general, existing sources (i) that replace components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, and (ii) for which compliance with standards of performance for new sources is technologically and economically feasible. 40 CFR 60.15.

As with NSPS modifications, our base of knowledge concerning reconstructions has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for reconstructions for GHGs at this time. Thus, we lack adequate information about the type of source; the type of changes; the extent of emissions increases; and the type of control measures, including their cost and emissions reductions, that we need

to propose a standard of performance for reconstructions.

As a result, in today's action, the EPA is not including a proposal for reconstructed units for GHGs. Instead, we solicit comment on how we should approach reconstructions and, depending on the information we receive, we may propose and finalize a standard for reconstructions at a later time.

6. Summary of Emissions Impacts, Costs and Benefits

Our IPM modeling, using Energy Information Administration (EIA) reference case assumptions, projects that there will be no construction of new coal-fired generation without CCS. In addition we examined a case with higher future electric demand and another case with higher future natural gas prices. We did not see any additional new construction of coal-fired generation through 2030 in either of these cases. Under the relevant assumptions, we do not project that this rule will impose notable costs.

We also examined a scenario with both increased future natural gas prices and increased future electric demand. In this sensitivity case we saw small amounts of coal-fired generation being

built in 2030. Even under this sensitivity analysis with small amounts of new coal generation under conditions of high natural gas prices and simultaneously high electricity demand in 2030, we do not project that this proposed rule will impose notable costs upon sources. (See the RIA for further discussion of sensitivities).

While this proposed rule also will not have direct impact on U.S. emissions of greenhouse gases under expected economic conditions, it provides assurance that emission rates from new fossil fuel-fired generation will not exceed the level of the standard and will send a strong signal both domestically and internationally. Domestically, this proposed rule can further stimulate investment in CCS and other clean coal technologies, by making it clear that such technologies do provide a clear path forward for new coal-fired generating capacity. Internationally, this rule may encourage others to consider less GHG-intensive forms of power generation.

B. Does this action apply to me?

The entities potentially affected by the proposed standards are shown in Table 1 below.

TABLE 1—POTENTIALLY AFFECTED ENTITIES ^a

Category	NAICS Code	Examples of potentially regulated entities
Industry	221112	Fossil fuel electric power generating units.
Federal Government	^b 221112	Fossil fuel electric power generating units owned by the federal government.
State/Local Government	^b 221112	Fossil fuel electric power generating units owned by municipalities.
Tribal Government	921150	Fossil fuel electric power generating units in Indian Country.

^a Include NAICS categories for source categories that own and operate electric power generating units (including boilers and stationary combined cycle combustion turbines).

^b Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive but rather to provide a guide for readers regarding entities likely to be affected by this proposed action. To determine whether your facility, company, business, organization, etc., would be regulated by this proposed action, you should examine the applicability criteria in 40 CFR 60.1. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

II. Background

A. Statutory Background for This Rule

Clean Air Act section 111 establishes mechanisms for controlling emissions of air pollutants from stationary sources.

As a preliminary step, CAA section 111(b)(1)(A) requires the EPA to list categories of stationary sources that the Administrator, in his or her judgment, finds "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."²⁷

Once it has listed a source category, the EPA establishes "standards of performance" that apply to new sources, which are sources that are constructed, or that undertake modifications or reconstruction, after the EPA proposes the standards of performance for the relevant source category. CAA section 111(b)(1)(B). Specific statutory and regulatory provisions define what

²⁷ The EPA has made endangerment findings under this section for more than 60 stationary source categories and subcategories that are now subject to NSPS.

constitutes a modification or reconstruction of a facility. An existing facility undertakes a modification if it undergoes "any physical change * * * or change in the method of operation * * * 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." CAA section 111(a)(4). The EPA's NSPS regulations provide exemptions for several types of changes, including the installation of pollution control projects. 40 CFR 60.2, 60.14(e). An existing facility undertakes a reconstruction if it replaces components to such an extent that the capital costs of the new equipment or components exceed 50 percent of what is believed to be the cost of a completely new facility. 40 CFR 60.15. In promulgating standards of performance, the EPA has significant

discretion to create subcategories based on source type, class or size. CAA section 111(b)(2).

Clean Air Act section 111(a)(1) defines a “standard of performance” 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 nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

We call this level of control the best system of emission reduction (BSER).²⁸ The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (e.g., a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.

B. Overview of Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the 2009 Endangerment Finding,²⁹ under CAA section 202(a)(1), as part of the process for promulgating the Light Duty Vehicle Rule.³⁰ With the Endangerment Finding, the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare. These adverse effects on public health and welfare are summarized here, and described in more detail in the RIA. As explained in the Endangerment Finding, the EPA made this determination based primarily upon the recent, major assessments by the U.S. Global Change Research Program (USGCRP), Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC).³¹ In brief, these assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change problem, and

underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S.

government review and acceptance. Below is a brief, non-comprehensive summary of effects noted in the Endangerment Finding and the assessment reports.

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change threatens public health through a number of impacts such as increases in hot weather, ozone pollution, and the severity and frequency of extreme weather events. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

By increasing higher average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also leads to decreases in cold-related mortality, some evidence suggests that the net impact on mortality is more likely to be adverse. Heat is already the leading cause of weather-related deaths in the U.S.

Climate change is expected to increase ozone pollution over broad areas of the country including large population areas with unhealthy surface ozone levels. Ozone health studies indicate that elevated surface ozone increases risks of premature death, acute bronchitis, heart attacks, asthma aggravation, and other respiratory effects.

Public health threats also stem from increases in intensity or frequency of extreme weather associated with climate change, such as increased hurricane intensity, increased frequency of intense storms and heavy precipitation. The assessment literature indicates that there is the potential for hurricanes to become more intense, and there is some evidence that Atlantic hurricanes have already become more intense. Hurricanes and floods from human-induced climate change can cause deaths, injuries, waterborne diseases, and mental health problems such as post-traumatic stress disorders. Drownings and other health impacts from coastal storms and storm surges are expected to increase due to rising sea levels.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change is expected to have numerous effects on public welfare. Large areas of the country are at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events

such as floods and droughts. Coastal areas face increased risks from storm and flooding damage to property, as well as adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss.

Climate change is expected to result in an increase in peak electricity demand, and changes in extreme weather threaten energy, transportation, and water resource infrastructure. Climate changes may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Over the 21st century, climate change will fundamentally rearrange U.S. ecosystems.

It is possible that in the next few decades, adverse effects in certain parts of the agriculture and forestry sectors—such as enhanced pest and weed growth, increased surface ozone, changes in the intensity and frequency of droughts and heavy storms, and increased wildfires—may be offset by benefits resulting from a stimulatory carbon dioxide effect and a longer growing season. However, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture, and forest productivity as temperatures continue to rise, with the potential for significant disruptions and crop failure.

Human-induced climate change has the potential to be far-reaching and multidimensional. Given the long atmospheric lifetime of the six GHGs,³² which range from roughly a decade to centuries, future atmospheric greenhouse gas concentrations for the remainder of this century and beyond will be influenced not only by future emissions but indeed by present-day emissions. The severity of all the described risks and impacts is likely to increase over time with accumulating GHG concentrations and the associated temperature increases and precipitation changes. Finally, these impacts are global, and may exacerbate problems that raise humanitarian, trade, and national security issues for the U.S.

3. Climate Impacts Detailed in Recent NRC Assessments

Since the EPA issued the 2009 Endangerment Finding, the NAS, which is a society established by an Act of Congress that is composed of distinguished scholars engaged in scientific and engineering research, has

²⁸ This level of control has historically been referred to as best demonstrated technology (BDT).

²⁹ “Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act.” 74 FR 66496 (December 15, 2009).

³⁰ “Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule.” 75 FR 25324 (May 7, 2010).

³¹ 74 FR 66510–66511.

³² Carbon dioxide (CO₂), nitrous oxide (N₂O), methane (CH₄), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF₆).

issued assessments with similar conclusions to those of the assessments upon which the EPA based the Endangerment Finding. In May 2010, the NRC, which is the operating arm of the National Academy of Sciences (NAS) that conducts most of the science policy and technical work, published its comprehensive assessment, "Advancing the Science of Climate Change" (the 2010 NRC Assessment).³³ It concluded that "climate change is occurring, is caused largely by human activities, and poses significant risks for—and in many cases is already affecting—a broad range of human and natural systems."³⁴ Furthermore, the NRC stated that this conclusion is based on findings that are "consistent with the conclusions of recent assessments by the U.S. Global Change Research Program, the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report, and other assessments of the state of scientific knowledge on climate change."³⁵ These are the same assessments that served as the primary scientific references underlying the 2009 Endangerment Finding. The 2010 NRC Assessment also warned of risks associated with abrupt changes and surprises that might occur when certain thresholds are crossed, such as the release of large quantities of GHGs stored in frozen soils in the Arctic or

irreversible drying and desertification in the subtropics; and of potential for broad, "catastrophic" impacts on marine ecosystems resulting from ocean acidification.

Another NRC assessment, "Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia", was published in 2011 (the 2011 NRC Assessment). This report found that climate change due to CO₂ emissions will persist for many centuries. The report also estimates a number of specific climate change impacts, finding that every degree Celsius (°C) of warming could lead to increases in heavy rainfall and decreases in crop yields and Arctic sea ice extent, along with other precipitation and stream flow changes. The assessment also found that with an increase of 4 °C, the average summer would be as warm as the warmest summers of the past century, that for an increase of 1 to 2 °C the area burnt by wildfires in western North America will likely more than double, that coral bleaching and erosion will increase due both to warming and ocean acidification, and that sea level will rise 1.6 to 3.3 feet by 2100 in a 3 °C scenario. The assessment notes that many important aspects of climate change are difficult to quantify but that the risk of adverse impacts is likely to increase with increasing temperature, and that

the risk of surprises can be expected to increase with the duration and magnitude of the warming. Importantly, these recent NRC assessments represent another independent and critical inquiry of the state of climate change science, separate and apart from the previous IPCC, NRC, and USGCRP assessments.

C. GHGs From Fossil Fuel-Fired Power Plants

Fossil fuel-fired electric utility generating units are by far the largest emitters of GHGs, primarily in the form of CO₂, among stationary sources in the U.S. This section describes the amount of those emissions and places that amount in the context of the national inventory of GHGs.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks³⁶ (the U.S. GHG Inventory) to comply with existing commitments under the United Nations Framework Convention on Climate Change. This inventory, which includes recent trends, is presented by industrial sectors. It is the source for the information provided in Table 2 below concerning total U.S. anthropogenic emissions and sinks of GHGs and CO₂ emissions, by industrial sector—including fossil fuel-fired EGUs—for the years 1990, 2000, and 2009.

TABLE 2—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Teragram Carbon Dioxide Equivalent (Tg CO₂ Eq.)]³⁷

Sector	1990	2000	2009
Energy	5,287.8	6,168.0	5,751.1
Industrial Processes	315.8	348.8	282.9
Solvent and Other Product Use	4.4	4.9	4.4
Agriculture	383.6	410.6	419.3
Land Use, Land-Use Change and Forestry (Emissions)	15.0	36.3	25.0
Waste	175.2	143.9	150.5
Total Emissions	6,181.8	7,112.7	6,633.2
Land Use, Land-Use Change and Forestry (Sinks)	(861.5)	(576.6)	(1,015.1)
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	5,618.2

Energy-related CO₂ emissions are the largest contributor to total U.S. GHG emissions, representing 86.7 percent of total 2009 GHG emissions. In 2009, the electric power sector—consisting of those entities whose primary business is the generation of electricity—accounted for 40 percent of all energy-related CO₂

emissions. The transportation sector, with emissions principally from the combustion of gasoline, diesel, and jet fuel, was the second-largest source, at 32 percent of the total. Other energy-related CO₂ emission sources included industrial, residential, and commercial fossil fuel combustion, natural gas and

petroleum systems, and incineration of waste.

Direct fuel use in the residential and commercial sectors accounted for 26 percent of total CO₂ emissions in 2009. Total CO₂ emissions from fossil fuel-fired EGUs, for years 1990, 2000 and 2009, are shown below in Table 3.

³³ NRC (2010). Advancing the Science of Climate Change. National Academy Press. Washington, DC.

³⁴ NRC (2010). Advancing the Science of Climate Change. National Academy Press. Washington, DC. Page 3.

³⁵ NRC (2010). Advancing the Science of Climate Change. National Academy Press. Washington, DC. Page 286.

³⁶ "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009", Report EPA 430-R-11-005,

United States Environmental Protection Agency, April 15, 2011.

³⁷ From Table 2–3 of the EPA GHG Emissions and Sinks Inventory, EPA 430-R-11-005.

TABLE 3—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS
[Tg CO₂ Eq.]

GHG Emissions	1990	2000	2009
Total CO ₂ from fossil fuel combustion	1,820.8	2,296.9	2,154.0
—from coal	1,547.6	1,927.4	1,747.6
—from natural gas	175.3	280.8	373.1
—from petroleum	97.5	88.4	32.9
From use of limestone and dolomite	2.6	2.5	3.8
Total CH ₄ —stationary combustion	0.6	0.7	0.7
Total N ₂ O—stationary combustion	8.1	10.0	9.0

We are aware that nitrous oxide (N₂O) (and to a lesser extent, methane (CH₄)) may be emitted from fossil fuel-fired EGUs, especially from coal-fired circulating fluidized bed (CFB) combustors and from units with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems installed for NO_x control. We are not proposing separate N₂O or CH₄ emission limits or an equivalent CO₂ emission limit in today's action because of a lack of available data for these affected sources. Additional information on the quantity and significance of emissions and on the availability of cost-effective controls would be needed before proposing standards for these pollutants. The estimated emissions for N₂O and CH₄ from fossil fuel-fired EGUs (9.0 and 0.7 Tg of CO₂ equivalent, respectively) is about 0.4 percent of total CO₂ equivalent emissions from fossil fuel-fired electric power generating units. We are requesting comment on this approach and on the need to collect additional data on N₂O and CH₄ emissions from these affected sources.

D. Litigation Directly Leading to This Rule

As discussed below, in section II.E., on February 27, 2006, the EPA published a final rule that revised the standards of performance for criteria pollutant emissions of EGUs included in the Da category. "Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units," 71 FR 9866 (Feb. 27, 2006) (the "2006 Final Rule"). The 2006 Final Rule did not establish standards of performance for GHG emissions. Two groups of petitioners filed petitions for judicial review of this rule in the U.S. Court of Appeals for the District of Columbia Circuit (the Court), contending, among other things, that the rule was required to include standards of performance for GHG emissions from EGUs. The two groups of petitioners were (1) the States of New York,

California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, and the City of New York (collectively "State Petitioners"); and (2) Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF) (collectively "Environmental Petitioners").

The portions of State and Environmental Petitioners' petitions for review of the 2006 Final Rule that related to GHG emissions were severed from other petitions for review of that rule, and were formally pending before the Court under the caption *State of New York, et al. v. EPA*, No. 06–1322. Following the U.S. Supreme Court's decision in *Massachusetts*, discussed above, the Court, upon motion from the EPA, remanded the 2006 Final Rule for further consideration of the issues related to GHG emissions in light of *Massachusetts*. The EPA did not act on that remand. To avoid further litigation, the State and Environmental Petitioners and the EPA negotiated a proposed settlement agreement that set deadlines for the EPA to propose and take final action on (1) a rule under CAA section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 CFR part 60, subpart Da; and (2) a rule under CAA section 111(d) that includes emission guidelines for GHGs from existing EGUs that would have been subject to 40 CFR part 60, subpart Da if they were new sources. Pursuant to CAA section 113(g), the EPA published a notice of the proposed settlement agreement in the **Federal Register**, and provided for a public comment period. 75 FR 82392 (December 30, 2010).³⁸ The EPA considered the comments received and concluded that they did not disclose facts or considerations indicating that the proposed settlement

agreement was inappropriate, improper, inadequate or inconsistent with the CAA. Therefore, the EPA concluded that the proposed settlement agreement should be finalized.

E. Coordination With Other Rulemakings

EGUs are the subject of several CAA rulemakings that have been recently completed. The EPA recognizes that it is important that all of these efforts achieve their intended environmental objectives in a common sense manner. The confluence of these rulemakings allows the industry to look across the regulatory requirements and design cost effective integrated compliance strategies.³⁹

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR)⁴⁰. 76 FR 48208 (August 8, 2011). Also known as the Transport Rule, the CSAPR requires a total of 28 states and the District of Columbia to improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other States. The CSAPR applies to 3,642 EGUs at 1,081 coal-, gas- and oil-fired facilities in the eastern half of the U.S. By 2014, combined with other final state and EPA actions, the CSAPR will reduce power plant SO₂ emissions by 73 percent and NO_x emissions by 54 percent from 2005 levels in the CSAPR region. The CSAPR was scheduled to begin on January 1, 2012. However, on December 30, 2011, the U.S. Court of Appeals for the DC Circuit issued a ruling to stay the rule pending judicial review. This decision is not a ruling on the merits of the CSAPR. While this decision delays implementation of the

³⁹ We include this discussion of other rulemakings for background purposes. The effort to coordinate rulemakings does not provide a defense to a violation to the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

⁴⁰ On December 15, 2011, EPA finalized a supplemental rule (76 FR 80760, December 27, 2012) to include five additional states in the CSAPR ozone season NO_x program. On February 7, 2012, EPA issued two sets of minor adjustments to the CSAPR (77 FR 10324, February 21, 2012).

³⁸ Copies of the **Federal Register** notice, the settlement agreement, other supporting documents and the comments received are available online at fdms.gov under docket EPA–HQ–2010–1057.

CSAPR and the significant health benefits associated with the rule, it leaves the Clean Air Interstate Rule (CAIR), the predecessor regulation to CSAPR, in place while the Court considers the merits of the challenges to the CSAPR. Oral arguments are scheduled for April 13, 2012.

On December 16, 2011, the EPA signed the Mercury and Air Toxic Standards (MATS) rule to reduce emissions of mercury and other HAP emissions from coal- and oil-fired power plants. This regulation requires investments in pollution controls to reduce emissions of mercury, other metals and acid gases by 2015 or 2016. In the same notice, the EPA also revised the NSPS for criteria pollutants from these sources. Because the control technologies and strategies that reduce SO₂ can also reduce or help to reduce HAP emissions, coordinating compliance strategies for the CSAPR and MATS rules, including the revised NSPS for criteria pollutants, will allow cost-effective compliance options.

In April, 2011, the EPA proposed standards under the Clean Water Act (CWA) to reduce injury and death of fish and other aquatic life caused by cooling water intake structures existing at power plants and factories. 76 FR 22174 (April 20, 2011). These facilities pull in large volumes of cooling water from lakes, rivers, estuaries or oceans to cool their machinery. The EPA is currently considering a wide range of comments to this proposal.

The EPA recognizes that it is important that each of these efforts achieves its intended environmental objectives in a common-sense, cost effective manner, that is consistent with the underlying statutory requirements and that allows the industry to comply with all of its obligations under these rules as efficiently as possible and to do so by making coordinated investment decisions and, to the greatest extent possible, by adopting integrated compliance strategies. In addition, EO 13563 states that “[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote * * * coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.” Recent guidance from the Office of Information and Regulatory Affairs has emphasized the importance of, where appropriate and feasible, considering cumulative effects and of seeking to harmonize rules in terms of both content and timing.

Thus, the EPA recognizes that it needs to approach these rulemakings, to the extent that its legal obligations permit, in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that the rulemakings must achieve.

F. PSD and Title V Implications

Commenters have asked whether the rulemaking the EPA is proposing today has implications for EGUs and other stationary sources under the prevention of significant deterioration (PSD) and Title V programs. We discuss this issue in section VI, below, and we include relevant background information in that discussion.

G. Stakeholder Input

The EPA has been engaged in extensive interactions with many different stakeholders on the subjects of climate change, source contributions, and potential emission reduction opportunities. These stakeholders have included industries, environmental organizations, and many regional, State, and local air quality management agencies that have been actively engaged in efforts to address GHG emissions over a period of several years. In addition to these conversations, as part of developing this proposed rule, the EPA held five listening sessions in February and March 2011 to obtain additional information and input from key stakeholders and the public. Each of the five sessions had a particular target audience: The electric power industry, environmental and environmental justice organizations, States and Tribes, coalition groups, and the petroleum refinery industry. Each session lasted two hours and featured a facilitated round table discussion among stakeholder representatives who were identified and selected for their expertise in the CAA standard-setting process. The EPA had asked key stakeholder groups to identify these round table participants in advance of the listening sessions. The EPA accepted comments from the public at the end of each session and via the electronic docket system.

From the listening sessions and written submissions, the EPA received a wide range of comments and ideas for this proposed rule. The main topics of the comments, which concerned requirements for both new and existing sources, included the following:

- Feasibility and availability of control technologies
- Output-based standards

- Subcategorization factors
- Fleet-wide averaging
- Neutrality of fuels
- Role of efficiency improvements
- Equivalency of state and regional reduction programs
- Recognition of early action by industries and states achieving reductions
- Use of a multi-pollutant, multi-media approach
- Market-based flexibility
- Use of a tiered structure, with requirements evolving over time
- Credits for replacement of older, less efficient generation units
- Role of biomass
- Consideration of compliance issues arising from conflicts with other regulatory programs
- Schedule for proposing and promulgating this rule
- Small business impacts

Comments submitted via the electronic docket system concerning development of this proposed rule are available at www.regulations.gov (docket number EPA-HQ-OAR-2011-0090).

III. Proposed Requirements for New Sources

This section describes the proposed requirements in this rulemaking for new sources. Our rationale for these proposed requirements is provided in Section IV of this preamble.

A. What is the affected source?

Sources affected by today's proposal for new source provisions are sources that are considered both covered EGUs as defined by this rule and “new” sources as defined under the provisions of CAA section 111.

1. Covered EGUs, Generally

The EPA is proposing to define a covered EGU, which is a source that is subject to this rule, as any fossil fuel-fired combustion unit that supplies more than one-third of its potential annual electric output and more than 25 MW net-electrical output (MWe) to any utility power distribution system for sale, with certain exceptions noted below. For this proposed rule, covered EGUs include electric utility steam generating units (“boilers”), stationary combined cycle combustion turbines and their associated HRSG) and duct burners; and IGCC units, including their combustion turbines and associated HRSG. However, for purposes of this rule, covered EGUs do not include stationary simple cycle combustion turbines or EGUs located in Hawaii or other non-continental areas. In addition, units subject to emission requirements

under CAA section 129 would not be subject to requirements under this proposed rule.

2. CO₂ Emissions Only

This action proposes to regulate covered EGU emissions of CO₂, and not other constituent gases of the air pollutant GHG, although we identify the pollutant we propose to regulate as GHGs. Note that emissions of criteria pollutants for covered EGUs remain covered under 40 CFR part 60 subparts Da and KKKK.

