

**ENVIRONMENTAL PROTECTION
AGENCY**
40 CFR Parts 60, 70, 71, and 98
[EPA-HQ-OAR-2013-0495; FRL-9839-4]
RIN 2060-AQ91
**Standards of Performance for
Greenhouse Gas Emissions From New
Stationary Sources: Electric Utility
Generating Units**
AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On April 13, 2012, the EPA proposed a new source performance standard for emissions of carbon dioxide for new affected fossil fuel-fired electric utility generating units. The EPA received more than 2.5 million comments on the proposed rule. After consideration of information provided in those comments, as well as consideration of continuing changes in the electricity sector, the EPA determined that revisions in its proposed approach are warranted. Thus, in a separate action, the EPA is withdrawing the April 13, 2012, proposal, and, in this action, the EPA is proposing new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. This action proposes a separate standard of performance for fossil fuel-fired electric utility steam generating units and integrated gasification combined cycle units that burn coal, petroleum coke and other fossil fuels that is based on partial implementation of carbon capture and storage as the best system of emission reduction. This action also proposes standards for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. This action also includes related proposals concerning permitting fees under Clean Air Act Title V, the Greenhouse Gas Reporting Program, and the definition of the pollutant covered under the prevention of significant deterioration program.

DATES: *Comments.* Comments must be received on or before March 10, 2014. 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 January 8, 2014, a comment to the OMB is best assured of having its full effect if the OMB receives it by February 7, 2014.

Public Hearing. A public hearing will be held on January 28, 2014, at the William Jefferson Clinton Building East, Room 1153 (Map Room), 1201 Constitution Avenue NW., Washington DC 20004. The hearing will convene at 9:00 a.m. (Eastern Standard Time) and end at 8:00 p.m. (Eastern Standard Time). Please contact Pamela Garrett at (919) (541-7966) or at garrett.pamela@epa.gov to register to speak at the hearing. The last day to pre-register in advance to speak at the hearing will be 2 business days in advance of the public hearing. Additionally, requests to speak will be taken the day of the hearing at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, please let us know at the time of registration.

The hearing will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because this hearing is being held at U.S. government facilities, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. Commenters should notify Ms. Garrett if they will need specific equipment, or if there are other special needs related to providing comments at the hearing. The EPA will provide equipment for commenters to show overhead slides or make computerized slide presentations if we receive special requests in advance. Oral testimony will be limited to 5 minutes for each commenter. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email or CD) or in hard copy form. Verbatim transcripts of the hearings and written statements will be included in the docket for the

rulemaking. The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearing to run either ahead of schedule or behind schedule. Information regarding the hearing (including information as to whether or not one will be held) will be available at: <http://www2.epa.gov/carbon-pollution-standards/>.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2013-0495, 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-2013-0495.

Facsimile: Fax your comments to (202) 566-9744, Attn: Docket ID No. EPA-HQ-OAR-2013-0495.

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-2013-0495. 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, William Jefferson Clinton Building West, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20004, Attn: Docket ID No. EPA-HQ-OAR-2013-0495. Such deliveries are accepted only during the Docket Center's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include the agency name and docket ID number (EPA-HQ-OAR-2013-0495). The EPA's policy is to include all comments received without change, including any personal information provided, in the public docket, available online at <http://www.regulations.gov>, 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>.

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-HQ-OAR-2013-0495. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on 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 you claim as CBI. In addition to one complete version of the comment that includes information claimed as CBI, you must submit a copy of the comment that does not contain the information claimed as CBI 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 you also submit a separate copy of your comments to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**). If the comment includes information you consider to be CBI or otherwise protected, you should send a copy of the comment that does not contain the information claimed as CBI or otherwise protected.

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, William Jefferson Clinton Building 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 federal 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 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/>.

FOR FURTHER INFORMATION CONTACT: 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 or 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.

SUPPLEMENTARY INFORMATION: *Comments on the April 13, 2012 proposal.* The EPA considered comments submitted in response to the original April 13, 2012, proposal in developing this new proposal. However, we are withdrawing the original proposal. If you would like comments submitted on the April 13, 2012 rulemaking to be considered in connection with this new proposal, you should submit new comments or re-submit your previous comments. Commenters who submitted comments concerning any aspect of the original proposal will need to consider the applicability of those comments to this current proposal and submit them again, if applicable, even if the comments are exactly or substantively the same as those previously submitted, to ensure consideration in the development of the final rulemaking.

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 Interface
 CEMS Continuous Emissions Monitoring System
 CFB Circulating Fluidized Bed
 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 Generating Unit
 EIA Energy Information Administration
 EO Executive Order
 EOR Enhanced Oil Recovery
 EPA Environmental Protection Agency
 FB Fluidized Bed
 FGD Flue Gas Desulfurization
 FOAK First-of-a-kind
 FR **Federal Register**
 GHG Greenhouse Gas
 GW Gigawatts
 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
 IRPs Integrated Resource Plans
 kg/MWh Kilogram per Megawatt-hour
 kJ/kg Kilojoules per Kilogram
 kWh Kilowatt-hour
 lb CO₂/MMBtu Pounds of CO₂ per Million British Thermal Unit
 lb CO₂/MWh Pounds of CO₂ per Megawatt-hour
 lb CO₂/yr Pounds of CO₂ per Year
 lb/lb-mole Pounds per Pound-Mole
 LCOE Levelized Cost of Electricity
 MATS Mercury and Air Toxic Standards
 MMBtu/hr Million British Thermal Units per Hour
 MW Megawatt

MWe Megawatt Electrical
 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
 NOAK nth-of-a-kind
 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
 PUC Public Utilities Commission
 RCRA Resource Conservation and Recovery Act
 RFA Regulatory Flexibility Act
 RGGI Regional Greenhouse Gas Initiative
 RIA Regulatory Impact Analysis
 RPS Renewable Portfolio Standard
 RTC Response to Comments
 RTP Response to Petitions
 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 (one trillion (10¹²) grams)
 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 Change Research Program
 VCS Voluntary Consensus Standard
 WGS Water Gas Shift
 WWW Worldwide Web

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

- I. General Information
 - A. Executive Summary
 - B. Overview
 - C. Does this action apply to me?
- II. Background
 - A. Climate Change Impacts from GHG Emissions
 - B. GHG Emissions from Fossil Fuel-fired EGUs
 - C. The Utility Power Sector and How its Structure is Changing
 - D. Statutory Background
 - E. Regulatory and Litigation Background
 - F. Coordination with Other Rulemakings
 - G. Stakeholder Input
- III. Proposed Requirements for New Sources
 - A. Applicability Requirements

- B. Emission Standards
- C. Startup, Shutdown, and Malfunction Requirements
- D. Continuous Monitoring Requirements
- E. Emissions Performance Testing Requirements
- F. Continuous Compliance Requirements
- G. Notification, Recordkeeping, and Reporting Requirements
- IV. Rationale for Reliance on Rational Basis To Regulate GHGs from Fossil-fired EGUs
 - A. Overview
 - B. Climate Change Impacts From GHG Emissions; Amounts of GHGs From Fossil Fuel-Fired EGUs
 - C. CAA Section 111 Requirements
 - D. Interpretation of CAA Section 111 Requirements
 - E. Rational Basis To Promulgate Standards for GHGs From Fossil-Fired EGUs
 - F. Alternative Findings of Endangerment and Significant Contribution
 - G. Comments on the State of the Science of Climate Change
- V. Rationale for Applicability Requirements
 - A. Applicability Requirements—Original Proposal and Comments
 - B. Applicability Requirements—Today's Proposal
 - C. Certain Projects Under Development
- VI. Legal Requirements for Establishing Emission Standards
 - A. Overview
 - B. CAA Requirements and Court Interpretation
 - C. Technical Feasibility
 - D. Factors To Consider in Determining the "Best System"
 - E. Nationwide Component of Factors in Determining the "Best System"
 - F. Chevron Framework
 - G. Agency Discretion
 - H. Lack of Requirement That Standard Be Able To Be Met by All Sources
- VII. Rationale for Emission Standards for New Fossil Fuel-Fired Boilers and IGCCs
 - A. Overview
 - B. Identification of the Best System of Emission Reduction
 - C. Determination of the Level of the Standard
 - D. Extent of Reductions in CO₂ Emissions
 - E. Technical Feasibility
 - F. Costs
 - G. Promotion of Technology
 - H. Nationwide, Longer-Term Perspective
 - I. Deference
 - J. CCS and BSER in Locations Where Costs Are Too High To Implement CCS
 - K. Compliance Period
 - L. Geologic Sequestration
- VIII. Rationale for Emission Standards for Natural Gas-Fired Stationary Combustion Turbines
 - A. Best System of Emission Reduction
 - B. Determination of the Standards of Performance
- IX. Implications for PSD and Title V Programs
 - A. Overview
 - B. Applicability of Tailoring Rule Thresholds Under the PSD Program
 - C. Implications for BACT Determinations Under PSD
 - D. Implications for Title V Program
 - E. Implications for Title V Fee Requirements for GHGs

- X. 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?
- XI. Request for Comments
- XII. 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
 - D. Unfunded Mandates Reform Act
 - 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
- XIII. Statutory Authority

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

On April 13, 2012, under the authority of Clean Air Act (CAA) section 111, the EPA proposed a new source performance standard (NSPS) to limit emissions of carbon dioxide (CO₂) from new fossil fuel-fired electric utility generating units (EGUs), including, primarily, coal- and natural gas-fired units (77 FR 22392). After consideration of the information provided in more than 2.5 million comments on the proposal, as well as consideration of continuing changes in the electricity sector, the EPA is issuing a new proposal. Today's action proposes to establish separate standards for fossil fuel-fired electric steam generating units (utility boilers and Integrated Gasification Combined Cycle (IGCC) units) and for natural gas-fired stationary combustion turbines. These proposed standards reflect separate determinations of the best system of emission reduction (BSER) adequately demonstrated for utility boilers and IGCC units and for natural gas-fired stationary combustion turbines. In contrast, the April 2012 proposal relied on a single standard and a single BSER determination for all new fossil fuel-

fired units. In addition, the applicability requirements proposed today differ from the applicability requirements in the original proposal. In light of these and other differences, the EPA is issuing a document (published separately in today's **Federal Register**) that withdraws the original proposal, as well as issuing this new proposal.

2. Summary of the Major Provisions

This action proposes a standard of performance for utility boilers and IGCC units based on partial implementation of carbon capture and storage (CCS) as the BSER. The proposed emission limit for those sources is 1,100 lb CO₂/MWh.¹ This action also proposes standards of performance for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle (NGCC) technology as the BSER. The proposed emission limits for those sources are 1,000 lb CO₂/MWh for larger units and 1,100 lb CO₂/MWh for smaller units. At this time, the EPA is not proposing standards of performance for modified or reconstructed sources.

3. Costs and Benefits

As explained in the Regulatory Impact Analysis (RIA) for this proposed rule, available data—including utility announcements and EIA modeling—indicate that, even in the absence of this rule, (i) existing and anticipated economic conditions mean that few, if any, solid fossil fuel-fired EGUs will be built in the foreseeable future; and (ii) electricity generators are expected to choose new generation technologies (primarily natural gas combined cycle) that would meet the proposed standards. Therefore, based on the analysis presented in Chapter 5 of the RIA, the EPA projects that this proposed rule will result in negligible CO₂ emission changes, quantified benefits, and costs by 2022.² These projections are in line with utility announcements and Energy Information Administration (EIA) modeling that indicate that coal units built between now and 2020 would have CCS, even in the absence of this rule. However, for a variety of reasons, some companies may consider coal units that the modeling does not anticipate. Therefore, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a new coal-fired unit with partial CCS alongside the project-level costs of a new coal-fired unit without CCS.

¹ In this rulemaking, all references to lb CO₂/MWh are on a gross output basis, unless specifically noted otherwise.

² Conditions in the analysis year of 2022 are represented by a model year of 2020.

B. Overview

1. Why is the EPA issuing this proposed rule?

Greenhouse gas (GHG) pollution³ threatens the American public's health and welfare by contributing to long-lasting changes in our climate that can have a range of negative effects on human health and the environment. The impacts could include: longer, more intense and more frequent heat waves; more intense precipitation events and storm surges; less precipitation and more prolonged drought in the West and Southwest; more fires and insect pest outbreaks in American forests, especially in the West; and increased ground level ozone pollution, otherwise known as smog, which has been linked to asthma and premature death. Health risks from climate change are especially serious for children, the elderly and those with heart and respiratory problems.

The U.S. Supreme Court ruled that GHGs meet the definition of "air pollutant" in the CAA, and this decision clarified that the CAA's authorities and requirements apply to GHG emissions. Unlike most other air pollutants, GHGs may persist in the atmosphere from decades to millennia, depending on the specific greenhouse gas. This special characteristic makes it crucial to take initial steps now to limit GHG emissions from fossil fuel-fired power plants, specifically emissions of CO₂, since they are the nation's largest sources of carbon pollution. This rule will ensure that the next generation of fossil fuel-fired power plants in this country will use modern technologies that limit harmful carbon pollution.

On April 13, 2012, the EPA issued a proposed rule to limit GHG emissions from fossil fuel-fired power plants by establishing a single standard applicable to all new fossil fuel-fired EGUs serving intermediate and base load power demand. After consideration of the information provided in more than 2.5 million comments on the proposal, as well as consideration of continuing changes in the electricity sector,⁴ the EPA is issuing a new proposal to establish separate standards for fossil fuel-fired electric steam generating units

³ Greenhouse gas pollution is the aggregate group of the following gases: CO₂, methane (CH₄), nitrous oxide (N₂O), sulfur hexafluoride (SF₆), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

⁴ For example, since April 2012, there has been significant progress on two CCS projects (Kemper County and Boundary Dam), and they are now both over 75 percent complete. Two other projects have continued to make progress toward construction (Texas Clean Energy Project and Hydrogen Energy California Project).

(utility boilers and IGCC units) and for natural gas-fired stationary combustion turbines. These proposed standards reflect separate determinations of the BSER adequately demonstrated for utility boilers and IGCC units and for natural gas-fired stationary combustion turbines. Because, in contrast, the April 2012 proposal relied on a single standard for all new fossil fuel-fired units, the EPA is issuing, as a final action, a document (published separately in today's **Federal Register**) that withdraws the original proposal, as well as issuing this new proposal.

2. What authority is the EPA relying on to address power plant CO₂ emissions?

Congress established requirements under section 111 of the 1970 CAA to control air pollution from new stationary sources through NSPS. Specifically, section 111 requires the EPA to set technology-based standards for new stationary sources to minimize emissions of air pollution to the environment. For more than four decades, the EPA has used its authority under section 111 to set cost-effective emission standards that ensure newly constructed sources use the best performing technologies to limit emissions of harmful air pollutants. In this proposal, the EPA is following the same well-established, customary interpretation and application of the law under section 111 to address GHG emissions from new fossil fuel-fired power plants.

3. What sources should the EPA include as it develops proposed standards for GHGs for power plants?

Before determining the appropriate technologies and levels of control that represent BSER for GHG emissions, the EPA must first identify the appropriate sources to control.

The starting point is to consider whether, given current trends concerning coal-fired and natural gas-fired power plants and the nature of GHGs, the EPA should regulate CO₂ from these power plants through the same NSPS regulatory structure that EPA has established for conventional pollutants. The EPA's NSPS regulations already regulate conventional pollutants from these sources under two 40 CFR part 60 subparts: subpart Da, electric utility steam generating units, which includes both steam electric utility boilers and IGCC units, and subpart KKKK, stationary combustion turbines, which includes both simple cycle and combined cycle stationary combustion turbines.

For sources covered under subpart Da, the original proposal relied on analyses,

primarily undertaken by EIA, indicating that, while substantial reliance on coal-fired electricity generation would continue in the future, few, if any, new coal-fired power plants were likely to be built by 2025. Based in part on these results, the EPA concluded that it was appropriate to propose in April 2012 a single fuel-neutral standard covering all intermediate and base load units based on the performance of recently constructed NGCC units. In light of developments in the electricity sector since the April 2012 proposal, and in response to numerous comments on the proposal itself, the EPA is changing the approach in today's document and proposing to set separate standards for new sources covered by subpart Da.⁵

The EPA notes that, since the original April 2012 proposal, a few coal-fired units have reached the advanced stages of construction and development, which suggests that proposing a separate standard for coal-fired units is appropriate. Since the original proposal, progress on Southern Company's Kemper County Energy Facility, an IGCC facility that will implement partial CCS, has continued, and the project is now over 75 percent complete. Similarly, SaskPower's Boundary Dam CCS Project in Estevan, Saskatchewan, a project that will fully integrate the rebuilt 110 MW coal-fired Unit #3 with available CCS technology to capture 90 percent of its CO₂ emissions, is more than 75 percent complete. Performance testing is expected to commence in late 2013 and the facility is expected to be fully operational in 2014.

Additionally, two other IGCC projects, Summit Power's Texas Clean Energy Project (TCEP) and the Hydrogen Energy California Project (HECA)—both of which are IGCC units with CCS—continue to move forward. Further, NRG Energy is developing a commercial-scale post-combustion carbon capture project at the company's W.A. Parish generating station southwest of Houston, Texas. The facility is expected to be operational in 2015. Continued progress on these projects is consistent with the EIA modeling which projects that few, if any, new coal-fired EGUs would be built in this decade and that those that are built would include CCS.⁶ The existence and apparent ongoing viability

⁵ While the emphasis of EPA's BSER determination is on coal- and petcoke-fired units, the subpart covers all fossil fuel-fired EGU boilers and IGCC units, including those burning oil and gas.

⁶ Even in its sensitivity analysis, the EIA does not project any additional coal projects beyond its reference case until 2023, in a case where power companies assume no emission limitations for GHGs, and until 2024 in any sensitivity analysis in which there are emission limitations for GHGs.

of these projects which include CCS justify a separate BSER determination for new fossil fuel-fired utility boilers and IGCC power plants.

In addition to these projects, a number of commenters (on the April 2012 proposal) noted that, if natural gas prices increase, there could be greater interest in the construction of additional coal-fired generation capacity. This, too, is consistent with the EIA analysis, which also suggests that, in a limited number of potential scenarios generally associated with both significantly higher than anticipated electric demand and significantly higher than expected natural gas prices, some additional new coal-fired generation capacity may be built beyond 2020. It is also consistent with publicly available electric utility Integrated Resource Plans (IRPs).⁷

Many of those IRPs indicated the utilities' interest in developing some amount of generating capacity using other intermediate-load and base load technologies, in addition to new NGCC capacity, to meet future demand (albeit, almost always at a higher cost than NGCC technology). Only a few utilities' IRPs indicated that new coal-fired generation without CCS was a technology option that was being considered to meet future demand. Finally, a number of commenters suggested that it was important to set standards that preserve options for fuel diversity, particularly if natural gas prices exceed projected levels. Given this information, the EPA believes that it is appropriate to set a separate standard for solid fossil fuel-fired EGUs, both to address the small number of coal plants that evidence suggests might get built and to set a standard that is robust across a full range of possible futures in the energy and electricity sectors.

Utility announcements about the status of coal projects, IRPs, and EIA projections suggest that, by far, the largest sources of new fossil fuel-fired electricity generation are likely to be NGCC units. The EPA believes, therefore, that it is also appropriate to set a standard for stationary combustion turbines used as EGUs. These units are currently covered under subpart KKKK (stationary combustion turbines).

The EPA also proposes to maintain the definition of EGUs under the NSPS that differentiates between EGUs (sources used primarily for generating electricity for sale to the grid) and non-EGUs (turbines primarily used to generate steam and/or electricity for on-

⁷ IRPs are planning documents that many Public Utility Commissions require utilities to file outlining their plans to meet future demand. Many of the IRPs that the EPA has reviewed included planning horizons of ten years or more.

site use). That definition defines EGUs as units that sell more than one-third of their potential electric output to the grid. Under this definition, most simple cycle "peaking" stationary combustion turbines, which typically sell significantly less than one-third of their potential electric output to the grid, would not be affected by today's proposal.

Finally, the EPA is not proposing standards today for one conventional coal-fired EGU project which, based on current information, appears to be the only such project under development that has an active air permit and that has not already commenced construction for NSPS purposes. If the EPA observes that the project is truly proceeding, it may propose a new source performance standard specifically for that source at the time the EPA finalizes today's proposed rule.

4. What is the EPA's general approach to setting standards for new sources under Section 111(b)?

Section 111(b) requires the EPA to identify the "best system of emission reduction ... adequately demonstrated" (BSER) available to limit pollution. The CAA and subsequent court decisions (detailed later in this notice) identify the factors for the EPA to consider in a BSER determination. For this rulemaking, the following factors are key: feasibility, costs, size of emission reductions and technology.

Feasibility: The EPA considers whether the system of emission reduction is technically feasible.

Costs: The EPA considers whether the costs of the system are reasonable.

Size of emission reductions: The EPA considers the amount of emissions reductions that the system would generate.

Technology: The EPA considers whether the system promotes the implementation and further development of technology.

After considering these four factors, we propose that efficient generation technology implementing partial CCS is the BSER for new affected fossil fuel-fired boilers and IGCC units (subpart Da sources) and modern, efficient NGCC technology is the BSER for new affected combustion turbines (subpart KKKK sources). The foundations for these determinations are described in Sections VII and VIII.

5. What is BSER for new fossil fuel-fired utility boilers and IGCC units?

Power generated from the combustion or gasification of coal emits more CO₂ than power generated from the combustion of natural gas or by other

means, such as solar or wind. If any new coal-fired unit is built, its CO₂ emissions would be approximately double that of a new NGCC unit of comparable capacity. Thus, it is important to set a standard for any new coal plant that might be built.

The three alternatives the EPA considered in the BSER analysis for new fossil fuel-fired utility boilers and IGCC units are: (1) highly efficient new generation that does not include CCS technology, (2) highly efficient new generation with “full capture” CCS and (3) highly efficient new generation with “partial capture” CCS.

Generation technologies representing enhancements in operational efficiency (e.g., supercritical or ultra-supercritical coal-fired boilers or IGCC units) are clearly technically feasible and present little or no incremental cost compared to the types of technologies that some companies are considering for new coal-fired generation capacity. However, they do not provide meaningful reductions in CO₂ emissions from new sources. Efficiency-improvement technologies alone result in only very small reductions (several percent) in CO₂ emissions, especially in contrast to those achieved by the application of CCS. Determining that these high-efficiency generating technologies represent the BSER for CO₂ emissions from coal-fired generation would fail to promote the development and deployment of CO₂ pollution-reduction technology from power plants. In fact, a determination that this efficiency-enhancing technology alone, as opposed to CCS, is the BSER for CO₂ emissions from new coal-fired generation likely would inhibit the development of technology that could reduce CO₂ emissions significantly, thus defeating one of the purposes of the CAA’s NSPS provisions. For example, during its pilot-scale CCS demonstration at the Mountaineer Plant in New Haven, WV, American Electric Power (AEP) announced in 2011 that it was placing on hold its plans to scale-up the CCS system, citing the uncertain status of U.S. climate policy as a key contributing factor to its decision.

An assessment of the technical feasibility and availability of CCS indicates that nearly all of the coal-fired power plants that are currently under development are designed to use some type of CCS. In most cases, the projects will sell or use the captured CO₂ to generate additional revenue. These projects include the following (note that each of the projects has obtained some governmental financial assistance):

Southern Company’s Kemper County Energy Facility, a 582 MW IGCC power

plant that is currently under construction in Kemper County, Mississippi. The plant will include a CCS system designed to capture approximately 65 percent of the produced CO₂.

SaskPower’s Boundary Dam CCS Project, in Estevan, Saskatchewan, Canada, is a commercial-scale CCS project that will fully integrate the rebuilt 110 MW coal-fired Unit #3 with available CCS technology to capture 90 percent of its CO₂ emissions.

Texas Clean Energy Project (TCEP), an IGCC plant near Odessa, Texas, that is under development by the Summit Power Group, Inc. (Summit). TCEP is a 400 MW IGCC plant that expects to capture approximately 90 percent of the produced CO₂.

Hydrogen Energy California, LLC (HECA), is proposing to build a plant similar to TCEP in western Kern County, California. The HECA plant is an IGCC plant fueled by coal and petroleum coke that will produce 300 MW of power and will capture CO₂ for use in enhanced oil recovery (EOR) operations. They expect to capture approximately 90 percent of the produced CO₂.

The above examples suggest that project developers who are incorporating CCS generally considered two variants: either a partial CCS system or a full CCS system (i.e., usually 90 percent capture or greater). Therefore, the EPA considered both options.

In assessing whether the cost of a certain option is reasonable, the EPA first considered the appropriate frame of reference. Power companies often choose the lowest cost form of generation when determining what type of new generation to build. Based on both the EIA modeling and utility IRPs, there appears to be a general acceptance that the lowest cost form of new power generation is NGCC.

Many states find value in coal investments and have policies and incentives to encourage coal energy generation. Utility IRPs (as well as comments on the April 2012 proposal) suggest that many companies also find value in other factors, such as fuel diversity, and are often willing to pay a premium for it. Utility IRPs suggest that a range of technologies can meet the preference for fuel diversity from a dispatchable form of generation that can provide intermediate or base-load power, including coal without CCS, coal with CCS and nuclear. Biomass-fired power generation⁸ and geothermal

⁸ The proposed CO₂ emission standards would only apply to new fossil fuel-fired EGUs. New EGUs that primarily fire biomass would not be subject to these proposed standards.

power generation are other technologies that are dispatchable and that could potentially meet this objective. These technologies all cost significantly more than natural gas-fired generation, which ranges from a levelized cost of electricity (LCOE)⁹ of \$59/MWh to \$86/MWh, depending upon assumptions about natural gas prices. In assessing whether the cost of coal with CCS would have an unreasonable impact on the cost of power generation, the EPA believes it is appropriate to compare coal with CCS to this range of non-natural gas-fired electricity generation options. Based on data from the EIA and the DOE National Energy and Technology Laboratory (NETL), the EPA believes that the levelized cost of technologies other than coal with CCS and NGCC range from \$80/MWh to \$130/MWh. These include nuclear, from \$103/MWh to \$114/MWh; biomass, from \$97/MWh to \$130/MWh; and geothermal, from \$80/MWh to \$99/MWh.

The EPA believes the cost of “full capture” CCS without EOR is outside the range of costs that companies are considering for comparable generation and therefore should not be considered BSER for CO₂ emissions for coal-fired power plants. The EPA projects the LCOE of generation technologies with full capture CCS to be in the range of \$136/MWh to \$147/MWh (without EOR benefits).¹⁰ Because these “full capture” CCS costs without EOR are significantly above the price range of potential alternative generation options, the EPA believes that full capture CCS does not meet the cost criterion of BSER.

Finally, the EPA considered whether implementation of “partial capture” CCS should be proposed to be BSER for new fossil fuel-fired utility boilers and IGCC units.

Partial capture CCS has been implemented successfully in a number of facilities over many years. The Great

⁹ The levelized cost of electricity is an economic assessment of the cost of electricity from a new generating unit or plant, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital. The LCOE value presented here are in \$2007.

¹⁰ The cost assumptions and technology configurations for these cost estimates are provided in the DOE/NETL “Cost and Performance Baseline” reports. For these cost estimates, we used costs for new SCPC and IGCC units utilizing bituminous coal from the reports “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity”, Revision 2, Report DOE/NETL-2010/1397 (November 2010) and “Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture”, DOE/NETL-2011/1498, May 27, 2011. Additional cost and performance information can be found in additional volumes that are available at http://www.netl.doe.gov/energy-analyses/baseline_studies.html.