3. “New” Sources

CAA section 111(a)(2) defines a “new source” as “any stationary source, the construction or modification of which is commenced after publication of regulations (or, if early, proposed regulations) prescribing a standard of performance under [CAA section 111] which will be applicable to such source.” In contrast, CAA section 111(a)(6) defines an “existing source” as “any stationary source other than a new source.” The definition of a “new source” applies according to its terms for purposes of this rulemaking, except that special considerations come into play for sources undertaking physical or operational changes, transitional sources, and sources undertaking reconstruction, as discussed below in Section V of this preamble.

B. What emissions limitations must I meet?

In this rulemaking, the EPA is proposing a standard of performance (NSPS), and we are requesting comment on a 30-year averaging compliance option, for CO₂ emissions from affected sources, which are new fossil fired EGUs described above in Section III.A.

1. Standard of Performance

The standard of performance is a gross output-based CO₂ emission limit expressed in units of emissions mass per unit of useful recovered energy (specifically, in pounds per megawatt-hour (lb/MWh)). This emission limit would be effective upon the effective date of the final action.

We are not proposing any subcategories for new affected sources. Instead, we are proposing a single output-based CO₂ emission limit that must be met by all affected sources.⁴¹ Specifically, the EPA is proposing a standard of 1,000 lb CO₂/MWh, but, as discussed below, is taking comment on

a range from 950 lb CO₂/MWh to 1,100 lb CO₂/MWh.

As discussed below, the proposed method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electrical energy output and useful thermal energy output, where applicable for combined heat and power (CHP) EGUs, over a rolling 12-month period. In the alternative, we solicit comment on requiring calculation of compliance on an annual (calendar year) period.

Under this proposal, no averaging or emissions trading among affected sources would be allowed.

We seek comment on all aspects of the proposed standard of performance, including using net, instead of gross, generation-based emissions rate measurement.

2. 30-Year Averaging Compliance Option

We also propose a 30-year averaging compliance option that would be available only for affected coal- and pet coke-fired sources that comply with the standard through the use of CCS. This approach involves a performance standard that includes both a 12-month annual average limit and a longer-term limit that may be met on an average basis by the end of a 30-year period. The 12-month limit is important because it is a practicably enforceable mechanism to ensure that the source is on a path to comply with the 30-year average limit. The annual limit will ensure that the source takes timely action to meet a 30-year limit. For instance, if meeting the 30-year limit was predicated on installing CCS technology before year eleven of operation, the annual compliance limits would provide an enforceable measure to ensure that CCS was installed and operating well before a 30-year average could be calculated. Note that after the 30th year, the source would be required to meet the 12-month annual average 1,000 lb CO₂/MWh emission limit.

Specifically, for the first ten years of operation, the affected source would be required to comply with a 12-month annual average CO₂ emissions limit based on the best demonstrated performance of a coal-fired facility without CCS, which is 1,800 lb CO₂/MWh (816 kg CO₂/MWh) (gross). This proposed emission limit can be met by modern coal-fired facilities using supercritical steam conditions, IGCC facilities, and pressurized CFBs boilers. By no later than the 11th year from the effective date of the rule, the facility would be required to meet a reduced emission limit of no more than 600 lb

CO₂/MWh (272 kg CO₂/MWh) (gross) on a 12-month annual average basis for the remaining 20 years of the 30-year averaging period, such that the weighted average CO₂ emissions rate from the facility over the 30-year time period would be equivalent to the proposed standard of performance of 1,000 lb CO₂/MWh. This reduced emissions standard during the remainder of the 30-year period would be met with some level of CCS.⁴²

For added flexibility, under this option, we are taking comment on allowing the owner/operator to select a different emission trajectory to achieving the 30-year average as long as the owner/operator obtains EPA approval of that rate before beginning operations. Such a trajectory would have to assure that, assuming similar amounts of operation in each year, the overall average emission rate would be at or below the required 30-year average of 1,000 lb CO₂/MWh. For instance, if an owner or operator wished to operate at a rate of 2,000 lb CO₂/MWh for the first period, it would have to commit to something more stringent than achieving a 600 lb CO₂/MWh standard by the 11th year. Potential compliance pathways could include committing to a limit of 500 lb CO₂/MWh by the 11th year or committing to a limit of 600 lb CO₂/MWh by the 8th year.

The EPA is also soliciting comment on what additional requirements would be necessary to implement the 30-year averaging requirement. Specifically, if the owners or operators did not intend to install CCS when the unit commenced operation, they could be required to submit a plan that includes a location to store CO₂ and a schedule for construction and operation of their carbon capture system. The schedule would include key milestone dates such as soliciting proposals, obtaining financing, beginning construction, and beginning operation. The EPA requests comment on the appropriateness of including these, and/or other requirements to ensure that the owners or operators of the facility have adequate plans in place to meet the 30-year average emission rate requirement. Further, the shorter term emission limits for the entire 30-year period must be included in the source's title V permit. We solicit comment on the

⁴¹ As discussed below, we are not proposing such a limit for modifications, transitional sources, or reconstructed sources.

⁴² As discussed elsewhere, EPA is soliciting comment on whether the emissions standard that reflects CCS should be somewhat higher or lower than 1,000 lb CO₂/MWh, and whether the emissions standard that reflects supercritical efficiency should be somewhat higher or lower than 1,800 lb CO₂/MWh. If EPA does promulgate a higher or lower standard in either case, then EPA may revise the 600 lb CO₂/MWh amount accordingly.

enforceability of the 30-year averaging period, how we can ensure that the owner/operator will comply with the second phase of the standard, and what sort of compliance demonstrations are appropriate with such a long-term standard. We also solicit comment on whether this alternative compliance mechanism should automatically terminate in 2020 such that only facilities that commenced construction prior to 2020 would be able to use the 30-year average.

The EPA suggests that this 30-year averaging compliance option may be warranted for at least two reasons. First, it provides power companies with the option of building a coal-fired power plant in the near term and installing CCS at a later time when costs will likely be lower and further experience from demonstration projects will have been gained. The 30-year averaging period is sufficiently long to allow sources, before they install CCS, to benefit from the experience that will be gained from commercial-scale CCS demonstration projects operating over the next decade from a number of DOE-funded demonstration projects. A new coal- or pet coke-fired unit could operate for at least a decade before installing CCS and still have enough years operating at a controlled emission rate to reach a 1,000 lb CO₂/MWh standard on a 30-year basis. A second reason that this alternative may be practicable is that, even for sources installing and operating CCS at the beginning of a project, there may be startup issues (other than those related to the capture technology or the arrangements for sequestration). For instance, a company's ability to sequester CO₂ may be dependent upon construction by a third party of a pipeline that will be transporting the CO₂ to a site to be used for enhanced oil recovery or permanent sequestration. Because the owner or operator does not have direct control over this part of the project, there may be concerns that it will not be completed on time and that even after spending all of the money to construct a coal-fired unit capable of capture, it will have to remain non-operational for a period of time until the pipeline project or sequestration destination is completed. The 30-year averaging compliance option could provide flexibility to operate the unit until the pipeline was completed as long as the carbon capture system is designed to meet a rate sufficiently below 1,000 lb CO₂/MWh to allow for compliance with a 30-year averaging period. Such flexibility is likely to be most important for the first several CCS

projects (i.e., "first movers") because of the complexity of integration of the technologies and the fact that the business model is new for the power sector. Because the policy purpose of this 30-year averaging compliance option is to leave open the option of building a coal-fired unit in the near term and installing CCS after several years or to allow for flexibility during startup of the system, a long-term averaging period is needed to allow time for such a unit to achieve the 1,000 lb CO₂/MWh level.

We note that under CAA section 111(b)(1)(B), "the Administrator shall, at least every 8 years, review and, if appropriate, revise [the] standards [of performance] * * *". This review is required to take place in 2020, if not sooner. In the event that the EPA adopts the 30-year averaging compliance option, then at the time of the next required review, the EPA will evaluate the state of development or commercialization of CCS technologies and make a determination as to whether or not the 30-year averaging approach is still warranted for new sources. Because we expect CCS technology to advance significantly over the next several years, we believe that it may not be necessary to include this type of compliance option for a 30-year average the next time we review this NSPS. In light of this, we further solicit comment as to whether the 30-year averaging compliance option should automatically terminate in 2020, so that it would be available only for facilities that commenced construction prior to 2020.

We recognize that this compliance option, by authorizing sources to average the CO₂ emission level over a 30-year period, is unique. We recognize that the uniqueness of this approach may give rise to new issues concerning compliance and enforcement. We solicit comment on any practical difficulties in compliance and enforcement. Along these lines, although we propose that sources be required to retain records to demonstrate compliance with the emission limits for at least 30 years following the date of initial startup of the affected EGU, we solicit comment on the merits of extending this period to 50 years. As with the proposed standard of performance, no averaging or emissions trading among affected sources would be allowed for this 30-year averaging compliance option.

This 30-year averaging compliance option is available only to new coal- and pet coke-fired EGUs. We do not believe that it is necessary for NGCC units, as they should be able to meet the proposed performance with no need for add-on technology. We also solicit

comment on the need to extend the applicability for the 30-year averaging compliance option to other fossil fuels beyond just coal and pet coke. We seek comment on all other aspects of this 30-year averaging compliance option.

C. What are the startup, shutdown, and malfunction requirements?

1. Startups and Shutdowns

The NSPS that the EPA is proposing in this action would apply at all times, including during startups and shutdowns. In establishing the level of the proposed NSPS, the EPA has taken into account startup and shutdown periods. The EPA is not proposing different standards for those periods.

To establish the proposed NSPS's output-based CO₂ standard, we accounted for periods of startup and shutdown by considering periods of part-load operation. As noted above, the proposed method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electrical energy output and useful thermal energy output, where applicable for CHP EGUs, over a rolling 12-month period. This averaging approach gives more weight to high-load hours and more accurately reflects overall environmental performance. In addition, because low-load hours do not factor as heavily into the calculated average, the impact of including periods of startup and shutdown is minimized when calculating emission rates.

We solicit comment on the alternative of requiring compliance through an annual (calendar year) average.

We propose that these same requirements for startups and shutdowns would apply to the 30-year averaging compliance option.

2. Malfunctions

The NSPS that the EPA is proposing in this action would apply at all times, including during malfunctions. Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. By contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 60.2). The EPA has determined that CAA section 111 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 111 standards. Further, nothing in section 111 or in case law requires that the EPA anticipate and account for

the innumerable types of potential malfunction events in setting emission standards. *See, Weyerhaeuser v. Costle*, 590 F.2d 1011, 1058 (DC Cir. 1978) (“In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by ‘uncontrollable acts of third parties,’ such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.”)

Further, it is reasonable to interpret CAA section 111 as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through “the application of the best system of emission reduction” that the EPA determines is adequately demonstrated. Applying the concept of “the application of the best system of emission reduction” to periods during which a source is malfunctioning presents difficulties. The “application of the best system of emission reduction” is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not “reasonably” foreseeable. *See, e.g., Sierra Club v. EPA*, 167 F.3d 658, 662 (DC Cir. 1999) (The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency’s decision to proceed on the basis of imperfect scientific information, rather than to “invest the resources to conduct the perfect study.”). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA’s approach to malfunctions is consistent with section 111 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source’s failure to comply with the CAA section 111 standard was, in fact, “sudden, infrequent, not reasonably preventable” and was not instead “caused in part by poor maintenance or careless operation.” 40 CFR section 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g., “State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown”* (Sept. 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (Feb. 15, 1983), which are both included in the docket for this rulemaking.) The EPA is therefore proposing to add to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 60.10042 (defining “affirmative defense” to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense: The source must prove by a preponderance of the evidence that it has met all of the elements set forth in 60.10001. (See 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions “[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution

control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *.” The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 60.10001 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that “[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *” and that “[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *.” In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR part 22.77).

The EPA is including an affirmative defense in an attempt to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that “limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.” 42 U.S.C. 7602(k) (defining “emission limitation and emission standard”). *See generally Sierra Club v. EPA*, 551 F.3d 1019, 1021 (DC Cir. 2008) Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief.⁴³ While “continuous” limitations, on the one hand, are required, there is also case law indicating that in many situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical v. Ruckelshaus*, 486 F.2d 427, 433 (DC Cir. 1973), the DC Circuit acknowledged that in setting standards under CAA section 111 “variant provisions” such as provisions allowing for upsets during startup, shutdown and equipment

⁴³ Note that the Ninth Circuit recently upheld EPA’s decision to apply this affirmative defense approach to only actions seeking civil penalties, and not also to actions seeking injunctive relief. *Montana Sulfur & Chemical Co. v. EPA*, No. 02–71657 (9th Cir. August 31, 2011) (slip op. at 456).

malfunction “appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the ‘never to be exceeded’ standard currently in force.” See also, *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (DC Cir. 1973). Though intervening case law such as *Sierra Club v. EPA* and the CAA 1977 amendments undermine the relevance of these cases today, they support the EPA’s view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating “upsets beyond the control of the permit holder.” *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1272–73 (9th Cir. 1977). But see, *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1057–58 (DC Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are “continuous” as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

We propose that these same requirements for malfunctions would apply to the 30-year averaging compliance option; however, we take comment on whether it is appropriate to have an affirmative defense for the 30-year averaging portion of that compliance option, given that we would expect malfunctions to only impact shorter emissions limits, and the longer the compliance period, the less likely malfunction events are to impact a source’s ability to meet the standard.

D. What are the continuous monitoring requirements?

The EPA is proposing that a CO₂ mass rate CEMS and the associated automatic data acquisition and handling system must be installed and operated in accordance with the requirements below.

1. Prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements consistent with the requirements in 40 CFR part 75.

2. Use all the data collected during all other required data collection periods in assessing the operation of the control device and associated control system.

3. Report any periods for which the monitoring system failed to collect required data.

4. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments); failure to collect required data is a deviation of the monitoring requirements.

We propose that owners/operators would install the CEMS and complete the CEMS certification in accordance with the schedule required in 40 CFR part 75, section 75.4(b).

We also request comment on the appropriateness of applying the backup monitor requirements in 40 CFR part 75.10(e), the missing data procedures in 40 CFR part 75, sections 75.31 through 75.37, and appendix C for this proposed rule.

We propose that these same monitoring requirements would apply to the 30-year averaging compliance option.

E. What are the emissions performance testing requirements?

Consistent with the performance testing requirements in the CAA section 111 regulatory general provisions (40 CFR part 60.8) and CEMS certification requirements (40 CFR part 75.4(b)), we propose that owners/operators of a new unit, conduct an initial performance test to demonstrate compliance with the CO₂ emissions limits beginning in the calendar month following initial certification of the CO₂ and flow rate monitoring CEMS.

We propose that the initial performance test consist of collection of hourly CO₂ average concentration, mass flow rate (standard cubic feet per hour) recorded with the certified CO₂ concentration and flow rate CEMS and the corresponding electrical power generation data for all of the hours of operation for the first calendar year beginning on the first day of the first month following completion of the CEMS installation and certification. For all of the operating hours during each monthly period, including startup and shutdown, you would calculate compliance with the emissions limit by dividing the sum of the hourly CO₂ mass values by the sum of the hourly useful energy output produced over the first 12 months of data.

We propose that these same emissions performance testing requirements would apply to the 30-year averaging compliance option.

F. What are the continuous compliance requirements?

In this rulemaking, we propose that compliance with the applicable average CO₂ mass emissions rate (lb/MWh) must be calculated as a 12-month rolling average, updated monthly, using the reported hourly CO₂ average concentration and flow rate values from the certified CEMS data collected for the previous month’s process operating days along with generation data tracked by the facility for the unit. We propose that compliance with the emissions limit must be calculated by dividing the sum of the hourly CO₂ mass emissions values by the sum of the useful energy output produced for each calendar month period and that the 12-month rolling average must be updated as the average of the previous 12 months’ calculations. Affected sources will continue to be subject to the standards and maintenance requirements in the section 111 regulatory general provisions. 40 CFR part 60, subpart A.

We solicit comment on, in the alternative, an annual (calendar year) average emission limit, which would be calculated through comparable methodology as just described.

We propose that these same continuous compliance requirements would apply to the 30-year averaging compliance option.

G. What are the notification, recordkeeping, and reporting requirements?

In this rulemaking, the EPA is proposing that you, as the owner or operator of a new unit, must comply with the notification and recordkeeping requirements in the section 111 regulatory general provisions, 40 CFR part 60, subpart A, and need to report results of performance testing and excess emissions; as well as record and maintain hourly average CO₂ emissions concentration, hourly average flow rate, and hourly useful electrical generation. Note that the summary form identified as Figure 1 in 40 CFR part 60.7(d) will be revised to include CO₂ as a pollutant. We are also seeking comments on whether the EPA should require initial notification of compliance status reports. In most rules, an initial notification of compliance status report, where owners and operators of sources subject to a particular rule notify the EPA and State and Local Air Pollution Control Agencies that their source is subject to the rule and how they intend to comply with the rule, is required. Regulators find this information very helpful in implementing and enforcing particular rules. In this case, most, if not

all, of the sources that are potentially subject to this rule have already been identified because they are subject to other New Source Performance Standards and Part 75 Acid Rain provisions.

As part of an Agency-wide effort to facilitate reporting of environmental data and reports, we are requiring electronic reporting of selected reports, required by this regulation, to the EPA. We are proposing that owners and operators subject to this regulation must electronically submit excess emissions, continuous monitoring systems performance and/or summary reports required under section 60.7(c). Owners and operators would need to submit these reports to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed in the Central Data Exchange (CDX). The CDX is the EPA's portal for submitting and managing electronic environmental data and reports and is accessed at www.epa.gov/cdx. The CDX is needed to meet the EPA standards for electronic reporting set by the Cross-Media Electronic Reporting Rule. For more information, please see <http://www.epa.gov/cromerr/>. Owners and operators required to submit electronic reports would need to register to use the CDX and for the CEDRI node at http://cdx.epa.gov/epa_home.asp. Once a user has access to CDX and CEDRI, the owners and operators would use the subpart specific forms in CEDRI to enter the information for the 60.7(c) required reports.

In most New Source Performance Standards owners and operators are required to keep records of their reports on site for at least 2 years. Since the owner or operator would be submitting the data in these reports to be housed in CDX and WebFIRE, we are proposing to forgo recordkeeping requirements for those reports required to be submitted in proposed section 60.5555(a)(1). We believe that since the WebFIRE database is public that the need for recordkeeping onsite for certain information will not be needed as the information will be readily available for all stakeholders to access.

We are aware that owners or operators of many existing EGUs are required to submit some emissions data through the EPA Acid Rain Program's Emissions Collection and Monitoring Plan System (ECMPS) for SO₂, NO_x, CO₂, and other related data. We propose for affected sources to continue to use ECMPS with modifications to allow for collecting CO₂ mass emissions data and the CEMS relative accuracy reports proposed in this rule.

We request comment on these and other modifications to ECMPS appropriate for implementing this rule and any other EPA rules that apply to EGUs in order to streamline and focus all applicable emissions data reporting requirements. We request comment on modification of the ECMPS system to collect, track, and calculate CO₂ emissions rates based on hourly useful energy output for the unit. We also request comment on tracking and making use of useful steam data for new facilities.

We are also aware that owners or operators of existing units are required to submit electrical generation data according to procedures required by the DOE's Energy Information Administration (EIA) for its reports. We request comment on the appropriateness of using these electrical generation data in this proposed rule.

The EPA proposes that these same notice, recordkeeping, and reporting requirements would apply to the 30-year averaging compliance option. The EPA requests comment on whether any alterations or additions are appropriate for the notice, recordkeeping, and reporting requirements that would apply to the 30-year averaging compliance option. The EPA also requests comment on whether sources that utilize the 30-year averaging compliance option should include, as applicable requirements in their title V permits, a specific explanation of their compliance plan, including when CCS would be deployed, what capture rate(s) would be achieved, how the CO₂ would be sequestered, and whether the company anticipates receiving government financial assistance or other incentives for the CCS.

IV. Rationale for the Proposed Standards for New Sources

A. How did the EPA establish the emission limits?

1. Rationale for Proposing to Combine the Subpart Da Category and a Component of the Subpart KKKK Category into a New Category for Purposes of Regulating GHG Emissions

The EPA is proposing to create a new subpart in 40 CFR part 60 by combining the sources in subpart Da (the Da category) and a subset of the sources in subpart KKKK (the KKKK category)—stationary combined cycle units, but not stationary simple cycle units—for purposes of promulgating standards of performance for emissions of GHGs from new sources. This new subpart will be numbered TTTT. Consistent with standard practice and Executive Order 13563, and in particular its

emphasis on “the open exchange of information and perspectives” and “providing an opportunity for public comment on all pertinent parts of the rulemaking docket, including relevant scientific and technical findings” and on consideration of alternatives, we invite comments on our decision to combine the two source categories.

At this time, the EPA is not proposing to subcategorize new sources and is not proposing to combine the Da category and components of the KKKK category for purposes of regulating criteria pollutants.

CAA section 111 provides legal authority for combining the categories into a new category. Clean Air Act section 111(b)(1)(A) provides:

The Administrator shall, within 90 days after December 31, 1970, publish (*and from time to time thereafter shall revise*) a list of categories of stationary sources. He shall include a category of sources in such a list if in his judgment it causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

(Emphasis added.)

As quoted, this provision grants to the Administrator the authority to “revise” the list of categories. Combining categories, in whole or in part, is a form of “revis[ing]” the list of categories (along with taking other actions, such as adding more categories or delisting categories), and accordingly is authorized.

For three principal reasons, it is appropriate for the EPA to combine the Da category and the stationary combined cycle component of the KKKK category at this time for purposes of regulating GHGs. First, all of the plants covered by the new combined category (including fossil fuel-fired boilers, IGCC units and NGCC units) perform the same essential function, which is to provide generation to serve baseload or intermediate load demand. It is sensible to treat as part of the same category units that generate baseload or intermediate load electricity, regardless of their design or fossil fuel type.

Second, all newly constructed sources have options in selecting their design (although it is true that natural gas-fired plants are inherently lower emitting with regard to CO₂ than coal-fired plants. As a result, prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC unit. These two factors provide sufficient legal rationale for the EPA to combine the Da category and the combined cycle component of the KKKK category for purposes of

establishing a standard of performance for GHG emissions.

The agency has previously combined one type of baseload and intermediate load combined cycle unit (IGCC, previously covered under Subpart GG) with Da units for the purposes of setting a standard [40 CFR 60.41Da(b), Feb. 28, 2005]. This action now similarly combines another type of baseload and intermediate load combined cycle unit (NGCC, previously covered under Subpart KKKK) with Subpart Da units for the purposes of setting a standard.

A third factor lends additional support. Combining the categories does not raise adverse policy concerns. On the basis of comments made during the listening sessions, we anticipate that some commenters may question whether combining the categories and applying the NGCC standard to all new plants within the combined category may limit construction of new coal-fired power plants, and thereby have a disruptive effect on the electric power industry, increase electricity prices and/or have adverse implications for energy diversity in new generation. We do not believe that this action would have those effects. As discussed below, and importantly, economic models forecast no new construction of coal-fired generation without CCS through the analysis period, which extends until 2020 (when the standard will be revisited). Accordingly, economic conditions are expected to be the main driver precluding, or at least limiting, construction of coal-fired EGUs. Because of those economic conditions, there is a strong independent movement of power plants serving baseload generation toward NGCC. In light of that movement, it is appropriate for the EPA to focus on this technology in developing the standard, rather than subcategorizing and providing a separate standard for new coal units. See *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 190 (D.C. Cir. 2011) (affirming the EPA's decision not to subcategorize in part because of "the universal movement in the portland cement industry towards adoption of preheater/precalciner technology").

Notwithstanding these points, we recognize the possibility that a limited amount of new coal-fired construction may nevertheless occur. Today's action would not foreclose construction of new coal-fired EGUs. Rather, the new coal-fired EGUs that may be expected to be built in the foreseeable future (and for reasons stated above, this is anticipated to be a relatively small number) may install CCS control equipment (if not at the time of construction, then not long thereafter). By doing so, they may

achieve the same average CO₂ emission rate (at least over time) as a natural gas-fired combined cycle unit. It is reasonable to expect that some coal-fired power plants may be able to implement CCS at the present time, and thereby achieve the 1,000 lb CO₂/MWh standard immediately. As noted elsewhere, CCS has been demonstrated to be technologically achievable, and, even though it is costly, there are some State and Federal programs that can make CCS more affordable. Several power companies have announced plans to incorporate CCS at six already permitted coal-fired EGU construction projects in this country (as we discuss below in section V.B., concerning transitional sources). Programs exist that provide some funding for CCS through pilot or other demonstration programs, and we expect those to continue. In addition, we reasonably expect the costs of CCS to decline over time. As discussed below, we are not proposing that CCS does or does not qualify as the "best system of emission reduction" that "has been adequately demonstrated" for new coal-fired power plants. Rather, the feasibility of CCS and its availability for the limited amount of new coal-fired construction that may be expected, means that this action to combine the categories and establish the NSPS at the proposed 1,000 lb CO₂/MWh emission limit will not have notable adverse effects on new coal-fired construction or, therefore, on the electric utility industry, electricity prices, or energy diversity. We welcome public comments on this discussion.

On the other hand, at this time, we do not consider it appropriate to include simple cycle facilities as an affected source in the new 40 CFR part 60, subpart TTTT for GHG emissions from new facilities. The reason for this is that the function of a new simple cycle power plant is different than that of a new combined cycle plant or coal-fired plant. Combined cycle plants and coal-fired plants are typically designed to provide baseload or intermediate-load power, while simple cycle turbines are designed to provide peaking power. Because combined cycle power plants and coal-fired power plants both serve the same purpose and have design options to emit CO₂ at similar levels, we believe it is appropriate to combine them. Because peaking turbines operate less and because it would be much more expensive to lower their emission profile to that of a combined cycle power plant or a coal-fired plant with CCS, the EPA does not believe it is appropriate to include them in this source category.

As noted above, some commenters in the listening sessions did suggest that the EPA not combine the two source categories. The EPA has rejected that option for all the reasons outlined above: (1) Fossil-fuel-fired boilers, combined cycle natural gas units, and IGCC units all serve the same basic function, generating baseload or intermediate load power; (2) the proposed standards can be met by different types of units in the category (NGCC units or coal-fired units with CCS); and (3) it is consistent with industry trends (as further explained elsewhere in this notice: Due largely to current and projected gas and coal price trends, new fossil-fuel-fired builds are projected to be natural gas combined cycle units or coal-fired units with CCS supported by federal funding). There is an additional reason for rejecting the option of retaining (and establishing separate standards for) separate source categories. The EPA's analysis (in Section 5.10 of the RIA) suggests that over a wide range of market conditions, constructing a new unit that meets a limit of 1,000 lb CO₂/MWh instead of an advanced coal-fired unit without CCS would likely produce net social benefits. For all of these reasons, retaining separate source categories would be unlikely to generate substantial private cost savings, but at the same time, would create the risk of significantly higher GHG emissions and other air pollutants from some new units, resulting, in turn, in higher social costs.

By the same token, at this time, we do not consider it appropriate to combine the Da category and the combined cycle component of the KKKK category for any pollutants other than GHGs, that is, for criteria pollutants. This is because although coal-fired EGUs have an array of control options for criteria and air toxic air pollutants to choose from, those controls generally do not reduce their criteria and air toxic emissions to the level of conventional emissions from natural gas-fired EGUs.

2. Endangerment and Cause-or-Contribute-Significantly Finding

a. *Overview.* In today's rulemaking, we propose or solicit comment on alternative interpretations for whether section 111 includes prerequisites to rulemaking that involve an endangerment finding and a cause-or-contribute-significantly finding. By its terms, CAA section 111 provides that once the EPA lists a source category for regulation because the category causes or contributes significantly to air pollution that may reasonably be anticipated to endanger public health or

welfare, the EPA then establishes requirements for new sources in that source category. The EPA proposes to interpret these provisions so that it is authorized to promulgate the rulemaking proposed today because it has already determined that both the Da and KKKK source categories cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA solicits comment on interpreting CAA section 111 in the alternative so as to require (i) an endangerment finding for air pollution not specifically covered by the endangerment finding the EPA made when listing the source category, but that in this case, the EPA's 2009 Endangerment Finding for GHGs under Section 202(a) of the CAA (along with the EPA's 2010 denial of petitions to reconsider (2010 Reconsideration Denial)), fulfills that requirement; and (ii) a cause-or-contribute-significantly finding for air pollutants not specifically covered by the cause-or-contribute-significantly finding the EPA made when listing the source category, and that in this case, the large amounts of CO₂ emissions from power plants provide a compelling basis allowing the EPA to propose that finding. The EPA also solicits comment on another alternative, which is interpreting CAA section 111 so as not to require a specific endangerment finding or cause or contribute finding, but simply to require the EPA to establish a rational basis for regulating an air pollutant from a source category. In this case, the EPA's 2009 Endangerment Finding for GHGs and the 2010 denial of petitions to reconsider the Endangerment Finding, as well as the large amounts of CO₂ emissions from power plants, provide that rational basis. Finally, as an alternative for the basis for a rational basis determination, the 2010 and 2011 Assessment Reports from the National Academies confirm the Endangerment Finding and the denial of petitions to reconsider.

b. *Proposal:* Previous Source Category Findings Meet Any Endangerment Prerequisite to Regulation. In this rulemaking, the EPA proposes to interpret CAA section 111 so that we are not required, as a prerequisite to regulating CO₂ emissions from EGUs, to issue a new finding as to the health or welfare impacts of GHG air pollution or a finding as to the extent that affected sources contribute to that air pollution.

Clean Air Act section 111(b)(1)(A), by its terms, requires that the Administrator list a source category for regulation if the "category * * * in [the Administrator's] judgment, * * * causes or contributes significantly to air

pollution which may reasonably be anticipated to endanger public health or welfare." Clean Air Act section 111(b)(1)(B) goes on to provide that after listing the source category, the EPA must promulgate regulations "establishing federal standards of performance for new sources within such category." In turn, CAA section 111(a)(1) defines a "standard of performance" as a "standard for emissions of air pollutants which reflects the degree of emission reduction which (taking into account * * * cost * * * and any nonair quality health and environmental impact and energy requirements) * * * has been adequately demonstrated."

Thus, although CAA section 111 clearly requires the EPA to list a source category if its emissions contribute significantly to air pollution that endangers public health or welfare, and then to promulgate standards of performance for particular pollutants, section 111 does not by its terms require that the EPA make any endangerment finding with respect to those particular pollutants, or any cause-or-contribute-significantly finding with respect to the source category, at the time the EPA promulgates the standards of performance for those pollutants. The lack of any such requirement contrasts with (i) the definition of "standard of performance," which specifically requires the EPA to consider "*nonair* quality health and environmental impact," CAA section 111(a)(1) (emphasis added); and (ii) other CAA provisions that do require the EPA to make endangerment and cause-or-contribute findings for the particular pollutant that the EPA regulates under those provisions. *E.g.*, CAA sections 202(a)(1), 211(c)(1), 231(a)(2)(A).

Accordingly, under our proposal, once the EPA has listed a source category, and the EPA proceeds to regulate particular pollutants from that source category, CAA section 111 does not require that the EPA make an endangerment finding for the relevant air pollution or a cause-or-contribute-significantly finding for the relevant air pollutants from that source category. The fact that the EPA is, in this rulemaking, proposing to partially combine the Da and KKKK source categories does not alter this outcome. As noted above, under CAA section 111(b)(1)(A), the EPA may add a source category to the list of categories only after determining that the source category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." The EPA has previously determined that each of the

Da and KKKK categories causes or contributes significantly to such air pollution. Combining the Da category and some of the sources in the KKKK category does not necessitate that the EPA make a new cause-or-contribute-significantly finding for the expanded Da category. This is because the EPA has already found that at least one component of the new category—the former Da sources—by itself causes or contributes significantly to such air pollution. There is no reason why this expansion of the Da category to include the pre-existing Da sources plus additional sources could be considered to contribute to such air pollution to an extent that is less than the contribution from the pre-existing Da sources alone. As a result, the new category must necessarily be considered to cause or contribute significantly to such air pollution.

In addition to proposing this interpretation, we also solicit comment on alternative interpretations under CAA section 111, including those described next.

c. *First Alternative Interpretation:* Endangerment Finding Prerequisite. We solicit comment on an alternative interpretation under which the EPA is required, as a prerequisite to promulgating standards of performance under CAA section 111(b), to have issued an endangerment finding specifically for the relevant air pollution and a cause-or-contribute-significantly finding specifically for the relevant source category and air pollutant. In particular, what would be the legal basis for such an interpretation?

Even if CAA section 111 is interpreted to require those findings, then, in a case in which the EPA did not make those findings under CAA section 111, it is the EPA's view that the EPA would satisfy the need for a CAA section 111 endangerment finding through an endangerment or comparable finding that the EPA made or that Congress adopted under any other provision of the CAA. For example, the EPA may regulate, under CAA section 111, (i) NAAQS pollutants because of the determinations the EPA made under CAA sections 108 and 109 and (ii) HAPs that Congress listed under CAA section 112(b)(1). It is the EPA's interpretation that once an endangerment or comparable finding is made with respect to the relevant air pollution under another CAA provision, regulation under CAA section 111 of source categories that cause or contribute significantly to that same air pollution may proceed without any need for the EPA to revisit or update that endangerment finding as part of the

CAA section 111 regulatory process. Instead, any concerns about the continued validity of that endangerment finding may be resolved through a petition to reconsider that finding under the applicable CAA provision.

Applying this alternative interpretation of CAA section 111 to this rulemaking, the 2009 Endangerment Finding for GHG air pollution fulfills any requirement under CAA section 111 that the EPA issue a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare in order for the EPA to establish standards of performance for GHG emissions from EGUs. As discussed above, the EPA already issued this endangerment finding under CAA section 202(a)(1), as part of its process for promulgating the Light Duty Vehicle Rule.

The EPA recognizes that under this alternative interpretation, the EPA could be required to issue a cause-or-contribute-significantly finding for CO₂ emissions from the fossil fuel-fired EGUs, as a prerequisite to regulating such emissions under CAA section 111. Therefore, under this alternative interpretation, in today's rulemaking, the EPA proposes to find that CO₂ emissions from fossil fuel-fired EGUs cause or contribute significantly to the GHG air pollution. The EPA's basis for this proposed finding is, in part, that the large amounts of CO₂ emitted by fossil fuel-fired EGUs clearly exceed the low hurdle necessary for the cause-or-contribute-significantly finding. As noted above in Tables 2 and 3, fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions, and constitute by far the largest single stationary source category of GHG emissions. Indeed, so great is the contribution of CO₂ air pollutants from EGUs to GHG air pollution, that it is simply not necessary in this rulemaking to determine thresholds for when a contribution may be considered to be a "significant[]" contribution. If it were necessary, the EPA proposes that a limited amount of contribution would meet that standard in light of the fact that GHG air pollution is caused by a large number of types of sources and that no one source category dominates the entire inventory.

d. *Second alternative interpretation: Rational Basis Prerequisite.* As a second alternative interpretation, the lack of any requirement in CAA section 111 addressing whether and how the EPA is to evaluate emissions of particular pollutants from sources in the listed source category as a prerequisite for regulation may be viewed as a statutory gap that requires a *Chevron* step 2

interpretation. In this case, the EPA is authorized to develop an interpretation that reasonably effectuates the purposes of CAA section 111. Under this alternative interpretation, the EPA must demonstrate a rational basis for controlling the emissions of the particular pollutants. That rational basis may consist of some type of factual showing that is consistent with the purposes of CAA section 111, but may be something short of an endangerment and a cause-or-contribute-significantly finding.

There are several options for the factual showings that comprise a rational basis. Under the first option, the EPA would be justified in the present case in taking action with respect to GHG air pollution because of the EPA's 2009 Endangerment Finding that GHG air pollution may reasonably be anticipated to endanger public health and welfare. The EPA issued that Endangerment Finding quite recently, in December, 2009, and by notice dated August 13, 2010, the EPA denied ten petitions to reconsider that Finding, an action that entailed further review of scientific information.

Under the second option, the EPA could conclude that the recent Endangerment Finding and denial of reconsideration, coupled with the even more recent assessments from the NAS, published in 2010 and 2011, which lend further credence to the science supporting the Endangerment Finding, suffice to provide a rational basis for promulgating regulations under CAA section 111 designed to address contributions to the GHG air pollution.

Under either of these options, the EPA would need to establish a rational basis for regulating CO₂ emissions from affected EGUs. The fact that affected EGUs emit almost one-third of all U.S. GHGs and comprise by far the largest stationary source category of GHG emissions, as discussed above, would readily provide such a rational basis.

3. Rationale for Emission Limits

a. *Few New Coal-fired Power Plants.*

An important part of the basis for the EPA's proposal for new sources in this rulemaking is that all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future. Although a small number of new coal-fired power plants have been built recently, the industry generally is not building these kinds of power plants at present and is not expected to do so for the foreseeable future. The reasons include the current economic environment, which has led to lower electricity demand, and competitive natural gas prices. Natural

gas prices have stabilized over the past few years as new drilling techniques have brought additional supply to the marketplace. As a result, natural gas prices are expected to be competitive for the foreseeable future and utilities are likely to rely heavily on natural gas to meet new demand for electricity generation. On average, the cost of generation from a new NGCC power plant is expected to be lower than the cost of generation from a new coal-fired power plant.⁴⁴

Other drivers that may influence decisions to build new power plants are State and Federal energy and tax policies. Many states have adopted renewable portfolio standards (RPS), which require that a certain portion of electricity come from renewable energy sources like solar or wind. The federal government has also adopted incentives for electric generation from renewable energy sources and loan guarantees for new nuclear power plants.

These economic, cost, and policy factors create an environment in which natural gas-fired power plants, renewable energy, and nuclear power are the forms of energy generation that are most often predicted to be built to meet new electricity demand over the coming years.

Various energy sector modeling efforts, including projections from both the EIA and the EPA, show results that are consistent with these findings. The Annual Energy Outlook (AEO) for 2011 shows a very modest amount of new coal-fired power coming online beyond 2012, although there are a number of coal-fired power plants that are currently under construction and expected to begin operation in the next year or two. According to the AEO 2011, the majority of new generating capacity will be either natural gas-fired or renewable, with some lesser amounts of nuclear power. The AEO 2011 is based on existing policy and regulations, such as state RPS programs and Federal tax credits for renewables.⁴⁵ The new generation that EIA does show coming on-line after 2012 fits into one of three categories: generation that is currently under construction, generation that will include CCS or industrial CHP. Units in the first group would not be subject to this rule because, since they have commenced construction, they are considered existing sources. Units in the second group would include either units in the transitional category or new

⁴⁴ Levelized Cost of New Generation in the Annual Energy Outlook 2011 http://205.254.135.24/oiaf/aeo/electricity_generation.html.

⁴⁵ http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm.

units. In either case, they could be built consistent with this action. Units in the third group would not be subject to this rule because CHP units that generate primarily on-site power are not considered EGUs and are thus not affected by the rule.

The EPA modeling using the Integrated Planning Model (IPM), a detailed power sector model that the EPA uses to support power sector regulations, is keyed to the AEO in a number of respects and shows similar patterns of little future construction of new coal-fired power plants under the base case.⁴⁶ The EPA's projections from IPM can be found in the RIA.

As discussed below, the fact that the expected number of coal-fired power plants is so limited supports both (i) basing the standard of performance on NGCC, which is expected to be the most commonly built new fossil fuel-fired generating technology; and (ii) allowing 30-year averaging as an alternative compliance option for coal- and pet coke-fired power plants because CCS is feasible and sufficiently available for the few such plants expected, in light of the demonstration programs or other incentives available for CCS, coupled with the prospects that the costs of CCS will decline over time.

b. Basis for the Proposed Standard of Performance. In this section, we describe our basis for proposing a standard of 1,000 lb/MWh, and for taking comment on a range of 950 to 1,100 lb/MWh (430 to 500 kg/MWh). We first describe our method for calculating these levels of CO₂ emissions, and then note that several states are already requiring these levels of CO₂ emissions.

(1) Calculation of the Standard. For reasons explained below (see “d. Legal Justification for the Standard of Performance and 30-year averaging compliance option”), a NGCC facility is the best system of emission reduction for new baseload and intermediate load EGUs. To establish an appropriate, natural gas-based standard, we reviewed the emissions rate of natural gas-fired (non-CHP) combined cycle facilities used in the power sector that commenced operation between 2006 and 2010 and that report complete generation data to EPA. Based on this analysis, nearly 95% of these facilities meet the proposed standards on an annual basis. These units represent a wide range of geographic locations (with differing elevations and ambient temperatures), operational characteristics, and sizes.

We are requesting comment on a range of 950 to 1,100 lb/MWh (430 to 500 kg/MWh) for the final rule. The upper limit would incorporate essentially all available new combined cycle designs and would have limited impact on improving efficiency of combined cycle facilities. This upper limit would also be consistent with standards promulgated by some states, as noted elsewhere. The stricter standard would in general eliminate designs without a steam reheat cycle and similar lower efficiency designs for use in electric-only generation, and could limit presently available options for generation below approximately 40 MW. However, an owner/operator of combined cycle facilities with higher heat rates could either implement CHP or integrated solar thermal for feedwater heating to achieve the proposed standard.

(2) States Implementing a Comparable Standard. Several states have recently established emission performance standards or other measures to limit emissions of GHGs from new EGUs that are comparable to the proposal in this rulemaking. For example, in September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in baseload 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 baseload 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 baseload 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. Baseload 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 baseload 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 baseload electricity with out-of-state facilities that do not meet that standard. Natural gas- and petroleum distillate-

fired facilities that are primarily used to serve peak demand or to integrate energy from renewable resources are specifically exempted from the performance standard.

c. Basis for CCS as a Feasible Technology Option. In this section, we describe the basis for our position that CCS is a feasible technology option for new coal-fired power plants because CCS is technically feasible and sufficiently available in light of the limited amount of new coal-fired construction expected in the foreseeable future. In brief, first, at present, CCS is technologically feasible for implementation at new coal-fired power plants and its core components (CO₂ capture, compression, transportation and storage) have already been implemented at commercial scale. Second, although the costs of CCS are presently high, we have reason to expect that the costs of CCS will decrease over time. This action will itself contribute to downward pressure on CCS costs by shifting the regulatory landscape towards CCS, consistent with the recent report by the Interagency Task Force on Carbon Capture and Storage, established by President Obama on February 3, 2010, which we describe below. Third, we expect construction of no more than a few new coal-fired power plants by 2020 and those plants may well be able to take advantage of demonstration programs or other sources of funding for CCS. Fourth, several states have set emission standards that will make implementation of CCS necessary for new coal-fired power plants, some projects that implement CCS or components of it are proceeding, and other CCS projects are in the planning stages.

(1) Technological Feasibility of CCS. The current state of affairs concerning CCS was described and analyzed by the Interagency Task Force on Carbon Capture and Storage, established by President Obama on February 3, 2010, co-chaired by the DOE and the EPA, and composed of 14 executive departments and federal agencies. The Task Force was 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 five to ten commercial demonstration projects online by 2016. The Task Force found that, although early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current high cost of CCS relative to other technologies, there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in

⁴⁶ <http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation>.

reducing GHG emissions. The Task Force also identified the need for comprehensive review of the overall environmental impacts of CCS.

(a) Capture and Compression Technologies and Costs. Capture of CO₂ from industrial gas streams has occurred since the 1930s using a variety of approaches to separate CO₂ from other gases. These processes have been used in the natural gas industry and to produce food and chemical-grade CO₂. Although current capture technologies are feasible, the costs of CO₂ capture and compression represent the largest stumbling block to widespread commercialization of CCS. Currently available CO₂ capture and compression processes are estimated to represent seventy to ninety percent of the overall CCS costs.⁴⁷

In general, CO₂ capture technologies applicable to coal-fired power generation can be categorized into three approaches:⁴⁸

- Pre-combustion systems are designed to separate CO₂ and H₂ in the high-pressure syngas produced at IGCC power plants.
- Post-combustion systems are designed to separate CO₂ from the flue gas produced by fossil-fuel combustion in air.
- Oxy-combustion uses high-purity O₂, rather than air, to combust coal and therefore produces a highly concentrated CO₂ stream.

Each of these three carbon capture approaches (pre-combustion, post-combustion, and oxy-combustion) is technologically feasible. However, each results in increased capital and operating costs and decreased electricity output (that is, an energy penalty), with a resulting increase in the cost of electricity. The energy penalty occurs because the CO₂ capture process uses some of the energy produced from the plant.

(b) Current Availability of Transportation and Sequestration. The remaining steps for CCS (i.e., pipeline transportation and storage), are also well established but less expensive than capture and compression.

Carbon dioxide has been transported via pipelines in the U.S. for nearly 40 years. Approximately 50 million metric tons of CO₂ are transported each year through 3,600 miles of pipelines. Moreover, a review of the 500 largest CO₂ point sources in the U.S. shows that 95 percent are within 50 miles of a possible geologic sequestration site,⁴⁹

which would lower transportation costs. For these reasons, the transportation component of CCS is not expected to be a significant stumbling block to the commercial availability of CCS in the future.

With respect to sequestration, globally, there are at least four commercial integrated CCS facilities sequestering captured CO₂ into deep geologic formations and applying a suite of technologies to monitor and verify that the CO₂ remains sequestered.⁵⁰ These four sites represent over 25 years of cumulative experience on safely and effectively storing anthropogenic CO₂ in appropriate deep geologic formations.⁵¹ Estimates based on DOE studies indicate that areas of the U.S. with appropriate geology have a storage potential of 1,800 billion to more than 20,000 billion metric tons of CO₂ in deep saline formations, oil and gas reservoirs and un-mineable coal seams.⁵² The U.S. experience with large-scale CO₂ injection, such as at enhanced oil and gas recovery projects, combined with ongoing research, development, and demonstration programs in the U.S. and throughout the world, provide confidence that the storage—along with capture, compression and transport—of large amounts of CO₂ can be achieved.