Plains Synfuels Facility¹¹ is a coal gasification facility that has captured at least 50 percent of its produced CO₂ for use in EOR operations since 2000. Projects such as AEP Mountaineer have successfully demonstrated the performance of partial capture CCS on a significant portion of their exhaust stream. The Southern Company Kemper County Energy Facility will use partial CCS to capture approximately 65 percent of the produced CO₂ for use in nearby EOR operations. The facility is now more than 75 percent complete and is expecting to begin operation in 2014. The Global CCS Institute maintains a database of international CCS projects in various stages of development.¹²

The EPA analysis shows that the costs of partial CCS are comparable to costs of other non-NGCC generation. The EPA projects LCOE generation ranging from \$92/MWh to \$110/MWh, depending upon assumptions about technology choices and the amount, if any, of revenue from sale of CO₂ for EOR. This range compares to leveled costs in a range of \$80/MWh to \$130/MWh for various forms of other non-natural gas-fired electricity generation. When considered against the range of costs that would be incurred by projects deploying non-natural gas-fired electricity generation, the implementation costs of partial CCS are reasonable.

The projects in development for new coal-fired generation are few in number, and most would already meet an emission limit based on implementation of CCS.¹³ As a result, a standard based on partial CCS would not have a significant impact on nationwide energy prices. Moreover, the fact that IGCC developers could meet the requirements of the standard through the use of a conventional turbine (i.e., a syngas turbine, rather than a more advanced hydrogen turbine) reinforces both the technical feasibility and cost basis of today's proposal to determine that CCS with partial capture is the BSER.

Partial CCS designed to meet an emission standard of 1,100 lb CO₂/MWh would also achieve significant emission reductions, emitting on the order of 30 to 50 percent less CO₂ than a coal-fired unit without CCS. Finally, a standard based on partial CCS clearly promotes

implementation and further development of CCS technologies, and does so as much as, and perhaps even more than, a standard based on a full capture CCS requirement would.

After conducting a BSER analysis of the three options described above, the EPA proposes that new fossil fuel-fired utility boilers and IGCC units implementing partial CCS best meets the requirements for BSER. It ensures that any new fossil fuel-fired utility boiler or IGCC unit will achieve meaningful emission reductions in CO₂, and it will also encourage greater use, development, and refinement of CCS technologies. CCS technology has been adequately demonstrated, and its implementation costs are reasonable. Therefore, the EPA is basing the standards for new fossil fuel-fired utility boilers and IGCC units on partial CCS technology operating to a level of 1,100 lb CO₂/MWh.

6. What is BSER for natural gas-fired stationary combustion turbines?

We considered two alternatives in evaluating the BSER for new fossil fuel-fired stationary combustion turbines: (1) modern, efficient NGCC units and (2) modern, efficient NGCC units with CCS.

NGCC units are the most common type of new fossil fuel-fired units being planned and built today. The technology is in wide use. Nearly all new fossil fuel-fired EGUs being constructed today are using this advanced, efficient system for generating intermediate and base load power. Importantly, NGCC is an inherently lower CO₂-emitting technology. Almost every natural gas-fired stationary combined cycle unit built in the U.S. in the last five years emits approximately 50 percent less CO₂ per MWh than a typical new coal-fired plant of the same size. The design is technically feasible, and evidence shows that NGCC units are currently the lowest-cost, most efficient option for new fossil fuel-fired power generation.

By contrast, NGCC with CCS is not a configuration that is being built today. The EPA considered whether NGCC with CCS could be identified as the BSER adequately demonstrated for new stationary combustion turbines, and we decided that it could not. At this time, CCS has not been implemented for NGCC units, and we believe there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units. The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream. This contrasts with coal units where, in addition to demonstration projects,

there are several full-scale projects under construction and a coal gasification plant which has been demonstrating much of the technology needed for an IGCC to capture CO₂ for more than ten years. The EPA is not aware of any demonstrations of NGCC units implementing CCS technology that would justify setting a national standard. Further, the EPA does not have sufficient information on the prospects of transferring the coal-based experience with CCS to NGCC units. In fact, CCS technology has primarily been applied to gas streams that have a relatively high to very high concentration of CO₂ (such as that from a coal combustion or coal gasification unit). The concentration of CO₂ in the flue gas stream of a coal combustion unit is normally about four times higher than the concentration of CO₂ in a natural gas-fired unit. Natural gas-fired stationary combustion turbines also operate differently from coal-fired boilers and IGCC units of similar size. The NGCC units are more easily cycled (i.e., ramped up and down as power demands increase and decrease). Adding CCS to a NGCC may limit the operating flexibility in particular during the frequent start-ups/shut-downs and the rapid load change requirements.¹⁴ This cyclical operation, combined with the already low concentration of CO₂ in the flue gas stream, means that we cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC. This would be true for both partial and full capture.

After considering both technology options, the EPA is proposing to find modern, efficient NGCC technology to be the BSER for stationary combustion turbines, and we are basing the proposed standards on the performance of recently constructed NGCC units. The EPA is proposing that larger units be required to meet a standard of 1,000 lb CO₂/MWh and that smaller units (typically slightly less efficient, as noted in comments on the original proposal) be required to meet a standard of 1,100 lb CO₂/MWh.

7. How is EPA proposing to codify the requirements?

The EPA is considering two options for codifying the requirements. Under the first option EPA is proposing to codify the standards of performance for the respective sources within existing 40 CFR Part 60 subparts. Applicable

¹⁴ "Operating Flexibility of Power Plants with CCS", International Energy Agency (IEAGHG) report 2012/6, June 2012.

¹¹ While this facility is not an EGU, it has significant similarities to a coal gasification combined cycle EGU, and the implementation of the partial CCS technology would be similar enough for comparison.

¹² The Global CCS Institute, <http://www.globalccsinstitute.com/projects/browse>.

¹³ For example, the Hydrogen Energy California facility plans to capture approximately 90 percent of the CO₂ in the emission stream.

GHG standards for electric utility steam generating units would be included in subpart Da and applicable GHG standards for stationary combustion turbines would be included in subpart KKKK. In the second option, the EPA is co-proposing to create a new subpart TTTT (as in the original proposal for this rulemaking) and to include all GHG standards of performance for covered sources in that newly created subpart. Unlike the original proposal, the subpart would contain two different categories, one for utility boilers and IGCC units and one for natural gas-fired stationary combustion turbines.

8. What is the organization and approach for the proposal?

This action presents the EPA’s proposed approach for setting standards of performance for new affected fossil fuel-fired electric utility steam generating units (utility boilers) and stationary combustion turbines. The

rationale for regulating GHG emissions from the utility power sector, including related regulatory and litigation background and relationship to other rulemakings, is presented below in Section II. The specific proposed requirements for new sources are described in detail in Section III. The rationale for reliance on a rational basis to regulate GHG emissions from fossil fuel-fired EGUs is presented in Section IV, followed by the rationale for applicability requirements in Section V. The legal requirements for establishing emission standards are discussed in detail in Section VI. Sections VII and VIII describe the rationale for each of the proposed emission standards, including an explanation of the determination of BSER for new fossil fuel-fired utility boilers and IGCC units and for natural gas-fired stationary combustion turbines, respectively. Implications for Prevention of Significant Deterioration (PSD) and title

V programs are described in Section IX, and impacts of the proposed action are described in Section X. In Section XI, the agency specifically requests comments on the proposal. A discussion of statutory and executive order reviews is provided in Section XII, and the statutory authority for this action is provided in Section XIII. Also published today in the **Federal Register** is the document withdrawing the original April 13, 2012 proposal.

Today’s proposal outlines an approach for setting standards of performance for emissions of carbon dioxide for new affected fossil fuel-fired electric utility steam generating units (utility boilers) and stationary combustion turbines.

C. 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 Affected 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 Includes 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

In this section we discuss climate change impacts from GHG emissions, both on public health and public welfare, and the science behind the agency’s conclusions. We present information about GHG emissions from fossil-fuel fired EGUs, and we describe the utility power sector and its changing structure. We then provide the statutory, regulatory, and litigation background for this proposed rule. We close this section by discussing how this proposed rule

coordinates with other rulemakings and describing actions to obtain stakeholder input on this topic and the original proposed rule.

A. Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the document we refer to as the Endangerment Finding under CAA section 202(a)(1).¹⁵ In the Endangerment Finding, which focused on public health and public welfare impacts within the United States, the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare of current and future generations. We summarize these adverse effects on public health and welfare briefly here and in more detail in the RIA.

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

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Anthropogenic emissions of GHGs and consequent climate change threaten public health in multiple aspects. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also leads to reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality. Climate change is expected to increase ozone pollution over broad areas of the country, including large population areas with already unhealthy surface ozone levels, and thereby increase morbidity and mortality. Other 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. Increased coastal storms and storm surges due to rising sea levels are expected to cause increased drownings and other health

impacts. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Anthropogenic emissions of GHGs and consequent climate change also threaten public welfare in multiple aspects. Climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face increased risks from storm and flooding damage to property, as well as adverse impacts from rising sea level, 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 extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Climate change also is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. The Science Upon Which the Agency Relies

The EPA received comments in response to the April 2012 proposed NSPS rule (77 FR 22392) that addressed the scientific underpinnings of the EPA's 2009 Endangerment Finding and hence the proposed rule. The EPA carefully reviewed all of those comments. It is important to place these comments in the context of the history and associated voluminous record on this subject that has been compiled over the last few years, including: (1) the process by which the Administrator reached the Endangerment Finding in 2009; (2) the EPA's response in 2010 to ten administrative petitions for reconsideration of the Endangerment Finding (the Reconsideration Denial)¹⁶;

¹⁶ EPA's Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute

and (3) the decision by the United States Court of Appeals for the District of Columbia Circuit (the D.C. Circuit or the Court) in 2012 to uphold the Endangerment Finding and the Reconsideration Denial.^{17 18}

As outlined in Section VIII.A. of the 2009 Endangerment Finding, the EPA's approach to providing the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare was to rely primarily upon the recent, major assessments by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies. These assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review. The EPA received thousands of comments on the proposed Endangerment Finding and responded to them in depth in an 11-volume Response to Comments (RTC) document.¹⁹ While the EPA gave careful consideration to all of the scientific and technical information received, the agency placed less weight on the much smaller number of individual studies that were not considered or reflected in the major assessments; often these studies were published after the submission deadline for those larger assessments. Primary reliance on the major scientific assessments provided the EPA greater assurance that it was basing its judgment on the best available, well-vetted science that reflected the consensus of the climate science community. The EPA reviewed individual studies not incorporated in the assessment literature largely to see if they would lead the EPA to change its interpretation of, or place less weight on, the major findings reflected in the assessment reports. From its review of

Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 75 FR 49557 (Aug. 13, 2010) ("Reconsideration Denial").

¹⁷ Coalition for Responsible Regulation, Inc. v. Environmental Protection Agency (CRR), 684 F.3d at 102 (D.C. Cir.), reh'g en banc denied, 2012 U.S. App. LEXIS 25997, 26313 (D.C. Cir. 2012), petitions for cert. filed, No. 12-1253 (U.S. Apr. 2013).

¹⁸ We discuss litigation history involving this rulemaking in more detail later in this section.

¹⁹ "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act: EPA's Response to Public Comments," <http://www.epa.gov/climatechange/endangerment/#comments> ("Response to Comments" or "RTC").

individual studies submitted by commenters, the EPA concluded that these studies did not change the various conclusions and judgments the EPA drew from the more comprehensive assessment reports. The major findings of the USGCRP, IPCC, and NRC assessments supported the EPA's determination that GHGs threaten the public health and welfare of current and future generations. The EPA presented this scientific support at length in the Endangerment Finding, in its Technical Support Document (which summarized the findings of USGCRP, IPCC and NRC)²⁰ and in the RTC.

The EPA then reviewed ten administrative petitions for reconsideration of the Endangerment Finding in 2010. In the Reconsideration Denial, the Administrator denied those petitions on the basis that the Petitioners failed to provide substantial support for the argument that the EPA should revise the Endangerment Finding and therefore their objections were not of "central relevance" to the Finding. The EPA prepared an accompanying three-volume Response to Petitions (RTP) document to provide additional information, often more technical in nature, in response to the arguments, claims, and assertions by the petitioners to reconsider the Endangerment Finding.²¹

The 2009 Endangerment Finding and the 2010 Reconsideration Denial were challenged in a lawsuit before the D.C. Circuit. On June 26, 2012, the Court upheld the Endangerment Finding and the Reconsideration Denial, ruling that the Finding (including the Reconsideration Denial) was not arbitrary or capricious, was consistent with the U.S. Supreme Court's decision in *Massachusetts v. EPA*, which granted to the EPA the authority to regulate GHGs,²² and was adequately supported by the administrative record.²³ The Court found that the EPA had based its decision on "substantial scientific evidence" and noted that the EPA's reliance on assessments was consistent with the methods decision-makers often use to make a science-based judgment.²⁴ The Court also agreed with the EPA that the Petitioners had "not provided substantial support for their argument

²⁰ "Technical Support Document for Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(s) of the Clean Air Act (Dec. 7, 2009), http://www.epa.gov/climatechange/Downloads/endangerment/Endangerment_TSD.pdf (TSD).

²¹ <http://www.epa.gov/climatechange/endangerment/petitions.html>.

²² 549 U.S. 497 (2007).

²³ CRR, 684 F.3d at 117-27.

²⁴ *Id.* at 121.

that the Endangerment Finding should be revised.”²⁵ Moreover, the Court supported the EPA’s reliance on the major scientific assessment reports conducted by USGCRP, IPCC, and NRC and found that:

The EPA evaluated the processes used to develop the various assessment reports, reviewed their contents, and considered the depth of the scientific consensus the reports represented. Based on these evaluations, the EPA determined the assessments represented the best source material to use in deciding whether GHG emissions may be reasonably anticipated to endanger public health or welfare.²⁶

As the Court stated—

It makes no difference that much of the scientific evidence in large part consisted of ‘syntheses’ of individual studies and research. Even individual studies and research papers often synthesize past work in an area and then build upon it. This is how science works. The EPA is not required to reprove the existence of the atom every time it approaches a scientific question.²⁷

In the context of this extensive record and the recent affirmation of the Endangerment Finding by the Court, the EPA considered all of the submitted comments and reports for the April 2012 proposed NSPS rule. As it did in the Endangerment Finding, the EPA gave careful consideration to all of the scientific and technical comments and information in the record. The major peer-reviewed scientific assessments, however, continue to be the primary scientific and technical basis for the Administrator’s judgment regarding the threats to public health and welfare posed by GHGs.

Commenters submitted two major peer-reviewed scientific assessments released after the administrative record concerning the Endangerment Finding closed following the EPA’s 2010 Reconsideration Denial: the IPCC’s 2012 “Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation” (SREX) and the NRC’s 2011 “Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia” (Climate Stabilization Targets).

According to the IPCC in the SREX, “A changing climate leads to changes in the frequency, intensity, spatial extent, duration, and timing of extreme weather and climate events, and can result in unprecedented extreme weather and climate events.”²⁸ The SREX documents observational evidence of changes in

some weather and climate extremes that have occurred globally since 1950. The assessment also provides evidence regarding the cause of some of these changes to elevated concentrations of GHGs, including warming of extreme daily temperatures, intensified extreme precipitation events, and increases in extreme coastal high water levels due to rising sea level. The SREX projects further increases in some extreme weather and climate events during the 21st century. Combined with increasing vulnerability and exposure of populations and assets, changes in extreme weather and climate events have consequences for disaster risk, with particular impacts on the water, agriculture and food security and health sectors.

In the Climate Stabilization Targets assessment, the NRC states:

Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth’s climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe.²⁹

The assessment concludes that carbon dioxide emissions will alter the atmosphere’s composition and therefore the climate for thousands of years; and attempts to quantify the results of stabilizing GHG concentrations at different levels. The report also projects the occurrence of several specific climate change impacts, finding warming could lead to increases in heavy rainfall and decreases in crop yields and Arctic sea ice extent, along with other significant changes in precipitation and stream flow. For an increase in global average temperature of 1 to 2 °C above pre-industrial levels, the assessment found that the area burnt by wildfires in western North America will likely more than double and coral bleaching and erosion will increase due both to warming and ocean acidification. An increase of 3 °C will lead to a sea level rise of 0.5 to 1 meter by 2100. With an increase of 4 °C, the average summer in the United States would be as warm as the warmest summers of the past century. The assessment notes that although many important aspects of climate change are difficult to quantify, the risk of adverse impacts is likely to increase with increasing temperature, and the risk of surprises can be expected to increase with the duration and magnitude of the warming.

Several other National Academy assessments regarding climate have also

been released recently. The EPA has reviewed these assessments and finds that in general, the improved understanding of the climate system they and the two assessments described above present strengthens the case that GHGs are endangering public health and welfare. Three of the new NRC assessments provide estimates of projected global sea level rise that are larger than, and in some cases more than twice as large as, the rise estimated in a 2007 IPCC assessment of between 0.18 and 0.59 meters by the end of the century, relative to 1990. (It should be noted that in 2007, the IPCC stated that including poorly understood ice sheet processes could lead to an increase in the projections.)³⁰ While these three NRC assessments continue to recognize and characterize the uncertainty inherent in accounting for ice sheet processes, these revised estimates strongly support and strengthen the existing finding that GHGs are reasonably anticipated to endanger public health and welfare. Other key findings of the recent assessments are described briefly below:

One of these assessments projects a global sea level rise of 0.5 to 1.4 meters by 2100, which is sufficient to lead to rising relative sea level even in the northern states.³¹ Another assessment considers potential impacts of sea level rise and suggests that “the Department of the Navy should expect roughly 0.4 to 2 meters global average sea-level rise by 2100.”³² This assessment also recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats. A third NRC assessment found that it would be “prudent for security analysts to expect climate surprises in the coming decade . . . and for them to become progressively more serious and more frequent thereafter[.]”³³

Another NRC assessment finds that “the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in

³⁰ Climate Stabilization Targets; “National Security Implications for U.S. Naval Forces” (2011) (National Security Implications); “Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future” (2012) (Sea Level Rise).

³¹ Sea Level Rise, p. 4.

³² National Security Implications, p. 9.

³³ “Climate and Social Stress: Implications for Security Analysis” (2012), p.3.

²⁵ *Id.* at 125.

²⁶ *Id.* at 120.

²⁷ *Id.* at 120.

²⁸ SREX, p. 7.

²⁹ Climate Stabilization Targets, p. 3.

Earth history.”³⁴ This assessment finds that CO₂ concentrations by the end of the century, without a reduction in emissions, are projected to increase to levels that Earth has not experienced for more than 30 million years.³⁵ The report draws potential parallels with non-linear events such as the Paleo-Eocene Thermal Maximum, a rapid global warming event about 55 million years ago associated with mass extinctions and other disruptions. The assessment notes that acidification and warming caused by GHG increases similar to the changes expected over the next hundred years likely caused up to four of the five major coral reef crises of the past 500 million years.

Similarly, another NRC assessment finds that “[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years.”³⁶ The assessment notes that the full range of consequences is still unknown, but the risks “threaten coral reefs, fisheries, protected species, and other natural resources of value to society.”³⁷

Comments were submitted in support of the Endangerment Finding, which provided additional documentation showing that climate change is a threat to public health and welfare. Commenters provided several individual studies and documentation of observed or projected climate changes of local importance or concern to commenters. The EPA appreciates these comments, but as previously stated, we place lesser weight on individual studies than on major scientific assessments. Local observed changes must be assessed in the context of the broader scientific picture, as it is more difficult to draw robust conclusions regarding climate change over short time scales and in small geographic regions.

The EPA plans to continue relying on the major assessments by the USGCRP, the IPCC, and the NRC. Studies from these bodies address the scientific issues that the Administrator must examine, represent the current state of knowledge on the key elements for the endangerment analysis, comprehensively cover and synthesize thousands of individual studies to obtain the majority conclusions from the

body of scientific literature and undergo a rigorous and exacting standard of review by the peer expert community and U.S. government.

Several commenters argued that the Endangerment Finding should be reconsidered or overturned based on those commenters’ reviews of specific climate science literature, including publications that have appeared since the EPA’s 2010 Reconsideration Denial. Some commenters presented their own compilations of individual studies and other documents to support their assertions that climate change will have beneficial effects in many cases and that climate impacts will not be as severe or adverse as the EPA, and the assessment reports upon which the EPA relied, have stated. Some commenters also concluded that U.S. society will easily adapt to climate change and that it therefore does not threaten public health and welfare, and some commenters questioned the Endangerment Finding based on a 2011 EPA Inspector General’s report.

The EPA reviewed the submitted information and found that overall, the commenters’ critiques of the rule’s scientific basis were addressed in the EPA’s response to comments for the 2009 Endangerment Finding, the EPA’s responses in the 2010 Reconsideration Denial, or the D.C. Circuit’s 2012 decision upholding the EPA’s 2009 Endangerment Finding. The EPA nonetheless carefully reviewed these comments and associated documents and found that nothing in them would change the conclusions reached in the Endangerment Finding. These recent publications submitted by commenters, and any new issues they may present, do not undermine either the significant body of scientific evidence that has accumulated over the years or the conclusions presented in the substantial peer-reviewed assessments of the USGCRP, NRC, and IPCC.

One commenter submitted emails between climate change researchers from the period 1999 to 2009 that were surreptitiously obtained from a University of East Anglia server in 2009 and publicly released in 2011. According to the commenter, these emails showed that the climatologists distorted their research results to prove that climate change causes adverse effects. The EPA reviewed these emails and found that they raised no issues that Petitioners had not already raised concerning other emails from the same incident, released in 2009. The commenter’s unsubstantiated assumptions and subjective assertions regarding what the emails purport to show about the state of climate change

science is not adequate evidence to challenge the voluminous and well-documented body of science that underpins the Administrator’s Endangerment Finding.

Some commenters argued for reconsideration based on uncertainty regarding climate science. However, the EPA made the decision to find endangerment with full and explicit recognition of the uncertainty involved, stating that “[t]he Administrator acknowledges that some aspects of climate change science and the projected impacts are more certain than others.”³⁸ The D.C. Circuit subsequently noted that “the existence of some uncertainty does not, without more, warrant invalidation of an endangerment finding.”³⁹

Some commenters also argued that the U.S. will adapt to climate change impacts and that therefore climate change impacts pose no threat. However, the D.C. Circuit, in *CRR*, held that considerations of adaption are irrelevant to the Endangerment determination. The Court stated, “These contentions are foreclosed by the language of the statute and the Supreme Court’s decision in *Massachusetts v. EPA*” because “predicting society’s adaptive response to the dangers or harms caused by climate change” does not inform the “scientific judgment” that the EPA is required to make regarding an Endangerment Finding.⁴⁰

Some commenters raised issues regarding the EPA Inspector General’s report, *Procedural Review of EPA’s Greenhouse Gases Endangerment Finding Data Quality Processes*.⁴¹ These commenters mischaracterized the report’s scope and conclusions and thus overstated the significance of the Inspector General’s procedural recommendations. Nothing in the Inspector General’s report questions the scientific validity of the Endangerment Finding, because that report did not evaluate the scientific basis of the Endangerment Finding. Rather, the Inspector General offers recommendations for clarifying and standardizing internal procedures for documenting data quality and peer

³⁸ 74 FR 66524.

³⁹ *CRR*, 684 F.3d at 121.

⁴⁰ *Id.* at 117. The EPA took a similar position in the Endangerment Finding, in which we responded to similar comments regarding society’s ability to adapt to climate change by stating: “Risk reduction through adaptation and GHG mitigation measures is of course a strong focal area of scientists and policy makers, including the EPA; however, the EPA considers adaptation and mitigation to be potential responses to endangerment, and as such has determined that they are outside the scope of the endangerment analysis.” 74 FR 66512.

⁴¹ Report No. 11–P–0702 (September 26, 2011).

³⁴ “Understanding Earth’s Deep Past: Lessons for Our Climate Future” (2011), p.138.

³⁵ *Ibid.*, p. 1.

³⁶ “Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean” (2010), p. 5.

³⁷ *Id.*

review processes when referencing existing peer reviewed science in the EPA actions.⁴²

In addition, some commenters argued that the Endangerment Finding should be overturned because of the carbon dioxide fertilization effect, that is, the proposition that increased amounts of carbon dioxide can spur growth of vegetation. However, these commenters did not show how the science they provide on the subject differs from the carbon dioxide fertilization science already considered by the Administrator in the Endangerment Finding or how the existence of some benefits from the carbon dioxide fertilization effect could outweigh the numerous negative impacts of climate change.

In sum, the EPA reviewed all of the comments purporting to refute the Endangerment Finding to determine whether they provide evidence that the Administrator’s judgment that climate change endangers public health and

welfare was flawed, because the Administrator misinterpreted the underlying assessments, because the science in new peer reviewed assessments differs from that in previous assessments, or because new individual studies provide compelling reasons for the EPA to change its interpretation of, or place less weight on, the major findings reflected in the assessment reports. In all cases, the commenters failed to demonstrate that the science that the Administrator relied on was inaccurate or that the additional information from the commenter is of central relevance to the Administrator’s judgment regarding endangerment. For these reasons, the commenters on the original proposal that criticized the Endangerment Finding have not provided a sufficient basis to cast doubt on the Finding.

B. GHG Emissions From Fossil Fuel-Fired EGUs

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., and among fossil fuel-fired units, coal-fired units are by far the largest emitters. This section describes the amounts of those emissions and places those amounts in the context of the national inventory of GHGs.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks⁴³ (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides the information in Table 2 below, which presents total U.S. anthropogenic emissions and sinks of GHGs, including CO₂ emissions, for the years 1990, 2005 and 2011.⁴⁴

TABLE 2—U.S. GHG EMISSIONS AND SINKS BY SECTOR (TERAGRAM CARBON DIOXIDE EQUIVALENT (Tg CO₂ Eq.))⁴⁵

Sector	1990	2005	2011
Energy	5,267.3	6,251.6	5,745.7
Industrial Processes	316.1	330.8	326.5
Solvent and Other Product Use	4.4	4.4	4.4
Agriculture	413.9	446.2	461.5
Land Use, Land-Use Change and Forestry	13.7	25.4	36.6
Waste	167.8	136.9	127.7
Total Emissions	6,183.3	7,195.3	6,702.3
Land Use, Land-Use Change and Forestry (Sinks)	(794.5)	(997.8)	(905.0)
Net Emissions (Sources and Sinks)	5,388.7	6,197.4	5,797.3

Total fossil energy-related CO₂ emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 78.7 percent of total 2011

GHG emissions. In 2011, fossil fuel combustion by the electric power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for

39.6 percent of all energy-related CO₂ emissions. Table 3 below presents total CO₂ emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2011.⁴⁶

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

GHG Emissions	1990	2005	2011
Total CO ₂ from fossil fuel combustion EGUs	1,820.8	2,402.1	2,158.5
—from coal	1,547.6	1,983.8	1,722.7
—from natural gas	175.3	318.8	408.8
—from petroleum	97.5	99.2	26.6

⁴² Unrelated to the Endangerment Finding and its validation by the Court, the EPA has made progress towards implementing the recommendations from the Inspector General.

⁴³ “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011”, Report EPA 430–R–13–001, United States Environmental Protection Agency, April 15, 2013.

⁴⁴ Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.

⁴⁵ From Table 2–3 of “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011”, April 15, 2013, EPA 430–R–13–001.