It should be noted that the EPA recently finalized two rules that aim to protect drinking water and track the amount of CO₂ that is sequestered from facilities that carry out geologic sequestration. The Underground Injection Control (UIC) Class VI rule, established under authority of the Safe Drinking Water Act, sets requirements to ensure that geologic sequestration wells are appropriately sited, constructed, tested, monitored, and closed in a manner that ensures protection of underground sources of drinking water.⁵³ The UIC Class VI regulations contain monitoring requirements to protect underground

sources of drinking water, including the development of a comprehensive testing and monitoring plan. This includes testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO₂ using direct and indirect methods. Projects are also required to do extended post-injection monitoring and site care to track the location of the injected CO₂ and monitor subsurface pressures until it can be demonstrated that underground sources of drinking water are no longer endangered. Subpart RR of the Greenhouse Gas Reporting Program, which was established under authority of the CAA and builds on UIC requirements, provides requirements for quantifying the amount of CO₂ sequestered by these facilities.⁵⁴ In addition, the EPA recently proposed a rule that would conditionally exclude CO₂ streams from the definition of hazardous waste under RCRA, where these streams are being injected for purposes of geologic sequestration, provided that they are managed in accordance with certain conditions.⁵⁵ That proposed rule is based upon the EPA's conclusion that the management of CO₂ streams, under the proposed conditions, does not present a substantial risk to human health or the environment, and was based upon a review of existing regulatory programs applicable to the transportation of CO₂ streams, and their injection into permitted UIC Class VI wells. Together, these actions help create a consistent national framework to ensure the safe and effective deployment of geologic sequestration.

(2) Expected reduction in CCS costs. Research is underway to reduce CO₂ capture costs and to improve performance. The DOE/National Energy Technology Laboratory (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 CO₂ from fossil-fuel energy plants compared to today's available capture technologies. The DOE/NETL estimates that using today's commercially available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal (PC) plant, and around 35 percent to the cost of electricity for a new advanced

Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change. Joint Global Change Research Institute, Battelle Pacific Northwest Division. PNWD-3602. College Park, MD.

⁵⁰ These projects are: Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada.

⁵¹ 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. Department of Energy, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830.

⁵² U.S. Department of Energy National Energy Technology Laboratory (2010). Carbon Sequestration Atlas of the United States and Canada, Third Edition.

⁵³ Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells, Final Rule, 75 FR 77230 (Dec. 10, 2010).

⁵⁴ Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide, Final Rule, 75 FR 75060 (Dec. 1, 2010).

⁵⁵ Hazardous Waste Management System: Identification and Listing of Hazardous Waste: Carbon Dioxide (CO₂) Streams in Geologic Sequestration Activities, Proposed Rule, 76 FR 48073 (Aug. 8, 2011).

⁴⁷ Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

⁴⁸ IPCC, 2005; DOE, 2007.

⁴⁹ JJ Dooley, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone (2006), Carbon

gasification-based (IGCC) plant. The CCS research, development and demonstration program is aggressively pursuing efforts to reduce these costs to a less than 30 percent increase in the cost of electricity for PC power plants and a less than 10 percent increase in the cost of electricity for new gasification-based power plants.⁵⁶ The large-scale CO₂ 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.

Gas absorption processes using chemical solvents, such as amines, to separate CO₂ from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO₂. The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO₂ 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 CO₂ 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. The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO₂ capture performance and reduce costs.

Significant reductions in the cost of CO₂ capture would be consistent with overall experience with the cost of pollution control technology. A significant body of literature suggests that the per-unit cost of producing or using a given technology declines as experience with that technology increases over time,⁵⁷ and this has

certainly been the case with air pollution control technologies. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, research and development investments, and other factors have been observed over the decades.

We expect that the costs of capture technology will follow this pattern. Rubin *et al.* assessed the historical rates of cost reductions achieved by other energy and environmental process technologies and then, by analogy, estimated future cost reductions that might be achieved by four types of new power plants employing CO₂ capture.⁵⁸ The results of the study suggested that total costs of CO₂ capture can be expected to decline by the following percentages: NGCC by 40 percent, PC by 26 percent, IGCC by 13 percent, and Oxyfuel by 13 percent after installation of the first 100 GW of capacity.

In a subsequent study, the model used in the initial study was extended with learning curves for several key performance variables, including overall energy loss in power plants, the energy required for CO₂ capture, the CO₂ capture ratio (removal efficiency) and the power plant availability. The model predicted continued reductions in cost with increased implementation.⁵⁹

In addition, we note that the Administration's CCS Task Force report recognized that CCS would not become more widely available without the advent of a regulatory framework that promoted CCS or a strong price signal for CO₂. Today's action is an important component in developing that framework.

(3) Limited amount of construction of new coal-fired power plants; opportunities for CCS funding. A third factor that supports CCS as a feasible technology option is that through the IPM model period of up to 2020, we expect few, if any, new builds of coal-fired EGUs, beyond those that already have approved PSD permits. We also expect continued opportunities for

financial support for some CCS projects through a variety of potential mechanisms such as direct grants, tax incentives and/or regulatory programs (e.g. Clean Energy Standards or guaranteed electricity purchase price agreements).⁶⁰ Accordingly, the few new coal-fired generation projects that may occur over this timeframe may well find that financial support for CCS is available.

(4) State Requirements for CCS; Projects and Permits for CCS. Several states have recently established requirements that new coal-fired EGUs must implement CCS, and a number of projects with CCS have been approved and/or are under construction.

In May 2007, Montana Governor Schweitzer signed House Bill 25, adopting a CO₂ emissions performance standard for electric generating units in the state. House Bill 25 prohibits the state Public Utility Commission from approving new electric generating units primarily fueled by coal unless a minimum of 50 percent of the CO₂ 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.

The following is a brief summary of currently operating or planned CO₂ capture or storage systems, including, in some cases, components necessary for coal-based power plant CCS applications.

AES's coal-fired Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) power plants are equipped with amine scrubbers developed by ABB/Lummus. They were designed to process a relatively small percentage of each plant's flue gas. At Warrior Run, approximately 110,000 tonnes of CO₂ per year are captured, whereas at Shady Point 66,000 tonnes of CO₂ per year are captured. The CO₂ from both plants is subsequently used in the food processing industry.⁶¹

⁶⁰ See Center for Climate and Energy Solutions, "Financial Incentives for CCS"—<http://www.c2es.org/sites/default/modules/usmap/pdf.php?file=8380>.

⁶¹ 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.

⁵⁶ DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap, U.S. Department of Energy National Energy Technology Laboratory, December 2010.

⁵⁷ These studies include John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," 2, 235–247; Dennis Epple, Linda Argote, and Rukmini Devadas, "Organizational Learning Curves: A Method for Investigating Intra-plant Transfer of Knowledge Acquired Through Learning by Doing," *Organizational Science*, Vol. 2, No. 1, February 1991; International Energy Agency, Experience

Curves for Energy Technology Policy, 2000; and Paul L. Joskow and Nancy L. Rose, "The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units," *RAND Journal of Economics*, Vol. 16, Issue 1, 1–27, 1985. See discussion in "The Benefits and Costs of the Clean Air Act from 1990 to 2020," U.S. EPA, Office of Air and Radiation, April 2011.

⁵⁸ Rubin, E.S.; Yeh, S.; Antes, M.; Berkenpas, M.; Davison, J.; "Use of experience curves to estimate the future cost of power plants with CO₂ capture", *Intl. J. of Greenhouse Gas Control*, 1, 188 (2007).

⁵⁹ Van den Broek, M.; Hoefnagels, R.; Rubin, E.; Turkenburg, W.; Faaij, A.; "Effects of technological learning on future cost and performance of power plants with CO₂ capture", *Progress in Energy and Combustion Science* 35 (2009) 457–480.

At the Searles Valley Minerals soda ash plant in Trona, CA, approximately 270,000 tonnes of CO₂ per year are captured from the flue gas of a coal power plant via amine scrubbing and used for the carbonation of brine in the process of producing soda ash.⁶²

A pre-combustion Rectisol® system is used for CO₂ capture at the Dakota Gasification Company's synthetic natural gas production plant located in North Dakota, which is designed to remove approximately 1.6 million tonnes of CO₂ per year from the synthesis gas. The CO₂ is purified, transported via a 200-mile pipeline, and injected into the Weyburn oilfield in Saskatchewan, Canada.

In September 2009, American Electric Power Co. (AEP) began a pilot-scale CCS demonstration at its Mountaineer Plant in New Haven, WV. The Mountaineer Plant is a 1,300 MWe coal-fired unit that was retrofitted with Alstom's patented chilled ammonia CO₂ capture technology on a 20 MWe portion, or "slipstream", of the plant's exhaust flue gas. In May 2011, Alstom Power announced the successful operation of the chilled-ammonia CCS validation project. The AEP-Alstom project, the world's first facility to both capture and store CO₂ from a coal-fired power plant, represents a successful scale-up of ten times the size of previous field pilots (e.g., at We Energies Pleasant Prairie). The demonstration achieved capture rates from 75 percent (design value) to as high as 90 percent, produced CO₂ at purity of greater than 99 percent, with energy penalties within a few percent of predictions. The facility reported robust steady-state operation during all modes of power plant operation including load changes, and saw an availability of the CCS system of greater than 90 percent.

AEP, with assistance from the DOE, had planned to expand the slipstream demonstration to a commercial scale, fully integrated demonstration at the Mountaineer facility. The commercial-scale system was designed to capture at least 90 percent of the CO₂ from 235 MW of the plant's 1,300 MW total capacity. Plans were for the project to be completed in four phases, with the system to begin commercial operation in 2015. However, in July 2011, AEP announced that it is terminating its cooperative agreement with the DOE and placing its plans to advance CO₂ capture and storage technology to commercial scale on hold, citing the current uncertain status of U.S. climate

policy and the continued weak economy as contributors to the decision.

Oxy-combustion of coal is being demonstrated in a 10 MWe facility in Germany. The Vattenfall plant in eastern Germany (Schwarze Pumpe) has been operating since September 2008. It is designed to capture 70,000 tonnes of CO₂ per year.

In June 2011, Mitsubishi Heavy Industries, an equipment manufacturer, announced the successful launch of operations at a 25 MW coal-fired carbon capture facility at Southern Company's Alabama Power Plant Barry. The demonstration is planned to capture approximately 150,000 tons of CO₂ annually at a CO₂ capture rate of over 90 percent. The captured CO₂ will be permanently stored underground in a deep saline geologic formation.

Southern Company has begun construction of Mississippi Power Plant Ratcliffe (formerly the Kemper County IGCC Project). Plant Ratcliffe is a 582 MW IGCC plant that will utilize local Mississippi lignite and include pre-combustion carbon capture to reduce CO₂ emissions by 65 percent. Operation is expected to begin in 2014. The CO₂ captured from Plant Ratcliffe will be used for enhanced oil recovery (EOR) in the Heidelberg Oil Fields in Jasper County, MS.

The Texas Clean Energy Project, a 400 MW IGCC facility located near Odessa, TX will capture 90 percent of its CO₂, which is approximately 3 million tonnes annually. The captured CO₂ will be used for EOR in the West Texas Permian Basin. (Additionally, the plant will produce urea and smaller quantities of commercial-grade sulfuric acid, argon, and inert slag, all of which will also be marketed.) Construction is expected to begin in 2012.

d. Legal Justification for the Standard of Performance and 30-year Averaging Compliance Option. This section describes our legal justification for proposing that new affected facilities in the TTTT category—which combines the Da and part of the KKKK categories—(i) must limit their CO₂ emissions to 1,000 lb CO₂/MWh, which an affected facility could achieve by constructing a NGCC unit or by constructing a coal-fired boiler that implements CCS immediately; or (ii) in the case of a coal- or pet coke-fired power plant, may either meet the 1,000 lb CO₂/MWh standard or implement an 30-year averaging compliance option that allows an affected facility to meet an initial CO₂ emission limit of 1,800 lb CO₂/MWh (gross), and then—through the implementation of CCS—meet the 1,000 lb CO₂/MWh standard, on a time-

averaged basis, over no longer than a 30-year period.

(1) Legal Justification for the Standard of Performance. The EPA proposes that the emission limit of 1,000 lb CO₂/MWh meets the requirements for a "standard of performance" applicable to new sources under CAA section 111(b)(1)(B). The term "standard of performance" is defined under CAA section 111(a)(1) as follows:

Definitions. For purposes of this section: (1) 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.

We apply this definition, in effect, from the bottom up. That is, first, we determine the "best system of emission reduction which (taking into account * * * cost [and other factors]) the Administrator determines has been adequately demonstrated." For EGUs, that is a NGCC facility, for reasons discussed below. Then, we calculate the "degree of emission limitation achievable through the application of" such best system; and after that, we formulate "a standard for emissions of air pollutants which reflects" that degree of emission limitation. This standard is 1,000 lb of CO₂/MWh. These analytical steps are also discussed further below.

In determining the "best system of emission reduction" for this category of boilers and combined cycle units, we considered a range of natural gas-fired and coal-fired generation technologies, with available controls. We considered modern supercritical and ultra-supercritical coal-fired boilers. This technology is available—it is currently deployed in Europe and is now being widely deployed in Asia (especially China)—and it offers much more efficient operation than the subcritical boilers that have more often been constructed in the U.S. These supercritical and ultra-supercritical boilers have CO₂ emissions of approximately 1,800 lb/MWh and provide the lowest overall costs for conventional coal-based electricity. We also considered new IGCC, or "coal gasification" facilities, which can have CO₂ emissions levels very similar to those of ultra-supercritical coal-fired units—albeit at a higher price.

We also considered natural gas-fired boilers which have CO₂ emissions of approximately 1,350 lb/MWh, obviously

DOE, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830.

⁶² IEA (2009a), World Energy Outlook 2009, OECD/IEA, Paris.

much lower than the advanced coal-fired or coal gasification technologies. However, it seems unlikely that utilities would choose a natural gas-fired boiler as the generation technology of choice when NGCC is a much more efficient, less expensive, and more widely used technology.

We propose that a NGCC facility is the best system of emission reduction for two main reasons. First, natural gas is far less polluting than coal. Combustion of natural gas emits only about 50 percent of the CO₂ emissions that combustion of coal does per unit of energy generated. Second, new natural gas-fired EGUs are less costly than new coal-fired EGUs, and as a result, our IPM model projects that for economic reasons, natural gas-fired EGUs will be the facilities of choice until at least 2020, which is the analysis period. Indeed, those models do not project construction of *any* new coal-fired EGUs during that period that would not comply with the proposed standard. This state of affairs has come about primarily because technological development and discoveries of abundant reserves have caused natural gas prices to decline precipitously in recent years and have secured those relatively low prices for the near-future. Importantly, because the IPM modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance in today's rulemaking—which is based on the emission rate of a new NGCC unit—does not add costs. In addition, compared to coal-fired EGUs, natural gas-fired EGUs have fewer nonair quality health and environmental impacts.

Essentially because natural gas generation is cleaner and cheaper than coal, natural gas-fired EGUs qualify as 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.”

We recognize that today's proposed approach of combining the Da category and a portion of the KKKK category, and applying as the standard of performance the rate that natural gas-fired EGUs can meet, represents a departure from prior agency practice. We consider this departure warranted in light of both the emissions benefits and the changed economic circumstances, notably the lowered prices of natural gas due to technological development and recent recoverable reserves. We are aware that in theory, those economic circumstances could change and if they

do, then a change in the standard of performance may be warranted. In this regard, we note that CAA section 111(b)(1)(B) requires that the EPA “shall, at least every 8 years, review and, if appropriate, revise [the] standards [of performance].” This 8-year review cycle provides a mechanism for the EPA to assure that the standard of performance for any particular source category continues to reflect the “best system.”

(2) Legal Justification for the 30-year Averaging Compliance Option. Although the IPM model projects that for economic reasons, new coal- or pet coke-fired EGUs will not be built in the foreseeable future (beyond early CCS projects), we recognize that in a few instances, owners or operators may in fact seek to build coal- or pet coke-fired EGUs. As discussed in detail below, those owners or operators could avail themselves of CCS as a 30-year averaging compliance option. In addition, today's proposed rulemaking offers flexibility for CCS installation: The owners or operators could (i) achieve the supercritical efficiency level for an initial period (e.g., up to the first 10 years), and (ii) after that, implement CCS so as to achieve a 600 lb CO₂/MWh rate on a 12-month annual average during the latter period (i.e., the back 20 years) and thereby achieve the 1,000 lb CO₂/MWh rate on an average annual basis over the 30-year period. The alternative compliance option could also allow them to install and operate CCS much earlier and use the 10-year period to address any startup challenges related to being an early adopter of the technology.

Because CO₂ is long-lived in the atmosphere, the 30-year averaging period, as structured, with shorter term compliance requirements, is not expected to have a different impact on climate compared to meeting the standard of performance.

(a) CCS. The significance of CCS as a compliance alternative is several-fold. As a practical matter, it offers a vehicle for the construction of new coal-fired EGUs in those few instances in which owners or operators decide to construct such EGUs, notwithstanding the underlying economics. Also, it offers a vehicle for the continued scaling of CCS, a process that can be expected to lower the costs of CCS in the future. In addition, this compliance alternative provides further support for the reasonableness of the EPA's proposals in this rulemaking to combine the Da category and a portion of the KKKK category and to determine that a NGCC facility is the “best system of emission reduction.” This is because this

compliance alternative, by providing a vehicle for new coal-fired power plant builds, would minimize any disruptions that the EPA's proposals might, at least in theory, otherwise entail to the power plant industry.

CCS as a compliance alternative does not achieve these goals by necessarily qualifying, under the CAA section 111(a)(1) definition of “standard of performance,” as the “best system of emission reduction which (taking into account cost [and other factors]) the Administrator determines has been adequately demonstrated.” Instead, this compliance alternative is feasible and sufficiently available for the limited amount of new coal-fired construction that is expected, whether or not it would qualify as the “best system.”

First, it is reasonable to expect that some coal-fired power plants may be able to implement CCS at the present time, and thereby achieve the 1,000 lb CO₂/MWh standard immediately. As noted elsewhere, CCS has been demonstrated to be technologically achievable, and, even though it is costly, there are some state and Federal subsidy programs that can make CCS more affordable, particularly in tandem with use of captured CO₂ for enhanced oil recovery, and those programs may be sufficient for the very few new coal-fired plants that are expected to be constructed in the foreseeable future. Some of these programs are discussed above.

We note that the need for governmental subsidies to reduce the costs of CCS is hardly unique in the electricity generation sector. Each of the major types of energy used to generate electricity has been or is currently supported by some type of government subsidy—such as tax benefits, loan guarantees, low-cost leases, or direct expenditures—for some aspect of development and utilization, ranging from exploration to control installation. This is true of fossil fuel-fired; as well as nuclear-, geothermal, wind-, and solar-generated electricity. These subsidies have been designed to overcome cost barriers to the utilization of the energy. In this context, the need for subsidies for CCS to overcome cost barriers does not mean that CCS cannot be considered an alternative compliance method in this rulemaking.

Second, it is reasonable to expect that some coal-fired power plants may be able to implement the supercritical efficiency standard for an initial period of time (the first 10 years) and then implement CCS and achieve lower 12-month annual average rates after that, so that the source achieves the 1,000 lb CO₂/MWh standard on average over the

30-year period following construction.⁶³ This is because, again, CCS is feasible and can be expected to be sufficiently available—in light of continued subsidies and lower future costs—in light of the limited demand.

Third, although we do not propose that the 30-year averaging compliance option meets the definition of the “best system of emission reduction [(BSER)] * * * adequately demonstrated,” under CAA section 111, we note that identifying CCS as a compliance option based in part on the expectation that CCS will cost less in the future is consistent with the section 111 requirements for determining the BSER adequately demonstrated. In determining what emissions controls qualify as the BSER adequately demonstrated—which must take costs into account—the EPA is authorized under CAA section 111 to anticipate that technology that is costly at present will come down in price in the future. It is clear from the legislative history of section 111 and relevant case law that the EPA may anticipate future developments—as long as supported by an adequate record—in determining whether a particular system of emission reduction is the BSER adequately demonstrated. The Senate Committee Report to the 1970 CAA Amendments, which first enacted CAA section 111, made clear that the EPA may anticipate future developments in determining the BSER adequately demonstrated:

As used in this section, the term “available control technology” is intended to mean that the Secretary 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. This does not mean that the technology must be in actual, routine use somewhere. It does mean that the technology must be available at a cost and at a time which the Secretary determines to be reasonable. 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 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.

Sen. Rep. 91–1196 at 16 (emphasis added). As quoted, this statement makes clear that a standard of performance may be based on a technology that is not “in actual routine use somewhere,” but

that “normally can be made available.” Moreover, the technology need not be available until “a time which the Secretary determines to be reasonable.” *Id.*

In addition, the D.C. Circuit has been explicit that in setting a CAA section 111 standard of performance, the EPA may make reasonable projections of what technology will be available to the regulated industry in the future. The Court stated, in *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973):

We begin by rejecting the suggestion of the cement manufacturers that the Act’s requirement that emission limitations be “adequately demonstrated” necessarily implies that any cement plant now in existence be able to meet the proposed standards. *Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present*, since it is addressed to standards for new plants—old stationary source pollution being controlled through other regulatory authority. It is the “achievability” of the proposed standard that is in issue. * * * The * * * standard is analogous to the one examined in *International Harvester* * * *. *The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on “crystal ball” inquiry.*⁶⁴

Id. at 391 (emphasis added). Again, although these statements in the legislative history and case law are in the context of establishing the basis for a standard of performance, the same principle — that the EPA may reasonably project the path of technological development — supports treating CCS as a compliance alternative.

Although, for the reasons noted above, we do expect the costs of CCS to decline, we recognize that the amount of the decrease is uncertain. Even so, the presence of cost uncertainty by itself does not mean that prospective power plants cannot be expected to adopt the 30-year averaging compliance option. We note that prospective power plants face significant cost uncertainties in any event.

For example we note that recently, several owner/operators have announced that they do not intend to construct coal-fired power plants without CCS. They have explained that they anticipate more widespread CO₂ control requirements in the future, so that constructing coal-fired plants at this time without CCS could leave them subject to liability for high retrofit control costs in the future. This sentiment indicates that some sources may avail themselves of the 30-year averaging compliance option.

The inclusion of a 30-year averaging compliance option has precedent in EPA rulemaking under the CAA. In the past, the EPA has promulgated rules that adopt an emission limit based on a particular technology (such as, in the present rulemaking, NGCC), but has supported that action on grounds that sources have compliance alternatives, even though higher priced. See “Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone: Final Rule” 63 FR 57356, 57378 (Oct. 27, 1998) (in the rule that became known as the “NO_x SIP Call,” the EPA based NO_x emission limits that states were required to meet on the assumption that states could adopt specified control measures that were “highly cost-effective,” but the EPA identified other control measures that, even though not as cost-effective, the states could adopt instead).

(b) 30-year Period. We propose a 30-year period because (i) we generally expect that ten years provides sufficient time either for owners/operators who are interested in considering cost improvements that occur as a result of the lessons learned from early adopters, or provides early adopters sufficient time to address any startup challenges; and (ii) as noted above, 30 years provides enough time for sources to achieve the 1,000 lb CO₂/MWh emission limit following an elevated level of emissions over the first 10-year period.