⁴⁶ Note that for the purposes of reporting national GHG emissions under the UNFCCC, the U.S. GHG Inventory is calculated using internationally accepted methodological guidance from the Intergovernmental Panel on Climate Change (IPCC). In accordance with IPCC guidance, CO₂ emissions from combustion of biogenic feedstocks are not reported in the energy sector, but are instead reported separately as a “Memo item” in the U.S. GHG Inventory. Consistent with the IPCC guidance,

any carbon stock changes related to the use of biogenic feedstocks in the energy sector, and the CO₂ emissions associated with those carbon stock changes, are accounted for under the forestry and/or agricultural sectors of the U.S. GHG Inventory. Attribution of CO₂ emissions from the combustion of biogenic feedstocks by stationary sources in the energy sector to the forestry and/or agricultural sectors, in the context of U.S. GHG emissions reporting to the UNFCCC, should not be interpreted as an indication that such emissions are “carbon neutral.”

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. The estimated emissions for N₂O and CH₄ from fossil fuel-fired EGUs are about 17.9 and 0.4 Tg of CO₂ equivalent in 2011, respectively, which is about 0.8 percent of total CO₂ equivalent emissions from fossil fuel-fired electric power generating units. However, we are not proposing separate N₂O or CH₄ emission limits or an equivalent CO₂ emission limit in today's document because we lack more precise data on the quantity of these emissions and information on cost-effective controls. We request comment on this approach and we solicit information about the quantity of N₂O and CH₄ emissions from these affected sources and possible controls.

C. The Utility Power Sector and How Its Structure Is Changing

1. Utility Power Sector

The majority of power in the U.S. is generated from the combustion of coal, natural gas and other fossil fuels.

Natural gas-fired EGUs typically use one of two technologies: NGCC and simple cycle combustion turbines. NGCC units first generate power from a combustion turbine (the combustion cycle). The unused heat from the combustion turbine is then routed to a Heat Recovery Steam Generator (HRSG) which generates steam which is used to generate power using a steam turbine (the steam cycle). The combining of these generation cycles increases the overall efficiency of the system.

Simple cycle combustion turbines only use a single combustion turbine to produce electricity (i.e., there is no heat recovery). The power output from these simple cycle combustion turbines can be easily ramped up and down making them ideal for "peaking" operations.

Coal-fired utility boilers are primarily either pulverized coal (PC) boilers or fluidized bed (FB) boilers. At a PC boiler, the coal is crushed (pulverized) into a powder in order to increase its surface area. The coal powder is then blown into a boiler and burned. In a coal-fired boiler using fluidized bed combustion, the coal is burned in a layer of heated particles suspended in flowing air.

Power can also be generated using gasification technology. An IGCC unit gasifies coal to form a syngas composed

of carbon monoxide (CO) and hydrogen (H₂), which can be combusted in a combined cycle system to generate power.

2. Changing Structure of the Power Sector

a. Technological Developments and Costs

Since the April 2012 proposal, a few coal-fired units have reached the advanced stages of construction and development, which suggests that setting a separate standard for new fossil fuel-fired boilers and IGCC units is appropriate. Progress on Southern Company's Kemper County Energy Facility, which will deploy IGCC with partial CCS, has continued, and the project is now over 75 percent complete. Additionally, two other projects, Summit Power's Texas Clean Energy Project (TCEP) and the Hydrogen Energy California Project (HECA)—both of which will deploy IGCC with CCS—continue to move forward. The EIA modeling projects that coal-fired power generation will remain the single largest portion of the electricity sector beyond 2030. The EIA modeling also projects that few, if any, new coal-fired EGUs would be built in this decade and that those that are built would have CCS.⁴⁷ Continued progress on these projects is consistent with the EIA modeling that suggests that a small number of coal-fired power plants may be constructed. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand, and increases in the supply of renewable energy.

Natural gas prices have decreased dramatically and generally stabilized in recent years, as new drilling techniques have brought additional supply to the marketplace and greatly increased the domestic resource base. As a result, natural gas prices are expected to be competitive for the foreseeable future and EIA modeling and utility announcements confirm that utilities are likely to rely heavily on natural gas to meet new demand for electricity generation. On average, as discussed below, the cost of generation from a new natural-gas fired power plant (a NGCC unit) is expected to be significantly

⁴⁷ Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations.

lower than the cost of generation from a new coal-fired power plant.⁴⁸

Other drivers that may influence decisions to build new power plants are increases in renewable energy supplies, often due to state and federal energy policies. Many states have adopted renewable portfolio standards (RPS), which require a certain portion of electricity to come from renewable energy sources such as 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.

Due to these factors, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2020, along with renewable energy, nuclear power, and a limited amount of coal with CCS.⁴⁹

b. Energy Sector Modeling

Various energy sector modeling efforts, including projections from the EIA and the EPA, forecast trends in new power plant construction and utilization of existing power plants that are consistent with the above-described technological developments and costs. The EIA forecasts the structure and developments in the power sector in its annual report, the Annual Energy Outlook (AEO). These reports are based on economic modeling that reflects existing policy and regulations, such as state RPS programs and federal tax credits for renewables.⁵⁰ The current report, AEO 2013,⁵¹ (i) shows that a modest amount of coal-fired power plants that are currently under construction are expected to begin operation in the next several years (referred to as "planned"); and (ii) projects in the reference case,⁵² that a very small amount of new ("unplanned") conventional coal-fired capacity, with CCS, will come online after 2012, and through 2034 in response to Federal and State incentives. According to the AEO 2013,

⁴⁸ Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011 http://www.eia.gov/forecasts/aeo/electricity_generation.html.

⁴⁹ [http://www.eia.gov/forecasts/aeo/pdf/0383\(2013\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf); [http://www.eia.gov/forecasts/aeo/pdf/0383\(2012\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf); <http://prod-http-80-800498448.us-east-1.elb.amazonaws.com/w/images/6/6d/0383%282011%29.pdf>.

⁵⁰ http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm.

⁵¹ Energy Information Administration's Annual Energy Outlook for 2013, Final Release available at <http://www.eia.gov/forecasts/aeo/index.cfm>.

⁵² EIA's reference case projections are the result of its baseline assumptions for economic growth, fuel supply, technology, and other key inputs.

the vast majority of new generating capacity during this period will be either natural gas-fired or renewable. Similarly, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2020.⁵³

Specifically, the AEO 2013 projects the need for 25.9 GW of additional base load or intermediate load generation capacity through 2020 (this includes projects that are under development—i.e., being constructed or in advance planning—and model-projected nuclear, coal, and NGCC projects). The vast majority of this new electric capacity (22.5 GW) is already under development (under construction or in advanced planning); it includes about 6.1 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 10.9 GW of new NGCC capacity. The EPA believes that most current fossil fuel-fired projects are already designed to meet limits consistent with today's proposal (or they have already commenced construction and are thus not impacted by today's notice). The AEO 2013 also projects an additional 3.4 GW of new base load capacity additions, which are model-projected (unplanned). This consists of 3.1 GW of new NGCC capacity, and 0.3 GW of new coal equipped with CCS (incentivized with some government funding). Therefore, the AEO 2013 projection suggests that this proposal would only impact small amounts of new power generating capacity through 2020, all of which is expected to already meet the proposed emissions standards without incurring further control costs. In AEO 2013, this is also true during the period from 2020 through 2034, where new model-projected (unplanned) intermediate and base load capacity is expected to be compliant with the proposed standard without incurring further control costs (i.e., an additional 45.1 GW of NGCC and no additional coal, for a total, from 2013 through 2030, of 48.2 GW of NGCC and 0.3 GW of coal with CCS).

It should be noted that under the EIA projections, existing coal-fired generation will remain an important part of the mix for power generation. Modeling from both the EIA and the EPA predict that coal-fired generation will remain the largest single source of electricity in the U.S. through 2040. Specifically, in the EIA's AEO 2013, coal will supply approximately 40 percent of all electricity in both 2020 and 2025.

The EPA modeling using the Integrated Planning Model (IPM), a detailed power sector model that the EPA uses to support power sector regulations, also shows limited future construction of new coal-fired power plants under the base case.⁵⁴ The EPA's projections from IPM can be found in the RIA.

c. Integrated Resource Plans

The trends in the power sector described above are also apparent in publicly available long-term resource plans, known as IRPs.

The EPA has reviewed publicly available IRPs from a range of companies (e.g., varying in size, location, current fuel mix), and these plans are generally consistent with both EIA and EPA modeling projections. Companies seem focused on demand-side management programs to lower future electricity demand and mostly reliant on a mix of new natural gas-fired generation and renewable energy to meet increased load demand and to replace retired generation capacity.

Notwithstanding this clear trend towards natural gas-fired generation and renewables, many of the IRPs raise fuel diversity concerns and include options to diversify new generation capacity beyond natural gas and renewable energy. Several IRPs indicate that companies are considering new nuclear generation, including either traditional nuclear power plants or small modular reactors, and new coal-fired generation capacity with and without CCS technology. Based on these IRPs, the EPA acknowledges that a small number of new coal-fired power plants may be built in the near future. While this is contrary to the economic modeling predictions, the Agency understands that economic modeling may not fully reflect the range of factors that a particular company may consider when evaluating new generation options, such as fuel diversification. By the same token, as discussed below, it is possible that some of this potential new coal-fired construction may occur because developers are able to design projects that can provide competitively priced electricity for a specific geographic region.

D. Statutory Background

Section 111 of the Clean Air Act sets forth the standards of performance for new sources (NSPS) program, and with this program, establishes mechanisms for regulating emissions of air pollutants from stationary sources that are key in

this rulemaking.⁵⁵ As a preliminary step to regulation, the EPA must 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."

Once the EPA has listed a source category, the EPA proposes and then promulgates "standards of performance" for "new sources" in the category.⁵⁶ A "new source" is "any stationary source, the construction or modification of which is commenced after," in general, the date of the proposal.⁵⁷ A modification is "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."⁵⁸ The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.⁵⁹ The EPA's regulations also provide that an existing facility is also considered a new source if it undertakes a "reconstruction," which is the replacement of 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.⁶⁰ In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class or size.⁶¹

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.

This definition makes clear that the standard of performance must be based on controls that constitute "the best system of emission reduction . . . adequately demonstrated" (BSER).⁶²

⁵⁵ CAA section 111(b)(1)(A). The EPA has regulated more than 60 stationary source categories under CAA section 111. See generally 40 CFR subparts D–MMMM.

⁵⁶ CAA section 111(b)(1)(B).

⁵⁷ CAA section 111(a)(2).

⁵⁸ CAA section 111(a)(4).

⁵⁹ 40 CFR 60.2, 60.14(e).

⁶⁰ 40 CFR 60.15.

⁶¹ CAA section 111(b)(2).

⁶² As noted, we generally refer to this system of control as the best system of emission reduction, or

⁵³ Annual Energy Outlook 2010, 2011, 2012, and 2013.

⁵⁴ <http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation>.

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 generally can select any measure or combination of measures that will achieve the emissions level of the standard.

Regarding other titles in the CAA, this rulemaking has implications for EGUs and other stationary sources in the CAA PSD program under Title I, part C, and the operating permits program under Title V. We discuss these implications in section IX of this preamble.

E. Regulatory and Litigation Background

The EPA initially included fossil fuel-fired EGUs (which includes EGUs that burn fossil fuel including coal, gas, oil and petroleum coke and that use different technologies, including boilers and combustion turbines) in a category that it listed under section 111(b)(1)(A), and the EPA promulgated the first set of standards of performance for EGUs in 1971, codified in subpart D.⁶³ As discussed in Section IV.D. of this preamble, the EPA has revised those regulations, and in some instances, revised the subparts, several times over the ensuing decades. None of these rulemakings or codifications, however, have constituted a new listing under CAA section 111(b)(1)(A).

In 1979, the EPA revised subpart D of 40 CFR part 60; as part of this revision, the EPA formed subpart Da and promulgated NSPS for electric utility steam generating units.⁶⁴ These NSPS on June 11, 1979 apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS for EGUs also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system.

The EPA promulgated amendments to subpart Da in 2006, resulting in new

criteria pollutant limitations for EGUs (the 2006 Final Rule).⁶⁵ The 2006 Final Rule did not establish standards of performance for GHG emissions. Two groups of petitioners—13 governmental entities and three environmental groups—filed petitions for judicial review of this rule by the D.C. Circuit.⁶⁶ These petitioners contended, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.

The Court severed portions of the petitions for review of the 2006 Final Rule that related to GHG emissions. Following the U.S. Supreme Court's 2007 decision in *Massachusetts v. EPA*, which gave authority to the EPA to regulate GHGs, the D.C. Circuit remanded the 2006 Final Rule to the EPA upon its own motion for further consideration of the issues related to GHG emissions in light of *Massachusetts*. The EPA did not act on that remand. Rather, these 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 provided for a notice-and-comment opportunity on the proposed settlement agreement and, after reviewing the comments received, finalized the agreement in late 2010.

In June 2012, the D.C. Circuit, in *Coalition for Responsible Regulation v. EPA*, upheld the EPA's Endangerment Finding concerning GHGs and the EPA's companion finding that GHGs from motor vehicles contribute to the air pollution that endangers public health and welfare.⁶⁷ The Court also upheld standards for motor vehicles that

limited GHG emissions.⁶⁸ In addition, the Court affirmed the EPA's view that the CAA PSD and title V permitting requirements became applicable to GHG-emitting stationary sources when the EPA regulated GHG emissions from motor vehicles, because PSD and title V are automatically applicable to a pollutant when that pollutant is regulated under any part of the Act. The Court also dismissed challenges to what we refer to as the Timing Decision,⁶⁹ which established the January 2, 2011 date when the PSD and title V permitting requirements applied to GHG-emitting stationary sources; and the Tailoring Rule,⁷⁰ which is the EPA's common sense approach to phasing in GHG permitting requirements to avoid an initial increase in the number of PSD and title V permit applications that would overwhelm the permitting authorities' administrative capacities.

In June 2012, several companies filed petitions for review of the original proposal for this rulemaking action in the D.C. Circuit. In December 2012, the D.C. Circuit dismissed these petitions on grounds that the challenged proposed rule is not final agency action subject to judicial review.⁷¹

In April 2013, EPA completed rulemaking to regulate power plants in the Mercury and Air Toxics rule ("MATS").⁷² In this same rulemaking, EPA promulgated revised standards of performance under CAA section 111(b) for criteria pollutant emissions from EGUs.

F. Coordination With Other Rulemakings

EGUs are the subject of several recent CAA rulemakings.⁷³ In general, most EPA rulemakings affecting the power sector focus on existing sources.

⁶⁸ "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule." 75 FR 25324 (May 7, 2010).

⁶⁹ "Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs." 75 FR 17004 (April 2, 2010).

⁷⁰ "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule." 75 FR 31514 (June 3, 2010).

⁷¹ *Las Brisas Energy Center, LLC v. Environmental Protection Agency*, No. 12-1248, 2012 U.S. App. LEXIS 25535 (D.C. Cir. Dec. 13, 2012).

⁷² "Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, Final Rulemaking," 78 FR 24073 (April 24, 2013).

⁷³ We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

BSER, but we may occasionally refer to it as the "best demonstrated system." In the past, this level of control was frequently referred to as the "best demonstrated technology" (BDT).

⁶³ "Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971," 36 FR 24875 (Dec. 23, 1971) codified at 40 CFR 60.40-46; 36 FR 5931 (Mar. 31, 1971).

⁶⁴ "Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978," 44 FR 33580 (June 11, 1979)

⁶⁵ "Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units, Final Rule." 71 FR 9866 (Feb. 27, 2006).

⁶⁶ *State of New York, et al. v. EPA, No. 06-1322*. 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").

⁶⁷ *CRR*, 684 F.3d at 102.

Therefore, few interactions are likely between other power sector rules and this rule, which focuses only on new sources.⁷⁴

We note that the EPA recently finalized revisions to the MATS rule as related to new sources.⁷⁵ The revised MATS new source emission standards for air toxics and new source performance standards for criteria pollutants, coupled with GHG performance standards in this proposed rule, provide a clear regulatory structure for new fossil fuel-fired generation.

The EPA recognizes that it is important that each of these regulatory efforts achieves its intended environmental objectives in a common-sense, cost-effective manner consistent with the underlying statutory requirements and assures a reliable power system. Executive Order (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 Management and Budget’s Office of Information and Regulatory Affairs has emphasized the importance of, where appropriate and feasible, the consideration of cumulative effects in regulated industries and the harmonization of rules in terms of both content and timing. We believe that these recent finalized and proposed rules will allow industry to comply with its obligations as efficiently as possible, by making coordinated investment decisions and, to the greatest extent possible, adopting integrated compliance strategies.

G. Stakeholder Input

The EPA has extensively interacted with many different stakeholders regarding climate change, source contributions, and emission reduction opportunities. These stakeholders included industry entities, environmental organizations and many regional, state, and local air quality management agencies, as well as the general public. As part of developing the original 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; these were 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 roundtable discussion among stakeholder representatives. The EPA asked key stakeholder groups to identify these roundtable 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.⁷⁶

On May 3, 2012, the EPA announced that it would hold two public hearings on the original proposed rule. The hearings were both held on May 24, 2012, in Washington, DC and Chicago, IL. Also on May 3, 2012, the EPA announced an extension of the public comment period for the original proposed rule, until June 25, 2012. The EPA received more than 2.5 million public comments on the original proposed rule.⁷⁷ While the Agency is not preparing a RTC document responding to the comments it received as part of that process, the EPA has taken into consideration those comments, as well as information received in the listening sessions, in developing this new proposal.

III. Proposed Requirements for New Sources

This section describes the proposed requirements in this rulemaking for new sources. We describe our rationale for several of these proposed requirements—the applicability requirements, the basis for the standards of performance for fossil-fuel fired boilers, and the basis for the standards of performance for combustion turbines—in Sections V–VIII of this preamble.

A. Applicability Requirements

We generally refer to sources that would be subject to the standards of performance in this rulemaking as “affected” or “covered” sources, units, facilities, or simply as EGUs. These sources meet both the definition of “affected” and “covered” EGUs subject to an emission standard as provided by this rule, and the requirements for “new” sources as defined under the provisions of CAA section 111.

⁷⁶ Comments related to the listening sessions submitted via the electronic docket system are available at www.regulations.gov (docket number EPA-HQ-OAR-2011-0090).

⁷⁷ Those comments are available at www.regulations.gov (docket number EPA-HQ-OAR-2011-0660).

1. Covered EGUs, Generally

Subpart Da currently defines an EGU as a boiler that is: (1) “capable of combusting” more than 250 MMBtu/h heat input of fossil fuel,⁷⁸ (2) “constructed for the purpose of supplying more than one-third of its potential net- electric output capacity . . . to any utility power distribution system for sale”⁷⁹ (that is, to the grid), and (3) “constructed for the purpose of supplying . . . more than 25 MW net- electric output” to the grid.⁸⁰ We are proposing to define an EGU slightly differently than it is currently defined in subpart Da or in the original proposal for this rulemaking. First, we are proposing to add additional criteria to be met in addition to the “constructed for the purpose of supplying more than one-third of its potential electric output capacity” to the grid. One new criterion would be that a unit actually “supplies more than one-third of its potential electric output” to the grid. Both criteria would also be used in subparts KKKK and TTTT. Combined with the three year rolling average methodology to determine if the one-third criteria is met (as explained further below), this approach makes it clear that a unit that was not originally constructed to supply more than one-third of its potential electric output to the grid, but does so for one year does not automatically become affected. The EPA believes that coal-fired utility boilers, IGCCs and large NGCC units are constructed with the purpose of supplying more than one-third of their potential electric output to the grid, and, except in rare cases (such as very extended outages), usually do. Small NGCC units and simple cycle combustion turbines that are generally designed for operation during peak demand will usually supply less than one-third of their potential electric output to the grid. Even though these projects are not generally designed to supply more than one-third of their potential electric output to the grid, there can be rare instances when they do. For instance, when a large base load unit in a transmission-constrained area experiences a long, unexpected outage, it may be necessary to operate simple cycle combustion turbines significantly more than anticipated. The EPA believes the combination of the actual sales criteria and the three year rolling average to determine if the sales criteria are met will address this concern. Second, we are proposing to revise the

⁷⁸ E.g., 40 CFR 60.40Da(a)(1).

⁷⁹ 40 CFR 60.41Da (definition of (“Electric utility steam-generating unit”).

⁸⁰ *Id.*

⁷⁴ Other pending EPA regulatory actions in the power sector are discussed in more detail in Chapter 4 of the RIA.

⁷⁵ 78 FR 24073.

third criteria to be met if the EGU is constructed for the purpose of supplying “more than 219,000 MWh,” as opposed to “25 MW,” net-electrical output to the grid. This proposed change to 219,000 MWh net sales is consistent with the EPA Acid Rain Program (ARP) definition, and we have concluded that it is functionally equivalent to the 25 MW net sales language. The 25 MW sales value has been interpreted to be the continuous sale of 25 MW of electricity on an annual basis, which is equivalent to 219,000 MWh. We are also proposing to revise the averaging period for electric sales from an annual basis to a three-year rolling average for stationary combustion turbines. In addition, we are proposing to add a new applicability criterion that is not currently in subpart Da: EGUs, for which 10 percent or less of the heat input over a three-year period is derived from a fossil fuel, are not subject to any of the proposed CO₂ standards.

For the purposes of this rule, we are proposing several additional changes to the way applicability is currently determined under subpart Da. First, the proposed definition of potential electric output includes “or the design net electric output efficiency” as an alternative to the default one-third efficiency value for determining the value of the potential electric output. Next, we are proposing to add “of the thermal host facility or facilities” to the definition of net-electric output for determining electric sales with respect to the NSPS. Finally, consistent with our approach in the NSPS part of the MATS rule and the original proposal for this rulemaking, we are proposing to amend the definition of a steam generating unit to include “plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment” instead of the existing language “plus any integrated combustion turbines and fuel cells”. We are also proposing to add the additional language to the definition of IGCC and stationary combustion turbine.

2. CO₂ Emissions Only

This action proposes to regulate covered EGU emissions of CO₂, and not other constituent gases of the air pollutant GHGs. We identify the pollutant we propose to regulate as GHGs, but, again, only CO₂ emissions are subject to the proposed standard of performance. We are not proposing separate emission limits for other GHGs (such as methane (CH₄) or nitrous oxide (N₂O)) as they represent less than 1 percent of total estimated GHG

emissions from fossil fuel-fired electric power generating units.

The proposed CO₂ emission standards do not apply a different accounting method for biogenic CO₂ emissions for the purpose of determining compliance with the standards. However, the proposed CO₂ emission standards only apply to new fossil fuel-fired EGUs. Based on the applicability provisions in the proposal, as discussed above, an EGU that primarily fires biomass would not be subject to the CO₂ emission standards. Such units could fire fossil fuels up to 10 percent on a three-year average annual heat input basis (e.g., for start-up and combustion stabilization) without becoming subject to the standards.

Issues related to accounting for biogenic CO₂ emissions from stationary sources are currently being evaluated by the EPA through its development of an Accounting Framework for Biogenic CO₂ Emissions from Stationary Sources (Accounting Framework).⁸¹ In general, the overall net atmospheric loading of CO₂ resulting from the use of a biogenic feedstock by a stationary source, such as an EGU, will ultimately depend on the stationary source process and the type of feedstock used, as well as the conditions under which that feedstock is grown and harvested. In September 2011, the EPA submitted a draft of the Accounting Framework to the Science Advisory Board (SAB) Biogenic Carbon Emissions (BCE) Panel for peer review. The SAB BCE Panel delivered its Peer Review Advisory to the EPA on September 28, 2012.⁸² In its Advisory, the SAB recommended revisions to the EPA’s proposed accounting approach, and also noted that biomass cannot be considered carbon neutral *a priori*, without an evaluation of the carbon cycle effects related to the use of the type of biomass being considered. The EPA is currently reviewing the SAB peer review report, and will move forward as warranted once the review is complete.

3. Sources Not Subject to This Rulemaking

We are not proposing standards for certain types of sources. These include new steam generating units and stationary combustion turbines that sell one-third or less of their potential output to the grid; new non-natural gas-

fired stationary combustion turbines;⁸³ existing sources undertaking modifications or reconstructions; or certain projects under development, including the proposed Wolverine EGU project in Rogers City, Michigan (and, perhaps, up to two others) as discussed below. As a result, under the CAA section 111(a) definitions of “new source” and “existing source,”⁸⁴ if those types of sources commence construction or modification, they would not be treated as “new source[s]” subject to the standards of performance proposed today, and instead, they would be treated as existing sources.

B. Emission Standards

In this rulemaking, the EPA is proposing NSPS for CO₂ emissions from several subcategories of affected sources, which are new fossil fired EGUs described above in Section III.A.

1. Standards of Performance for Affected Sources

a. Emission Standard

The proposed standard of performance for each subcategory is in the form of a gross energy 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 apply to affected sources upon the effective date of the final action. In this notice, we sometimes refer to “gross energy output” as “gross output” or “adjusted gross output.”

The subcategories, for which the EPA is proposing separate standards of performance, are (1) natural gas-fired stationary combustion turbines with a heat input rating that is greater than 850 MMBtu/h;⁸⁵ (2) natural gas-fired stationary combustion turbines with a heat input rating that is less than or equal to 850 MMBtu/h; and (3) all fossil fuel-fired boilers and IGCC units, which generally are solid-fuel fired.

We are proposing that all affected new fossil fuel-fired EGUs are required to meet an output-based emission rate of a specific mass of CO₂ per MWh of useful output. Specifically, new combustion turbines with a heat input rating greater

⁸³ Oil-fired stationary combustion turbines, including both simple and combined cycle units, are not subject to these proposed standards. These units are typically used only in areas that do not have reliable access to pipeline natural gas (for example, in non-continental areas).

⁸⁴ CAA section 111(a)(2), (6).

⁸⁵ This subcategorization of stationary combustion turbines is consistent with the subcategories used in the combustion turbine (subpart KKKK) criteria pollutant NSPS. The size limit of 850 MMBtu/h corresponds to approximately 100 MWe.

⁸¹ The EPA’s draft accounting framework is available at <http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html>.

⁸² The text of the SAB Peer Review Advisory is available at <http://yosemite.epa.gov/sab/sabproduct.nsf/0/2f9b572c712ac52e8525783100704886!OpenDocument&TableRow=2.3#2>.

than 850 MMBtu/h would be required to meet a standard of 1,000 lb CO₂/MWh. New combustion turbines with a heat input rating less than or equal to 850 MMBtu/h would be required to meet a standard of 1,100 lb CO₂/MWh. As discussed below, these proposed standards are based on the demonstrated performance of recently constructed NGCC units, which are currently in wide use throughout the country, and are currently the predominant fossil fuel-fired technology for new electric generating units in the near future.

While the EPA is proposing specific standards of performance for each subcategory, we are also taking comment on a range of potential emission limitations. We solicit comment on a range of 950–1,100 lb CO₂/MWh for new stationary combustion turbines with a heat input rating greater than 850 MMBtu/h. We also solicit comment on an emission limitation range of 1,000–1,200 lb CO₂/MWh for new stationary combustion turbines with a heat input rating less than or equal to 850 MMBtu/h. In addition, we solicit comment on an emission limitation for new fossil fuel-fired boilers and IGCC units in the range of 1,000–1,200 lb CO₂/MWh.

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 useful energy output over a rolling 12-operating-month period. In the alternative, we solicit comment on requiring calculation of compliance on an annual (calendar year) period.

b. Gross Output

Subpart Da currently defines “gross energy output” from new units as the “gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions”^{86 87} (referred to in today’s document as “adjusted gross output”). The current criteria pollutant emission standards for new subpart Da units were developed by analyzing the gross emission rates of PC and CFB facilities, and were finalized on February 16, 2013 (77 FR 9304). In that rulemaking, we applied the same standards to traditional coal-fired and

IGCC EGUs. The adjusted gross output definition accounts for the largest gas compressors at an IGCC facility. Consequently, IGCC facilities complying with the NSPS requirements would emit at approximately the same net output based emissions rate (i.e., gross output minus auxiliary power requirements) as a comparable traditional coal-fired EGU. Therefore, with the definition of gross energy output for criteria pollutant emission standards (i.e., adjusted gross output), both IGCC and traditional coal-fired EGUs that have the same gross energy output-based emissions rate would have a similar net output-based emissions rate. If we did not include the parasitic load from the primary gas compressors when determining the gross emissions rate of an IGCC facility, it would emit more pollutants to the atmosphere than a traditional coal-fired EGU when complying with the criteria pollutant NSPS.

In contrast, in the April 2012 proposal, we proposed a definition of gross output as “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).” This definition was appropriate since NGCC was the BSER for the combined subcategory and auxiliary loads associated with feedwater pumps and associated compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) are not relevant to the gross efficiency of an NGCC. However, we requested comment on requiring the use of net output based standards. Part of the rationale behind the use of net output-based standards is that the use of a gross output-based standard as defined could have potentially driven the installation of electrically driven feed pumps instead of steam driven feed pumps at a steam generating unit, even though from an overall net efficiency basis it may be more efficient to use steam-driven feed pumps.

After further consideration and because many of the proposed IGCC facilities are actually co-production facilities (i.e., they produce useful byproducts and chemicals along with electricity), we have concluded that measuring the electricity used by the primary gas compressors associated with electricity production at IGCC facilities could be more challenging to implement.

Therefore, we are proposing to define the gross energy output for traditional

steam generating units to include the electricity measured at the generator terminals minus electric power used to run the feedwater pumps, and to define the gross electric output for IGCC and subpart KKKK affected facilities to include the electricity measured at the generator terminals. We are considering and requesting comment on (1) whether the definition of “gross energy output” in subpart Da for GHGs should be consistent with the current definition in subpart Da for criteria pollutants, (2) whether we should adopt the proposed definition of “gross energy output”, and (3) whether the definition should be the same for both traditional and IGCC facilities. We seek comment on how to account for energy consumption associated with products other than electricity and useful thermal output created at a poly-generation facility and the impact of that energy use on the numerical emissions standard, all of which is relevant to possible adoption of an adjusted gross output definition.

We are also considering and requesting comment on using net-output based standards either as a compliance alternative for, or in lieu of, gross-output based standards, including whether we should have a different approach for different subcategories. In the compliance alternative approach, owners/operators would elect to comply with either a gross-output based standard or an alternate net-output based standard. As described in the original proposal for this rulemaking, net output is the combination of the gross electrical output of the electric generating unit minus the parasitic (i.e., auxiliary) 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 non-IGCC and non-CCS coal-fired station power output, approximately 15 percent of non-CCS IGCC-based coal-fired station power output and about 2.5 percent of non-CCS 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.

⁸⁶ 40 CFR 60.41Da.

⁸⁷ International Standards Organization Metric (ISO) Conditions are 288 Kelvin (15 °C), 60 percent relative humidity, and 101.325 kilopascals (kPa) pressure.

While the EPA has concluded that the net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer, we only have CEMS emissions data reported on a gross output basis because that is the way the data is currently reported under 40 CFR

part 75. As noted, switching from gross output to net or adjusted gross output would have little or no impact on the required rates for gas-fired NGCC plants, which are likely to be the dominant fossil fuel-fired technology for new intermediate or base load power generation. Since the change would

have little impact on these units in terms of environmental performance, the EPA has proposed to use a standard consistent with current reporting protocols. However, as is noted in Table 4, the use of net instead of gross output could have a much larger impact on coal-fired power plants.

TABLE 4—SUBPART DA EMISSION RATES⁸⁸

Gross output based standard	Approximate equivalent adjusted gross output based standard	Approximate equivalent net output based standard
450 kg/MWh (1,000 lb/MWh)	510 kg/MWh (1,100 lb/MWh)	560 kg/MWh (1,200 lb/MWh).
500 kg/MWh (1,100 lb/MWh)	570 kg/MWh (1,300 lb/MWh)	620 kg/MWh (1,400 lb/MWh).
540 kg/MWh (1,200 lb/MWh)	610 kg/MWh (1,300 lb/MWh)	670 kg/MWh (1,500 lb/MWh).

TABLE 5—SUBPART KKKK EMISSION RATES

Gross output based standard	Approximate equivalent net output based standard
430 kg/MWh (950 lb/MWh).	440 kg/MWh (970 lb/MWh).
450 kg/MWh (1,000 lb/MWh).	460 kg/MWh (1,000 lb/MWh).
500 kg/MWh (1,100 lb/MWh).	510 kg/MWh (1,100 lb/MWh).
540 kg/MWh (1,200 lb/MWh).	560 kg/MWh (1,200 lb/MWh).

Requiring or including an optional net-output based standard would provide more operational flexibility and expand the technology options available to comply with the standard for coal-fired PC and CFB EGUs.

In addition, we are proposing that with respect to CO₂ emissions, 75 percent credit is the appropriate discount factor for useful thermal output. However, we are requesting comment on a range of two-thirds to three-fourths credit for useful thermal output in the final rule.

2. 84-Operating-Month Rolling Average Compliance Option

We also propose an 84-operating-month rolling average compliance option that would be available for affected subpart Da boilers and IGCC facilities. The EPA suggests that this 84-operating-month rolling average compliance option will offer operational flexibility and will tend to dampen short-term emission excursions, which may be warranted especially at the initial startup of the facility and the CCS system.

Thus, under our proposed approach, new fossil fuel-fired boilers and IGCC units would be required, based on the

performance of currently available CCS technology, to meet a standard of 1,100 lb CO₂/MWh on a 12-operating-month rolling average, or alternatively a lower—but equivalently stringent—standard on an 84-operating-month rolling average, which we propose as between 1,000 lb CO₂/MWh and 1,050 lb CO₂/MWh. The EPA has previously offered sources optional, longer-term emission standards that are discounted from the primary emissions standard in combination with a longer averaging period. We are requesting comment on the appropriate numerical standard such that the 84-operating-month standard would be as stringent as or more stringent than the 12-operating-month standard. We also request comment on whether owners/operators electing to comply with the 84-operating-month standard should also be required to comply with a maximum 12-operating-month standard. This standard would be between the otherwise applicable proposed 1,100 lb CO₂/MWh standard and an emissions rate of a coal-fired EGU without CCS (e.g., 1,800 lb CO₂/MWh), and we solicit comment on what the standard should be. This shorter term standard would facilitate enforceability and assure adequate emission reductions.

We have concluded that this alternative compliance option is not necessary for new stationary combustion turbine EGUs, as they should be able to meet the proposed performance standard with no need for add-on technology. We seek comment on all other aspects of this 84-operating-month rolling averaging compliance option.

3. Combined Heat and Power

To recognize the environmental benefit of reduced electric transmission and distribution losses of CHP, we are proposing that CHP facilities where at least 20.0 percent of the total gross useful energy output consists of electric

or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on a rolling three calendar year basis receive similar credit as currently in subpart Da and the proposed amendments to subpart KKKK (77 FR 52554). Specifically, the measured electric output would be divided by 0.95 to account for a five percent avoided energy loss in the transmission of electricity. The minimal electric and thermal output requirements are to avoid owners/operators from selling trivial amounts of thermal output and claiming a line loss benefit when in reality they are similar to a central power station.

Actual transmission and distribution losses vary from location to location, but we propose that this 5 percent of actual MWh represents a reasonable average amount for the avoided transmission and distribution losses for CHP facilities. Note that we propose to limit this 5 percent adjustment to facilities for which the useful thermal output is at least 20 percent of the total output.

C. Startup, Shutdown, and Malfunction Requirements

1. Startups and Shutdowns

Consistent with *Sierra Club v. EPA*,⁸⁹ the EPA is proposing standards in this rule that apply at all times, including during startups and shutdowns. In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below has not proposed alternate standards for those periods. In the compliance calculation, periods of startup and shutdown are included as periods of partial load. To establish the proposed NSPS's output-based CO₂ standard, we accounted for periods of startup and shutdown by incorporating them as periods of partial load operation. As noted above, the proposed

⁸⁸ Rounding to two significant figures results in the same standard in units of lb/MWh in some cases.

⁸⁹ 551 F.3d 1019 (D.C. Cir. 2008).

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-operating-month period. The EPA is proposing that sources incorporate in their compliance determinations emissions from all periods, including startup or shutdown, that fuel is combusted and emissions monitors are not out-of-control, as well as all power produced over the periods of emissions measurements. Given that the duration of startup or shutdown periods are expected to be small relative to the duration of periods of normal operation and that the fraction of power generated during periods of startup or shutdown is expected to be very small during startup or shutdown periods, the impact of these periods on the total average is expected to be minimal. Periods of startup and shutdown will be short, relative to total operating time. Since we are primarily concerned with overall environmental performance over extended periods of time, incorporating relatively short periods of partial load is believed to have a negligible effect on the performance of the source with respect to long-term efficiency.

We solicit comment on any alternative to our proposal that the periods of startup and shutdown be included as periods of partial load in the 12- and 84-operating-month rolling averaging compliance option.

2. Malfunctions

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, 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. Failures that are caused in part by poor maintenance or careless operations are not malfunctions. (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. Nothing in CAA 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. CAA 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 (D.C. 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."). *See also, Weyerhaeuser v. Costle*, 590 F.2d 1011, 1058 (D.C. 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"). In addition, the goal of a source that uses the best system of emission reduction 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 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 a violation of the relevant emission standard. (*See, e.g., State Implementation Plans: Response to Petition for Rulemaking; Finding of Excess Emissions During Periods of Startup, Shutdown, and Malfunction; Proposed Rule*, 78 FR 12460 (Feb. 22, 2013); (*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)). The EPA is therefore proposing to add an affirmative defense to civil penalties for violations of emission standards 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 § 60.5530. (*See* 40 CFR 22.24). The criteria are designed in part to ensure that the affirmative defense is available only where the event that causes a violation of the emission standard 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 the violation "[w]as caused by a sudden, infrequent, and unavoidable failure of air pollution control, 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 § 60.5530 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 a violation occurred . . .” and that “[a]ll possible steps were taken to minimize the impact of the violation 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 22.27).

The EPA included an affirmative defense in the proposed rule 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 standards may be violated 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 (D.C. Cir. 2008) Thus, the EPA is required to ensure that section 111 emissions standards are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission standard is still enforceable through injunctive relief. The United States Court of Appeals for the Fifth Circuit recently upheld the EPA’s view that an affirmative defense provision is consistent with section 113(e) of the Clean Air Act. *Luminant Generation Co. LLC v. United States EPA*, 2013 U.S. App. LEXIS 6397 (5th Cir. Mar. 25, 2013) 699 F.3d. 427 (5th Cir. Oct. 12, 2012) (upholding the EPA’s approval of affirmative defense provisions in a CAA State Implementation Plan). While “continuous” standards, 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 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 “variant provisions” such as provisions allowing for upsets during startup, shutdown and equipment 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 (D.C. Cir. 1973). Although due to intervening case law such as *Sierra Club v. EPA* and the CAA 1977 amendments (which added the “continuous” requirement of 42 U.S.C. 7602(k)) these cases are no longer good law on whether EPA can exempt malfunctions from liability, their core principle remains valid: regulatory accommodation is appropriate where a standard cannot be achieved 100 percent of the time due to circumstances out of the control of the owner/operator of the source, and a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to malfunctions. 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). See also, *Mont. Sulphur & Chem. Co. v. United States EPA*, 666 F.3d. 1174 (9th Cir. 2012) (rejecting industry argument that reliance on the affirmative defense was not adequate). But see, *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards 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, an affirmative defense to civil penalties for violations of emission limits that are caused by malfunctions, would apply to both the 12-operating-month standard and the 84-operating-month rolling average compliance option; however, we will take comment on whether it is appropriate to have an affirmative defense for the 84-operating-month rolling average portion of that compliance option, given that we would expect malfunctions to only impact shorter averaging periods, and the longer the compliance period, the less likely malfunction events are to impact a source’s ability to meet the standard.

D. Continuous Monitoring Requirements

Today’s proposed rule would require owners or operators of EGUs that combust solid fuel to install, certify, maintain, and operate continuous emission monitoring systems (CEMS) to

measure CO₂ concentration, stack gas flow rate, and (if needed) stack gas moisture content in accordance with 40 CFR Part 75, in order to determine hourly CO₂ mass emissions rates (tons/hr).

The proposed rule would allow owners or operators of EGUs that burn exclusively gaseous or liquid fuels to install fuel flow meters as an alternative to CEMS and to calculate the hourly CO₂ mass emissions rates using Equation G–4 in Appendix G of part 75. To implement this option, hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of the fuel are also required, in accordance with Appendix D of part 75.

In addition to requiring monitoring of the CO₂ mass emission rate, the proposed rule would require EGU owners or operators to monitor the hourly unit operating time and “gross output”, expressed in megawatt hours (MWh). The gross output includes electrical output plus any mechanical output, plus 75 percent of any useful thermal output.

The proposed rule would require EGU owners or operators to prepare and submit a monitoring plan that includes both electronic and hard copy components, in accordance with §§ 75.53(g) and (h). The electronic portion of the monitoring plan would be submitted to the EPA’s Clean Air Markets Division (CAMD) using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. The hard copy portion of the plan would be sent to the applicable State and EPA Regional office. Further, all monitoring systems used to determine the CO₂ mass emission rates would have to be certified according to § 75.20 and section 6 of Appendix A to part 75 within the 180-day window of time allotted under § 75.4(b), and would be required to meet the applicable on-going quality assurance procedures in Appendices B and D of part 75.

The proposed rule would require all valid data collected and recorded by the monitoring systems (including data recorded during startup, shutdown, and malfunction) to be used in assessing compliance. Failure to collect and record required data is a violation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of stack emissions (e.g., calibration error tests, linearity checks, and required zero and span

adjustments). An affirmative defense to civil penalties for malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied.

The proposed rule would require only those operating hours in which valid data are collected and recorded for all of the parameters in the CO₂ mass emission rate equation to be used for compliance purposes. Additionally for EGUs using CO₂ CEMS, only unadjusted stack gas flow rate values would be used in the emissions calculations. In this proposal, Part 75 bias adjustment factors (BAFs) would not be applied to the flow rate data. These restrictions on the use of Part 75 data for Part 60 compliance are consistent with previous NSPS regulations and revisions.

The following variations from and additions to the basic part 75 monitoring would be required:

- If you determine compliance using CEMS, you would be required to use a laser device to measure the stack diameter at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, you would need to make measurements of the diameter at 3 or more distinct locations and average the results. For rectangular stacks or ducts, you would need to make measurements of each dimension (i.e., depth and width) at 3 or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, you would repeat these measurements at the new location.

- If you elect to use Method 2 in Appendix A–1 of part 60 to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, you would have to use a calibrated Type-S pitot tube or pitot tube assembly. Use of the default Type-S pitot tube coefficient would not be permitted.

- If your EGU combusts natural gas and/or fuel oil and you elect to measure the CO₂ mass emissions rate using Equation G–4 in Appendix G of part 75, you would be allowed to determine site-specific carbon-based F-factors using Equation F–7b in section 3.3.6 of Appendix F of part 75, and you could use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

Today's proposed rule includes the following special compliance provisions for units with common stack or multiple stack configurations; these provisions are consistent with § 60.13(g):

- If two or more of your EGUs share a common exhaust stack, are subject to the same emission limit, and you are required to (or elect to) determine compliance using CEMS, you would be allowed to monitor the hourly CO₂ mass emission rate at the common stack instead of monitoring each EGU separately. If this option is chosen, the hourly gross electrical load (or steam load) would be the sum of the hourly loads for the individual EGUs and the operating time would be expressed as “stack operating hours” (as defined in 40 CFR 72.2). Then, if compliance with the applicable emission limit is attained at the common stack, each EGU sharing the stack would be in compliance with the CO₂ emissions limit.

- If you are required to (or elect to) determine compliance using CEMS and the effluent from your EGU discharges to the atmosphere through multiple stacks (or, if the effluent is fed to a stack through multiple ducts and you choose to monitor in the ducts), you would be required to monitor the hourly CO₂ mass emission rate and the “stack operating time” at each stack or duct separately. In this case, compliance with the applicable emission limit would be determined by summing the CO₂ mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the unit.

The proposed rule would require 95 percent of the operating hours in each compliance period (including the compliance periods for the intermediate emission limits) to be valid hours, i.e., operating hours in which quality-assured data are collected and recorded for all of the parameters used to calculate CO₂ mass emissions. EGU owners or operators would have the option to use backup monitoring systems, as provided in §§ 75.10(e) and 75.20(d), to help meet this proposed data capture requirement.

E. Emissions Performance Testing Requirements

In accordance with § 75.64(a), the proposed rule would require an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in § 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). For EGUs subject to the 450 kg/MWh (1,000 lb/MWh) standard or the 500 kg/MWh (1,100 lb/MWh) emission standard, the initial performance test would consist of the first 12-operating-months of data, starting with the month in which emissions are first required to be reported. The initial 12-operating-month compliance period would begin

with the first month of the first calendar year of EGU operation in which the facility exceeds the capacity factor applicability threshold.

The traditional 3-run performance tests (i.e., stack tests) described in § 60.8 would not be required for this rule. Following the initial compliance determination, the emission standard would be met on a 12-operating-month rolling average basis. For EGUs that combust coal and/or petroleum coke and whose owners or operators elect to comply with the alternative 84-operating-month rolling average emissions standard, the first month in the compliance period would be the month in which emissions reporting is required to begin under § 75.64(a).

F. Continuous Compliance Requirements

Today's proposed rule specifies that compliance with the 1,000 lb/MWh (450 kg/MWh) and 1,100 lb/MWh (500 kg/MWh) CO₂ mass emissions rate limits would be determined on a 12-operating-month rolling average basis, updated after each new operating month. For each 12-operating-month compliance period, quality-assured data from the certified Part 75 monitoring systems would be used together with the gross output over that period of time to calculate the average CO₂ mass emissions rate.

The proposed rule specifies that the first operating month included in either the initial 12- or 84-operating-month compliance period would be the month in which reporting of emissions data is required to begin under § 75.64(a), i.e., either the month in which monitoring system certification is completed or the month in which the 180-day window allotted to finish certification testing expires (whichever month is earlier).

We are proposing that initial compliance with the applicable emissions limit in kg/MWh be calculated by dividing the sum of the hourly CO₂ mass emissions values by the total gross output for the 12- or 84-operating-month period. Affected EGUs would continue to be subject to the standards and maintenance requirements in the section 111 regulatory general provisions contained in 40 CFR Part 60, subpart A.

G. Notification, Recordkeeping, and Reporting Requirements

Today's proposed rule would require an EGU owner or operator to comply with the applicable notification requirements in §§ 75.61, 60.7(a)(1) and (a)(3) and 60.19. The proposed rule would also require the applicable recordkeeping requirements in subpart

F of part 75 to be met. For EGUs using CEMS, the data elements that would be recorded include, among others, hourly CO₂ concentration, stack gas flow rate, stack gas moisture content (if needed), unit operating time, and gross electric generation. For EGUs that exclusively combust liquid and/or gaseous fuel(s) and elect to determine CO₂ emissions using Equation G–4 in Appendix G of part 75, the key data elements in subpart F that would be recorded include hourly fuel flow rates, fuel usage times, fuel GCV, gross electric generation.

The proposed rule would require EGU owners or operators to keep records of the calculations performed to determine the total CO₂ mass emissions and gross output for each operating month. Records would be kept of the calculations performed to determine the average CO₂ mass emission rate (kg/MWh) and the percentage of valid CO₂ mass emission rates in each compliance period. The proposed rule would also require records to be kept of calculations performed to determine site-specific carbon-based F-factors for use in Equation G–4 of part 75, Appendix G (if applicable).

For EGU owners or operators who would elect to comply with the 84-operating-month rolling average emissions standard, records must be kept for 10 years. All other records would be kept for a period of three years. All required records would be kept on-site for a minimum of two years, after which the records could be maintained off-site.

The proposed rule would require all affected EGU owners/operators to submit quarterly electronic emissions reports in accordance with subpart G of part 75. The proposed rule would require these reports to be submitted using the ECMPS Client Tool. Except for a few EGUs that may be exempt from the Acid Rain Program (e.g., oil-fired units), this is not a new reporting requirement. Sources subject to the Acid Rain Program are already required to report the hourly CO₂ mass emission rates that are needed to assess compliance with today's rule.

Additionally, in the proposed rule and as part of an Agency-wide effort to streamline and facilitate the reporting of environmental data, the rule would require selected data elements that pertain to compliance under this rule, and that serve the purpose of traditional excess emissions reports, to be reported periodically using ECMPS.

Specifically, for EGU owners/operators who would comply with a 12-operating-month rolling average standard, quarterly electronic "excess emissions" reports must be submitted,

within 30 days after the end of each quarter. The first report would be for the quarter that includes the final (12th) operating month of the initial 12-operating-month compliance period. For that initial report and any subsequent report in which the twelfth operating month of a compliance period (or periods) occurs during the calendar quarter, the average CO₂ mass emissions rate (kg/MWh) would be reported for each compliance period, along with the dates (year and month) of the first and twelfth operating months in the compliance period and the percentage of valid CO₂ mass emission rates obtained in the compliance period. The dates of the first and last operating months in the compliance period would clearly bracket the period used in the determination, which facilitates auditing of the data. Reporting the percentage of valid CO₂ mass emission rates is necessary to demonstrate compliance with the requirement to obtain valid data for 95 percent of the operating hours in each compliance period. Any excess emissions that occur during the quarter would be identified. If there are no compliance periods that end in the quarter, a definitive statement to that effect would be included in the report. If one or more compliance periods end in the quarter but there are no excess emissions, a statement to that effect would be included in the report.

For EGU owners or operators that would comply with an 84-operating-month rolling average basis, quarterly electronic "excess emissions" reports would be submitted, within 30 days after the end of each quarter. The first report would be for the quarter that includes the final (60th) operating month of the initial 84-operating-month compliance period. For that initial report and any subsequent report in which the sixtieth operating month of a compliance period (or periods) occurs during the calendar quarter, the average CO₂ mass emissions rate (kg/MWh) must be reported for each compliance period, along with the dates (year and month) of the first and sixtieth operating months in the compliance period and the percentage of valid CO₂ mass emission rates obtained in the compliance period. The dates of the first and last operating months in the compliance period would clearly bracket the period used in the determination, which facilitates auditing of the data. Reporting of the percentage of valid CO₂ mass emission rates is necessary to demonstrate compliance with the requirement to obtain valid data for 95 percent of the

operating hours in each compliance period. Any excess emissions that occur during the quarter would be identified. If there are no compliance periods that end in the quarter, a definitive statement to that effect would be included in the report. If one or more compliance periods end in the quarter but there are no excess emissions, a statement to that effect would be included in the report.

Currently, ECMPS is not programmed to receive excess emission report information from EGUs. However, we will make the necessary modifications to the system in order to fully implement the reporting requirements of this rule upon promulgation.

For EGU owners or operators that would assert an affirmative defense for a failure to meet a standard due to malfunction, the owner or operator must follow the reporting requirements for affirmative defense. Those requirements are found in 40 CFR 60.5530. The report to the Administrator, with all necessary supporting documentation, explains how the source has met the requirements set forth in subparts Da, KKKK, and TTTT to assert affirmative defense. This report must be submitted on the same schedule as the next quarterly report required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If the quarterly report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second quarterly report due after the initial occurrence of the violation of the relevant standard.

IV. Rationale for Reliance on Rational Basis To Regulate GHGs From Fossil-Fired EGUs

A. Overview

In our original proposal, we proposed and solicited comment on what basis we are required to have concerning the health and welfare impacts of GHG emissions from fossil-fuel fired power plants in order to regulate those emissions under CAA section 111. However, we took the position that we are not required to make findings that GHGs from fossil-fired power plants "cause [], or contribute [] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare," under CAA section 111(b)(1)(A).

We have reconsidered that proposal in light of the numerous comments we received. In today's document, we propose that under section 111, the EPA is required to have a rational basis for

promulgating standards for GHG emissions from electricity generating plants, and that the EPA has such a basis because the EPA has already determined that GHG emissions may reasonably be anticipated to endanger public health and welfare, and because electricity generating plants, as an industry, constitute, by a significant margin, the largest emitters in the inventory. In the April 2012 proposal, the EPA discussed whether CAA section 111 requires that the EPA issue, as a prerequisite for this rulemaking, another “endangerment” finding. After reviewing the comments, recent scientific developments, the amount of emissions from the power plant sector, and the case law, the EPA has concluded that even if section 111 requires an endangerment finding, the rational basis described in today’s action would qualify as an endangerment finding as well.

As related matters, in this notice, we are proposing to establish regulatory requirements for CO₂ emissions of affected units, which are included in source categories (both steam-generating units and turbines) that the EPA already listed under CAA section 111(b)(1)(A) for regulation under CAA and we are not proposing a listing of a new source category. We are, however, proposing to subcategorize different sets of sources, and establish different CO₂ standards of performance for them, in accordance with CAA section 111(b)(2). To avoid confusion, we are proposing to codify the CO₂ standards of performance in the same subparts—Da and KKKK, depending on the types of units—that currently include the standards of performance for conventional pollutants. We are also co-proposing, in the alternative, to codify the CO₂ standards in a new subpart, TTTT, as we proposed in the original proposal for this rulemaking in April, 2012.⁹⁰

⁹⁰It should be noted that CAA section 111 clearly applies to GHGs. The U.S. Supreme Court has made this clear because (i) section 111 applies to “any air pollutant,” CAA section 111(a)(3), *see* section 111(d)(1)(A) (exempting, for purposes of section 111(d), certain air pollutants); and in *Massachusetts v. EPA*, 549 U.S. 497 (2007), the Supreme Court held that the term “air pollutant,” as defined under CAA section 302(g), includes GHGs; and (ii) in *American Electric Power Company v. Connecticut*, 131 S.Ct. 2527 (2011), the Supreme Court based its holding that “the Clean Air Act and the EPA actions it authorizes displace any federal common law right to seek abatement of carbon-dioxide emissions from fossil fuel-fired power plants” on the grounds that CAA section 111 “provides a means to seek limits on emissions of carbon dioxide from domestic power plants * * *.” *Id.* at 2538.

B. Climate Change Impacts From GHG Emissions; Amounts of GHGs From Fossil Fuel-Fired EGUs

In 2009, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1). 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 of current and future generations, and focused on public health and public welfare impacts within the United States. Fossil fuel-fired EGUs are by far the largest emitters of GHGs, primarily in the form of CO₂, among stationary sources in the U.S. These adverse effects of GHGs on public health and welfare, and the amounts of GHGs emitted by fossil fuel-fired EGUs are briefly summarized in the Section II of this preamble and described in more detail in the RIA, and need not be recited here.

C. CAA Section 111 Requirements

To review the key CAA section 111 requirements: CAA section 111(b)(1)(A), by its terms, requires that the Administrator 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 list if in his judgment it causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

CAA 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.” CAA section 111(b)(2) provides that “The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.”