(c) Supercritical Efficiency Level. According to the Department of Energy Cost and Performance Baseline for Fossil Energy Plants reports, the use of supercritical steam is the most cost effective option for new conventional coal-fired generation and results in the lowest overall costs. In addition, the increased efficiency results in reduced cooling water requirements and reduced environmental impacts associated with coal mining, delivery, and handling. Therefore, considering the benefits and minimal, if any, cost of using supercritical steam conditions, as opposed to subcritical steam conditions, we have concluded that an annual standard based on the best performing conventional coal-fired generation is appropriate.

There are a dozen bituminous-fired and 2 subbituminous-fired EGUs that have demonstrated the proposed annual standard is achievable on a long term basis. Furthermore, we have concluded that with coal drying technology, which is being used on a number of power plants today, the annual standard is achievable by a wide range of units

⁶³ Note that under today’s proposed rulemaking, the 30-year averaging proposal is associated only with the implementation of CCS at new coal- or pet coke-fired EGUs. This proposal does not allow 30-year averaging for any other purpose.

firing a variety of coal types, including lignites. There are multiple vendors that offer processes to upgrade lignites to heating values that are equal to or greater than those of subbituminous coals. The best performing subbituminous-fired EGU has maintained a 12-month emissions rate of 1,730 lb CO₂/MWh. A new EGU using a similar design would be able to burn upgraded lignite and be in compliance with the proposed annual standard.

We solicit comment on all aspects of the alternative compliance option, including the 30-year averaging period we propose in this action. Although we are not proposing that CCS, including the 30-year averaging compliance option, does or does not qualify as the BSER adequately demonstrated, we also solicit comment on that issue.

B. How did the EPA determine the other requirements for the proposed standards?

1. Compliance Requirements

The proposed compliance requirements, to the extent possible, incorporate monitoring already being performed as part of existing part 60 and part 75 requirements.

In addition, we intend to recognize the environmental benefit of electricity generated by CHP facilities to account for the increased end use efficiency resulting from avoided transmission and distribution losses. Actual line losses vary from location to location, but we intend to assume a benefit of 5 percent avoided transmission and distribution losses when determining the electric output for CHP facilities. This provision would be restricted to facilities where the useful thermal output is at least 20 percent of the total output.

We also propose to base compliance requirements on a 12-month rolling average basis. The variability in GHG emissions rates is such that establishing a shorter averaging period would necessitate establishing a standard to account for the conditions that result in the lowest efficiency and therefore the highest GHG emissions rate. A 12-month rolling average accounts for variable operating conditions, allows consistent emissions rate averaging, allows for a more protective standard and decreased compliance burden, and simplifies compliance for state permitting authorities. Because the 12-month rolling average can be calculated each month, this form of standard makes it possible to assess compliance and take any needed corrective action on a monthly basis. The EPA proposes that it is not necessary to have a shorter averaging period for CO₂ from these

sources because the effect of GHGs on climate change depends on global atmospheric concentrations which are dependent on cumulative total emissions over time, rather than hourly or daily emissions fluctuations or local pollutant concentrations.

Even so, we solicit comment on, in the alternative basing compliance requirements on an annual (calendar year) average basis.

V. Requirements for Modifications, Transitional Sources, Reconstructions

A. Requirements for Modifications

1. Overview

Under CAA section 111, existing sources are treated as new sources if they undertake “modification[s],” which are generally defined as physical or operational changes that increase emissions. CAA section 111(a)(2) and (4). The EPA’s regulations exempt certain types of changes from the definition of modification. 40 CFR 60.14(e). Available information does not provide an adequate basis for the EPA to develop proposed standards of performance for modifications. Our base of knowledge concerning NSPS modifications has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for NSPS modifications for GHGs at this time.

We note that the types of projects that these EGUs are most likely to undertake that could increase GHG emissions are projects that put on pollution controls required under other CAA provisions and that emit CO₂ as a byproduct, and those types of projects are specifically exempted from the definition of “modifications” under 40 CFR 60.14(e)(5). In addition, based on past experience, we expect that actions that do constitute modifications to be from different types of sources and to take different forms. In light of this, the EPA does not have sufficient information to develop standards of performance for modifications, and therefore the EPA is not proposing any standards for modifications. As a result, EGUs that undertake pollution control projects or other physical or operational changes would continue to be treated as existing sources.

2. Statutory and Regulatory Requirements

Clean Air Act section 111(b)(1)(B) requires the EPA to promulgate

“standards of performance” for “new sources” within source categories. For certain pollutants, CAA section 111(d)(1) requires the EPA to prescribe regulations for state plans covering “existing source[s]” in a category regulated for that pollutant under section 111(b). Clean Air Act section 111(a)(2) defines a “new source” 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.” Clean Air Act section 111(a)(6) defines an “existing source” as “any stationary source other than a new source.” Clean Air Act section 111(a)(4) defines “modification” as “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.”

The EPA’s regulations provide that under CAA section 111(a)(4), for purposes of determining whether an existing electric utility steam generating unit undertakes a modification, a physical or operational change is treated as increasing emissions only when it increases the “maximum hourly emissions” above the “maximum hourly emissions achievable” at the unit. 40 CFR 60.14(h). In addition, the EPA’s regulations exempt certain physical or operational changes from the definition of modification. 40 CFR 60.14(e)(5). The exemptions include pollution control projects:

(e) The following shall not, by themselves, be considered modifications * * *:

* * * * *

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

40 CFR 60.14(e)(5). Thus, the EPA’s current regulations define a modification as a physical or operational change that increases an existing affected EGU’s maximum achievable hourly rate of emissions, but specifically exempt from that definition pollution control projects, which are projects that entail the installation of pollution control equipment or systems.

3. The EPA’s Proposed Course of Action

We expect EGUs to undertake changes in the foreseeable future that would increase their maximum achievable hourly rate of CO₂ emissions for

purposes of the NSPS. We expect that most of those actions would constitute pollution control projects. In many cases, those projects would involve the installation of add-on control equipment required to meet CAA requirements for conventional air pollutants. We expect that these increases in CO₂ emissions would occur as a chemical byproduct of the operation of the control equipment, and would be small. In other cases, those projects will involve equipment changes to meet the requirements of this rulemaking and that may have the effect of increasing the sources' maximum hourly achievable emission rate, even while decreasing actual emission rate. Because such actions would be treated as pollution control projects under the EPA's current NSPS regulations, they would be specifically exempted from the definition of modification.

Aside from pollution control projects, in the past, there have also been, as noted, a limited number of instances, on an annual basis, in which power plants have undertaken actions that should be treated as NSPS modifications. The sources that took these actions vary widely, one from another, depending on, among other things, size, fuel type, and physical plant configuration. The diversity of sources undertaking modifications has reflected the diversity among power plants as a whole. Moreover, the types of modifications they have undertaken have also varied widely.

Because of the limited number of modifications, their disparate nature, and the disparate type of sources, we do not at present have an adequate base of information to propose standards of performance for modifications. For example, we do not have adequate information as to the types of physical or operational changes sources may undertake or the amount of increase in CO₂ emissions from those changes. Nor do we have adequate information as to the types of control actions sources could take to reduce emissions, including the types of controls that may be available or the cost or effectiveness of those controls. The most likely candidates for control actions would be efficiency measures and we do not have adequate information as to the types of sources and types of changes at issue that could provide the basis for a proposal for efficiency measures. If there were a more robust set of data on facilities of a particular type undertaking NSPS modifications of a particular kind, the EPA may be able to develop a standard of performance for that type. But, as noted, that is not the case here.

As a result, in this action, the EPA is not proposing standards of performance for NSPS modifications for GHGs. The EPA is soliciting comment on the types of sources that may be expected to undertake modifications, the types of modifications, the types of control measures, and all other aspects of this issue. This solicitation of comment is in the nature of an advance notice of proposed rulemaking. If we receive sufficient additional information, we may issue a proposal for modifications in the future. However, to reiterate, we are not proposing any standards of performance for these modifications at this time. Accordingly, the EPA does not expect to promulgate any standards of performance for modifications when it takes final action on this rulemaking.

The definitional provisions of CAA section 111, quoted above, make clear that a stationary source that undertakes construction or modification is considered a "new source" only if there is a proposed or final "standard of performance under this section which will be applicable to such source." CAA section 111(a)(2). Accordingly, if there is no proposed or promulgated standard of performance applicable to a particular source, then the source cannot be considered a "new source" and therefore will not be subject to any standards of performance we finalize for new sources.

Further, under the definitional provisions, any source that is not a "new" source is an "existing source." CAA section 111(a)(6). Therefore, affected EGUs that undertake NSPS modifications for GHGs will continue to be treated as existing sources. Although modified sources would not be subject to the 1,000 lb CO₂/MWh standard for new sources, the EPA anticipates that modified sources would become subject to the requirements the EPA would promulgate at the appropriate time, for existing sources under 111(d). It is important to note that at the same time that the EPA promulgated the pollution control provision in the EPA's regulations under CAA section 111, the EPA promulgated a similar provision in EPA's NSR regulations. The DC Circuit, in *New York v. EPA*, 413 F.3d 3, 40 (DC Cir. 2005), vacated the NSR pollution-control-project exemption. Because of the similarities between the NSR and the section 111 pollution control project regulatory provisions, the Court's vacatur of the NSR regulatory provision may call into question the continued validity of the section 111 regulatory provision. As a result, we are soliciting comment on whether this exemption from the definition of "modification" for pollution control projects, under 40

CFR 60.14(e)(5), continues to be valid or not, and what course of action, if any, would be appropriate for the EPA to take.

B. Requirements for Transitional Sources

1. Overview

In this action, the EPA is not proposing a standard of performance for transitional sources. We define these sources as coal-fired power plants that, by the date of this proposal, have received approval for their PSD preconstruction permits that meet CAA PSD requirements (or that have approved PSD permits that expired and are in the process of being extended, if those sources are participating in a Department of Energy CCS funding program), and that commence construction within a year of the date of this proposal. For convenience, we refer to the new sources for which we are proposing a standard of performance as non-transitional sources.

Transitional sources are a distinct set of sources with unique circumstances.⁶⁵ We have identified 15 proposed sources that may qualify as transitional sources based on the above criteria. These proposed sources differ considerably one from another. They range in size from as small as 80 megawatts (MW) to as large as 1320 MWs; they will burn different fuels: Conventional coal, waste coal, or petcoke; and they will use different technologies: Circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), supercritical pulverized coal, or subcritical pulverized coal. Recent industry practice raises the probability that no more than a few of these 15 proposed sources will in fact be constructed.

We recognize that by the date of this proposal, some of the 15 proposed sources may have incurred substantial sunk costs and may have progressed in their preconstruction planning to the point where they are poised to commence construction in the very near future. Under these circumstances, the 1,000 lb CO₂/MWh standard of performance that applies to non-transitional sources would not be appropriate for these proposed sources. As noted, that standard is based on natural gas combined cycle (NGCC) as the "best system of emission reduction * * * adequately demonstrated" because NGCC is the least expensive

⁶⁵ Nothing in this discussion of the unique circumstances of transitional sources facing new GHG requirements should be interpreted as providing a defense to any violation of the CAA by sources that, for example, fail to obtain PSD permits or comply with NSPS before construction.

and lowest emitting design for a fossil-fuel fired power plant, and because a proposed new source may choose to construct as an NGCC facility. However, proposed coal-fired power plants that have already received a PSD permit and that have incurred substantial sunk costs and developed plans to commence construction in the very near future are not in the same position as non-transitional sources. Applying the 1,000 lb CO₂/MWh standard would likely result in the loss of their sunk costs and would likely cause multi-year delays, or even abandonment, of their plans to construct. (Nor is the 1,000 lb CO₂/MWh standard appropriate for CCS sources, as discussed below.) This is not within the scope of BSER.

However, we do not have sufficient information concerning the 15 proposed sources to identify which ones may be in this position. Specifically, we do not have information as to the extent of their sunk costs, their preconstruction planning, or their overall business plans.

Accordingly, we propose to include a requirement that proposed sources must commence construction within 12 months of today's rulemaking proposal as a mechanism for revealing which of these sources qualifies as a transitional source. We believe that any of these 15 proposed sources that commences construction within 12 months of today's rulemaking proposal should be considered to have incurred substantial sunk costs and will have engaged in sufficient preconstruction planning so that the 1,000 lb CO₂/MWh standard should not apply. Any of these 15 proposed sources that do not commence construction within this period should not be considered to be similarly situated. For any of these latter sources that ultimately are constructed, the 1,000 lb CO₂/MWh standard would apply.

Having identified which proposed sources could qualify as transitional sources, we further believe that for several reasons, it is not appropriate to propose any standard of performance for those sources. As noted above, we necessarily lack information specifically as to which of the 15 proposed sources will actually qualify as transitional sources, and, given the range of size, fuel types, and technologies among these proposed sources, that renders it problematic to propose standards of performance. In addition, for the proposed sources that are planning to install CCS, we lack important information concerning the extent to which they are planning to capture CO₂ or their costs to do so. We also lack information as to whether they have

made contractual arrangements for the sale of the CO₂ or carbon credits, which may be critical to their financing arrangements. In addition, attempting to propose a standard of performance would give rise to serious practical problems that would undermine the usefulness of the requirement that sources commence construction within 12 months of today's rulemaking proposal as a mechanism for revealing which of these sources qualifies as a transitional source. These include creating uncertainty as to the level of the final standard of performance to which the proposed sources would be subject, which may have the effect of forcing them to delay commencing construction until after we finalize the standards, at which time they would have missed their 12-month window to commence construction and as a result, would fail to qualify as transitional sources. We note that CAA section 111 does not require that we propose or promulgate standards of performance for all sources in a source category, and on numerous occasions in past rulemakings the EPA has taken the similar approach of not proposing standards of performance for all sources in the source category.

Even without an applicable standard of performance, transitional sources will remain constrained in their emissions of CO₂ by the requirements of their PSD permits. In addition, although transitional sources would not be subject to the 1,000 lb CO₂/MWh standard for new sources, the EPA anticipates that transitional sources would become subject to the requirements the EPA would promulgate at the appropriate time, for existing sources under 111(d).

2. Identification of Transitional Sources

For purposes of this action, we define a transitional source as a coal-fired power plant that has received approval for its complete PSD preconstruction permit by the date of this proposal (or that has an approved PSD permit that expired and for which the source is seeking an extension, if the source has been issued or awarded a DOE CCS loan guarantee or grant) for the project, and that commences construction within 12 months of the date of this proposal. For this purpose, the date of this proposal is the date of publication in the **Federal Register** of this notice of proposed rulemaking. The 12-month period would not be extended for any reason, including because of any challenges to the permit that may be brought in any Federal or State court or agency.

The EPA is aware of approximately 15 sources that could potentially qualify as

transitional sources because, except as otherwise noted, they have obtained PSD permits but have not yet commenced construction. These proposed sources vary considerably one from another. They range in size from as small as 80 megawatts (MW) to as large as 1320 MWs; they will burn different fuels: conventional coal, waste coal, or petcoke; and they will use different technologies: Circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), supercritical pulverized coal, or sub-critical pulverized coal.

Based on recent industry practice, it appears that no more than a few of these sources will be constructed.⁶⁶

Of these 15 identified potential transitional sources, six have indicated that they plan to install CCS (and in most if not all cases have been issued or awarded a DOE CCS loan guarantee or grant). These six projects are: The Texas Clean Energy Project in Texas, the Trailblazer project in Texas, the Taylorville project in Illinois, the Good Spring facility in Pennsylvania, the Power County Advanced Energy Center in Idaho and the Cash Creek Generation Plant in Kentucky. The remaining nine plants, which are without CCS, are: Limestone 3, White Stallion and Coletto Creek in Texas, Holcomb 2 in Kansas, James De Young and Wolverine in Michigan, Washington County in Georgia, Bonanza in Utah, and Two Elk in Wyoming.⁶⁷

We request that during the public comment period on this rulemaking, each of these EGUs confirm to us that we have correctly identified the status of their PSD permits and, in the case of any sources that had approved permits that are in the process of being extended, and that plan to install CCS, that they have been issued or awarded a DOE CCS loan guarantee or grant. We also request that the sources indicate whether their permits are undergoing challenges before Federal or state authorities or courts. We further request that any other EGU not listed above that has a complete PSD permit and that otherwise meets the parameters for transitional sources described in this

⁶⁶ Since 2008, some 15 proposed coal-fired power plants with approved PSD permits have cancelled plans to construct, and since 2009, only one coal-fired power plant has constructed (Southern Company's Kemper County Project, which installed CCS and received DOE funding).

⁶⁷ We note that there may be some proposed natural gas-fired EGUs that are similarly situated to the coal-fired transitional sources because the natural-gas fired sources have received PSD permits but have not commenced construction by the date of this proposal. Because they are new gas-fired EGUs, we expect that they will be able to meet the requirements of the proposed new source standard of performance.

section identify itself to us (including indicating whether its PSD permit is undergoing challenge before Federal or state authorities or courts). In our final rulemaking, we intend to include a confirmed list of sources that would qualify as transitional sources if they commence construction within the 12-month period following publication of this proposal in the **Federal Register**.

As commenters have noted, among these 15 proposed sources, some may have incurred substantial sunk costs associated with processing their permits as well as taking additional preconstruction steps (e.g., purchasing land) so that they may be able to commence construction within the near term. As examples of these types of steps, several sources, such as the Texas Clean Energy Project, have signed contracts for the sale of electricity, the sale or disposal of CO₂ or other enabling products, or supporting systems.⁶⁸ Although the Taylorville project's PSD permit has expired, the source is seeking to extend it, and the source has entered into CCS funding arrangements with DOE. These actions indicate that this proposed source, too, has sunk costs and may be in a position to commence construction within the near term, and therefore is similarly situated to the other 14 proposed plants (assuming that it is able to secure an extension of its PSD permit).

Even so, we face major gaps in our information about these sources that would inform us at this point as to which of these sources have incurred costs and material commitments to the extent that a 1,000 lb CO₂/MWh standard would be so costly and disruptive as not to be BSER. For example, we do not have specific information as to those sources' specific sunk costs, specific project development actions to date, or overall business plan. Accordingly, we are not able to determine which ones are in a position to commence construction in the near term. In addition, for the sources whose PSD permit indicates that they will install CCS, we do not have specific information as to the amount of CO₂ that they plan to capture; their costs to operate CCS; or their possible revenue streams associated with CCS, such as from the sale or use of CO₂ in enhanced oil recovery or the possible sale of carbon credits in voluntary or other carbon markets.

Instead, the 12-month period, serving as a surrogate for the missing information, provides a mechanism for revealing the qualification of proposed

sources for treatment as transitional sources. In light of the complex of requirements, which range from siting to financing, needed to commence construction of a project as large and expensive as a power plant, any proposed source that does commence construction within the relatively short period of 12 months of the date of proposal can be said to have incurred substantial sunk costs and to have taken preconstruction steps by the time of this proposal. It is these sources that would be most disadvantaged by being subjected to the standards of performance proposed in today's rulemaking. The one-year period serves as a type of surrogate for more precise information as to the amount of sunk costs sources must incur or steps leading to commencement of construction that sources must undertake in order to qualify as transitional sources, as well as which sources have incurred those costs or taken those steps, which information is not available at this time. In addition, 12 months is long enough to give these sources a reasonable period to commence construction in accordance with the terms of their permit. Any proposed source that does not commence construction within 12 months cannot be said to be similarly situated.

3. The EPA's Treatment of Transitional Sources

In this action, the EPA is treating transitional sources as a distinct set of sources. We make clear that the proposed standard of performance for non-transitional sources of 1,000 lb CO₂/MWh is not applicable to transitional sources because that standard is not based on the BSER adequately demonstrated for transitional sources. In addition, in light of the unique circumstances of transitional sources, including a lack of information and other considerations, we do not propose any other standard of performance for transitional sources.⁶⁹

Although a transitional source would not be subject to new source CO₂ emissions controls under CAA section 111(b), it would be subject to CO₂ emissions limits due to any CO₂ limits in the source's PSD permit. If the source

received the permit prior to January 2, 2011, the permit will not include CO₂ limits, but in that case, as a practical matter, CO₂ emissions would be limited by whatever design or operating constraints are imposed on the source under the PSD permit.

We also note that the fact that transitional sources would not be subject to the proposed standard of performance, would not relieve them from any requirements applicable to existing sources under section 111(d) and related state plans.

4. Legal Basis for the EPA's Treatment of Transitional Sources

In this section, we describe the legal basis for our treatment of transitional sources. First, we identify the relevant CAA section 111 provisions. Second, we explain why the standard of performance we propose for non-transitional sources does not apply to transitional sources, which is because that standard does not reflect the best system of emission reduction adequately demonstrated for transitional sources. Third, we explain why we are not proposing any other standard of performance for transitional sources, which is due to lack of information and other considerations. In the course of these explanations, we discuss the relevant CAA section 111 requirements and our interpretations of them.

a. Key CAA Section 111 Provisions

As the first step in the process of promulgating regulations under section 111, under CAA section 111(b)(1)(A), the Administrator must "publish * * * a list of categories of stationary sources." Then, the Administrator must "[propose] * * * Federal standards of performance for new sources within [the source] category," and then "promulgate * * * such standards with such modifications as he deems appropriate." Section 111(b)(1)(B). Section 111(b)(2) goes on to provide that "[t]he Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards."

Section 111 includes several key definitions. The provision defines a "new source" 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." CAA section 111(a)(2).⁷⁰ A

⁶⁹ EPA intends that its treatment of transitional and non-transitional sources be severable from each other and considers that severability is logical because of the record-based differences between the two types of sources and because there is no interdependency in EPA's treatment of the two types of sources. This statement concerning severability for these components in this rulemaking should not be construed to have implications for whether other components in this rulemaking are severable.

⁷⁰ The CAA does not include a definition of the term "commenced" for these purposes, but the EPA

⁶⁸ <http://www.texascleanenergyproject.com/newsroom/>.

“standard of performance” is 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 nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

CAA section 111(a)(2).

Once the Administrator promulgates standards for new sources under CAA section 111(b), the States, consistent with EPA regulatory requirements, must take action under CAA section 111(d) to establish requirements for “any existing source for any air pollutant (i) [that falls into specified categories] but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

Section 111(d)(1). An “existing source” is defined as “any stationary source other than a new source.” Section 111(a)(6).

b. Reasons for Not Applying the 1,000 lb CO₂/MWh Standard of Performance to Transitional Sources

(i) Introduction

In this action, the EPA is treating transitional sources as a distinct set of sources, although the EPA is not establishing a specific subcategory for these sources in the regulatory provisions.⁷¹ Under CAA section 111, the EPA may not apply a standard of performance to sources unless it reflects the “best system of emission reduction” (BSER) adequately demonstrated.