D. Interpretation of CAA Section 111 Requirements

CAA section 111(b)(1)(A) requires the EPA to list a source category if it contributes significantly to air pollution that endangers public health or welfare. The EPA must necessarily conduct this listing by making determinations as to the health or welfare impacts of the

pollution to which the source category’s pollutants contribute, and as to the significance of the amount of such contribution. However, by the terms of CAA section 111(b)(1)(A), the EPA may make these determinations on the basis of the impacts of the air pollution as a whole to which the source category’s pollutants, taken as a whole, contribute. Nothing in CAA section 111(b)(1)(A) requires that the EPA make separate determinations for each type of pollution or each pollutant.

After listing a source category, the EPA must proceed to promulgate standards of performance for the source category’s pollutants under CAA section 111(b)(1)(B) and 111(a)(1). However, nothing in those provisions requires that, at the time when the EPA promulgates the standards of performance for the individual pollutants, the EPA must make a determination as to the health or welfare effects of those particular pollutants or as to the significance of the amount of the source category’s emissions of those pollutants. Clearly, CAA section 111 does not by its terms require that as a prerequisite for the EPA to promulgate a standard of performance for a particular pollutant, the EPA must first find that the pollutant causes or contributes significantly to air pollution that endangers public health or welfare. The lack of any such requirement contrasts with 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).

The lack of any express requirement in CAA section 111 addressing whether and how the EPA is to evaluate emissions of a particular pollutant from the listed source category as a prerequisite for promulgation of a standard of performance is properly viewed as a statutory gap that requires the EPA to make what we refer to as a *Chevron* step 2 interpretation. Under the U.S. Supreme Court’s 1984 decision in *Chevron U.S.A. Inc. v. NRDC*,⁹¹ to interpret how a statute applies to a particular question, an agency must, at Step 1, determine whether Congress’s intent as to the specific question is clear, and, if so, the agency must give effect to that intent. If congressional intent is not clear, then the agency, at Step 2, has discretion to fashion an interpretation that is a reasonable construction of the statute.⁹² In this

⁹¹467 U.S. 837 (1984).

⁹²*Id.* at 842–43.

case, the EPA is authorized to develop a reasonable interpretation.

Our interpretation is that in order to promulgate a section 111 standard of performance for a particular pollutant, we do not need to make a pollutant-specific endangerment finding, but instead must demonstrate a rational basis for controlling the emissions of the pollutant. That rational basis may be based on information concerning the health and welfare impacts of the air pollution at issue, and the amount of contribution that the source category's emissions make to that air pollution.

Commenters on the April 2012 proposal stated that the EPA is required to make an endangerment finding for CO₂ because when the EPA listed this source category, it was on the basis of other pollutants, and not CO₂. However, to reiterate, CAA section 111(b)(1)(A) by its terms requires that the EPA "shall publish (and from time to time thereafter, shall revise) a list of categories of stationary sources," and that the EPA shall list "a category of sources" based on the EPA's judgment that the category "causes, or contributes significantly to, air pollution" that endangers public health or welfare. Thus, this provision requires that the EPA make the listing decision on a category basis, and not on a pollutant-by-pollutant basis. That is, this provision does not require that the EPA establish separate lists of source categories, with each list covering a different pollutant. Therefore, this provision does not require that the EPA make an endangerment finding on a pollutant by pollutant basis.

Commenters on the April 2012 proposal stated that the EPA was required to make an endangerment finding because by creating the new subpart TTTT in 40 CFR Part 60, the EPA was listing a new source category that included the affected units. However, in neither the original April 2012 proposal nor this new proposal has EPA proposed to list a new source category. The EPA initially included fossil fuel-fired electric steam generating units (which included boilers) in a category that it listed under section 111(b)(1)(A)⁹³ and the EPA promulgated the first set of standards of performance for this source category in 1971, which the EPA codified in subpart D.⁹⁴ Subsequently, the EPA included

fossil fuel-fired combustion turbines in a category that the EPA listed under section 111(b)(1)(A),⁹⁵ and the EPA promulgated standards of performance for this source category in 1979, which the EPA codified in subpart GG.⁹⁶

The EPA has revised those regulations, and in some instances, has revised the codifications (that is, the subparts), several times over the ensuing decades. In 1979, the EPA divided subpart D into 3 subparts—Da ("Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978"), Db ("Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units") and Dc ("Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units")—in order to codify separate requirements that it established for these subcategories.⁹⁷ In 2006, the EPA created subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," which applied to certain sources previously regulated in subparts Da and GG.⁹⁸ None of these rulemakings, including the revised codifications, however, constituted a new listing under CAA section 111(b)(1)(A).

In today's rulemaking, the EPA is promulgating new standards of performance for CO₂ emissions from certain sets of sources, e.g., steam-generating boilers and turbines. Moreover, we are establishing different requirements for different sets of sources, including steam-generating boilers as well as smaller and larger combustion turbines, in accordance with CAA section 111(b)(2). That provision authorizes the EPA to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing . . . standards [of performance.]"

In today's rulemaking, we are including a proposal and, in the alternative, a co-proposal, which take two different approaches to the source categories and their codification.⁹⁹ Our

proposal is to codify the new CO₂ standards in the same subparts in which the standards of performance for conventional pollutants are codified. Thus, we propose to codify the GHG standards for steam-generating boilers as a new section in subpart Da, and the GHG standards for combustion turbines as new sections in subpart KKKK. This proposal does not list a new category under section 111(a)(1)(A). Nor does this proposal revise either of the two source categories—steam-generating boilers and combustion turbines—that EPA has already listed, or revise the codification of the new source requirements for those categories in subparts Da, GG, and KKKK. Under this proposal, the establishment of different requirements for different sets of sources—for example, coal-fired power plants, larger NGCC plants, and smaller NGCC plants—constitute subcategorizations within the existing categories.

In the alternative, we co-propose to combine the two source categories—again, steam-generating boilers and combustion turbines—for purposes of regulating CO₂ emissions (but not for regulating emissions of conventional pollutants), and to codify all of the proposed regulatory requirements in a new subpart, TTTT.¹⁰⁰ This category, created by combining two existing categories, cannot be considered a new source category that EPA is placing on the list of categories for regulation under CAA section 111(b)(1)(A). Under this co-proposal, the establishment of different requirements for different sets of sources continues to constitute subcategorizations within the existing category.

We solicit comment on the relative merits of each approach. In particular we seek comment on whether the co-proposal to combine the categories and codify the GHG standards for all new affected sources in subpart TTTT will offer any additional flexibility for any future emission guidelines for existing sources, for example, by facilitating a system-wide approach, such as emission rate averaging, that covers fossil-fuel

electricity for sale and meet certain size and operational criteria, conventional pollutant regulatory requirements are codified under subpart KKKK. The EPA proposed to number this newly created subpart as subpart TTTT. The EPA explained that combining the GHG regulatory requirements for those sources in TTTT was appropriate because the EPA was establishing the same limit for all those sources based on the same BSER, which was NGCC. 77 FR 22410/2–22411/3.

¹⁰⁰ Under this co-proposal, these regulatory requirements are substantively the same as the requirements proposed for inclusion in subparts Da and KKKK, and are simply collected in a separate subpart, TTTT.

⁹³ "Air Pollution Prevention and Control: List of Categories of Stationary Sources," 36 FR 5931 (March 31, 1971).

⁹⁴ "Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971," 36 FR 24875 (Dec. 23, 1971) codified at 40 CFR 60.40–46; 36 FR 5931 (Mar. 31, 1971).

⁹⁵ 42 FR 53657 (Oct. 3, 1977).

⁹⁶ "Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978," 44 FR 33580 (June 11, 1979).

⁹⁷ 44 FR 33580 (June 11, 1979).

⁹⁸ 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (Mar. 20, 2009).

⁹⁹ In the original proposal for this rulemaking, the EPA proposed to create within 40 CFR part 60 a new subpart that would include GHG emission regulatory requirements for electric utility steam generating units (i.e., boilers and IGCC units), whose conventional pollutant regulatory requirements are codified under subpart Da; as well as stationary combustion turbines that generate

fired steam generating units and combustion turbines.

E. Rational Basis To Promulgate Standards for GHGs From Fossil-Fired EGUs

In this rulemaking, the EPA has a rational basis for concluding that emissions of CO₂ from fossil-fired power plants, which are the major U.S. source of greenhouse gas air pollution, merits taking action under CAA section 111. As noted, in 2009, the EPA made a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare, and in 2010, the EPA denied petitions to reconsider that finding. The EPA extensively reviewed the available science concerning GHG pollution and its impacts in taking those actions. In 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the finding and denial of petitions to reconsider. In addition, assessments from the NRC and the IPCC, published in 2010, 2011, and 2012 lend further credence to the validity of the Endangerment Finding. As discussed below, no information that commenters have presented or that the EPA has reviewed provides a basis for rescinding that finding. In addition, as noted, the high level of GHG emissions from the fossil-fired EGUs makes clear that it is rational for the EPA to regulate GHG emissions from this sector. This information amply supports that the EPA has a rational basis for promulgating regulations under CAA section 111 designed to address GHG air pollution.

Our conclusion is consistent with the case law handed down by the D.C. Circuit. In its 1980 decision in *National Lime Association v. EPA*,¹⁰¹ the Court upheld EPA's determination that lime manufacturing plants emit particulates that contribute significantly to air pollution that endangers public health or welfare. The Court noted that (i) EPA's basis was its prior determination that "the significant production of particulate emissions . . . cause[s] or contribute[s] to air pollution (which may reasonably be anticipated to endanger public health or welfare);" and (ii) "[t]he Agency has made this determination for purposes of establishing national primary and secondary ambient air quality standards under [CAA section 109]." The Court held:

We think the danger of particulate emissions' effect on health has been sufficiently supported in the Agency's (and its predecessor's) previous determinations to

provide a rational basis for the Administrator's finding in this case.¹⁰²

Similarly, in *National Asphalt Pavement Ass'n v. Train*,¹⁰³ the D.C. Circuit upheld a determination by the EPA that asphalt cement plants contribute significantly to particulate matter air pollution that endangers public health and welfare. The Court indicated that the EPA's determination that particulate matter endangers is valid simply on grounds that the EPA established a NAAQS for that pollutant.¹⁰⁴

These cases support our relying primarily on the analysis and conclusions in our previous Endangerment Finding, and the subsequent assessments, as providing a rational basis for our decision to impose standards of performance on GHG emissions from fossil-fuel fired EGUs.

In comments on the original proposal, commenters state that because the proposed rulemaking limits emissions of only CO₂, and not other GHGs, the EPA cannot rely on the analysis and conclusions in the 2009 Endangerment Finding because it concerned a mix of six GHGs: carbon dioxide and five others. These commenters assert that as a prerequisite for regulating CO₂ emissions alone, the EPA must make an endangerment finding for CO₂ alone. Because the present proposal also limits emissions of only CO₂, and not the other GHGs, we expect that the same issue may arise with respect to this proposal. Commenters' assertion is incorrect for two reasons. First, as discussed above, the EPA does not need to make an endangerment finding with respect to a particular pollutant to set standards for that pollutant under section 111(b)(1)(B). Second, the EPA may reasonably rely on the analysis and conclusions in the 2009 Endangerment Finding on GHGs even when regulating only CO₂. With respect to this proposed rulemaking, the air pollution at issue here is the mix of six GHGs. It is that air pollution that has caused the various impacts on health and welfare that formed the basis for the Endangerment Finding. The CO₂ emissions from EGUs are a major component of that air pollution. As we noted in the 2009 Endangerment Finding, CO₂ is the "dominant anthropogenic greenhouse gas."¹⁰⁵ The fact that we are not regulating the other five GHGs in this rulemaking does not mean that we are required to identify the air pollution as CO₂ alone rather than the mix of six

GHGs. This is consistent with the EPA's past actions. In the 2010 Light Duty Vehicle Rule for which the Endangerment Finding served as the predicate, the EPA regulated only four of the GHGs, not all six.¹⁰⁶

Further, 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, along with the fact that the CO₂ emissions from even a single new coal-fired power plant may amount to millions of tons each year, provide a rational basis for regulating CO₂ emissions from affected EGUs.¹⁰⁷ This is consistent with previous EPA actions that have been upheld by the D.C. Circuit. In the *National Lime Association v. EPA* case, noted above, the Court upheld the EPA's regulation of lime plants on grounds that they were one of the largest—although not within the largest 10 percent—emitting industries of particulates. The Court stated,

EPA . . . focused . . . on the sheer quantity of dust generated by lime plants. 42 Fed. Reg. 22507 ("A study performed for EPA in 1975 by the Research Corporation of New England ranked the lime industry twenty-fifth on a list of 112 stationary sources categories which are emitters of particulate matter"); SSEIS 8-2 ("In a study performed for EPA by Argonne National Laboratory in 1975, the lime industry ranked seventh on a list of the 56 largest particulate source categories in the U.S.").¹⁰⁸

In the *National Asphalt Pavement Ass'n v. Train* case, noted above, the Court upheld the EPA's determination that the asphalt industry contributed significantly to the air pollution based on "the number of existing plants, the expected rate of growth in the number of plants, the rate of uncontrolled emissions, and the level of emissions currently tolerated."¹⁰⁹

F. Alternative Findings of Endangerment and Significant Contribution

Even if CAA section 111 is interpreted to require that the EPA make endangerment and cause-or-contribute significantly findings as prerequisites for today's rulemaking, then our rational

¹⁰⁶ 75 FR 25324, 25396–97 (May 7, 2010).

¹⁰⁷ Commenters on the original proposal stated that new solid-fuel fired power plants made no contribution to air pollution because EPA's modeling projected no new construction of those types of plants. However, CAA section 111(b)(1)(A) is clear by its terms that the source category listing that is the prerequisite to regulation is based on the contribution of the "category" to air pollution, and therefore is not based on the contribution of only new sources in the category. The same reasoning applies to the rational basis determination.

¹⁰⁸ 627 F.2d at 432, n. 48.

¹⁰⁹ 539 F.2d at 784–85.

¹⁰² *Id.* at 431–32 n.48.

¹⁰³ 539 F.2d 775 (D.C. Cir. 1976).

¹⁰⁴ *Id.* at 784.

¹⁰⁵ 74 FR 66496, 66519 (Dec. 15, 2009).

¹⁰¹ 627 F.2d 416 (D.C. Cir. 1980).

basis, as described, should be considered to constitute those findings.

As noted above, the EPA's rational basis for regulating under section 111 GHGs is based primarily on the analysis and conclusions in the EPA's 2009 Endangerment Finding and 2010 denial of petitions to reconsider that Finding, coupled with the 2010, 2011, and 2012 assessments from the IPCC and NRC that describe scientific developments since those EPA actions. In addition, as noted above, we would review comments presenting other scientific information to determine whether that information has any meaningful impact on our primary basis.

This rational basis approach is substantially similar to the approach the EPA took in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider. As noted, the D.C. Circuit upheld that approach in the *CRR* case. Accordingly, that approach would support an endangerment finding for this rulemaking.

By the same token, if the EPA were required to make 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, the same facts that support our rational basis determination would support such a finding. In particular, as noted, 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; and the CO₂ emissions from even a single new coal-fired power plant may amount to millions of tons each year. It should be noted that at present, it is not necessary for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution. Under any reasonable threshold or definition, the emissions from EGUs are a significant contribution.¹¹⁰

G. Comments on the State of the Science of Climate Change

The EPA received a number of comments in response to the original proposed NSPS rule addressing the scientific underpinnings of the EPA's 2009 Endangerment Finding and, in essence, the scientific justification for this rule. Because this action is not a final action, we are not required to respond to those comments. Even so, we

¹¹⁰ Indeed, it is literally true that if fossil-fuel fired EGUs cannot be found to contribute significantly to GHG air pollution, then there is no source category in the U.S. that does contribute significantly to GHG air pollution, a result that would defeat the purposes of CAA section 111.

have carefully reviewed all of those comments, and we do provide some responses in this action. It is important to place these comments in the context of the voluminous record on this subject that has been compiled over the last few years. This includes: (1) The process by which the Administrator reached the 2009 finding that GHGs are reasonably anticipated to endanger the public health and welfare of current and future generations; (2) the EPA's response in 2010 to ten administrative petitions for reconsideration of the Endangerment Finding, the "Reconsideration Denial"; and, (3) the decision by the United States Court of Appeals for the D.C. Circuit (D.C. Circuit) in 2012 to uphold the Endangerment Finding and the Reconsideration Denial.

As outlined in Section VIII.A. of the 2009 Endangerment Finding, the EPA's approach to providing the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger human health and welfare was to rely primarily upon the recent, major assessments by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies. 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, in which the EPA took part. The EPA received thousands of comments on the proposed Endangerment Finding and responded to them in depth in an 11-volume RTC document. While the EPA gave careful consideration to *all* of the scientific and technical information received, it placed less weight on the much smaller number of individual studies that were not considered or reflected in the major assessments—often these studies were published after the submission deadline for those larger assessments. Primary reliance on the major scientific assessments provided the EPA greater assurance that it was basing its judgment on the best available, well-vetted science that reflected the consensus of the climate science community, rather than selecting the studies it would rely on. Nonetheless, the EPA reviewed individual studies not incorporated in the assessment literature to see if they would lead the EPA to change its interpretation of, or place less weight

on, the major findings reflected in the assessment reports. From its review of individual studies submitted by commenters, the EPA concluded that these studies did not change the various conclusions or judgments the EPA would draw based on the more comprehensive assessment reports. The major findings of the USGCRP, IPCC, and NRC assessments supported the EPA's determination that GHGs threaten the public health and welfare of current and future generations. The EPA demonstrated this scientific support at length in the Endangerment Finding itself, in its Technical Support Document (which summarized the findings of USGCRP, IPCC and NRC), and in its RTC document.

The EPA then reviewed ten administrative petitions for reconsideration of the Endangerment Finding in 2010. The Administrator denied those petitions in the "Reconsideration Denial" on the basis that the Petitioners failed to provide substantial support for the argument that the Endangerment Finding should be revised and therefore their objections were not of "central relevance" to the Finding.¹¹¹ The EPA prepared an accompanying 3-volume RTP document to provide additional information, often more technical in nature, in response to the arguments, claims, and assertions by the petitioners to reconsider the Endangerment Finding.

The 2009 Endangerment Finding and the 2010 Reconsideration Denial were challenged in a lawsuit, and on June 26, 2012, the D.C. Circuit upheld them, ruling that they were neither arbitrary nor capricious, were consistent with *Massachusetts v. EPA*,¹¹² and were adequately supported by the administrative record.¹¹³ The Court found that the EPA had based its decision on "substantial scientific evidence,"¹¹⁴ and noted that the EPA's reliance on assessments was consistent with the methods decision-makers often use to make a science-based judgment.¹¹⁵ The Court also found that the Petitioners had "not provided substantial support for their argument that the Endangerment Finding should be revised."¹¹⁶ Moreover, the Court assessed the EPA's reliance on the major scientific assessment reports that were

¹¹¹ "EPA's Denial of the Petitions To Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" ("Reconsideration Denial"), 75 FR 49556, 58 (Aug. 13, 2010).

¹¹² *Massachusetts v. EPA*, 549 U.S. 497.

¹¹³ *CRR*, 684 F.3d at 102.

¹¹⁴ *Id.* at 121.

¹¹⁵ *Id.* at 120.

¹¹⁶ *Id.* at 125.

conducted by USGCRP, IPCC, and NRC, and subjected to rigorous expert and government review, and found that—

EPA evaluated the processes used to develop the various assessment reports, reviewed their contents, and considered the depth of the scientific consensus the reports represented. Based on these evaluations, the EPA determined the assessments represented the best source material to use in deciding whether GHG emissions may be reasonably anticipated to endanger public health or welfare.¹¹⁷

As the Court stated,

It makes no difference that much of the scientific evidence in large part consisted of ‘syntheses’ of individual studies and research. Even individual studies and research papers often synthesize past work in an area and then build upon it. This is how science works. The EPA is not required to reprove the existence of the atom every time it approaches a scientific question.¹¹⁸

It is within the context of this extensive record, and recent affirmation of the Endangerment Finding by the Court, that the EPA has considered all of the submitted science-related comments and reports for the April 2012 proposed rule, and will consider any further comments in response to today’s proposed rule. As we did in the original Endangerment Finding, the EPA is giving careful consideration to all of the scientific and technical information in the record. However, the major peer-reviewed scientific assessments continue to provide the primary scientific and technical basis upon which the Administrator’s judgment relies regarding the threat to public health and welfare posed by GHGs.

Commenters on the April 2012 proposed rule submitted two major peer-reviewed scientific assessments that were released since the administrative record concerning the Endangerment Finding was closed after the EPA’s 2010 Reconsideration Denial: the IPCC Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation (2012) (SREX) and the NRC Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia (2011) (Climate Stabilization Targets). The EPA has reviewed these assessments and they are briefly characterized here:

SREX. The IPCC SREX assessment states that, “A changing climate leads to changes in the frequency, intensity, spatial extent, duration, and timing of extreme weather and climate events, and can result in unprecedented extreme weather and climate events.”

The SREX documents observational evidence of changes in some of the weather and climate extremes that have occurred globally since 1950. The SREX assessment provides evidence regarding the attribution of some of these changes to elevated concentrations of GHGs, including warming of extreme daily temperatures, intensification of extreme precipitation events, and rising extreme coastal high water due to increases in sea level. The assessment notes that further increases in some extreme weather and climate events are projected over the 21st century. The assessment also concludes that, combined with increasing vulnerability and exposure of populations and assets, changes in extreme weather and climate events have consequences for disaster risk, with particular impacts on the water, agriculture and food security, and health sectors.

Climate Stabilization Targets. The NRC Climate Stabilization Targets assessment states that, “Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth’s climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe.” The assessment addresses the fact that emissions of carbon dioxide will alter the composition of the atmosphere, and therefore the climate, for thousands of years and attempts to quantify the implications of stabilizing GHG concentrations at different levels. The report also estimates a number of specific climate change impacts, finding warming could lead to increases in heavy rainfall and decreases in crop yields and Arctic sea ice extent, along with other important changes in precipitation and stream flow. For an increase in global average temperature of 1 to 2 °C above pre-industrial levels, the assessment found that the area burnt by wildfires in western North America will likely more than double and coral bleaching and erosion will increase due both to warming and ocean acidification; an increase of 3 °C will lead to a sea level rise of 0.5 to 1.0 meters by 2100; and with an increase of 4 °C, the average summer in the United States would be as warm as the warmest summers of the past century. The assessment notes that although many important aspects of climate change are difficult to quantify, the risk of adverse impacts is likely to increase with increasing temperature, and the risk of dangerous surprises can be expected to

increase with the duration and magnitude of the warming.

A number of other National Academy assessments regarding climate have also been released recently. The EPA has reviewed these assessments, and finds that the improved understanding of the climate system resulting from the two assessments described above and the National Academy assessments strengthens the case that GHGs are endangering public health and welfare. Perhaps the most dramatic change relative to the prior assessments concern sea level rise. The previous 2007 IPCC AR4 assessment projected a rise in global sea level of between 7 and 23 inches by the end of the century relative to 1990 (with an acknowledgment that inclusion of ice sheet processes that were poorly understood would likely increase those projections). Three new NRC assessments have provided estimates of projected sea level rise that are much larger, in some cases more than twice as large as the previous IPCC estimates. *Climate Stabilization Targets; National Security Implications for U.S. Naval Forces* (2011); *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future* (2012). While the three NRC assessments continue to recognize and characterize the uncertainty inherent in accounting for ice sheet processes, these revised estimates strongly support and strengthen the existing finding that GHGs are reasonably anticipated to endanger human health and welfare. Other key findings of the recent assessments are described briefly below:

The *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future* (2012) assessment notes that observations have shown that sea level rise on the West Coast has risen south of Cape Mendocino over the past century but dropped north of that point during that time due to tectonic uplift and other factors in Oregon and Washington. However, the assessment projects a global sea level rise of 1.6 to 4.6 feet by 2100, which is sufficient to lead to rising relative sea level even in the northern states. The *National Security Implications of Climate Change for U.S. Naval Forces* also considers potential impacts of sea level rise, using a range of 1.3 to 6.6 feet by 2100. This assessment also suggests preparing for increased needs for humanitarian aid, responses to climate change in geopolitical hotspots including possible mass migrations, and addressing changing security needs in the Arctic as sea ice retreats. The *Climate and Social Stress: Implications for Security Analysis* (2012) assessment found that it

¹¹⁷ Id at 120.

¹¹⁸ Id at 120.

would be “prudent for security analysts to expect climate surprises in the coming decade . . . and for them to become progressively more serious and more frequent thereafter[.]”

Understanding Earth’s Deep Past: Lessons for Our Climate Future (2011) examines the period of Earth’s history prior to the formation of the Antarctic and Greenland Ice Sheets because CO₂ concentrations by the end of the century will have exceeded levels seen in the 30 million years since that time. The assessment discusses the possibility that analogous paleoclimate states might suggest higher climate sensitivity, less well regulated tropical surface temperatures, higher sea level rise, more anoxic oceans, and more potential for non-linear events such as the Paleocene Thermal Maximum than previously estimated. The assessment notes that three or four out of the five major coral reef crises of the past 500 million years were probably driven by acidification and warming caused by GHG increases similar to the changes expected over the next hundred years. The assessment states that “the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.” Similarly, the *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (2010) assessment found that “[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years.” The assessment notes that the full range of consequences is still unknown, but the risks “threaten coral reefs, fisheries, protected species, and other natural resources of value to society.”

Several commenters on the April 2012 proposed rule argue that the Endangerment Finding should be reconsidered or overturned based on those commenters’ reviews of specific climate science literature, particularly newer publications that have appeared since the EPA’s 2010 Denial of Petitions. Some commenters have presented their own compilations of individual studies as support for their assertions that climate change will have beneficial effects in many cases and that climate impacts will not be as severe or adverse as the EPA and assessments like the USGCRP (2009) report have stated. These commenters conclude that U.S. society will continue to easily adapt to

climate change and that climate change therefore does not pose a threat to human health and welfare.

The EPA has reviewed the information submitted and finds that, the fundamental issues raised in the comments that critique the scientific justification for the rule have been addressed by the EPA’s 11-volume response to comments for the 2009 Endangerment Finding, the EPA’s responses to all issues raised by Petitioners in the Reconsideration Denial, or the D.C. Circuit in its 2012 decision to uphold the EPA’s 2009 Endangerment Finding. These comments do not change the various conclusions or judgments that the EPA would draw based on the assessment reports relied upon in the recent 2009 Finding.

These comments often highlight uncertainty regarding climate science as an argument for reconsideration. However, uncertainty was explicitly recognized in the 2009 Endangerment Finding: “The Administrator acknowledges that some aspects of climate change science and the projected impacts are more certain than others”,¹¹⁹ and the decision to find endangerment was made with full recognition of the uncertainty involved. In addition, the D.C. Circuit Court decision noted that, “the existence of some uncertainty does not, without more, warrant invalidation of an endangerment finding.”¹²⁰ In short, these recent publications submitted by commenters, and any new issues that are extracted from them, do not undermine either the significant body of scientific evidence that has accumulated over the years or the conclusions presented in the substantial peer-reviewed assessments of the USGCRP, NRC, and IPCC.