As noted, the EPA proposes that non-transitional source fossil-fired power plants that commence construction after the date of proposal are subject to the standard of 1,000 lb CO₂/MWh, and the EPA proposes to base this standard on the EPA’s identification of natural gas combined cycle (NGCC) as the BSER

adequately demonstrated. The EPA justifies this proposal because owners or operators contemplating construction of non-transitional power plants to serve baseload and intermediate load demand have choices: They can choose the type of facility and therefore may choose to construct a NGCC plant. As a result, for these sources, NGCC constitutes the BSER, and the 1,000 lb CO₂/MWh emission limit reflects that BSER and therefore is the appropriate standard of performance under section 111.

Moreover, for those that choose to construct a coal-fired unit, they may choose to construct the plant in a place and a manner that allows installation of CCS—and thereby meet the 1,000 lb CO₂/MWh standard—either at the time of construction or, in accordance with the 30-year averaging proposal, some years later.

(ii) Transitional Sources and NGCC

In contrast, the circumstances surrounding transitional sources are quite different. Transitional sources are a very small group of sources with a distinct profile of costs, preconstruction planning, overall business plans, technical and design concerns, and equitable concerns. Because they are such large facilities, their sunk costs and planning horizons are substantial.

Transitional sources have already incurred substantial costs in permitting and taking other steps preparatory to commencing construction as coal-fired power plants within 12 months of the date of this proposal, which may include purchasing land for the new facility. Considering these sunk costs, converting their plant design to NGCC would be significantly more expensive than for proposed non-transitional sources that have not reached the stage of development that transitional sources have reached. The EPA is required to consider costs in determining the BSER adequately demonstrated, and under these circumstances, the costs factor points away from treating NGCC as BSER for transitional sources.

In addition, because transitional sources have obtained a PSD permit and have developed their plans to the point where they are on the verge of commencing construction, the converting of their plant design to NGCC would be significantly more disruptive to their plans than for proposed non-transitional sources. It may require them to start over the process of developing the plant, and thereby render futile the planning and steps they have taken to date. These losses would, at a minimum, lead to delays in their commencing construction that realistically would be

measured in years, and in fact may lead them to abandon the project.

Although the potentially significant planning impacts at issue here are not explicitly identified as part of the definition of the “standard of performance,” they should nevertheless be considered in determining the BSER. This is because CAA section 111(a)(2), in its definition of “new source,” clearly contemplates that sources are expected to be able to commence construction after the EPA proposes, and before the EPA promulgates, a standard of performance applicable to them. There is nothing in CAA section 111 that suggests that Congress expected that the EPA may determine the BSER in a way that would significantly disrupt the plans of the regulated sources that are implicated here. Therefore, for this reason, too, the 1,000 lb CO₂/MWh standard cannot be considered to reflect the BSER for transitional sources, and therefore cannot be the appropriate standard of performance.

Nor can transitional sources reasonably be expected to meet the 1,000 lb CO₂/MWh standard through the installation of CCS, for the reasons discussed below.

Note that the EPA takes the position that in this particular action, both of those factors—sunk costs and extent of planning to commence construction—must be considered in determining whether the 1,000 lb CO₂/MWh standard reflects the BSER adequately demonstrated. That is, both are necessary conditions, and neither one, by itself, is a sufficient condition. We believe that these reasons concerning costs and planning suffice to justify our position that the 1,000 lb CO₂/MWh standard is not appropriate for transitional sources.

(iii) Coal-Fired Transitional Sources Not Designed for CCS

As noted, while it is generally the case that proposed new sources could choose to build coal-fired power plants with CCS and thereby meet the 1,000 lb CO₂/MWh standard, that is not the case for those transitional sources that are not designed for CCS. As a practical matter, it would be challenging for such a source to proceed with construction without substantial re-design of the project in order to install CCS and thereby be in compliance with the 1,000 lb CO₂/MWh standard. There are several reasons for this. First, captured CO₂ must be sequestered or used. If this was not considered as part of the original site selection, the source will likely be significantly challenged in its efforts to adopt CCS. Second, if CCS was not considered in the original project

framework regulations promulgated under section 111 define this term as follows:

Commenced means, with respect to the definition of new source in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

40 CFR 60.2.

⁷¹ Section 111(b)(2) authorizes the EPA to “distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.” In other words, once the EPA selects the set of sources for which to propose regulations, the EPA may establish subcategories among those new sources and promulgate different standards for those subcategories.

design, space considerations may make it difficult to now accommodate it in the facility's design. Third, the requirement to use CCS could necessitate a change in the very power generation technology that a source may choose to use. For instance, instead of building a pulverized coal boiler, IGCC technology may be more appropriate. This is not to say that CCS could not be added to a project at this stage. Projects like the AEP Mountaineer project have shown that CCS can be successfully retrofitted into an existing plant. However, unlike in an existing facility where retrofit decisions must take into account previously made design decisions, in a facility in the pre-design phase, there is more opportunity for cost savings from re-designing the project, rather than having to adapt through retrofit.

It bears emphasis that the requirements created by the new source standard in today's action are fundamentally different from post-combustion controls required to meet new source standards for conventional pollutants in the sense that those controls could be much more easily re-designed into an already planned plant without changing the plant's basic underlying characteristics (such as type of unit or even location). In contrast, CCS is more fundamental to both the design and siting of a unit, and therefore would likely involve fundamental changes to the underlying project. This is much more difficult in a project that has progressed through the permitting stage and is very close to commencing construction than it would be in other types of projects.

(iv) Coal-Fired Transitional Sources Designed for CCS

Although some of the proposed sources that may qualify as transitional sources are planning for CCS, that does not provide a basis for concluding that the 1,000 lb CO₂/MWh standard is appropriate for them. As noted, the EPA is not, in this rulemaking, proposing that CCS is the BSER adequately demonstrated for coal-fired EGUs.

Moreover, these proposed sources have established their location and developed their business plans without the expectation that the proposal in this rulemaking for CCS would apply to them. For example, their plans may assume installing CCS in a manner that results in emissions at levels higher than 1,000 lb CO₂/MWh, or it may assume the sale of emission reduction credits based on an allowable emission rate above 1,000 lb CO₂/MWh. Imposition of an unexpected emission rate requirement at such a late date could upset carefully crafted financial

plans, causing delay or even cancellation of the project.

Importantly, we do not have information as to key components of their proposed project and business plan, including, among other things, the amount of capture from the planned CCS system or possible revenue streams associated with CCS. Any proposal for what is BSER would depend on those costs and other information. Accordingly, we are not able to propose determinations that are essential to proposing the BSER for these proposed sources. As a result, we are not able to propose a standard of performance for these proposed sources.

(v) Equitable Considerations

For all transitional sources, the costs and delays discussed above give rise to equitable considerations that also support our treatment of these proposed sources. As noted, owners or operators of transitional sources have incurred significant expenses and undertaken a long planning period that has led them to being able to commence construction in the very near future, and, having invested so substantially in their current plans, should as an equitable matter be allowed to proceed without concern about requirements other than those in their PSD permits. To reiterate, they are in a posture that is fundamentally different from non-transitional sources.

c. Reasons for Not Applying Other Standard of Performance

Although, for the reasons described above, the 1,000 lb CO₂/MWh standard that the EPA proposes for non-transitional sources does not reflect BSER for transitional sources, the EPA is not proposing any other standard of performance for transitional sources. It is reasonable to read section 111 not to require the EPA to propose a standard of performance when faced with the specific circumstances presented by this rulemaking. These circumstances include: (1) The EPA's lack of information with regard to these sources and the appropriate BSER for these sources; (2) the unique challenges with regard to adaptation of proposed projects to the requirements of this standard; (3) the small number of these sources and the possibility that promulgating a standard of performance would not have a beneficial environmental impact; and (4) although transitional sources would not be subject to the 1,000 lb CO₂/MWh standard for new sources, the EPA anticipates that transitional sources would become subject to the requirements the EPA would

promulgate at the appropriate time, for existing sources under 111(d).

(i) CAA Requirements for Promulgating Standards of Performance for Sources in a Source Category

The EPA interprets the CAA provisions described above to authorize the EPA not to promulgate a standard of performance for transitional sources. Under section 111(b)(1)(B), once the EPA lists a category of sources, the EPA is required to propose and promulgate standards of performance for new sources in that category. The EPA is not, however, required to promulgate standards of performance that cover all new sources. This is clear from the directive in section 111(b)(1)(B), which requires that the EPA propose standards of performance "for new sources" within the category, but does not require that the EPA propose such standards for *all* new sources or for *any* new source. The EPA may fulfill that directive by proposing standards that cover some, but not all, sources that newly commence construction or modification.

Similarly, the term "new source" in section 111(a)(2) is defined to incorporate the limitation that the EPA must propose or promulgate a standard applicable to the source for the source to be considered "new." That is, section 111(a)(2) defines a "new source" as any source for which construction or modification commences after the EPA proposes "a standard of performance * * * which will be applicable to such source." By its terms, this provision contemplates that the EPA may not propose a standard of performance applicable to certain sources, and that if the EPA does not, those sources would not be considered to be "new source[s]" and therefore not subject to any new source standard of performance.

Thus, these provisions do not, by their terms, mandate that the EPA propose standards for each and every source in the source category. Under *Chevron* step 1, these provisions do not unambiguously require that the EPA propose standards of performance for all sources in the source category. We read these provisions as according the EPA some measure of discretion for the EPA to determine not to set standards for a particular portion of the source category, where appropriate, bounded by the principle of rationality. If these provisions are read to be ambiguous as to whether the EPA has discretion to propose and promulgate standards of performance for all sources in the source category, we believe it reasonable to read the provisions to provide such discretion in appropriate circumstances and that such reading is entitled to

deference under *Chevron* step 2. In addition, interpreting these provisions to give the EPA the discretion not to propose and promulgate standards covering all sources in a category under appropriate circumstances—such as those present here—is consistent with the caselaw that authorizes agencies to establish a regulatory framework in an incremental fashion, that is, a step at a time.⁷²

(ii) Precedents in Prior NSPS Rulemakings

In applying section 111 over the past several decades, there have been a number of rulemakings in which the EPA has promulgated new source performance standards that do not cover all sources within the relevant source category that newly commence construction or modification. Some examples include the following: (i) In an early NSPS, involving lime kilns, the EPA promulgated an NSPS for certain types of kilns, but not for all types of sources that remained within the relevant source category. The DC Circuit, in its opinion reviewing the rule, noted this state of affairs, without expressing concerns. *National Lime Ass'n v. EPA*, 627 F.2d 416, 426 & n. 28 (DC Cir. 1980) (noting that “of the various types of kilns that may be used in the calcinations of limestone, only rotary kilns are regulated by the standards,” and not “the vertical kiln; the rotary hearth kiln; and the fluidized bed kiln”). (ii) In the EPA’s initial promulgation of NSPS regulations for petroleum refineries, the EPA did not promulgate standards of performance for certain units, including fluid coking units, delayed coking units, and process heaters, instead promulgating standards of performance for those units subsequently. See 40 CFR 60.100a(a); “Standards of Performance for Petroleum Refineries: Proposed Rules,” 72 FR 27178 (May 14, 2007). (iii) Similarly, in the EPA’s recent revision of the NSPS regulations for coal preparation and processing plants, the EPA “expand[ed] applicability of the existing NSPS by revising the definitions of thermal dryers, pneumatic

coal-cleaning equipment, and coal. It also establish[ed] work practice standards for open storage piles. The final rule amend[ed] the definition of thermal dryer for units constructed, reconstructed, or modified after May 27, 2009, to include both direct and indirect dryers drying all coal ranks (*i.e.*, bituminous, subbituminous, lignite, and anthracite coals) and coal refuse.”

“Standards of Performance for Coal Preparation and Processing Plants,” 74 FR 51950, 51952 (Oct. 8, 2009). (iv) In subpart KKKK of the NSPS regulations, the EPA promulgated regulations for the source category of stationary combustion turbines. The EPA did not promulgate regulations for turbines with smaller than 10 MMBtu/hr heat input, emergency units, or combustion turbine test cells. 40 CFR 60.4305(a), 60.4310(a), (d). (v) For other source categories, the EPA also declined to propose and promulgate standards of performance for the smaller sources. For example, for the source category of metal furniture coating operations, the EPA did not apply standards of performance to metal furniture surface coating operations that use less than 3.842 liters of coating (as applied) per year. 40 CFR 60.310(b). (vi) In proposing standards of performance for natural gas processing plants, the EPA proposed standards for only two of the three emission points in the plants (“storage emission sources” and “equipment leaks”) and declined to propose standards for the third emission point (“process emission sources”) on grounds that “[b]est demonstrated control technology has not been identified for [the latter] sources.” “Standards of Performance for New Stationary Sources: Onshore Natural Gas Processing Plants in the Natural Gas Production Industry, Equipment Leaks of VOC,” 49 FR 2636, 2637 (January 20, 1984).

(iii) Lack of Basis for Specifying Information

A major reason why the EPA is not proposing a standard of performance for transitional sources is that it is relying, in part, on the one-year commencement-construction limit to qualify a source as transitional: The EPA does not have sufficient information about the proposed sources’ sunk costs and preconstruction steps to be able to identify which of these proposed sources may qualify as transitional sources. In addition, even if the EPA could determine that a particular proposed source would in fact become a transitional source, the EPA lacks information that, under these circumstances, may be important for determining BSER. For example, the

EPA lacks information as to the amount of the proposed source’s sunk costs, which may be relevant in determining BSER for these proposed sources. In addition, for proposed CCS sources, as noted above, the EPA does not have information as to key components of their proposed project and business plan, including, among other things, the amount of capture from the planned CCS system or possible revenue streams associated with CCS.

Moreover, because transitional sources are defined by reference to the fact that they will commence construction within 12 months of the date of this proposal, it would be futile for the EPA to attempt to develop that information and then issue a proposal. By the time the EPA could do this, which would likely take at least a year, this set of sources will have become a null set: They either will have commenced construction, such that they would no longer be deemed “new sources” for purposes of CAA section 111, or they will not have commenced construction, such that they would be subject to the new source standard for non-transitional sources we are proposing today.⁷³

(iv) Practical Problems

In addition, the EPA’s lack of information and other considerations give rise to several serious practical problems that would arise were the EPA to propose a standard of performance for transitional sources. Importantly, were the EPA to propose a standard of performance, all transitional sources would face substantial uncertainty as to what final standard the EPA would promulgate. This uncertainty would arise for several reasons. As noted, the EPA lacks information concerning transitional sources. In addition, transitional sources differ one from another in terms of design and in other respects, which would render the EPA’s task more complex. As a result, there is risk that the EPA might finalize standards of performance different from what the EPA proposed. The final standards of performance may be more difficult for a given transitional source to meet.

⁷² As the U.S. Supreme Court recently stated in *Massachusetts v. EPA*, 549 U.S. 497, 524 (2007): “Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;” and instead they may permissibly implement such regulatory programs over time, “refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed.” See *Grand Canyon Air Tour Coalition v. F.A.A.*, 154 F.3d 455 (DC Cir. 1998), *City of Las Vegas v. Lujan*, 891 F.2d 927, 935 (DC Cir. 1989), *National Association of Broadcasters v. FCC*, 740 F.2d 1190, 1209–14 (DC Cir. 1984).

⁷³ Note that because the basic rationale for EPA’s treatment of transitional sources is that they have already incurred substantial sunk costs and have positioned themselves to be close to commencing construction, and the one-year period for commencing construction is a surrogate for that, this treatment of transitional sources cannot logically be stretched to cover sources that do not commence within a substantially longer period. There is no reason to believe those latter sources would have, by the time of the proposal for the rest of the source category, already incurred significant costs and moved close to commencing construction.

Other forms of uncertainty may arise as well. For example, a possible standard of performance that the EPA would consider would be based on identifying the BSER for transitional sources as the controls to which they would be subject under the terms of their PSD permits, with no further controls under section 111.⁷⁴ With this approach, the EPA would need to determine the emission rate for each source that would reflect that source's level of CO₂ emissions in accord with the terms of its PSD permit. This emission rate would constitute the "no-further-control" standard of performance. Note that under such an approach, each source would receive an emission limit unique to that source. However, some of the transitional sources may have a PSD permit that does not regulate CO₂ because GHGs were not subject to PSD until the January 2, 2011 effective date of the first regulatory action controlling CO₂ emissions under the CAA. Particularly for those sources, this approach could create uncertainty as to what the EPA would promulgate as the emission rate in the final standard of performance. This is because since these sources' permits do not specify a CO₂ limit, the EPA would have to develop limits based on the design of the unit (including the project's type of technology and fuels).

The uncertainties that the sources could experience as to what the final standards of performance would entail could well deter those sources from commencing construction until the EPA promulgated the final standard of performance. Such delay would undermine the usefulness of the requirement that sources commence construction within 12 months of today's rulemaking proposal as a mechanism for revealing which of these sources qualifies as a transitional source, and thus defeat the policy underlying the EPA's approach to transitional sources, which, for the reasons explained above, is to exclude from coverage by this new source standard only those sources that commence construction within 12 months of proposal. If sources are deterred from commencing construction until after the final rule, they will have lost the benefit of the 12-month window. As another practical problem, we also note concern with attempting to promulgate standards of performance

for transitional sources at a time when it may reasonably be expected that some of the 15 sources with PSD permits may well not commence construction within 12 months (or may never do so). As a result, the effort to develop a standard of performance for those sources would have been unnecessary.

(v) Small Number of Transitional Sources, Lack of Environmental Benefit

As part of our reasoning for not proposing a standard of performance for transitional sources, we also take into consideration the fact that we expect the number of transitional sources to be small, no more than a few of the 15 potential sources listed above. Further, if we were to propose a "no further control" standard of performance, as described above, that approach would provide little, if any, environmental benefit because that standard would not likely provide further control beyond the limits of the sources' PSD permits. In fact, treating transitional sources as existing sources may achieve more reductions than a no-further-control NSPS standard for those sources by including them under the flexible existing source standard that the EPA expects to promulgate.

(vi) Other Considerations

The EPA's approach of not proposing a standard of performance for transitional sources does not leave these sources uncontrolled. Rather, they would remain subject to whatever CO₂ emission limits are included in, or result from compliance with, their PSD permits. And, although transitional sources would not be subject to the 1,000 lb CO₂/MWh for new sources, the EPA anticipates that transitional sources would become subject to the requirements the EPA would promulgate at the appropriate time for existing sources under 111(d).

In notable contrast, in the previous rulemakings cited above in which the EPA did not propose coverage of all sources within the relevant source category, because of the pollutants at issue in these actions, the decision not to propose coverage of all sources within the relevant source category operated without the assurance afforded by section 111(d) that uncovered sources would necessarily be picked up as existing sources subject to existing source guidelines. Where, as here, that assurance mechanism applies, the recognition and application of the Agency's discretion to not propose coverage of all sources in the source category is all the more appropriate.

We recognize that this approach of not proposing a standard of performance

for transitional sources could raise the question of consistency with the requirement implicit in the definition of "new source" under CAA section 111(a)(2) that a source be subject to a standard of performance when it commences construction after the date of proposal for that standard. We believe the approach is consistent with, and does not circumvent, that requirement. As noted, CAA section 111 does not require that all sources that newly commence construction be treated as new sources, and in past section 111 rulemakings, the EPA has not applied the standards of performance that it proposes and promulgates to all sources that newly commence construction in a source category. In addition to the reasons for not promulgating a standard for transitional sources provided above, where, as here, the pollutants covered by the proposed new source standard give rise to an obligation to develop section 111(d) guidelines for existing sources with the source category, ultimate coverage of the sources in question is inevitable, eliminating any prospect of a regulatory gap of any material concern.

C. Requirements for Reconstructions

1. Overview

The EPA's framework regulations under CAA section 111 provide that reconstructed sources—which, in general, are existing sources that conduct extensive replacement of components—are to be treated as new sources and, therefore, subject to new source standards of performance. In today's rulemaking, we do not propose any standard of performance for reconstructed sources, and we take comment how to approach reconstructions. We note that if we do not establish a new standard of performance for reconstructions, as a practical matter, that would mean that reconstructed sources would be treated as existing sources.

2. Background

a. The EPA Regulations. The EPA's framework regulations, interpreting the definition of "new source" in CAA section 111(a)(2),⁷⁵ provide that an existing source, "upon reconstruction," becomes subject to the standard of performance for new sources. 40 CFR 60.15(a). The regulations define "reconstruction" as—

[T]he replacement of components of an existing facility to such an extent that:

⁷⁵ CAA section 111 does not explicitly include provisions for reconstructed sources.

⁷⁴ This type of standard of performance could take one of several different forms, such as a standard that would not limit the source's CO₂ emissions, or a standard that the transitional source itself would identify as equaling the emission limit it would achieve through compliance with the applicable terms of its permit.

(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 set forth in this part.

40 CFR 60.15(b). Thus, a reconstruction occurs if the existing source replaces components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, even if the existing source does not increase emissions. In addition, the component replacement constitutes a reconstruction only if it is technologically and economically feasible for the source to meet the applicable standards.

The regulations go on to require the owner or operator of an existing source that proposes to replace components to an extent that exceeds the 50 percent level, to notify the EPA and to provide specified information, including “a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.” In addition, the regulations require the EPA to determine, within a specified time period, whether the proposed replacement constitutes a reconstruction. 40 CFR 60.15(d)–(e).

b. Reconstructions. As with modifications, our base of knowledge concerning reconstructions has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for reconstructions for GHGs at this time. The EPA is not aware that any power plants are presently planning any project that could meet the requirements for a reconstruction.

2. Options

In this action, the EPA is not issuing a proposal for affected sources that undertake reconstructions. Our reasoning is much the same as with NSPS modifications, which is that the lack of adequate information about the type of source; the type of changes; the extent of emissions increases; and the type of control measures, including their cost and emissions reductions, precludes proposing a standard of performance. Instead of issuing a proposal, the EPA solicits comment on all issues related to reconstructions, including the aspects just noted.

Depending on the information the EPA acquires about reconstructions, the EPA may, in the future, propose and promulgate standards of performance for them.

VI. Implications for PSD and Title V Programs

A. Overview

The proposal in this rulemaking would, for the first time, regulate GHGs under CAA section 111. Under the EPA’s regulations for the CAA PSD preconstruction permit program, and the CAA Title V operating permit program, regulation of GHGs under CAA section 111 triggers the applicability of PSD. Even so, today’s proposal should not require any additional SIP revisions to make clear that the Tailoring Rule thresholds—described below—continue to apply to the PSD program.

This issue arises because States with approved PSD programs in their state implementation plans (SIPs) implement PSD, and most of these States have recently revised their SIPs to incorporate the higher thresholds for PSD applicability to GHGs that the EPA promulgated under what we call the Tailoring Rule.⁷⁶ Commenters have queried whether under the EPA’s PSD regulations, promulgation of a section 111 standard of performance GHGs would require these states to revise their SIPs again to incorporate the Tailoring Rule thresholds again. The EPA included an interpretation in the Tailoring Rule preamble, which makes clear that the Tailoring Rule thresholds continue to apply if and when the EPA promulgates requirements under CAA section 111. Even so, in today’s proposal, the EPA is including a provision in the CAA section 111 regulations that confirms this interpretation.