Regarding the contentions that the U.S. will adapt to climate change impacts and that therefore climate change impacts pose no threat, the EPA stated in the 2009 Endangerment Finding,

Risk reduction through adaptation and GHG mitigation measures is of course a strong focal area of scientists and policy makers, including the EPA; however, the EPA considers adaptation and mitigation to be potential *responses* to endangerment, and as such has determined that they are outside the scope of the endangerment analysis.¹²¹

The D.C. Circuit upheld this position, ruling that “These contentions [that the U.S. can adapt] are foreclosed by the language of the statute and the Supreme

Court’s decision in *Massachusetts v. EPA*” because “predicting society’s adaptive response to the dangers or harms caused by climate change” does not inform the “scientific judgment” that the EPA is required to take regarding Endangerment.¹²²

Some commenters raise issues regarding the EPA Inspector General’s report, *Procedural Review of EPA’s Greenhouse Gases Endangerment Finding Data Quality Processes* (2011). These commenters mischaracterize the report’s scope and conclusions and, thus, vastly overstate the significance of the Inspector General’s procedural recommendations. Ultimately, nothing in the Inspector General report questions the validity of the EPA’s Endangerment Finding because that report did not evaluate the scientific basis of the Endangerment Finding. Rather, the Inspector General offers recommendations for clarifying and standardizing internal procedures for documenting data quality and peer review processes when referencing existing peer reviewed science in the EPA actions. Unrelated to the Endangerment Finding and its validation by the Court, the EPA has made progress towards implementing the recommendations by the Inspector General.

One commenter submitted a number of emails from the period 1999 to 2009 that were obtained from a University of East Anglia server in 2009 and publicly released in 2011. After reviewing these emails, the EPA finds that they raise no issues that were not previously raised by Petitioners in regard to an earlier group of emails from the same incident, released in 2009. The commenter makes unsubstantiated assumptions and subjective assertions regarding what the emails purport to show about the state of climate change science; this provides inadequate evidence to challenge the voluminous and well documented body of science that is the technical foundation of the Administrator’s Endangerment Finding.

A number of comments were also submitted in support of the Endangerment Finding and/or providing further evidence that climate change is a threat to human health and welfare. A number of individual studies were submitted and a number of observed or projected climate changes of local importance or concern to commenters were documented. Again, the EPA places lesser weight on individual studies than on the major scientific assessments. Local observed changes can be of great concern to individuals

¹¹⁹ 74 FR 66524.

¹²⁰ *CRR*, 684 F.3d at 121.

¹²¹ 74 FR 66512 (emphasis added).

¹²² 984 F.3d at 117.

and communities but must be assessed in the context of the broader science, as it is more difficult to draw robust conclusions regarding climate change over short time scales and in small geographic regions.

V. Rationale for Applicability Requirements

A. Applicability Requirements—Original Proposal and Comments

The original proposal was designed to apply to new intermediate and base load EGUs, specifically, (1) fossil fuel-fired utility boilers and IGCC EGUs subject to subpart Da for criteria pollutant emissions, and (2) natural gas combined cycle EGUs subject to subpart KKKK for criteria pollutant emissions. The original proposal explicitly did not apply to simple cycle turbines because we concluded that they were operated infrequently and therefore only contributed small amounts to total GHG emissions. (For convenience, we occasionally refer to this explicit statement that the original proposed NSPS did not apply to a type of source as an exclusion.)

We received comments that supported the simple cycle exclusion and others that opposed it. Commenters in support stated that a new simple cycle power plant serves a different purpose than a new combined cycle plant and that economics will drive the use of combined cycle facilities over simple cycle plants. They also stated that the original proposed standard is not achievable by, and therefore is not BSER for, simple cycle turbines. Commenters opposing the exclusion stated that it creates an opportunity to evade the standard and could thereby increase GHG emissions. According to these commenters, any applicability distinctions should be based on utilization and function rather than purpose or technology.

After considering these comments, we are proposing a different approach to the applicability provisions with respect to simple cycle turbines.

B. Applicability Requirements—Today's Proposal

In today's rulemaking, we propose that standards of performance apply to a facility if the facility supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year. (We refer to a facility's sale of more than one-third of its potential electric output as the one-third sales criterion, and we refer to the amount of potential electric output supplied to a utility power distribution system, expressed in MWh,

as the capacity factor.) This proposed definition does not explicitly exclude simple cycle combustion turbines, but as a practical matter, it would exclude most of them because the vast majority of simple cycle turbines sell less than one-third of their potential electric output. The few simple-cycle combustion turbines that sell more than one-third of their potential electric output to the grid would be subject to the proposed standards of performance. As explained below, we have concluded that at this level of output, there are less expensive and lower emitting technologies that could be constructed consistent with today's proposed standards. Although, as noted, today's proposal does not explicitly exclude simple cycle combustion turbines, we solicit comment on whether to provide an explicit exclusion.

We are proposing to apply the one-third sales criterion on a rolling three year basis instead of an annual basis for stationary combustion turbines for multiple reasons. First, extending the period to three years would ensure that the CO₂ standards apply only to intermediate and base load EGUs by allowing facilities intended to generally operate at low capacity factors (e.g. simple cycle turbines that generally sell less than one-third of their potential electric output) to avoid applicability even though they may provide system capacity and, in fact, operate at high capacity factors during individual years with abnormally high electric demand. Second, only 0.2 percent of existing simple cycle turbines had a three-year average capacity factor of greater than one-third between 2000 and 2012. Therefore, as noted, from a practical standpoint, few new simple cycle turbines will be subjected to the standards of performance in this rulemaking.

The 2013 AEO cost and performance characteristics for new generation technologies include costs for advanced and conventional combined cycle facilities and advanced simple cycle turbines. According to the AEO 2013 values, advanced combined cycle facilities have a lower cost of electricity than advanced simple cycle turbine facilities above approximately a 20 percent capacity factor. Therefore, the use of a combined cycle technology would be BSER for higher capacity factor stationary combustion turbines. However, advanced combined cycle facilities do not have a lower cost of electricity than less capital intensive conventional combined cycle facilities until above approximately a 40 percent capacity factor. Between approximately 20 to 40 percent capacity factors,

conventional combined cycle facilities offer the lowest cost of electricity, and below approximately 20 percent capacity factors advanced simple cycle turbines offer the lowest cost of electricity. A capacity factor exemption at 40 percent (i.e., sales of less than two-fifths of potential electric output per year) would allow conventional combined cycle facilities built with the intent to operate at relatively low capacity factors as an alternative technology to simple cycle turbines because neither would be subject to the NSPS requirements. Based on these cost considerations, we are specifically requesting comment on a range of 20 to 40 percent of potential electric output sales on a three-year basis for the capacity factor exemption. The 20 percent applicability limit is consistent with generating the lowest cost of electricity for advanced combined cycle turbines compared to advanced simple cycle turbines, and based on historical capacity factors would impact the operation of only approximately two percent of simple cycle turbines. The 40 percent applicability limit would be more consistent with the annual run hour limitations currently contained in many simple cycle operating permits.

We are also requesting comments on whether applicability for stationary combustion turbines should be defined on a single calendar year basis, similar to the current subpart Da applicability provisions for criteria pollutants, instead of a three-year basis. With a single year basis, we are considering an applicability level of up to 40 (instead of 33 and one-third) percent sales. Only 0.4 percent of existing simple cycle turbines had an annual capacity factor of greater than 40 percent between 2000 and 2012. Assuming the average hourly output of a simple cycle turbine is 80 percent of the maximum rated output, a simple cycle turbine could operate up to 4,400 hours annually before exceeding the capacity factor threshold. This is consistent with the operation hour limitation in many permits. Therefore, with this 40 percent sales criterion on a single-year basis, as a practical matter, it is anticipated that few new simple cycle turbines would be subject to the proposed standards of performance. Thus, we are specifically requesting comment on a range of one-third to two-fifths of potential electric output annual sales. The lower range would be consistent with how an EGU is currently defined in the EPA rules, and would mean that the proposed standards of performance would impact approximately one percent of new simple cycle turbines.

We are also proposing a different definition of potential electric output from the current definition that determines the potential electric output (in MWh on an annual basis) considering only the design heat input capacity of the facility and does not account for efficiency. It assumes a 33 percent net electric efficiency, regardless of the actual efficiency of the facility and could discourage the installation of more efficient facilities. For example, a 33 percent efficient 100 MW facility would have a heat input of 1,034 MMBtu/h and a 40 percent efficient 100 MW facility would have a heat input of 853 MMBtu/h.¹²³ The 33 percent efficient facility would become subject to the NSPS requirements when it sells more than one-third of its potential electric output, 880,000 MWh. The 40 percent efficient facility would become subject to the NSPS requirements when it sells more than 730,000 MWh.¹²⁴ This could potentially encourage the construction of less efficient facilities, since they could have a higher actual capacity factor than a more efficient unit, while still not being an EGU subject to a CO₂ standard. Therefore, we are proposing a definition of potential electric output that allows the source the option of calculating its potential electric output on the basis of its actual design electric output efficiency on a net output basis, as an alternative to the default one-third value. The proposed definition would permit the 40 percent efficient facility to use the actual efficiency of the facility so that the electric sales applicability criteria would be 880,000 MWh and applicability would be determined the same as for the less efficient facility.

The April 2012 proposal would have applied to facilities that primarily burn non-fossil fuels but also co-fire a fossil fuel. We have concluded that it is not appropriate to subject these facilities to the standards in today's proposal. This is because these types of units more closely resemble the non-fossil fuel-fired boilers and stationary combustion turbines that are not covered by today's proposed rule, than they do the fossil fuel-fired boilers and stationary combustion turbines that are covered by this rule. This approach is similar to the approach used in the Mercury and Air Toxics Standards, another CAA regulatory effort focused on fossil fuel-fired power plants. Therefore, we are

proposing to limit the applicability of the standard to facilities where the heat input is comprised of more than 10.0 percent fossil fuel on a three-year rolling average basis. To simplify determining applicability with the CO₂ standard, we also request comment on whether the applicability for facilities that co-fire non-fossil fuels should be made on an annual average basis, instead of a three-year rolling average basis.

In the original proposal, we requested comment on the applicability of the GHG NSPS to combined heat and power (CHP) facilities and if applicability should be changed from how it is currently determined in subpart Da. In today's action, we propose that if CHP facilities meet the general applicability criteria they should be subject to the same requirements as electric-only generators. However, one potential issue that we have identified is inequitable applicability to third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility. As noted above, we propose that the proposed CO₂ standard of performance apply to a facility that supplies more than one-third of its potential electricity output and more than 219,000 MWh "net electric output" to the grid per year. The current definition of net electric output for purposes of criteria pollutants is "the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis." 40 CFR 60.41Da. Owners/operators of a CHP facility under common ownership as an adjacent facility using the thermal output from the CHP facility (i.e., the thermal host) can subtract out power purchased by the adjacent facility on an annual basis when determining applicability. However, third-party CHP developers would not be able to benefit from the "minus purchased power on a calendar year basis" provision in the definition of net electric output when determining applicability since the CHP facility and the thermal host(s) are not under common ownership. We are therefore proposing to add "of the thermal host facility or facilities" to the definition of net-electric output for qualifying CHP facilities (i.e., the clause would read, "the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities on a calendar year basis" (emphasis added)). This would make applicability consistent for both facility-owned CHP and third-party-owned CHP.

This proposal includes within the definition of a steam electric generating unit, IGCC, and stationary combustion

turbine that are subject to the proposed requirements, any integrated device that provides electricity or useful thermal output to the boiler, the stationary combustion turbine or to power auxiliary equipment. The rationale behind including integrated equipment recognizes that the integrated equipment may be a type of combustion unit that emits GHGs, and that it is important to assure that those GHG emissions are included as part of the overall GHG emissions from the affected source. Including integrated equipment avoids circumvention of the requirements by having a boiler not subject to the standard supplying useful energy input (e.g., an industrial boiler supplying steam for amine regeneration in a CCS system) without accounting for the GHG emissions when determining compliance with the NSPS. In addition, the proposed definition would provide additional compliance flexibility similar to when the HRSG was included in the combustion turbine NSPS by recognizing the environmental benefit of integrated equipment that lowers the overall emissions rate of the affected facility. Even without this specific language, the original 1979 steam electric generating unit definition in subpart Da allows the use of solar thermal equipment for feedwater heating as an approach to integrating non-emitting generation to reduce environmental impact and lower the overall emissions rate. The current definition expands the flexibility to include combustion turbines, fuel cells, or other combustion technology for reheating or preheating boiler feedwater, preheating combustion air, producing steam for use in the steam turbine or to power the boiler feedpumps, or using the exhaust directly in the boiler to generate steam. This in theory could lower generation costs as well as lower the GHG emissions rate for an EGU.

We solicit comment on various issues concerning, and different approaches to, the applicability requirements for steam generating units and combustion turbines. In particular, we recognize that several of the requirements proposed today are based on the source's operations. These include, for both steam generating units and combustion turbines, the requirement that the source supply more than one-third of its potential electric output and more than 219,000 MWh net-electric output to the grid for sale on an annual or tri-annual basis (the one-third and 219,000 MWh sales requirement), as well as the requirement that the source burn fossil fuel for more than 10 percent of the heat input during three years; and for

¹²³ $(100 \text{ MW}) * (3.412 \text{ MMBtu/h/1 MW}) * (1/0.33) = 1,034 \text{ MMBtu/h}$. $(100 \text{ MW}) * (3.412 \text{ MMBtu/h/1 MW}) * (1/0.40) = 853 \text{ MMBtu/h}$.

¹²⁴ $(1,034 \text{ MMBtu/h}) * (1 \text{ MW}/3.412 \text{ MMBtu/h}) * (1/3) * (8,760 \text{ h/yr}) = 880,000 \text{ MWh}$. $(853 \text{ MMBtu/h}) * (1 \text{ MW}/3.412 \text{ MMBtu/h}) * (1/3) * (8,760 \text{ h/yr}) = 730,000 \text{ MWh}$.

combustion turbines, the additional requirement that the source combust over 90 percent natural gas on a heat input basis over three years.

We solicit comment on whether these requirements raise implementation issues because they are based on source operation after construction has occurred. We also solicit comment on whether, to avoid any such implementation issues, these requirements should be recast to be based on the source's purpose at the time of construction. For example, should we recast the 10% percent requirement so that it would be met if the source was constructed for the purpose of burning fossil fuel for more than 10 percent of its heat input over any three-year period?

In addition, we solicit comment on whether we should include these requirements not as applicability requirements for whether the source is subject to the standard of performance, but rather as criteria for which part of the standard of performance the source is subject to. Under this approach, at least for combustion turbines, the EPA would promulgate applicability requirements or a definition of utility unit designed to assure that combustion turbine utility units—but not combustion turbine industrial units or other types of non-utility units—would be subject to the standard of performance. For example, under this approach, all combustion turbine units that meet such applicability requirements or definition of utility units and that have a design heat input to the turbine engine greater than 250 MMBtu/h, would be subject to the standard of performance for CO₂ emissions. That standard would be: (i) during periods when certain conditions (noted below) are met, 1,000 or 1,100 lb CO₂/MWh (depending on whether the unit has a design heat input to the turbine engine of greater than 850 MMBtu/h); and (ii) during periods when one or more of those conditions is not met, no emission limit (that is, the unit could emit at an uncontrolled level). In the latter case, although the unit would not be subject to an emission limit, it would remain subject to the standard of performance, and therefore would be subject to any monitoring, reporting, and recordkeeping requirements. The conditions could include, during any 3-year period on a rolling average basis, combusting over 10% fossil fuel on a heat input basis, combusting over 90% natural gas on a heat input basis, and selling more than one-third of potential electric output and more than 219,000 MWh net-electric output to the grid.

Under this approach, as noted, in order to be consistent with today's proposal to apply the standard of performance for CO₂ emissions to only utility units—and not to industrial or other non-utility units—we would need to include other applicability requirements or definitional provisions that would explicitly limit the standard to utility units.

We solicit comment on all aspects of this approach, including the extent to which it would achieve the policy objectives of assuring that a simple cycle turbine and a combined cycle turbine are subject to the same standard if they sell more than one-third of their capacity and more than 219,000 KWh net electric output to the grid, and are subject to the same standard if they sell less than those amounts to the grid. We also solicit comment on how to implement the three-year requirements described above during the period within three years after an affected EGU begins operations. For example, under the approach where operational criteria that entail a three-year compliance period are used to determine to which standard of performance the facility is subject, the owner or operator and permitting authority would not know for certain what standard applies to the facility until three years after initial startup. For this scenario, we request comment on how to implement the three year operational requirements and what documentation should be collected and reported to the EPA during the period up to the end of the third year after a source begins operation.

C. Certain Projects Under Development

This proposal does not apply to the proposed Wolverine EGU project in Rogers City, Michigan. Based on current information, the Wolverine project appears to be the only fossil fuel-fired boiler or IGCC EGU project presently under development that may be capable of “commencing construction” for NSPS purposes¹²⁵ in the very near future and, as currently designed, could not meet the 1,100 lb CO₂/MWh standard proposed for other new fossil fuel-fired boiler and IGCC EGUs. The EPA has not formulated a view as to the project's status in the development process or as to whether the proposed 1,100 lb CO₂/MWh standard or some other CO₂ standard of performance would be representative of BSER for this project, and invites comment on these

¹²⁵ The NSPS regulations include definitions of “commenced” and “construction”. See 40 CFR 60.2.

questions.¹²⁶ At the time of finalization of this proposal, if the Wolverine project remains under development and has not either commenced construction or been canceled, we anticipate proposing that the project either be made subject to the 1,100 lb CO₂/MWh standard or be assigned to a subcategory with an alternate CO₂ standard. Further discussion is provided in the technical support document in the docket entitled “Fossil Fuel-Fired Boiler and IGCC EGU Projects under Development: Status and Approach.”

There are two other fossil fuel-fired boiler or IGCC EGU projects without CCS—the Washington County project in Georgia and the Holcomb project in Kansas—that appear to remain under development but whose developers have recently represented that the projects have commenced construction for NSPS purposes. Based solely on the developers' representations, the projects would be existing sources, and thus not subject to this proposal. However, neither developer has sought a formal EPA determination of NSPS applicability; and, if upon review it was determined that the projects have not commenced constructions, the projects should be situated similarly to the Wolverine project. Accordingly, if it is determined in the future that either of these projects has not commenced construction as of the date of this proposal, then that project will be addressed in the same manner as the Wolverine project.¹²⁷ Further discussion

¹²⁶ The EPA's lack of view regarding the appropriate CO₂ standard is closely related to the existence of conflicting information on where the project stands in the development process. The developer has claimed that the project was delayed by issues related to the standards of performance for hazardous air pollutants promulgated in December 2011, 77 FR 9304 (Feb. 16, 2012) (Mercury and Air Toxics Standards, or MATS). Specifically, the developer cited a perceived inability to obtain guarantees from pollution control equipment vendors that the plant would achieve the MATS standards. See Jim Dulzo, *As Coal Plant Teeters, Groups Mount Legal Attack*, Michigan Land Use Institute blog, Feb. 13, 2012, <http://www.mlui.org/energy/news-views/news-views-articles/as-coal-plant-teeters-groups-mount-legal-attack.html>. While some of the MATS new-unit standards were revised upon reconsideration in March 2013, 78 FR 24073 (Apr. 24, 2013), the developer's claims raise the possibility that the EPA's own actions may have delayed the project and contributed to the present uncertainty as to the project's development status.

¹²⁷ In this event, there will not be any proposed standard “which will be applicable to such source” within the meaning of CAA section 111(a)(2), and to the extent that this proposal did, until the time of the construction commencement determination, apply to that project, this proposal will be considered automatically to be withdrawn as it applies to that project as of the time of that determination. The purpose of this automatic withdrawal is to ensure that the project is placed on the same footing as the Wolverine project as

is provided in the technical support document in the docket referenced above.¹²⁸

We invite comment on all aspects of this approach for addressing the Wolverine project (and the Washington County and Holcomb projects, if applicable).¹²⁹

VI. Legal Requirements for Establishing Emission Standards

A. Overview

In this section, we describe the principal legal requirement for the standards of performance under CAA section 111 that we propose in this rulemaking, which is that the standards must consist of emission limits that are based on the “best system of emission reduction . . . adequately demonstrated,” taking into account cost and other factors (BSER). In this manner, CAA section 111 provides that the EPA’s central task is to identify the BSER. The D.C. Circuit has handed down case law, which we review in detail, that interprets this CAA provision, including its component elements. The Court’s interpretation indicates the technical, economic, and energy-related factors that are relevant for determining the BSER, and provides the framework for analyzing those factors.

According to the D.C. Circuit, EPA determines the best demonstrated system based on the following key considerations, among others:

- The system of emission reduction must be technically feasible.
 - EPA must consider the amount of emissions reductions that the system would generate.
 - The costs of the system must be reasonable. EPA may consider the costs on the source level, the industry-wide level, and, at least in the case of the power sector, on the national level in terms of the overall costs of electricity and the impact on the national economy over time.
 - EPA must also consider that CAA section 111 is designed to promote the development and implementation of technology.
- Other considerations are also important, including that EPA must also consider energy impacts, and, as with costs, may consider them on the source level and on the nationwide structure of the power sector over time. Importantly, EPA has discretion to weigh these various considerations, may determine that some merit greater weight than others, and may vary the weighting depending on the source category.

B. CAA Requirements and Court Interpretation

1. Clean Air Act Requirements

The EPA’s basis for proposing that partial capture CCS is the BSER for new fossil fuel-fired utility boilers and IGCC units, and that NGCC is the BSER for natural gas-fired stationary combustion turbines, is rooted in the provisions of CAA section 111 requirements, as interpreted by the United States Court of Appeals for the D.C. Circuit (“D.C. Circuit” or “Court”), which is the federal Court of Appeals with jurisdiction over the EPA’s CAA rulemaking.

As the first step towards establishing standards of performance, the EPA “shall publish . . . a list of categories of stationary sources . . . [that] cause[,], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” section 111(b)(1)(A). Following that listing, the EPA “shall publish proposed regulations, establishing federal standards of performance for new sources within such category” and then “promulgate . . . such standards” within a year after proposal. section 111(b)(1)(B). The EPA “may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.” section 111(b)(2). The term “standard of performance” is defined to “mean[] 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.” section 111(a)(1).

2. Court Interpretation

For present purposes, the key section 111 provisions are the definition of “standard of performance,” under CAA section 111(a)(1), and, in particular, the “best system of emission reduction which (taking into account . . . cost . . . nonair quality health and environmental impact and energy requirements) . . . has been adequately demonstrated.” The D.C. Circuit has reviewed rulemakings under section 111 on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,¹³⁰ through which the Court has developed a body of case law that interprets the term “standard of performance.” These interpretations are of central importance to the EPA’s justification for the standards of performance in the present rulemaking.

At the outset, it should be noted that Congress first included the definition of “standard of performance” when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), and then amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA, generally repealing the amendments in the 1977 CAAA and, therefore, reverting to the version as it read after the 1970 CAAA. The legislative history for the 1970 and 1977 CAAs explained various aspects of the definition as it read at those times. Moreover, the various decisions of the D.C. Circuit interpreted the definition that was applicable to the rulemakings before the Court. Notwithstanding the amendments to the definition, the D.C. Circuit’s interpretations discussed below remain applicable to the current definition.¹³¹

¹³⁰ *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, (D.C. Cir. 1973); *Portland Cement Ass’n v. EPA*, 665 F.3d 177 (D.C. Cir. 2011).

¹³¹ In the 1970 CAAA, Congress defined “standard of performance,” under section 111(a)(1), 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) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard (i) be based on, in lieu of the “best system of emission reduction . . . adequately

soon as possible. It is worth noting that nothing in this proposal binds the EPA to the position that the projects have “commenced construction” for NSPS purposes.

¹²⁸ In the April 2012 GHG NSPS proposal, the Wolverine, Washington County, and Holcomb projects were among a group of 15 projects distinguished from other EGU projects as “potential transitional sources.” This proposal does not continue that distinction. Except as described above for the Wolverine project, and possibly the Washington County and Holcomb projects, any former “potential transitional source” that commences construction after publication of this proposal (and meets any other applicability criteria) will be subject to the final CO₂ standards established in this rulemaking. Any former “potential transitional source” that commenced construction prior to publication of this proposal is an existing source not subject to the CO₂ standards established in this rulemaking, but instead subject to the CO₂ standards that are required to be established for existing sources pursuant to CAA section 111(d).

¹²⁹ The EPA intends that its treatment of the Wolverine project (and the Washington County and Holcomb projects, if applicable) be severable from its treatment of differently situated sources and considers that severability is logical because of the record-based differences between these sources and differently situated sources and because there is no interdependency in the EPA’s treatment of the different types of sources. This statement concerning severability should not be construed to have implications for whether other components in this rulemaking are severable.

3. Overview of Interpretation

By its terms, the definition of “standard of performance” under CAA section 111(a)(1) provides that the emission limit that the EPA promulgates must be “achievable” and must be based on a system of emission reduction—generally, but not required to be always, a technological control—that the EPA determines to be the “best system” that is “adequately demonstrated,” “taking into account . . . cost . . . nonair quality health and environmental impact and energy requirements.” The D.C. Circuit has stated that in determining the “best” system, the EPA must also take into account “the amount of air pollution”¹³² and “technological innovation.”¹³³

As discussed below, the D.C. Circuit has elaborated on the criteria and process for determining whether a standard is “achievable,” based on an “adequately demonstrated” technology or system. In addition, the Court has identified limits on the costs and other factors that are acceptable for the technology or system to qualify as the “best.” The Court has also held that the EPA may consider the costs and other factors on a regional or national level (e.g., the EPA may consider impacts on the national economy and the affected industry as a whole) and over time, and not just on a plant-specific level at the time of the rulemaking.¹³⁴ In addition, the Court has emphasized that the EPA has a great deal of discretion in weighing the various factors to determine the “best system.”¹³⁵

demonstrated,” the “best technological system of continuous emission reduction . . . adequately demonstrated;” and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider “any nonair quality health and environment impact and energy requirements.”

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of section 111(a)(1) that the standard of performance be based on the “best system of emission reduction . . . adequately demonstrated.” This 1990 CAAA version is the current definition, which is applicable at present. Even so, because parts of the definition as it read under the 1977 CAAA were retained in the 1990 CAAA, the explanation in the 1977 CAAA legislative history, and the interpretation in the case law, of those parts of the definition remain relevant to the definition as it reads today.

¹³² See *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).

¹³³ See *Sierra Club v. Costle*, 657 F.2d at 347.

¹³⁴ See *Sierra Club v. Costle*, 657 F.2d at 330.

¹³⁵ See *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).

Moreover, the Court has stated that in considering the various factors and determining the “best system,” the EPA must be mindful of the purposes of section 111, and the Court has identified those purposes as “not giv[ing] a competitive advantage to one State over another in attracting industry[.]” . . . “reducing emissions as much as practicable[.]” . . . “forc[ing] the installation of all the control technology that will ever be necessary on new plants at the time of construction[.]” . . . and “forc[ing] the development of improved technology.”¹³⁶ Finally, based on cases the D.C. Circuit has handed down under related provisions of the CAA and the EPA’s regulatory precedent under section 111, the EPA may promulgate a standard of performance for a particular category of sources even if not every type of new source in the category would be able to achieve that standard.¹³⁷

We next discuss in more detail each of these components of the interpretation of “standard of performance.”

C. Technical Feasibility

The D.C. Circuit’s first decision under section 111, *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973), concerned whether EPA’s standard of performance for the cement industry met the requirement to be “achievable,” which, in turn, depended on whether the technology on which EPA based the standard was “adequately demonstrated.”¹³⁸ In this case, the Court interpreted these provisions to require that the technology must be technically feasible for the source category, and established criteria for determining technical feasibility.

The Court explained that a standard of performance is “achievable” if a technology can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard. Specifically, the D.C. Circuit explained:

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.

. . . —It is the “achievability” of the proposed standard that is in issue

The Senate Report made clear that it did not intend that the technology “must be in actual routine use somewhere.” The essential question was rather whether the technology would be available for installation in new plants. . . . The Administrator may make a

¹³⁶ *Sierra Club v. Costle*, 657 F.2d at 325 & n.83 (quoting 44 FR 33580, 33581/3–33582/1).

¹³⁷ See, e.g., *International Harvester Co. v. EPA*, 478 F.2d 615, 640 (D.C. Cir. 1973).

¹³⁸ 486 F.2d at 390.

projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on “crystal ball” inquiry.¹³⁹ In subsequent cases, the D.C. Circuit has consistently reiterated this formulation of “achievable.”¹⁴⁰

It should be noted that in another of the early cases, *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973), the D.C. Circuit upheld a standard of performance as “achievable” on the basis of test data showing that the tested plant emitted less than or at the standard on three occasions and emitted above the standard on 16 occasions, and that, on average, it emitted 15 percent above the standard on a total of 19 occasions.¹⁴¹ The fact that the plant had achieved the standard on at least a few occasions, even though the plant had not done so on the great majority of occasions, “adequately demonstrated” that the standard was “achievable.”

D. Factors To Consider in Determining the “Best System”

1. Amount of Emissions Reductions

Although the definition of “standard of performance” does not by its terms identify the amount of emissions from the category of sources and the amount of emission reductions achieved as factors the EPA must consider in determining the “best system of emission reduction,” the D.C. Circuit has stated that the EPA must do so. See *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981) (“we can think of no sensible interpretation of the statutory words “best . . . system” which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions”).¹⁴² This is consistent with the Court’s statements in *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973) that it is necessary to “[k]eep[] in mind Congress’ intent that new plants be

¹³⁹ *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

¹⁴⁰ See, e.g., *National Asphalt Pavement Ass’n v. Train*, 539 F.2d 775, 785 (D.C. Cir. 1976); *Lignite Energy Council v. EPA*, 109 F.3d 930, 934 (D.C. Cir. 1999).

¹⁴¹ *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d at 437 & n. 27.

¹⁴² *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of “standard of performance,” which revised the phrase “best system” to read, “best technological system.” The 1990 CAAA deleted “technological,” and thereby returned the phrase to how it read under the 1970 CAAA. The *Sierra Club v. Costle*’s interpretation of this phrase to require consideration of the amount of air emissions remains valid for the phrase “best system.”

controlled to the ‘maximum practicable degree.’”¹⁴³

2. Costs

In several cases, the D.C. Circuit has elaborated on the cost factor that the EPA is required to consider under CAA section 111(a)(1), and has identified limits to how costly a control technology may be before it no longer qualifies as the “best system of emission reduction . . . adequately demonstrated.” As a related matter, although no D.C. Circuit case addresses how to account for revenue generated from the byproducts of pollution control, it is logical and a reasonable interpretation of the statute that any expected revenues from the sale of pollutants or pollution control byproducts associated with those controls may be considered when determining the overall costs of implementation of the control technology. Clearly, such a sale would offset regulatory costs and so must be included to accurately assess the costs of the standard.

a. Criteria for Costs

(i) Formulation

In *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit stated that to be “adequately demonstrated,” the system must be “reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.” The Court has reiterated this limit in subsequent case law, including *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999), in which it stated: “EPA’s choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.” In *Portland Cement Ass’n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975), the Court elaborated by explaining that the inquiry is whether the costs of the standard are “greater than the industry could bear and survive.”¹⁴⁴

¹⁴³ *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d at 437 & n. 27 (citing “Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970,” 116 Cong. Rec. 42384, 42385 (1970)).

¹⁴⁴ The 1977 House Committee Report noted:

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

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

The implicit consideration of economic factors in determining whether technology is “available” should not affect the usefulness of this section. The

In *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981), the Court provided a substantially similar formulation of the cost standard when it held: “EPA concluded that the Electric Utilities’ forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.” We believe that these various formulations of the cost standard—“exorbitant,” “greater than the industry could bear and survive,” “excessive,” and “unreasonable”—are synonymous; the D.C. Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use reasonableness as the standard, so that a control technology may be considered the “best system of emission reduction . . . adequately demonstrated” if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.

(ii) Examples

In the case law under CAA section 111, the D.C. Circuit has never invalidated a standard of performance on grounds that it was too costly. In several cases, the Court upheld standards that entailed high costs. In *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973), the Court considered a standard of performance that the EPA promulgated for particulate matter emissions from new and modified Portland cement plants. According to the Court, the cost for the control technologies that a new facility would need to install to meet the standard was about 12 percent of the capital investment for the total facility, and annual operating costs for the control equipment would be 5–7 percent of the total plant operating costs. The Court found that these costs “could be passed on without substantially affecting competition” because the demand for the product was not “highly elastic with regard to price and would not be very sensitive to small price changes.” The Court held that the EPA gave appropriate consideration to the “economic costs to the industry.”¹⁴⁵ In *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981), the D.C. Circuit upheld a standard of performance imposing

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.

S. Comm. Rep. No. 91–1196 at 16.

¹⁴⁵ *Portland Cement Association v. Ruckelshaus*, 486 F.2d at 387–88.

costly controls on SO₂ emissions from coal-fired power plants. The Court noted:

The importance of the challenged standards arises not only from the magnitude of the environmental and health interests involved, but also from the critical implications the new pollution controls have for the economy at the local and national levels.

* * * * *

Coal is the dominant fuel used for generating electricity in the United States. . . . In 1976 power plant emissions accounted for 64 percent of the total estimated sulfur dioxide emissions and 24 percent of the total estimated particulate matter emissions in the entire country.

EPA’s revised NSPS are designed to curtail these emissions. EPA predicts that the new standards would reduce national sulfur dioxide emissions from new plants by 50 percent and national particulate matter emissions by 70 percent by 1995. The cost of the new controls, however, is *substantial*. EPA estimates that utilities will have to spend *tens of billions of dollars* by 1995 on pollution control under the new NSPS. *Consumers will ultimately bear these costs, both directly in the form of residential utility bills, and indirectly in the form of higher consumer prices due to increased energy costs.*¹⁴⁶

b. Revenue Enhancements

In determining the costs of pollution control technology, it is reasonable to take into account any revenues generated by the sale of any by-products of the control process. Many types of pollution control technology generate byproducts that must be disposed, and the costs of that disposal are considered part of the costs of the control technology. For example, CCS generates a stream of CO₂ that must be disposed of through sequestration.

In some instances, however, the by-products of pollution control have marketable value. In these cases, revenues from selling the by-products would defray the costs of pollution control. For example, in a recent rulemaking under the CAA regional haze program that entailed determining the “best available retrofit technology” (BART) for power plants, revenue from fly ash generated during boiler combustion and sold for use in concrete production factored into the State’s selection of BART).¹⁴⁷

¹⁴⁶ *Sierra Club v. Costle*, 657 F.2d at 313 (citations omitted) (emphasis added).

¹⁴⁷ Similarly, the EPA has taken into account the value of fuel savings in determining the costs of rules that limit emissions from motor vehicles, which limits manufacturers are expected to achieve by reducing the rates of fuel consumption by the vehicles. *See, e.g.*, 77 FR 62624, 62628–29; 62923–27; 62942–46 (October 15, 2012) (rulemaking setting GHG emissions standards for Light-Duty Vehicles for Model Years 2017–2025).

3. Expanded Use and Development of Technology

In *Sierra Club v. Costle*, the Court made clear that technological innovation was grounded in the terms of section 111 itself, and therefore should be considered one of the factors to be considered in determining the “best system of emission reduction:”

Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.¹⁴⁸

The Court’s interpretation finds firm grounding in the legislative history. For example, the 1970 Senate Committee Report stated:

Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources, since more effective emission control will provide greater latitude in the selection of sites for new facilities.¹⁴⁹

Similarly, the 1977 Senate Committee Report stated:

In passing the Clean Air Amendments of 1970, the Congress for the first time imposed a requirement for specified levels of control technology. The section 111 Standards of Performance for New Stationary Sources required the use of the “best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.” This requirement sought to assure the use of available technology and to stimulate the development of new technology.¹⁵⁰

¹⁴⁸ *Sierra Club v. Costle*, 657 F.2d at 347.

¹⁴⁹ S. Rep. 91–1196 at 16 (1970). The technology-forcing nature of section 111 is consistent with the technology-forcing nature of the 1970 CAAA as a whole. The principal Senate author of the 1970 CAAA, Sen. Edmund Muskie (D-ME), during the Senate floor debate, described the overall requirements of the 1970 CAAA and then observed:

These five sets of requirements will be difficult to meet. But the committee is convinced that industry can make compliance with them possible or impossible. It is completely within their control. Industry has been presented with challenges in the past that seemed impossible to meet, but has been made possible.

116 Cong. Rec. 32902 (Sept. 21, 1970) (statement of Sen. Muskie).

¹⁵⁰ S. Rep. 95–127 at 17 (1977), cited in *Sierra Club v. Costle*, 657 F.2d at 346 n. 174. The 1977 CAAA legislative history is replete with other references to the technology forcing nature of section 111 or the CAAA as a whole. See “1977 Clean Air Act Conference Report: Statement of Intent; Clarification of Select Provisions,” 123 Cong. Rec. 27071 (1977) (quoted in *Sierra Club v. Costle*, 657 F.2d at 346 n. 174) (one of the enumerated purposes of section 111 was to “create incentives for new technology”); 123 Cong. Reg. 16195 (May 24, 1977) (statement of Rep. Meads) (“The main

The legislative history just quoted identifies three different ways that Congress designed section 111 to authorize standards of performance that promote technological improvement: (i) the development of technology that may be treated as the “best system of emission reduction . . . adequately demonstrated;” under section 111(a)(1)¹⁵¹; (ii) the expanded use of the best demonstrated technology;¹⁵² and (iii) the development of emerging technology.¹⁵³

E. Nationwide Component of Factors in Determining the “Best System”

Another component of the D.C. Circuit’s interpretations of section 111 is that the EPA may consider the various factors it is required to balance on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.¹⁵⁴ As the D.C. Circuit stated in *Sierra Club v. Costle*:

The language of [the definition of ‘standard of performance’ in] section 111 . . . gives EPA authority when determining the best . . . system to weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.¹⁵⁵

In that case, in upholding the EPA’s variable standard for SO₂ emissions, the D.C. Circuit justified and elaborated on that interpretation of the definition of “standard of performance” and then went on to evaluate the EPA’s justification for its rulemaking in light of that interpretation. It is useful to set out these parts of the Court’s opinion at some length in order to make clear the scope of the factors and the nature of the balancing exercise that the Court held section 111(a)(1) authorizes the EPA to take.

The Court first recited the terms of the definition of “standard of performance,” as it read following the 1977 CAA Amendments:

The pertinent portion of section 111 reads:

purposes of the Clean Air Act Amendments of 1977 are as follows: . . . tenth, to promote the utilization of new technologies for pollution choice”).

¹⁵¹ See *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must “look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present”).

¹⁵² See 1970 Senate Committee Report No. 91–1196 at 15 (“The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems”).

¹⁵³ See *Sierra Club v. Costle*, 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

¹⁵⁴ *Sierra Club v. Costle*, 657 F.2d at 351.

¹⁵⁵ *Sierra Club v. Costle*, 657 F.2d at 330.

A standard of performance shall reflect the degree of emission limitation . . . achievable through application of the best . . . system of . . . emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.¹⁵⁶

The Court then stated that these terms could reasonably be read to authorize the EPA to establish the standard of performance based on environmental, economic, and energy considerations “on the grand scale:”

Parsed, section 111 most reasonably seems to require that EPA identify the emission levels that are “achievable” with “adequately demonstrated technology.” After EPA makes this determination, it must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations. It follows that to exercise this discretion EPA must examine the effects of technology on the grand scale in order to decide which level of control is best. For example, an efficient water intensive technology capable of 95 percent removal efficiency might be “best” in the East where water is plentiful, but environmentally disastrous in the water-scarce West where a different technology, capable of only 80 percent reduction efficiency might be “best.” . . . The standard is, after all, a national standard with long-term effects.¹⁵⁷

The Court then justified its “reading of . . . section 111 as authorizing the EPA to balance long-term national and regional impacts of alternative standards” on the 1977 CAAA legislative history:

The Conferees defined the best technology in terms of “long-term growth,” “long-term cost savings,” effects on the “coal market,” including prices and utilization of coal reserves, and “incentives for improved technology.” Indeed, the Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.¹⁵⁸

¹⁵⁶ *Sierra Club v. Costle*, 657 F.2d at 330. Note that the ellipses in the quotation of the definition of “standard of performance” in the text indicate the omission of terms repealed by the 1990 CAAA. The Court’s analysis of the meaning of this definition did not turn on those repealed terms, and as a result, the Court’s analysis remains relevant for the current definition of “standard of performance.”

¹⁵⁷ *Sierra Club v. Costle*, 657 F.2d at 330 (emphasis added). As noted, after the 1990 CAAA—which changed the term “best technological system . . . of emission reduction . . . adequately demonstrated” to “best system . . . of emission reduction . . . adequately demonstrated”—the Court’s discussion of “adequately demonstrated technology” should be considered to hold true for adequately demonstrated system of emission reduction.

¹⁵⁸ *Sierra Club v. Costle*, 657 F.2d at 331 (citations omitted) (citing legislative history).

The Court then examined the EPA's justification for the variable standard, and held that the justification was reasonable.¹⁵⁹ The Court quoted at length the EPA's discussion of how it "justified the variable standard in terms of the policies of the Act," including balancing long-term national and regional impacts:

The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO₂ emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . . By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO₂ control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.

By substantially reducing SO₂ emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.¹⁶⁰

F. Chevron Framework

Above, we discuss how in *Sierra Club v. Costle* the D.C. Circuit interpreted the definition of "standard of performance" in CAA section 111(a)(1), among other things, to authorize the EPA to balance economic, environmental, or energy factors through a nationwide lens, and to encompass technology forcing. The D.C. Circuit handed down this decision in 1981, and therefore it did not employ the two-step framework for statutory construction in federal rulemaking that the U.S. Supreme Court mandated in 1984, in *Chevron U.S.A. Inc. v. NRDC*, 467 U.S. 837 (1984). However, the D.C. Circuit's interpretations are fully consistent with the *Chevron* framework.

In *Chevron*, the Supreme Court held that an agency must, at Step 1, determine whether Congress's intent as to the specific matter at issue is clear, and, if so, the agency must give effect to that intent. If congressional intent is not clear, then, at Step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.¹⁶¹

As noted, under CAA section 111(a)(1), a standard of performance must be based on 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) . . . has been adequately demonstrated." The terms "best system of emission reduction," "cost," and

"energy requirements," on their face, can be interpreted to apply on a nationwide or nationwide basis, and are not limited to the individual source. Thus, this interpretation is supportable under *Chevron* step 1, but even if not, then the EPA considers the interpretation supportable under step 2 because it is reasonable and consistent with the purposes of the CAA. Similarly, the technology-development interpretation is supportable under *Chevron* step 1 because encouraging the utilization or development of improved technology is a logical consideration in determining the "best system of emission reduction" and, as noted, was clearly a focus of the legislative history. Even if that interpretation is not supportable under *Chevron* step 1, however, then the EPA considers the interpretation supportable under step 2 because it is reasonable and consistent with the purposes of the CAA.

G. Agency Discretion

The D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981), the Court explained that "section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,"¹⁶² and emphasized that "[t]he text gives the EPA broad discretion to weigh different factors in setting the standard."¹⁶³ In *Lignite Energy Council v. EPA*, 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them. . . . EPA's choice [of the "best system"] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.¹⁶⁴

The important point is that Courts acknowledge that there are several factors to be considered and what is "best" depends on how much weight to give the factors. In promulgating certain standards of performance, EPA may give greater weight to particular factors than it may do so in promulgating other standards of performance. Thus, the determination of what is "best" is complex and necessarily requires an exercise of judgment. By analogy, the question of who is the "best" sprinter in

the 100-meter dash primarily depends on only one criterion—speed—and therefore is relatively straightforward, while the question of who is the "best" baseball player depends on a more complex weighing of several criteria and therefore requires a greater exercise of judgment.

H. Lack of Requirement That Standard Be Able To Be Met by All Sources

Under CAA section 111, an emissions standard may meet the requirements of a "standard of performance" even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard. As discussed below, this is clear in light of (i) the legislative history of CAA section 111, read in conjunction with the legislative history of the CAA as a whole; (ii) case law under analogous CAA provisions; and (iii) long-standing precedent in the EPA rulemakings under CAA section 111.

1. Legislative History

As noted, Congress, in enacting section 111 in the 1970 CAAA, intended that the EPA promulgate uniform, nationwide controls. Congress was explicit that this meant that large industrial sources, including electric generating power plants, would be required to implement controls meeting the requirements regardless of their location. According to the 1970 Senate Committee Report:

Major new facilities such as electric generating plants, kraft pulp mills, petroleum refineries, steel mills, primary smelting plants, and various other commercial and industrial operations must be controlled to the maximum practicable degree regardless of their location and industrial operations * * *.¹⁶⁵

Congress's purposes in designing a standard that called for uniform national controls were to prevent pollution havens—caused by some states seeking competitive advantage by limiting their pollution control requirements—and to assure that areas that had good air quality would be able to maintain good air quality even after new industrial sources located there, which, in turn, would allow more sources to locate there as well.¹⁶⁶

At the same time, Congress recognized that in light of the attainment provisions of the CAAA of 1970, sources—particularly large industrial sources, again, including electric generating plants—may not be

¹⁵⁹ *Sierra Club v. Costle*, 657 F.2d at 337–39.

¹⁶⁰ *Sierra Club v. Costle*, 657 F.2d at 327–28 (quoting 44 FR 33583/3–33584/1).

¹⁶¹ *Chevron U.S.A. Inc. v. NRDC*, 467 U.S. 837, 842–43 (1984).

¹⁶² *Sierra Club v. Costle*, 657 F.2d at 319.

¹⁶³ *Sierra Club v. Costle*, 657 F.2d at 321.

¹⁶⁴ *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience).

¹⁶⁵ S. Rep. 91–1116 at 16 (1970). See 116 Cong. Rec. 42,384 (statement of Sen. Muskie) (summarizing the House-Senate Conference agreement.)

¹⁶⁶ See S. Rep. 91–1196 at 16 (1970).

able to construct new facilities anywhere in the country; that is, an area with air quality at or above the NAAQS limits might not have enough room in its airshed to accommodate these new facilities. The 1970 Senate Committee Report stated, “[l]and use policies must be developed to prevent location of facilities which are not compatible with implementation of national standards.”¹⁶⁷ Senator Muskie added:

Land use planning and control should be used by State, local, and regional agencies as a method of minimizing air pollution. Large industries and power generating facilities should be located in places where their adverse effect on the air is minimal. There is a need for State or regional agencies to revise proposed power plant sites to assure that a number of environmental values, including air pollution, are considered.¹⁶⁸

The 1970 CAAA legislative history includes other statements that also recognize that under the newly required air pollution control requirements, new sources may not be able to build anywhere in the country and, in fact, some existing sources might have to be shut down.¹⁶⁹

Thus, in 1970, Congress designed section 111 to require uniform national controls for large industrial facilities, while recognizing that those facilities could not necessarily construct in every place in the country. Although at the time, Congress expected that the reason why some sources would not be able to locate in certain places was related to local air quality concerns, if the reason turns out to be related to the emission limits that the EPA promulgates under section 111, that should not be viewed as inconsistent with congressional intent for section 111. For example, if the EPA promulgates section 111 emission limits based on a particular type of technology, and for economic or technical reasons, sources are able to utilize that technology in only certain parts of the country and not other parts, that result should not be viewed as inconsistent with congressional intent for CAA section 111. Rather, that result is consistent with Congress’s recognition that certain sources may be precluded from locating in certain areas.

2. Case Law Under Analogous CAA Provisions

Under analogous CAA provisions, the D.C. Circuit has recognized that the EPA may promulgate uniform standards that

apply to new sources in a group or category of sources, even though some types of those new sources that would otherwise construct would no longer be able to construct because they could not meet the standard. One of these cases was *International Harvester Co. v. EPA*, 478 F.2d 615 (D.C. Cir. 1973). There, the EPA declined to exercise its discretion under the CAA mobile source provisions, as they read at that time (42 U.S.C. 1857f–1(b)(5)(D) (1970 CAAA)), to grant automakers a one-year extension to comply with exhaust standards. The EPA stated that the automakers had failed to meet their burden of establishing that controls were not available. The EPA based its decision on grounds that certain technology was available for the motor vehicles in question. The EPA dismissed the automakers’ objections that this technology could not feasibly be installed in all models or engine types, and the EPA explained that the public’s “basic demand” for automobiles could be met by the models and engine types that could feasibly install that technology. 478 F.2d at 626.

Although the Court remanded the EPA’s decision not to grant the one-year extension, it agreed with the EPA on this point, stating:

We are inclined to agree with the Administrator that as long as feasible technology permits the demand for new passenger automobiles to be generally met, the basic requirements of the Act would be satisfied, even though this might occasion fewer models and a more limited choice of engine types. The driving preferences of hot rodders are not to outweigh the goal of a clean environment.¹⁷⁰

Similarly, in a 2007 decision under CAA section 112, *NRDC v. EPA*, 489 F.3d 1364, 1376 (D.C. Cir. 2007) the D.C. Circuit upheld the EPA’s decision to apply the same hazardous air pollutant requirements to different types of plywood and composite wood products facilities—even though one of those types of facilities faced greater difficulties meeting the requirements than the other types of facilities—in part on the grounds that the facilities “compet[ed] in the same markets.”¹⁷¹

Thus, these decisions supported EPA’s emissions requirements, even though certain types of sources could meet those requirements more readily than others, on grounds that the requirements would not impede the manufacture of products that would satisfy overall consumer demand. By the same token, the inability of some coal-

fired sources to locate in certain areas would not create reliability problems or prevent the satisfaction of overall demand for electricity.

3. Section 111 Rulemaking Precedent

Through long-standing rulemaking precedent, the EPA has taken the position that section 111 authorizes a standard of performance for a source category that may not be feasible for all types of new sources in the category, as long as there are other types of sources in the category that can serve the same function and meet the standard. Specifically, in a 1976 rulemaking under section 111 covering primary copper, zinc, and lead smelters, the EPA established, as the standard of performance, a single standard for SO₂ emissions for new construction or modifications of reverberatory, flash, and electric smelting furnaces in primary copper smelters that process materials with low levels of volatile impurities. The EPA acknowledged that although for flash and electric smelting furnaces, the cost of the controls was “reasonable,” for reverberatory smelting furnaces, the cost of the standard was “unreasonable in most cases.” Even so, the EPA determined that this standard would not adversely affect new construction or modification of primary copper smelters processing materials containing low levels of volatile impurities because new construction could use flash and electric smelting furnaces, and existing sources could expand without increasing emissions.¹⁷² The EPA explained:

[T]he Agency believes that section 111 authorizes the promulgation of one standard applicable to all processes used by a class of sources, in order that the standard may reflect the maximum feasible control for that class. When the application of a standard to a given process would effectively ban the process, however, a separate standard must be prescribed for it unless some other process(es) is available to perform the function at reasonable cost. . . .

The Administrator has determined that the flash copper smelting process is available and will perform the function of the reverberatory copper smelting process at reasonable cost. . . .¹⁷³

VII. Rationale for Emission Standards for New Fossil Fuel-Fired Boilers and IGCCs

A. Overview

In this section we explain our rationale for emission standards for new fossil fuel-fired boiler and IGCC EGUs,

¹⁷² Standards of Performance for New Stationary Sources, Primary Copper, Zinc, and Lead Smelters, 41 FR 2331, 2333 (Jan. 15, 1976).

¹⁷³ 41 FR 2333.

¹⁶⁷ 1970 Senate Committee Report at 2.

¹⁶⁸ 116 Cong. Rec. 32,917 (1970) (statement of Sen. Muskie).

¹⁶⁹ See 116 Cong. Rec. 42,385 (Dec. 18, 1970) (statement of Sen. Muskie) (sources of hazardous air pollutants could be required to close due to absence of control techniques).

¹⁷⁰ *International Harvester Co. v. EPA*, 478 F.2d at 640.

¹⁷¹ *NRDC v. EPA*, 489 F.3d at 1376.

which are based on our proposal that efficient generating technology implementing partial CCS is the BSER adequately demonstrated for those sources.

As noted, CAA section 111 and subsequent court decisions establish a set of factors for the EPA to consider in a BSER determination, including criteria listed in CAA section 111 or identified in the court decisions and the underlying purposes of section 111. Key factors include: emission reductions, technical feasibility, costs, and encouragement of technology. Other factors, such as energy impacts, may also be important. As also noted, the EPA has discretion in balancing those factors, and may balance them differently in promulgating standards for different source categories.

The EPA considered three alternative control technology configurations as potentially representing the BSER for new fossil fuel-fired boilers and IGCC units. Power company announcements indicate that the few new coal-fired projects that may occur will likely consider one or more of these three configurations. The three alternatives are: (1) Highly efficient new generation technology that does not include any level of CCS, (2) highly efficient new generation technology with “full capture” CCS (that is, CCS with capture of at least 90 percent CO₂ emissions) and (3) highly efficient new generation technology with “partial capture” CCS (that is, CCS with capture of a lower level of CO₂ emissions).

We discuss each of these alternatives below, and explain why we propose that partial capture CCS qualifies as the BSER. We first discuss the technical systems that we considered for the BSER, our evaluations of them, and our reasons for determining that only partial CCS meets the criteria to qualify as the BSER. We include in this discussion our rationale for selecting 1,100 lb CO₂/MWh as the emission limitation for these sources and why we are considering a range from 1,000 to 1,200 lb CO₂/MWh for the final rule. We next discuss our rationale for allowing an 84-operating-month averaging period as an alternative compliance method, with the requirement that sources choosing that method meet a limit of between 1,000 lb CO₂/MWh and 1,050 lb CO₂/MWh.¹⁷⁴ We then explain our rationale for the requirements for geologic sequestration.¹⁷⁵

¹⁷⁴ This is on a gross output basis. All emission rates in this section are on a gross output basis unless specifically noted otherwise.

¹⁷⁵ It should be noted that the standard of performance that we propose in this rulemaking for

B. Identification of the Best System of Emission Reduction

1. Highly Efficient New Generation Without CCS Technology

Some commenters on the April 2012 proposal suggested that the emission limitation for new coal-fired EGUs should be based on the performance of highly efficient generation technology that does not include CCS, such as (i) a supercritical¹⁷⁶ pulverized coal (SCPC) or CFB boiler, or (ii) a modern, well-performing IGCC unit.

These options are technically feasible. However, we do not consider them to qualify as the BSER for the following reasons:

a. Lack of Significant CO₂ Reductions

Because of the large amount of CO₂ emissions from solid-fuel fired power plants, it is important, in promulgating a standard of performance for these sources, to give effect to the purpose of CAA section 111 of providing “as much [emission reduction] as practicable.”¹⁷⁷ Accordingly, we reviewed the emission rates of efficient PC and CFB units. According to the DOE/NETL estimates, a new subcritical PC unit firing bituminous coal would emit approximately 1,800 lb CO₂/MWh,¹⁷⁸ a new SCPC unit using bituminous coal would emit nearly 1,700 lb CO₂/MWh, and a new IGCC unit¹⁷⁹ would emit about 1,450 lb CO₂/MWh.¹⁸⁰

new fossil-fired utility steam-generating units of 1,100 lb CO₂/MWh applies to new liquid oil- and natural-gas fired units, as well as solid fuel-fired units. However, we are not conducting a separate analysis of the best system of emission reduction for new liquid oil- and natural gas-fired units. That is because no new utility steam-generating units designed to be fired primarily with liquid oil or natural gas have been built for many years, and none are expected to be built in the foreseeable future, due to the significantly lower costs of building combustion turbines to be fired with those fuels.