However, if a state with an approved PSD SIP program that applies to GHGs believes that were the EPA to finalize the rulemaking proposed today, the state would be required to revise its SIP to make clear that the Tailoring Rule thresholds continue to apply, then (i) the EPA encourages the state to do so as soon as possible, and (ii) the EPA will proceed with a separate rulemaking action to narrow its approval of that state’s SIP so as to assure that for federal purposes, the Tailoring Rule thresholds

will continue to apply as of the effective date of today’s rulemaking.

In the alternative, if the Tailoring Rule thresholds did not continue to apply when the EPA promulgates requirements under CAA section 111, then the EPA would shortly proceed with a separate rulemaking action to narrow its approval of all of the State’s approved SIP PSD programs to assure that for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of today’s proposal.

As discussed below, in the case of title V, today’s rulemaking does not have implications for the Tailoring Rule thresholds established with respect to sources subject to title V requirements.

B. Implications for PSD Program

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds, is required to obtain a preconstruction permit. This permit assures that the source meets specified requirements, including application of best available control technology. States authorized for the PSD program may issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits.

Regulation of GHG emissions in the Light Duty Vehicle Rule (75 FR 25324) triggered applicability of stationary sources to regulations for GHGs under the PSD and title V provisions of the CAA. Hence, on June 3, 2010 (75 FR 31514), the EPA issued the “Tailoring Rule,” which establishes thresholds for GHG emissions in order to define and limit when new and modified industrial facilities must have permits under the PSD and title V programs. The rule addresses emissions of six GHGs: CO₂, CH₄, N₂O, HFCs, PFCs and SF₆. On January 2, 2011, large industrial sources, including power plants, became subject to permitting requirements for their GHG emissions if they were already are required to obtain PSD or title V permits due to emissions of other (non-GHG) air pollutants.

Commenters have queried whether, because of the way that the EPA’s PSD regulations are written, promulgating the rule we propose today may raise questions as to whether the EPA must revise its PSD regulations—and, by the same token, whether states must revise their SIPs—to assure that the Tailoring Rule thresholds will continue to apply to sources subject to PSD. That is, under the EPA’s regulations, PSD applies to a “major stationary source” that

⁷⁶ “Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule,” 75 FR 31514 (June 3, 2010). In the Tailoring Rule, EPA established a process for phasing in PSD and Title V applicability to sources based on the amount of their GHG emissions, instead of immediately applying PSD and title V at the 100 or 250 ton per year or thresholds included under the PSD and title V applicability provisions.

undertakes construction, 40 CFR 51.166(a)(7)(i), and to a “major modification.” 40 CFR 51.166(a)(7)(iii). A “major modification” is defined as “any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase * * * and a significant net emissions increase. * * *” Thus, for present purposes, the key component of these applicability provisions is that PSD applies to a “major stationary source.” This term is the regulatory replacement for the term “major emitting facility,” which is central to the PSD applicability requirements established in the CAA itself, under sections 165(a)(1) and 169(1).

The EPA’s regulations define the term “major stationary source” as a “stationary source of air pollutants which emits, or has the potential to emit, 100 [or, depending on the source category, 250] tons per year or more of any regulated NSR pollutant.” 40 CFR 51.166(b)(1)(i)(a). The EPA’s regulations go on to define “regulated NSR pollutant” to include, among other things, “Any pollutant that is subject to any standard promulgated under section 111 of the Act.” 40 CFR 51.166(b)(49)(ii).

Thus, the PSD regulations contain a separate PSD trigger for pollutants regulated under the NSPS, 40 CFR 51.166(b)(49)(ii) (the “NSPS trigger provision”), so that as soon as the EPA promulgates the first NSPS for a particular air pollutant, as we are doing in this rulemaking with respect to the GHG air pollutant, then PSD is triggered for that air pollutant.

The Tailoring Rule, on the face of its regulatory provisions, incorporated the revised thresholds it promulgated into only the fourth prong (“[a]ny pollutant that otherwise is subject to regulation under the Act”), and not the second prong (“[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act”). For this reason, a question may arise as to whether the Tailoring Rule thresholds apply to the PSD requirement as triggered by the NSPS that the EPA is promulgating in this rulemaking.

However, although the Tailoring Rule thresholds on their face apply to only the term, “subject to regulation” in the definition of “regulated NSR pollutant,” the EPA stated in the Tailoring Rule preamble that the thresholds should be interpreted to apply to other terms in the definition of “major stationary source” and in the statutory provision, “major emitting facility.” Specifically, the EPA stated:

3. Other Mechanisms

As just described, we selected the “subject to regulation” mechanism because it most readily accommodated the needs of States to expeditiously revise—through interpretation or otherwise—their state rules. Even so, it is important to recognize that this mechanism has the same substantive effect as the mechanism we considered in the proposed rule, which was revising numerical thresholds in the definitions of major stationary source and major modification. Most importantly, although we are codifying the “subject to regulation” mechanism, that approach is driven by the needs of the states, and our action in this rulemaking should be interpreted to rely on any of several legal mechanisms to accomplish this result. Thus, our action in this rule should be understood as revising the meaning of several terms in these definitions, including: (1) The numerical thresholds, as we proposed; (2) the term, “any source,” which some commenters identified as the most relevant term for purposes of our proposal; (3) the term, “any air pollutant; or (4) the term, “subject to regulation.” The specific choice of which of these constitutes the nominal mechanism does not have a substantive legal effect because each mechanism involves one or another of the components of the terms “major stationary source”—which embodies the statutory term, “major emitting facility”—and “major modification,” which embodies the statutory term, “modification,” and it is those statutory and regulatory terms that we are defining to exclude the indicated GHG-emitting sources. ^[Footnote]

[Footnote:] We also think that this approach better clarifies our long standing practice of interpreting open-ended SIP regulations to automatically adjust for changes in the regulatory status of an air pollutant, because it appropriately assures that the Tailoring Rule applies to both the definition of “major stationary source” and “regulated NSR pollutant.”]

75 FR 31582.

Thus, according to the preamble, the definition of “major stationary source” itself already incorporates the Tailoring Rule thresholds, and not just through one component (the “subject to regulation” prong of the term “regulated NSR pollutant”) of that definition. For this reason, it is the EPA’s position that the Tailoring Rule thresholds continue to apply even when the EPA promulgates the first NSPS for GHGs (which, as noted above, triggers the PSD requirement under the NSPS trigger provision in the definition of “regulated NSR pollutant”).⁷⁷ To clarify and

⁷⁷ This position reads the regulations to be consistent with the CAA PSD provisions themselves. Under those provisions, PSD applies to any “major emitting facility,” which is defined to mean stationary sources that emit or have the potential to emit “any air pollutant” at either 100 or 250 tons per year, depending on the source category. CAA section 165(a), 169(1). EPA has long interpreted these provisions to apply PSD to a stationary source that emits the threshold amounts

confirm that the Tailoring Rule thresholds apply to the section 111 prong of the definition of regulated NSR pollutant, in this proposed rulemaking, the EPA is proposing to revise the NSPS regulations, although not the PSD regulations, to explicitly make clear that the NSPS trigger provision in the PSD regulations incorporate the Tailoring Rule thresholds.

As a result, the EPA believes that states that incorporated the Tailoring Rule thresholds into their SIPs may take the position that they also incorporated the EPA’s interpretation in the preamble that the thresholds apply to the definition “major stationary source.”

The EPA requests that all States with approved SIP PSD programs that apply to GHGs indicate during the comment period on this rule whether they can interpret their SIPs already to apply the Tailoring Rule thresholds to the NSPS prong or whether they must revise their SIPs. For any State that says it must revise its SIP (or that does not respond), the EPA expects to propose a rule that is comparable to the SIP PSD Narrowing Rule shortly after the close of the comment period, and expects to finalize that rule at the same time that it finalizes this NSPS rule.

C. Implications for Title V Program

Under the title V program, a source that emits any air pollutant subject to regulation at or above specified thresholds (along with certain other sources) is required to obtain an operating permit. This permit includes all of the CAA requirements applicable to the source. These permits are generally issued through EPA-approved State title V programs.

As the EPA explained in the Tailoring Rule preamble, title V applies to a “major source,” CAA section 502(a), which is defined to include, among other things, certain sources, including any “major stationary source,” CAA section 501(2)(B), which, in turn, is defined to include a stationary source of “any air pollutant” at or above 100 tpy. CAA section 302(j). The EPA’s regulations under title V define the term “major source,” and in the Tailoring Rule, the EPA revised that definition to make clear that the term is limited to stationary sources that emit any air pollutant “subject to regulation.” The EPA incorporated the Tailoring Rule threshold within this definition of “subject to regulation.” The EPA

of any air pollutant subject to regulation. See Tailoring Rule, 75 FR 31579. Under these provisions, at present, PSD is already applicable to GHGs because GHGs are already subject to regulation, and regulating GHGs under CAA section 111 does not any additional type of PSD trigger.

described its action as follows in the preamble to the Tailoring Rule:

Thus, EPA is adding the phrase “subject to regulation” to the definition of “major source” under 40 CFR 70.2 and 71.2. EPA is also adding to these regulations a definition of “subject to regulation.” Under the part 70 and part 71 regulatory changes adopted, the term “subject to regulation,” for purposes of the definition of “major source,” has two components. The first component codifies the general approach EPA recently articulated in the “Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting,” 75 FR 17704. Under this first component, a pollutant “subject to regulation” is defined to mean a pollutant subject to either a provision in the CAA or regulation adopted by EPA under the CAA that requires actual control of emissions of that pollutant and that has taken effect under the CAA. *See id.* at 17022–23; Wegman Memorandum at 4–5. To address tailoring for GHGs, EPA includes a second component of the definition of “subject to regulation,” specifying that GHGs are not subject to regulation for purposes of defining a major source, unless as of July 1, 2011, the emissions of GHGs are from a source emitting or having the potential to emit 100,000 tpy of GHGs on a CO₂e basis.

75 FR at 31,583.

Unlike the PSD regulations described above, the title V definition of “major source”, as revised by the Tailoring Rule, does not on its face distinguish among types of regulatory triggers for title V. Because title V has already been triggered for GHG-emitting sources, the promulgation of CAA section 111 requirements has no further impact on title V requirements for major sources of GHGs. Accordingly, today’s rulemaking has no title V implications with respect to the Tailoring Rule threshold. Of course, unless exempted by the Administrator through regulation under CAA section 502(a), sources subject to a NSPS are required to apply for, and operate pursuant to, a title V permit that assures compliance with all applicable CAA requirements for the source, including any GHG-related requirements. We have concluded that this rule will not affect non-major sources and there is no need to consider whether to exempt non-major sources

VII. Impacts of the Proposed Action

A. What are the air impacts?

The EPA believes that electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of this proposal, because of existing and expected market conditions. We do not project any new coal-fired EGUs without CCS to be built in the absence of this proposal.

Accordingly, the EPA believes that this proposed rule is not likely to produce changes in emissions of greenhouse gases or other pollutants although it does encourage the current trend towards cleaner generation.

B. What are the energy impacts?

This proposed rule is not anticipated to have a notable effect on the supply, distribution, or use of energy. As previously stated, we believe that electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, because of existing and expected market conditions. In addition, we do not project any new coal-fired EGUs without CCS to be built in the absence of this proposal.

C. What are the compliance costs?

The EPA believes this proposed rule will have no notable compliance costs associated with it, because electric power companies would be expected to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, due to existing and expected market conditions. The EPA does not project any new coal-fired EGUs without CCS to be built in the absence of the proposal.

D. How will this proposal contribute to climate change protection?

As previously explained, the special characteristics of GHGs make it important to take initial steps to control the largest emissions categories without delay. Unlike most traditional air pollutants, GHGs persist in the atmosphere for time periods ranging from decades to millennia, depending on the gas. Fossil-fueled power plants emit more GHG emissions than any other stationary source category in the United States, and among new GHG emissions sources, the largest individual sources are in this source category.

This proposed rule will limit GHG emissions from new sources in this source category to levels consistent with current projections for new fossil-fuel-fired generating units. The proposed rule will also serve as a necessary predicate for the regulation of existing sources within this source category under CAA section 111(d). In these ways, the proposed rule will contribute to the actions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against projected climate change impacts and risks.

E. What are the economic and employment impacts?

The EPA does not anticipate that this proposed rule will result in notable CO₂ emission changes, energy impacts, monetized benefits, costs, or economic impacts by 2020. Essentially the EPA believes that owners of newly built electric generating units will choose technologies that meet these standards even in the absence of this proposal due to existing economic conditions as normal business practice. Likewise, we believe this rule will not have any impacts on the price of electricity, employment or labor markets, or the US economy.

F. What are the benefits of the proposed standards?

As previously stated, the EPA does not anticipate that the power industry will incur compliance costs as a result of this proposal and we do not anticipate any notable CO₂ emission changes resulting from the rule. Therefore, there are no direct monetized climate benefits in terms of CO₂ emission reductions associated with this rulemaking. However, by clarifying that in the future, new coal-fired power plants will be required to install CCS, this rulemaking eliminates uncertainty about the status of coal and may well enhance the prospects for new coal-fired generation and the deployment of CCS, and thereby promote energy diversity.

VIII. Request for Comments

We request comments on all aspects of the proposed rulemaking including the RIA. All significant comments received will be considered in the development and selection of the final rule. We specifically solicit comments on additional issues under consideration as described below.

CEMS. We are considering and requesting comment on requiring the use of CO₂ CEMS including stack gas flow rate monitoring for all new affected facilities, including those burning exclusively natural gas and/or distillate oil. In addition, we are requesting comment on requiring the use the following measurement procedures in conducting CEMS relative accuracy testing:

a. EPA Method 2F of 40 CFR part 60 for flow rate measurement during the relative accuracy test audit and performance testing. Method 2F provides velocity data for three dimensions and provides measurements more representative of actual gas flow rates than EPA Method 2 or 2G of 40 CFR part 60.

b. EPA Method 2H of 40 CFR part 60 or Conditional Test Method (CTM)–041

(see: <http://www.epa.gov/airmarkets/emissions/docs/square-ducts-wall-effects-test-method-ctm-041.pdf>) to account for wall effects on for stack gas flow rate calculations during CEMS relative accuracy determinations and for performance testing.

c. EPA Method 4 of 40 CFR part 60 to determine moisture for flow rate during CEMS relative accuracy determinations and for performance test calculations.

d. EPA Method 3A of 40 CFR part 60 for CO₂ concentration measurement and for molecular weight determination during CEMS relative accuracy determinations or for performance testing. Account for ambient air argon concentration of 0.93 percent⁷⁸ and a molecular weight of 39.9 lb/lb-mol in calculating the dry gas molecular weight.

e. Measure the stack diameter at the CEMS measurement site and the reference method sampling site with a laser distance measurement device. Determine the mean average of three separate diameter measurements for circular stack areas or the mean average of three depth and width measurements for rectangular measurement areas. Calculate the effective stack area for all flow rate measurements, both CEMS system and Reference Method, using this measurement data. This would be a one-time measurement that would fix the effective area of the stack emissions point unless a new location is chosen for the CEMS or Reference Method measurement point. All calculations involving pi would use a value of 3.14159.

f. Apply a daily calibration drift criteria not to exceed 0.3 percent CO₂ for CO₂ CEMS.

g. Do not exceed a relative accuracy specification of 2.5 percent for both CO₂ and flow rate measurement CEMS.

We also request comment on whether Method 3B of 40 CFR part 60 (integrated bag sample), in addition to Method 3A, should be allowed for CO₂ concentration measurement and for molecular weight determination during CEMS relative accuracy determinations or for performance testing.

Coal refuse. Due to the multiple environmental benefits of remediating coal refuse piles, we are considering and requesting comment on subcategorizing EGUs that burn over 75 percent coal refuse on an annual basis. As part of the GHG listening sessions, one commenter mentioned the advantages of utilizing coal refuse to create electricity. The commenter stated that if net emissions

caused by using mining waste to generate electricity are calculated, then mining waste facility would produce no net GHG emissions in the long term and emissions would be no greater than the short term emissions of a combined cycle gas plant in. The comment states that due to the size of the piles, mining waste pile exposure to atmospheric oxygen and pressure promotes heat-generating reactions, primarily oxidation of the mining waste itself (i.e., the coal refuse piles are slowly burning). This process emits CO₂ and other air pollutants. Remediation would stop current and future CO₂ emissions resulting from the uncontrolled combustion of waste piles.

Coordinates. We realize that geographic latitude and longitude coordinates of each stack in terms of decimal degrees are presently reported to the EPA's Clean Air Markets Division in terms of four decimal points to the right of the decimal point. We are requesting comment on whether we should require owners/operators of affected facilities to submit to the EPA Administrator the geographic latitude and longitude coordinates of each stack to have at least six values to the right of the decimal for each location. By way of example, the coordinates for the monument next to Zachary Taylor's tomb in Louisville, KY are 38.279401 latitude and -85.643751 longitude.

Combined Heat and Power. We are also considering and requesting comment on if exempting all CHP facilities where useful thermal output accounts for at least 20 percent of the total useful output from this proposed rule would recognize the environmental benefit of CHP and result in additional installations that would otherwise not occur. In considering exemption of CHP units, the EPA is particularly interested in the overall impact this would have on the composition of new builds. The definition of affected sources under this rule already exempts CHP sources that primarily generate on-site power. Therefore, as explained earlier, today's proposal does not impact any of the small amount of projected coal-fired CHP in EIA's AEO 2011. CHPs that would be covered by this rule generate and sell large quantities of electricity. While building such units is more energy efficient and results in some GHG reductions, building new coal-fired units to meet a standard of 1,000 lb CO₂/MWh would likely result in greater reductions. If potential developers of new coal-fired generation opted instead to build coal-fired CHP to avoid the CO₂ limitations proposed under today's rule, it could result in greater emissions of CO₂. Furthermore,

requiring such units to meet a standard of 1,000 lb CO₂/MWh does not preclude new coal-fired units from being CHP units.

Format of the Proposed Standards.

Although we have proposed gross output-based emission standards, the EPA believes that the net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer. Net output is the combination of the gross electrical output of the electric generating unit minus the parasitic power requirements. A parasitic load for an electric generating unit is any of the loads or devices powered by electricity, steam, hot water, or directly by the gross output of the electric generating unit that does not contribute electrical, mechanical, or thermal output. In general, less than 7.5 percent of coal-fired station power output, and about 2.5 percent of a combined cycle station power output, is used internally by parasitic energy demands, but the amount of these parasitic loads vary from source to source. Reasons for using net output include (1) recognizing the efficiency gains of selecting EGU designs and control equipment that require less auxiliary power, (2) selecting fuels that require less emissions control equipment, and (3) recognizing the environmental benefit of higher efficiency motors, pumps, and fans. In addition, use of a gross output-based standard could potentially drive the installation of electrically driven feed pumps instead of steam driven feed pumps, even though from an overall net efficiency basis, it may be more efficient to use steam-driven feed pumps. Further, monitoring net output for new and reconstructed facilities can be designed into the facility at low costs. Thus, we are requesting comment on the use of net output-based emission standards for owners/operators of new facilities.

Stationary Simple Cycle Turbines. As stated in the preamble, the intent of the proposed regulations is to cover stationary combustion turbines use for intermediate and base load electric power generation and to exempt stationary combustion turbines used for peaking operations (i.e., simple cycle turbines). We are considering and requesting comment on not including a definition of simple cycle turbines in the final rule. The potential electric output requirement in the definition of electric generating unit would already exclude facilities with permit restricting limiting operation to less than 1/3 of their potential electric output, approximately 2,900 hours of full load

⁷⁸ <http://www.physicalgeography.net/fundamentals/7a.html>.

operation annually. The peaking season is generally considered to be less than 2,500 hours annually, and we are requesting comment on if the capacity factor exemption is sufficient such that specifically exempting simple cycle turbine is unnecessary. We are also requesting comment on whether the exemption would provide a perverse incentive to build less efficient simple cycle combustion turbines in order to avoid applicability with the proposed rule. While few existing simple cycle turbines presently generate greater than $\frac{1}{3}$ of their potential electric output for sale, we are requesting comment on whether the exemption for simple cycle turbines would result in the greater use of simple cycle turbines for intermediate load applications when more efficient combined cycle facilities would have otherwise been built. In addition, it is our understanding that combined cycle facilities are sometimes built in stages with the combustion turbine engine installation occurring first and the heat recovery steam generator being installed in later years as electricity demand increases. We are requesting comment on whether the exemption would potentially delay the installation of the heat recovery steam generator portion of new combined cycle facilities. Finally, in the event we use the definition approach in the final rule, we are requesting comment on whether a CHP facility that uses the recovered exhaust heat for purposes other than to generate steam and recuperated combustion turbines should be considered simple or combined cycle combustion turbines.

IX. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order (EO) 12866 (58 FR 51,735, October 4, 1993), this action is a “significant regulatory action” because it “raises novel legal or policy issues arising out of legal mandates”. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New

Stationary Sources: Electric Utility Generating Units.

The EPA believes this rule will have no notable compliance costs associated with it over a range of likely sensitivity conditions because electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, because of existing and expected market conditions. (See the RIA for further discussion of sensitivities.) Because our modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance—which is based on the emission rate of a new NGCC unit—would not add costs. The EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this proposal.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2465.01.

This proposed action would impose minimal new information collection burden on affected sources beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs based on requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there are no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The 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 EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory

requirements of this proposal because of existing and expected market conditions. The EPA does not project any new coal-fired EGUs that commence construction after this proposal to commence operation over the 3-year period covered by this ICR. We estimate that 17 new affected NGCC units would commence operation during that time period. As a result of this proposal, those units would be required to prepare a summary report, which includes reporting of excess emissions and downtime, every 6 months.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 60, subpart TTTT. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has estimated what the notification, recordkeeping, and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA’s estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals \$3,141, and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small. In fact, we estimate that there will be no such occurrences for any new sources subject to 40 CFR part 60, subpart TTTT over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual information collection burden for this collection consists only

of reporting burden as explained above. The reporting burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be \$15,570 and 396 labor hours. This estimate includes semi-annual summary reports which include reporting of excess emissions and downtime. All burden estimates are in 2010 dollars. Average burden hours per response are estimated to be 16.5 hours. The total number of respondents over the 3-year ICR period is estimated to be 36. Burden is defined at 5 CFR 1320.3(b).

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.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA-HQ-OAR-2011-0660. Submit any comments related to the ICR to the EPA and OMB. See ADDRESSES section at the beginning of this notice for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after April 13, 2012, a comment to OMB is best assured of having its full effect if OMB receives it by May 14, 2012. The final rule will

respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. et seq.

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as:

(1) A small business that is defined by the SBA's regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million MWh or less in the previous fiscal year. The NAICS codes for the affected industry are in Table 4 below);

(2) A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

TABLE 4—POTENTIALLY REGULATED CATEGORIES AND ENTITIES ^a

Category	NAICS Code	Examples of potentially regulated entities
Industry	221112	Fossil fuel electric power generating units.
Federal Government	^b 221112	Fossil fuel electric power generating units owned by the federal government.
State/Local Government	^b 221112	Fossil fuel electric power generating units owned by municipalities.
Tribal Government	921150	Fossil fuel electric power generating units in Indian Country.

^a Include NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).

^b Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

We do not include an analysis of the illustrative impacts on small entities that may result from implementation of this proposed rule because we do not anticipate any compliance costs over a

range of likely sensitivity conditions as a result of this proposal. Thus the cost-to-sales ratios for any affected small entity would be zero costs as compared to annual sales revenue for the entity. The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market

conditions. (See the RIA for further discussion of sensitivities.) Because our modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance—which is based on the emission rate of a new NGCC unit—would not add costs. The EPA does not project any new coal-fired EGUs without CCS to be built. Accordingly, there are no anticipated

economic impacts as a result of this proposal.

Nevertheless, the EPA is aware that there is substantial interest in this rule among small entities (municipal and rural electric cooperatives). In light of this interest, the EPA determined to seek early input from representatives of small entities while formulating the provisions of this proposed regulation. Such outreach is also consistent with the President's January 18, 2011 Memorandum on Regulatory Flexibility, Small Business, and Job Creation, which emphasizes the important role small businesses play in the American economy. This process has enabled the EPA to hear directly from these representatives, at a very preliminary stage, about how it should approach the complex question of how to apply Section 111 of the CAA to the regulation of GHGs from these source categories. The EPA's outreach regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

The EPA conducted an initial outreach meeting with small entity representatives on April 6, 2011. The purpose of the meeting was to provide an overview of recent EPA proposals impacting the power sector. Specifically, overviews of the Transport Rule, the Mercury and Air Toxics Standards, and the Clean Water Act 316(b) Rule proposals were presented.

The EPA conducted outreach with representatives from 20 various small entities that potentially would be affected by this rule. The representatives included small entity municipalities, cooperatives, and private investors. We distributed outreach materials to the small entity representatives; these materials included background, an overview of affected sources and GHG emissions from the power sector, an overview of CAA section 111, an assessment of CO₂ emissions control technologies, potential impacts on small entities, and a summary of the listening sessions. We met with eight of the small entity representatives, as well as three participants from organizations representing power producers, on June 17, 2011, to discuss the outreach materials, potential requirements of the rule, and regulatory areas where the EPA has discretion and could potentially provide flexibility.

A second outreach meeting was conducted on July 13, 2011. We met with nine of the small entity representatives, as well as three participants from organizations representing power producers. During the second outreach meeting, various small entity representatives and

participants from organizations representing power producers presented information regarding issues of concern with respect to development of standards for GHG emissions. Specifically, topics suggested by the small entity representatives and discussed included: boilers with limited opportunities for efficiency improvements due to NSR complications for conventional pollutants; variances per kilowatt-hour and in heat rates over monthly and annual operations; significance of plant age; legal issues; importance of future determination of carbon neutrality of biomass; and differences between municipal government electric utilities and other utilities.

Small entities expressed concern regarding units making modifications being regulated as new sources. As explained above, we are not proposing a standard of performance for modifications. As a result, sources that undertake modifications would be treated as existing sources and thus would not be subject to the requirements proposed in this notice. As also explained above, the EPA is not proposing standards of performance for existing proposed EGUs, which are referred to as transitional sources, that have acquired a complete preconstruction permit by the time of this proposal and that commence construction within 12 months of this proposal. As a result, any transitional sources owned by small entities would not be subject to the standards of performance proposed in today's rule.

We invite comments on all aspects of the proposal and its impacts, including potential adverse impacts, on small entities.

D. Unfunded Mandates Reform Act of 1995

This proposed rule does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. The EPA believes this proposed rule will have no compliance costs associated with it over a range of likely sensitivity conditions because electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market conditions. (See the RIA for further discussion of sensitivities.) As previously explained, because our modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance—which is based on the emission rate of a new NGCC unit—would not add costs.

The EPA does not project any new coal-fired EGUs without CCS to be built. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest in this rule among governmental entities, the EPA initiated consultations with governmental entities. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on April 12, 2011, in Washington DC: (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. The purposes of the consultation were to provide general background on the proposal, answer questions, and solicit input from state/local governments. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

During the meeting, officials asked clarifying questions regarding CAA section 111 requirements and efficiency improvements that would reduce CO₂ emissions. In addition, they expressed concern with regard to the potential burden associated with impacts on state and local entities that own/operate affected utility boilers, as well as on state and local entities with regard to implementing the rule. Subsequent to the April 12, 2011 meeting, the EPA received a letter from the National Conference of State Legislatures. In that letter, the National Conference of State Legislatures urged the EPA to ensure that the choice of regulatory options maximizes benefit and minimizes implementation and compliance costs on state and local governments; to pay particular attention to options that would provide states with as much flexibility as possible; and to take into consideration the constraints of the state legislative calendars and ensure that sufficient time is allowed for state

actions necessary to come into compliance.

E. Executive Order 13132, Federalism

This proposed action does not have federalism implications. It would 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, as specified in EO 13132. This proposed action would not impose substantial direct compliance costs on state or local governments, nor would it preempt state law. Thus, Executive Order 13132 does not apply to this action. The EPA consulted with state and local officials in the process of developing the proposed rule to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposal, answer questions, and solicit input from state/local governments. The UMRA discussion in this preamble includes a description of the consultation. In the spirit of EO 13132, and consistent with EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Subject to the EO 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this proposed action would not have tribal implications. It would neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This proposed rule would impose requirements on owners and operators of new EGUs. The EPA is aware of three coal-fired EGUs located in Indian Country but is not aware of any EGUs owned or operated by tribal entities. The EPA notes that this proposal does not affect existing sources such as the

three coal-fired EGUs located in Indian Country, but addresses CO₂ emissions for new EGU sources only.

Because the EPA is aware of Tribal interest in this proposed rule, the EPA offered consultation with tribal officials early in the process of developing this proposed regulation to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

Consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of NSPS and emission guidelines for EGUs and offered consultation. A consultation/outreach meeting was held on May 23, 2011, with the Forest County Potawatomi Community, the Fond du Lac Band of Lake Superior Chippewa Reservation, and the Leech Lake Band of Ojibwe. Other tribes participated in the call for information gathering purposes. In this meeting, the EPA provided background information on the GHG emission standards to be developed and a summary of issues being explored by the Agency. Tribes suggested that the EPA consider expanding coverage of the GHG standards to include combustion turbines, lowering the 250 MMBtu per hour heat input threshold so as to capture more EGUs, and including credit for use of renewables. The tribes were also interested in the scope of the emissions averaging being considered by the Agency (e.g., over what time period, across what units). In addition, the EPA held a series of listening sessions on this proposed action. Tribes participated in a session on February 17, 2011 with the state agencies, as well as in a separate session with tribes on April 20, 2011.

The EPA will also hold additional meetings with tribal environmental staff to inform them of the content of this proposal as well as provide additional consultation with tribal elected officials where it is appropriate. We specifically solicit additional comment on this proposed rule from tribal officials.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5-501 of the Order has the potential to influence the regulation. This proposed action is not subject to EO 13045 because it is based solely on technology

performance. The proposal is not expected to produce notable changes in emissions of greenhouse gases or other pollutants but does encourage the current trend towards cleaner generation, helping to protect air quality and children's health. The Agency recognizes that children are among the groups most vulnerable to climate change impacts and the public is invited to submit comments or identify peer reviewed studies relevant to this proposal.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not a "significant energy action" as defined in EO 13211 (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This proposed action is not anticipated to have notable impacts on emissions, costs or energy supply decisions for the affected electric utility industry.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995 (Pub. L. 104-113; 15 U.S.C. 272 note) directs the EPA to use Voluntary Consensus Standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable VCS.

This proposed rulemaking involves technical standards. The EPA cites the following standards in this proposed rule: D5287-08 (Standard Practice for Automatic Sampling of Gaseous Fuels), D4057-06 (Standard Practice for Manual Sampling of Petroleum and Petroleum Products), and D4177-95(2010) (Standard Practice for Automatic Sampling of Petroleum and Petroleum Products). The EPA is proposing use of Appendices B, D, F, and G to 40 CFR part 75; these Appendices contain standards that have already been reviewed under the NTTAA.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this action.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

The EPA has determined that this proposed rule would not result in disproportionately high and adverse human health or environmental effects on minority or low-income populations, including any minority, low-income population or indigenous populations.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: March 27, 2012.

Lisa P. Jackson,
Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

2. Part 60 is amended by adding subpart TTTT to read as follows:

Subpart TTTT Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units

Applicability

Sec.

60.5508 What is the purpose of this subpart?

60.5509 Am I subject to this subpart?

60.5510 What is the affected EGU of this subpart?

Emissions Standards

60.5515 What greenhouse gases are regulated by this subpart?

60.5520 What CO₂ emissions standards must I meet?

General Compliance Requirements

60.5525 What are my general requirements for complying with this subpart?

60.5530 Affirmative Defense for Exceedance of Emission Limit During Malfunction

Monitoring and Compliance Determination Procedures

60.5535 How do I monitor and collect data to demonstrate compliance?

60.5540 How do I demonstrate compliance and determine excess emissions with my CO₂ emissions limit?

Notifications, Reports, and Records

60.5550 What notifications must I submit and when?

60.5555 What reports must I submit and when?

60.5560 What records must I keep?

60.5565 In what form and how long must I keep my records?

Other Requirements and Information

60.5570 What parts of the General Provisions apply to me?

60.5575 Who implements and enforces this subpart?

60.5580 What definitions apply to this subpart?

Table 1 to Subpart TTTT of Part 60—
Applicability of Subpart A General Provisions to Subpart TTTT

Applicability

§ 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 electric utility generating units that commenced construction after April 13, 2012.

§ 60.5509 Am I subject to this subpart?

You are subject to this subpart if you own or operate an electric utility generating unit that commences construction after April 13, 2012 with a base load rating of more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/h)) heat input of fossil fuel except as specified under § 60.5510(b).

§ 60.5510 What is the affected EGU of this subpart?

(a) The affected facility to which this subpart applies is each electric utility generating unit (EGU) except as provided for in paragraph (b) of this section.

(b) An electric utility generating unit that meets the conditions specified in paragraphs (b)(1) through (b)(3) of this section is exempt from this subpart.

(1) A steam electric generating unit that meets the definition of municipal waste combustor unit and is subject to subpart Eb of this part.

(2) A steam electric generating unit that meets the definition of a commercial or industrial solid waste incineration unit and is subject to subpart CCCC of this part.

(3) Transitional sources.

(i) You are not subject to this subpart if you own or operate a transitional source that commences construction within 12 months after April 13, 2012.

(ii) For purposes of paragraph (b)(3)(ii) a “transitional source” is defined as an EGU with a base load rating of more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/h)) heat input of fossil fuel, except as provided for in § 60.5510(b)(1) and (2), and that received a complete permit that meets the requirements of the Prevention of Significant Deterioration Program under part C of Title I of the Clean Air Act prior to April 13, 2012 (*or that had an approved PSD permit that has expired and is in the process of being extended, if the source is participating in a Department of Energy CCS funding program*).

Emissions Standards

§ 60.5515 What greenhouse gases are regulated by this subpart?

The greenhouse gas regulated by this subpart is carbon dioxide (CO₂).

§ 60.5520 What CO₂ emissions standards must I meet?

(a) You must not discharge any gases that contain CO₂ from any affected EGU into the atmosphere in excess of 454 kilograms (kg) of CO₂ per gross output in Megawatt-hours (MWh) (454 kg/MWh) (1,000 lb/MWh) on a 12-operating month annual average basis, except as provided for in paragraphs (b) through (d) of this section.

(b) If the affected EGU utilizes coal or petroleum coke for fuel and is designed to allow installation and operation of a carbon capture and storage (CCS) system, you may comply with each standard in paragraphs (b)(1) through (3) as an alternative to complying with paragraph (a) of this section.

(1) For each year until the 11th year of operation, you must not discharge any gases that contain CO₂ from the affected EGU into the atmosphere in excess of 816 kg/MWh (1,800 lb/MWh) gross output on a 12-operating month annual average basis, and

(2) Beginning with the 11th year of operation, the CCS system must be operational and you must not discharge any gases that contain CO₂ from the affected EGU into the atmosphere in excess of 272 kg/MWh (600 lb/MWh) gross output on a 12-operating month annual average basis, and

(3) You must not discharge any gases that contain CO₂ from the affected EGU into the atmosphere in excess of 454 kg/MWh gross output on a 30-year average basis.

(c) Electric utility generating units located in a non-continental area are not subject to the requirements of this subpart.

(d) Simple cycle combustion turbines are not subject to the requirements of this subpart.

General Compliance Requirements

§ 60.5525 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emissions limits in this subpart applicable to your affected EGU. These limits apply at all times.

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitoring equipment, in a manner consistent with safety and good practices for minimizing CO₂ emissions.

Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, review of reports required by this subpart, and inspection of the facility.

(c) For each affected EGU subject to the CO₂ emissions limits in § 60.5520, you must measure or calculate a 12 month rolling average CO₂ emission rate, calculated per calendar month, in terms of tons/MWh.

(1) If your EGU is subject to the requirements of 40 CFR 75.10(a)(3)(i), you must use the CO₂ CEMS to measure the 12 month rolling average CO₂ emissions rate.

(d) You must conduct an initial compliance determination for your affected EGU according to the requirements in this subpart within 30 days following the first day of the 13th operating month following the date of initial operations. Thereafter, you must demonstrate continuous compliance according to the requirements in this subpart each calendar month determined to be an operating month.

§ 60.5530 Affirmative Defense for Exceedance of Emission Limit During Malfunction.

In response to an action to enforce the standards you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if the respondent fails to meet its burden of proving all of the requirements in the affirmative defense. The affirmative defense shall

not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, the owners or operators of facilities must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner;

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not result from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(2) Repairs were made as expeditiously as practicable when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs;

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(5) All practicable steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health;

(6) All emissions monitoring and control systems were kept in operation if at all practicable, consistent with safety and good air pollution control practices;

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs;

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the

amount of excess emissions that were the result of the malfunction.

(b) The owner or operator of an affected EGU experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as practicable, but no later than two (2) business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedances.

Monitoring and Compliance Determination Procedures

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection and the quality assurance and quality control elements consistent with the applicable requirements in § 60.13, 40 CFR part 75, and this section.

(b) Follow the applicable quality assurance procedures for CO₂ emissions in appendices B, D, and G to 40 CFR part 75.

(c) If you determine the your affected EGU's CO₂ mass emissions rate by monitoring fuel combusted in the affected EGU and periodic fuel sampling as allowed under § 60.5525(c)(2), you must use the procedures specified in 40 CFR part 75, appendix G.

(1) Determine a site-specific F factor using the ultimate analysis and GCV in equation F-7a of 40 CFR part 75, Appendix F; and

(2) Monitor and determine the affected EGU's daily fuel consumption for each type of fuel combusted in the affected EGU.

(3) Use ASTM D5287-08 (Standard Practice for Automatic Sampling of Gaseous Fuels) to collect a representative gaseous fuel sample.

(4) Use one of the following methods to collect a representative liquid oil fuel sample:

- (i) ASTM D4057–06 (Standard Practice for Manual Sampling of Petroleum and Petroleum Products) or
- (ii) ASTM D4177–95 (2010) (Standard Practice for Automatic Sampling of Petroleum and Petroleum Products).

(d) You must monitor and record the applicable data needed to determine your affected EGU's gross output for each operating month.

(e) Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§ 60.5540 How do I demonstrate compliance and determine excess emissions with my CO₂ emissions limit?

(a) If you use a CO₂ CEMS to demonstrate compliance you must use the procedure specified in paragraphs (a)(1) through (5) of this section to determine the 12-operating month rolling average CO₂ emissions rate for your affected EGU.

(1) Calculate hourly CO₂ mass emissions for each hour of the operating month in terms of kilograms CO₂ using CFR 40 part 75 appendix G.

(2) Determine hourly gross output in terms of MWh for each hour of the operating month.

(3) Sum the hourly CO₂ mass emissions for the operating month, and sum the hourly gross output for the operating month.

(4) Divide the total CO₂ mass emissions calculated for the month by the total hourly gross output calculated for the operating month.

(5) Add the quotient to the sum of the quotients of the previous 11 operating months and divide by 12 to determine the 12-operating month rolling average.

(6) If the 12-operating month rolling average value does not exceed the applicable emissions limit in § 60.5520, your affected EGU is determined to be in compliance with the emissions limit. Otherwise, your affected EGU is determined to have excess emissions.

(b) If you use fuel sampling to demonstrate compliance, you must use the procedure specified in paragraphs (b)(1) through (5) of this section to determine the 12-operating month rolling average CO₂ emissions rate for your affected EGU.

(1) Calculate monthly CO₂ mass emissions by multiplying the monthly F factor by the monthly fuel consumption.

(2) Sum the hourly gross output in terms of MWh for the month.

(3) Divide the monthly CO₂ mass emissions by the sum of the hourly gross output for the month.

(4) Add the quotient to the sum of the quotients of the previous 11 operating months to determine the 12-operating month rolling average.

(5) If the 12-operating month rolling average value does not exceed the applicable emissions limit in § 60.5520, your affected EGU is determined to be in compliance with the emissions limit. Otherwise, your affected EGU is determined to have excess emissions.

(c) If you elect to comply with § 60.5520(b), the 30-year average CO₂ emissions rate for your affected EGU is the sum of the monthly CO₂ emissions for each operating month for the 30-year period divided by the sum of the monthly gross output in terms of MWh for the 30-year period. Use the procedure specified in paragraphs (c)(1) through (4) of this section to determine the 12-month annual average CO₂ emissions rate for your affected EGU.

(1) If you do not use a CO₂ CERMS to demonstrate compliance with § 60.5520(b), you must calculate hourly CO₂ mass emissions for each hour of the 12-month annual period in terms of kilograms CO₂ using CFR 40 Part 75 Appendix G. If you use a CO₂ CERMS to demonstrate compliance with § 60.5520(b) you must calculate hourly CO₂ mass emissions for each hour of the 12-month annual period in terms of kilograms CO₂ using the CERMS hourly mass emissions measurements.

(2) Determine hourly gross output in terms of MWh for each hour of the 12-month annual period.

(3) Sum the hourly CO₂ mass emissions for the 12-month annual operating period, and sum the hourly gross output for the 12-month annual operating period.

(4) Divide the total CO₂ mass emissions calculated for the 12-month annual operating period by the total hourly gross output calculated for the 12-month annual operating period.

(5) If the 12-month annual average value does not exceed the applicable emissions limit in § 60.5520, your affected EGU is determined to be in compliance with the emissions limit. Otherwise, your affected EGU is determined to have excess emissions.

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit notifications specified in § 60.7(a) and § 60.19, as applicable to your affected EGU.

(b) You must prepare and submit notifications specified in 40 CFR part 75.61, as applicable to your affected EGU.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports specified in § 60.7(c) through (e) and § 60.19, as applicable to your affected EGU. All reports required under § 60.7 must be submitted by the 30th day following the end of each 6-month period.

(1) The excess emissions and continuous monitoring systems performance reports and/or summary report forms required in § 60.7(c) must be submitted to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX)(www.epa.gov/cdx). In CEDRI, the owner or operator shall use the appropriate electronic reporting form for this subpart or provide an alternate electronic file consistent with EPA's form output format.

(b) You must follow the applicable reporting requirements and submit reports as required in subpart G of 40 CFR part 75. You must report CO₂ mass emissions data, and other related data electronically using the Emissions Collection and Monitoring Plan System (ECMPS).

§ 60.5560 What records must I maintain?

(a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7 (b) and (f).

(1) Notwithstanding the requirements of this section you do not need to maintain records of the reports that have been submitted to the EPA's WebFIRE database as required in § 60.5555(a)(1).

(b) You must follow the applicable recordkeeping requirements and maintain records as required in subpart F of 40 CFR part 75.

(c) If you determine the CO₂ mass emissions rate by monitoring fuel combusted in an affected EGU and periodic fuel sampling according to the requirements in this rule then you must maintain records of fuel type and quantity combusted in the affected EGU for each operating month the information specified in paragraphs (c) (1) and (2) of this section.

(1) Records of fuel type and quantity combusted in the affected EGU for each operating month.

(2) Records of the calculations performed to determine the site-specific F factor and monthly total CO₂ mass emissions rates.

(d) Records of the applicable data recorded and calculations performed used to determine your affected EGU's gross output for each operating month.

§ 60.5565 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 keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record except those records required to demonstrate compliance with the emissions limits in § 60.5520(b). Records required to demonstrate compliance with the emissions limits in § 60.5520(b) must be kept for at least 40 years following the date of initial startup of the affected EGU.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.10. You can keep the records off site for the remaining years as required by this subpart.

Other Requirements and Information**§ 60.5570 What parts of the General Provisions apply to me?**

Table 1 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5575 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 authorities listed in paragraphs (b)(1) through (5) of this section are retained by the Administrator and are not transferred to the state, local, or tribal agency; however, 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).

§ 60.5580 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).

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Base load rating means the maximum amount of heat input (fuel) that a steam generating unit can combust on a steady state basis, as determined by the physical design and characteristics of the steam generating unit at ISO conditions. For a stationary combustion turbine *base load* means 100 percent of the design heat input capacity of the stationary combustion turbine engine at ISO conditions.

Carbon capture and storage (CCS) means a process that includes capture and compression of CO₂ produced by an electric utility generating unit before release to the atmosphere; transport of the captured CO₂ (usually in pipelines); and storage of that CO₂ in geologic formations, such as deep saline formations, oil and gas reservoirs, and unmineable coal seams.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (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 refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Combined cycle means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit.

Combined heat and power, also known as "cogeneration," means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Electric utility generating unit or EGU means any steam electric generating unit or stationary combustion turbine that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected EGU.

Excess emissions means a specified averaging period over which the CO₂ emissions rate are higher than the applicable emissions standard.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

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 standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross output means the gross electrical or mechanical output from the unit plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of

the unit (*i.e.*, steam delivered to an industrial process).

Integrated gasification combined cycle electric utility generating unit means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15° C), 60 percent relative humidity and 101.3 kilopascals pressure.

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. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. 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 sulfur content or heating value.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Operating month means a calendar month during which any fuel is combusted in the electric utility generating unit at any time.

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Potential electric output means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a steam generating unit with a 100 MW (340 MMBtu/h) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity).

Simple cycle combustion turbine means a stationary combustion turbine that which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

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.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, 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. 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.

Steam electric generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated device that provides electricity or useful thermal output to either the boiler or to power auxiliary equipment.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, *i.e.*, total thermal energy made available for processes and applications other than electrical generation or to enhance the performance of the stationary combustion turbine. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at ISO conditions.

TABLE 1 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A GENERAL PROVISIONS TO SUBPART TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	Additional terms defined in § 60.5580.
§ 60.2	Definitions	Yes	
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	Except for the requirements to submit written excess emissions reports under § 60.7(c).
§ 60.7	Notification and Recordkeeping	Yes	
§ 60.8	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	Monitoring requirements	Yes.	
§ 60.14	Modification	No.	
§ 60.15	Reconstruction	No.	

TABLE 1 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A GENERAL PROVISIONS TO SUBPART TTTT—
Continued

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting re- quirements.	Yes.	

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