¹⁷⁶ Subcritical coal-fired boilers are designed and operated with a steam cycle below the critical point of water. Supercritical coal-fired boilers are designed and operated with a steam cycle above the critical point of water. Increasing the steam pressure and temperature increases the amount of energy within the steam, so that more energy can be extracted by the steam turbine, which in turn leads to increased efficiency and lower emissions.

¹⁷⁷ Sierra Club, F.2d at 327 & n. 83 (quoting 44 FR 33581/3—33582/1).

¹⁷⁸ Exhibit ES-2 from “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity”, Revision 2, Report DOE/NETL-2010/1397 (November 2010).

¹⁷⁹ “Case 1” from Exhibit ES-2 from “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity”, Revision 2, Report DOE/NETL-2010/1397 (November 2010).

¹⁸⁰ The comparable emissions on a net basis are: subcritical PC—1,888 lb CO₂/MWh; supercritical PC—1,768 lb CO₂/MWh; and IGCC—1,723 lb CO₂/MWh.

New power sector projects using coal as a primary fuel that have been proposed or are currently under construction are generally SCPC or IGCC projects. For example, since 2007, almost all coal-fired EGUs that have broken ground have been high performing versions of SCPC or IGCC projects.¹⁸¹ Among those plants are: (1) AEP’s John W. Turk, Jr. Power Plant, a 600 MW ultra-supercritical¹⁸² PC (USCPC) facility located in the southwest corner of Arkansas; (2) Duke Power’s Edwardsport plant, a 618 MW coal IGCC unit located in Knox County, Indiana; and (3) Southern Company’s Kemper County Energy Facility, a 582 MW lignite IGCC unit located in Kemper County, Mississippi. These facilities all use advanced generation technology: Turk, as noted, is an ultra-supercritical boiler; Edwardsport is an IGCC unit that is “CCS ready;” and Kemper is an IGCC unit that will implement partial CCS.

Under these circumstances, in this rule, identifying a new supercritical unit as the BSER and requiring the associated emission limitation, would provide little meaningful CO₂ emission reductions for this source category. As noted, for the most part, new sources are already designed to achieve at least that emission limitation. Identifying IGCC as the BSER and requiring the associated emission limitation, would provide some CO₂ emission reductions from the segment of the industry that would otherwise construct new PC units, but not from the segment of the industry that would already construct new IGCC units.

As a result, emission reductions in the amount that would result from an emission standard based on SCPC/USCPC or even IGCC as the BSER would not be consistent with the purpose of CAA section 111 to achieve “as much [emission reduction] as practicable.”¹⁸³ As we discuss below, identifying CCS-partial capture as the BSER would provide for significantly greater emissions reductions.

b. Lack of Incentive for Technological Innovation

Identifying highly efficient generation technology as the BSER would not achieve another purpose of CAA section 111, to encourage the development and implementation of control technology.

¹⁸¹ The only exception that we are aware of is the Virginia City subcritical CFB unit.

¹⁸² Ultra-supercritical (USC) and advanced ultra-supercritical (A-USC) are terms often used to designate a coal-fired power plant design with steam conditions well above the critical point.

¹⁸³ Sierra Club, F.2d at 327 & n. 83 (quoting 44 FR 33581/3—33582/1).

At present, CCS technologies are the most promising options to achieve significant reductions in CO₂ emissions from fossil-fuel fired utility boilers and IGCC units. A standard based on the performance of highly efficient coal-fired generation does not advance the development and implementation of control technologies that reduce CO₂ emissions. In addition, highly efficient generation technology does not develop control technology that is transferrable to existing EGUs. Further, highly efficient generation technology does not necessarily promote the development of generation technologies that would minimize the auxiliary load requirements and costs of future CCS requirements (e.g., developing an IGCC design where the costs and auxiliary load requirements of adding CCS are minimized).

On the contrary, such a standard could impede the advancement of CCS technology by creating regulatory disincentives for such technology. In 2011, AEP deferred construction of a large-scale CCS retrofit demonstration project on one of their coal-fired power plants because the state's utility regulators would not approve cost recovery for CCS investments without a regulatory requirement to reduce CO₂ emissions. AEP's chairman was explicit on this point, stating in a July 17, 2011 press release announcing the deferral:

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.¹⁸⁴

As we discuss below, regulatory requirements for CO₂ reductions with some level of CCS as the BSER will promote further development of the technology.

2. Carbon Capture and Storage

We have also considered whether the emission limitation for new coal-fired EGUs should be based on the performance of CCS, including either "full capture" CCS that treats the entire flue gas or syngas stream to achieve on the order of 90 percent reduction in CO₂

emissions, or "partial capture" CCS that achieves some level less than 90 percent of capture.

We propose that implementation of partial capture CCS technology is the BSER for new fossil fuel-fired boilers and IGCC units because it fulfills the criteria established under CAA section 111. In the sections that follow, we explain the technical configurations that facilitate full and partial capture, describe the operational flexibilities that partial capture offers, and then identify and justify the emission rate that we propose based on partial capture. After that, we discuss the criteria for BSER, and describe why partial capture meets those criteria and why full capture does not. Among other things, partial capture provides meaningful emission reductions, it has been adequately demonstrated to be technically feasible, it can be implemented at a reasonable cost, and it promotes deployment and further development of the technology.

3. Technical Configurations for CCS

The DOE's National Energy Technology Laboratory (NETL) performed a study to establish the cost and performance for a range of CO₂ capture levels for new SCPC and IGCC power plants.¹⁸⁵ The study identified technical configurations that were tailored to achieve a specific level of carbon capture.

a. SCPC

For the new SCPC case, the study assumed a new SCPC boiler with a combination of low-NO_x burners (LNB) with overfire air (OFA) and a selective catalytic reduction (SCR) system for NO_x control. The plant was assumed to have a fabric filter and a wet limestone flue gas desulfurization (FGD) scrubber for particulate matter and sulfur dioxide (SO₂) control, respectively. The plant was also assumed to have a sodium hydroxide (NaOH) polishing scrubber to ensure that the flue gas entering the CO₂ capture system has a SO₂ concentration of 10 ppmv or less. The SCPC plant was equipped with Fluor's Econamine FG PlusSM process for post-combustion CO₂ capture via temperature swing absorption with a monoethanolamine (MEA) solution as the chemical solvent.

The study's authors identified two options for achieving partial capture (i.e., less than 90 percent CO₂ capture) in the SCPC unit. The first option was to process the entire flue gas stream through the MEA capture system at reduced solvent circulation rates. The

second option was to maintain the same high solvent circulation rate and steam stripping requirement as would be used for full capture but only treat a portion of the total flue gas stream. The authors determined that the second approach—the "slip stream" approach—was the most economical. The authors further noted that the cost of CO₂ capture with an amine scrubbing process is dependent on the volume of gas being treated, and a reduction in flue gas flow rate will: (1) Decrease the quantity of energy consumed by flue gas blowers, (2) reduce the size of the CO₂ absorption columns, and (3) trim the cooling water requirement of the direct contact cooling system. The slip stream approach leads to lower capital and operating costs. All of the partial capture cases in the NETL study assumed this approach.

b. IGCC

For a new IGCC unit, the product syngas would contain primarily H₂, CO and some lesser amount of CO₂.¹⁸⁶ The amount of CO₂ can be increased by "shifting" the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam ("water") with CO ("gas") to form H₂ and CO₂. An emission standard that requires partial capture of CO₂ from the syngas could be met by adjusting the level of CO₂ in the syngas stream by controlling the level of syngas "shift" prior to treatment in the pre-combustion acid gas treatment system.

For a new IGCC EGU, the study's authors assumed the use of the GE gasifier coupled with a variety of potential configurations (i.e., no WGS reactor, single-stage WGS, two-stage WGS, varying WGS bypass ratios, and CO₂ scrubber removal efficiency). The study evaluated a number of IGCC plant configurations. The first was an IGCC that used the SelexolTM process for acid gas control (i.e., hydrogen sulfide (H₂S) and CO₂) but no WGS reactor. This unit was capable of CO₂ capture ranging from zero up to 25 percent. The no-CO₂ capture case employed a one-stage SelexolTM unit for H₂S control and the 25 percent CO₂ capture case utilized a two-stage SelexolTM unit to maximize CO₂ capture from the unshifted syngas (i.e., >90 percent of the CO₂ from the unshifted syngas was captured in the second stage SelexolTM scrubber).

¹⁸⁶ The amount of CO₂ in un-shifted syngas depends upon the specific gasifier technology used, the operating conditions, and the fuel used; but is typically less than 20 volume percent (http://www.netl.doe.gov/technologies/coalpower/gasification/gasification/gasification/4-gasifiers/4-3_syngas-table2.html).

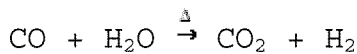
¹⁸⁴ <http://www.aep.com/newsroom/newsreleases/?id=1704>.

¹⁸⁵ "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture", DOE/NETL-2011/1498, May 27, 2011.

To achieve moderate levels of partial CO₂ capture—approximately 25 to 75 percent—the IGCC was configured with a single-stage WGS reactor with bypass and a two-stage Selexol™ unit. Varying the extent of the WGS reaction by controlling the amount of syngas that was processed through the WGS reactor (by controlling the amount that bypassed the WGS reactor) manipulated the level of CO₂ capture. As more syngas is processed through the WGS reactor, the steam demand increases. The Selexol™ removal efficiency was manipulated by varying the solvent circulation rate. Thus, a facility using this configuration could select or “dial in” a level of control of between 25–75 percent.

To achieve higher CO₂ capture levels—levels greater than 75 percent—the IGCC was configured with a two-stage WGS with bypass and the two-stage acid gas (Selexol™) scrubbing system. The facility could “dial in” a level of control of between 25 to greater than 90 percent by controlling the WGS bypass and the Selexol™ scrubber recirculation rates.

The water-gas shift involves the catalytic reaction of carbon monoxide and steam. Since the syngas initially contains primarily CO and H₂, this shift reaction diminishes the concentration of CO and enriches the concentration of H₂ in the pre-combustion syngas stream via the following reaction:



An unshifted or partially shifted syngas can be combusted using a typical combustion turbine. However, as the level of H₂ in the syngas increases, the more the syngas must be diluted with N₂ or air. Very high levels of H₂ in the syngas stream require use of a specialty hydrogen turbine.

4. Operational and Design Flexibility

To this point, most of the studies involving research, development and demonstration of carbon capture technology, along with most of the studies that have modeled the costs and implementation of such technology have assumed capture requirements of 90 percent for fossil fuel-fired power plants (“full capture”). However, the EPA believes that partial capture provides significant benefits because an emission limit based on partial capture offers operators considerable operational flexibility. With such emission limits, project developers would have the option of designing and installing CO₂ capture technology at a size sufficient to treat the entire flue gas stream, with the capability to meet CO₂

emission limits that are much lower than required. The operator of the plant could then choose to achieve those deeper capture rates during non-peak electricity demand periods and to achieve lesser capture rates (and thus generate more electricity) during peak electricity demand periods. This type of operational flexibility provides owners and operators the opportunity to optimize the operation and minimize the cost of CCS in new fossil fuel-fired projects.

In addition, an emission standard that can be met with partial capture offers the opportunity for design flexibility. A project developer of a new conventional coal-fired plant (i.e., a new supercritical PC or CFB) could install post-combustion CO₂ scrubbers that have been designed and sized to treat only a portion of the flue gas stream.

For a new IGCC unit, as noted, an emission standard that requires partial capture of CO₂ offers operational flexibility because the standard could be met by adjusting the level of CO₂ in the syngas stream by controlling the level of syngas “shift” prior to treatment in the pre-combustion acid gas treatment system.

C. Determination of the Level of the Standard

Once the EPA has determined that a technology has been adequately demonstrated based on cost and other factors, including the impact a standard will have on further technology development, and therefore represents BSER, the EPA must establish an emission standard. In this case, for new fossil fuel-fired boiler and IGCC EGUs, the EPA proposes to find that the level of partial capture of CO₂ that qualifies as the BSER supports a standard of 1,100 lb CO₂/MWh on a gross basis. The level of the standard is based on the emission reductions that can be achieved by an IGCC with a single-stage WGS reactor and a two-stage acid gas removal system. According to the DOE/NETL partial capture study, an IGCC with this configuration would be expected to achieve a CO₂ emission reduction of 25 to 75 percent, which corresponds to emissions of approximately 1,060 and 380 lb CO₂/MWh-gross, respectively. The EPA is proposing a standard of performance of 1,100 lb CO₂/MWh-gross, which is the high end of this range, for several reasons.

First, both a new IGCC and a conventional coal-fired boiler (PC or CFB), can achieve this emission standard at a reasonable cost and the standard is based on technology that has been adequately demonstrated.

The partial capture requirement and standard of performance will allow new IGCC project developers to minimize the need for multi-stage water-gas shift reactors (and the associated steam requirement) and will allow for the continued use of conventional syngas combustion turbines (rather than requiring the use of advanced hydrogen turbines). Second, this partial capture configuration will provide operators with operational flexibility. Third, this level of the standard best promotes further enhancement of the performance of existing technology and promotes continued development of new, better performing technology. Because the proposed emission standard would require only partial implementation of CCS, it will provide developers with the opportunity to investigate new emerging technologies that may achieve deeper reductions at lower or comparable cost. For instance, developers could build plants with the capacity to achieve deeper CO₂ reductions and choose to employ those greater capture rates during non-peak periods, and then employ lower capture rates (and thus generate more electricity) during peak periods.

While the EPA is proposing an emission rate of 1,100 lb CO₂/MWh, we are also soliciting comment on whether the emission limit may be more appropriately set at a different level. Based on the rationale included in this proposal, we are considering a range of 1,000 to 1,200 lb CO₂/MWh-gross for the final rule. An emission rate of 1,200 lb CO₂/MWh-gross could potentially be met by an IGCC unit that does not include a WGS reactor (although an owner/operator might still use a WGS reactor or co-fire natural gas to maintain operational flexibility), thus further reducing the capital and operating costs. An emission limit of 1,000 lb CO₂/MWh-gross would provide greater emission reductions, could still be achieved with a single WGS reactor, and would also advance CCS technology but would offer less operational flexibility and increase costs.

We are not currently considering a standard below 1,000 lb CO₂/MWh. With a standard of 1,000 lb CO₂/MWh, an owner/operator of an IGCC facility could burn natural gas during periods when the gasifier is unavailable while still maintaining an annual emissions rate that is below the NSPS. In addition, an owner/operator could elect to co-fire natural gas as an option to reduce the amount of CCS required to comply with the NSPS. With a standard below 1,000 lb CO₂/MWh, those operational flexibilities may not be available. We request that commenters who suggest

emission rates below 1,000 lb CO₂/MWh address potential concerns about operational flexibility.

We are not currently considering a standard above 1,200 lb CO₂/MWh because at that level, the NSPS would not necessarily promote the development of CO₂ emissions control technology or provide significant CO₂ reductions. At an emissions rate of 1,300 lb CO₂/MWh, IGCC facilities would only be required to capture approximately 10 percent of the CO₂, and many designs would have a sufficient compliance margin that they would not need to use a WGS reactor. Further, an owner/operator of an IGCC facility could comply with this standard without the use of any CCS. For example, a new IGCC facility designed to co-fire 20 percent natural gas or using fuel cells instead of combustion turbines could comply with an emissions rate of 1,300 lb CO₂/MWh without the use of CCS. An emissions rate of 1,400 lb CO₂/MWh would provide even less technology development and emissions reductions. At an emissions rate of 1,400 lb CO₂/MWh, an IGCC facility could comply with no WGS reactor and by (i) capturing less than 5 percent of the CO₂, (ii) co-firing less than 10 percent natural gas with no CCS, or (iii) using integrated solar thermal for supplemental steam production without CCS. In addition, at an emissions rate of 1,400 lb CO₂/MWh a PC or CFB could use integrated combustion turbines or fuel cells for boiler feedwater heating, supplemental steam production, or for preheated air for the boiler as an alternative to CCS. We request that commenters who suggest emission rates above 1,200 lb CO₂/MWh address potential concerns about providing adequate reductions and technology development to be considered BSER.

The next several sections review the factors for determining BSER and explain why partial capture at the level we are proposing meets those requirements, as well as why full capture does not meet some of them.

D. Extent of Reductions in CO₂ Emissions

The proposed standard of 1,100 lb CO₂/MWh will provide meaningful reductions in emissions. As mentioned earlier, the DOE/NETL has estimated that a new SCPC boiler using bituminous coal would emit 1,675 lb CO₂/MWh. The DOE/NETL has also estimated that a new IGCC unit would emit 1,434 lb CO₂/MWh. The emissions would be higher for units utilizing subbituminous coal or lignite and will vary when utilizing other fossil fuels such as petroleum coke or mixtures of

fuels. We estimate that this standard will result in reduction in emissions of at least 40 percent when compared to the expected emissions of a new SCPC boiler.

E. Technical Feasibility

The EPA proposes to find that partial CCS is feasible because each step in the process has been demonstrated to be feasible through an extensive literature record, fossil fuel-fired industrial plants currently in commercial operation and pilot-scale fossil fuel-fired EGUs currently in operation, the progress towards completion of construction of fossil fuel-fired EGUs implementing CCS at commercial scale. This literature record and experience demonstrate that partial CCS is achievable for all types of new boiler and IGCC configurations. Although much of this information also serves to demonstrate the technical feasibility of full capture, we note that several of the CCS projects that are the furthest along are partial capture projects, which further supports our view that partial capture is BSER.

1. Literature

The current status of CCS technology was described and analyzed by the 2010 Interagency Task Force on CCS, 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 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 reducing GHG emissions.¹⁸⁷

The Pacific Northwest National Laboratory (PNNL) recently prepared a study that evaluated the development status of various CCS technologies for the DOE.¹⁸⁸ The study addressed the availability of capture processes, transportation options (CO₂ pipelines),

¹⁸⁷ Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 7.

¹⁸⁸ "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009", PNNL-18520, Pacific Northwest National Laboratory, Richland, WA, June 2009. Available at: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18520.pdf.

injection technologies, and measurement, verification and monitoring technologies. The study concluded that, in general, CCS is technically viable today and that key component technologies of complete CCS systems have been deployed at scales large enough to meaningfully inform discussions about CCS deployment on large commercial fossil-fired power plants.

In addition, DOE/NETL has prepared other reports—in particular their "Cost and Performance Baseline" reports,¹⁸⁹ including one on partial capture¹⁹⁰—that further support our proposed determination of the technical feasibility of partial capture.

2. Capture, Transportation and Storage Technologies

Each of the core components of CCS—CO₂ capture, compression, transportation and storage—has already been implemented and, in fact, in some instances, implemented on a commercial scale. The U.S. experience with large-scale CO₂ injection, including injection at enhanced oil and gas recovery projects, combined with ongoing CCS research, development, and demonstration programs in the U.S. and throughout the world, provide confidence that the capture, transport, compression, and storage of large amounts of CO₂ can be achieved.

a. CO₂ Capture Technology

Capture of CO₂ from industrial gas streams has occurred since the 1930s, through use of 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 barriers to widespread commercialization of CCS. Currently available CO₂ capture and compression processes are estimated to represent 70 to 90 percent of the overall CCS costs.¹⁹¹

In general, CO₂ capture technologies applicable to coal-fired power generation can be categorized into three approaches:¹⁹²

¹⁸⁹ The "Cost and Performance Baseline" reports are a series of reports by DOE/NETL that establish estimates for the cost and performance of combustion- and gasification-based power plants—all with and without CO₂ capture and storage. Available at www.netl.doe.gov/energy-analyses/baseline_studies.html.

¹⁹⁰ "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture", DOE/NETL-2011/1498, May 27, 2011.

¹⁹¹ Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

¹⁹² *Id.* at 29.

- Pre-combustion systems that are designed to separate CO₂ and H₂ in the high-pressure syngas produced at IGCC power plants.

- Post-combustion systems that are designed to separate CO₂ from the flue gas produced by fossil-fuel combustion in air.

- Oxy-combustion that uses high-purity O₂, rather than air, to combust coal and thereby produce 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 (e.g., electricity, steam, heat) produced from the plant.

b. CO₂ Transportation

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,¹⁹³ which would lower transportation costs. There are multiple factors that contribute to the cost of CO₂ transportation via pipelines including but not limited to: availability and acquisition of rights-of-way for new pipelines, capital costs, operating costs, length and diameter of pipeline, terrain, flow rate of CO₂, and the number of sources utilizing the pipeline. At the same time, studies and DOE quality guidelines have shown CO₂ pipeline transport costs in the \$1 to \$4 dollar per ton of CO₂ range.^{194 195 196 197} For these

¹⁹³ JJ Dooley, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone (2006), Carbon 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.

¹⁹⁴ Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

¹⁹⁵ McCollum, D., Ogden, J., 2006. Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. Institute of Transportation Studies, University of California, Davis, Davis, CA.

¹⁹⁶ McCoy, S., E.S. Rubin and M.B. Berkenpas, 2008. Technical Documentation: The Economics of CO₂ Transport by Pipeline Storage in Saline Aquifers and Oil Reserves. *Final Report*, Prepared by Carnegie Mellon University, Pittsburgh, PA for U.S. Department of Energy, National Energy Technology Center, Pittsburgh, PA.

reasons, the transportation component of CCS is well-established as technically feasible and is not a significant component of the cost of CCS.

c. CO₂ Storage

(i) Current availability of geologic sequestration

Existing project and regulatory experience (including EOR), research, and analogs (e.g. naturally existing CO₂ sinks, natural gas storage, and acid gas injection), indicate that geologic sequestration is a viable long term CO₂ storage option. While EPA has confidence that geologic sequestration is technically feasible and available, EPA recognizes the need to continue to advance the understanding of various aspects of the technology, including, but not limited to, site selection and characterization, CO₂ plume tracking, and monitoring. On-going Federal government efforts such as DOE/NETL's activities to enhance the commercial development of safe, affordable, and broadly deployable CCS technologies in the United States, including: Research, development, and demonstration of CCS technologies and the assessment of the country's geologic capacity to store carbon dioxide, are particularly important.¹⁹⁸ Furthermore, this rule, including the information collected through the GHG Reporting Program, will facilitate further deployment of CCS and advancements in the technology. Information collected under the GHG Reporting Program will provide a transparent means for EPA and the public to continue to evaluate the effectiveness of CCS, including improvements needed in monitoring technologies.

The viability of geologic sequestration of CO₂ is based on a demonstrated understanding of the fate of CO₂ in the subsurface. Geologic sequestration occurs through a combination of structural and stratigraphic trapping (trapping below a low permeability confining layer), residual CO₂ trapping (retention as an immobile phase trapped in the pore spaces of the storage formation), solubility trapping (dissolution in the in situ formation fluids), mineral trapping (reaction with the minerals in the storage formation and confining layer to produce carbonate minerals), and preferential adsorption trapping (adsorption onto

¹⁹⁷ DOE/NETL. (2013). Carbon Dioxide Transport and Storage Costs in NETL Studies, Quality Guidelines for energy system studies. March 2013. DOE/NETL-2013/1614.

¹⁹⁸ Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

organic matter in coal and shale).^{199 200} These mechanisms are functions of the physical and chemical properties of CO₂ and the geologic formations into which the CO₂ is injected.

Project and research experience continues to add to the confidence in geologic sequestration as a viable CO₂ reduction technology. In addition to the four existing commercial CCS facilities in other countries,²⁰¹ multiple studies have been completed that have demonstrated geologic sequestration of CO₂ as well as have improved technologies to monitor and verify that the CO₂ remains sequestered.²⁰² For example, CO₂ has been injected in the SACROC Unit in the Permian basin since 1972 for enhanced oil recovery purposes. A study evaluated this project, and estimated that about 93 million metric tons of CO₂ were injected and about 38 million metric tons were produced from 1972 to 2005, resulting in a geologic CO₂ accumulation of 55 million metric tons of CO₂.²⁰³ This study evaluated the ongoing and potential CO₂ trapping occurring through various mechanisms using modeling and simulations, and collection and analysis of seismic surveys and well logging data. The monitoring at this site demonstrated that CO₂ can indeed become trapped in geologic formations. Studies on the permanence of CO₂ storage in geologic sequestration have been conducted internationally as well. For example, the Gorgon Carbon Dioxide Injection Project and Colliie-South West CO₂ Geosequestration Hub project in Australia have both demonstrated geologic CO₂ trapping mechanisms.²⁰⁴

Numerous other field studies, for example those conducted by the DOE/

¹⁹⁹ Intergovernmental Panel on Climate Change. (2005). *Special Report on Carbon Dioxide Capture and Storage*. Retrieved from http://www.ipcc.ch/pdf/special-reports/srccs/srccs_chapter5.pdf.

²⁰⁰ Benson, Sally M. and David R. Cole. (2008). *CO₂ Sequestration in Deep Sedimentary Formations*. Elements, Vol. 4, pp. 325-331.

²⁰¹ Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada.

²⁰² Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

²⁰³ Han, Weon Shik et al. (2010). *Evaluation of trapping mechanisms in geologic CO₂ sequestration: Case study of SACROC northern platform, a 35-year CO₂ injection site*. American Journal of Science Online April 2010 vol. 310 no. 4 282-324. Retrieved from: <http://www.ajsonline.org/content/310/4/282.abstract>.

²⁰⁴ Sewell, Margaret, Frank Smith and Dominique Van Gent. Western Australia Greenhouse Gas Capture and Storage: A tale of two projects. (2012) Australian Department of Resources, Energy and Tourism and Western Australia Government of Western Australia. Retrieved from <http://cdn.globalccsinstitute.com/sites/default/files/publications/39961/ccsinwareport-opt.pdf>.

NETL Regional Carbon Sequestration Partnerships, have been completed that demonstrate CO₂ trapping mechanisms working in geologic formations in smaller scale projects. Examples of these DOE/NETL studies include:²⁰⁵

- Midwest Regional Carbon Sequestration Partnership Michigan Basin Phase II Validation Test, which injected approximately 60,000 metric tons of CO₂ over two periods from February to March 2008 (~10,000 metric tons) and from January to July 2009 (~50,000 metric tons).

- Midwest Geologic Sequestration Consortium Loudon, Mumford Hills, and Sugar Creek Phase II Validation Test, which consisted of injecting over 14,000 tons of CO₂ across three EOR-scale field tests.

- Southwest Regional Partnership on Carbon Sequestration (SWP) San Juan Basin Phase II Validation Test, which injected 16,700 metric tons into the coal layers of the Fruitland Formation.

Geologic storage potential for CO₂ is widespread and available throughout the U.S. and Canada. Estimates based on DOE studies indicate that areas of the U.S. with appropriate geology have a storage potential of 2,300 billion to more than 20,000 billion metric tons of CO₂ in deep saline formations, oil and gas reservoirs and un-mineable coal seams.²⁰⁶ Other types of geologic formations such as organic rich shale and basalt may also have the ability to store CO₂; and the DOE is currently evaluating their potential storage capacity. While these are estimates, each potential geologic sequestration site must undergo appropriate site characterization to ensure that the site can safely and securely store CO₂. Estimates of CO₂ storage resources by state/province are compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB).

Further evidence of the widespread availability CO₂ storage reserves in the U.S. comes from the Department of Interior's U.S. Geological Survey (USGS) which has recently completed a comprehensive evaluation of the technically accessible storage resource for carbon storage for 36 sedimentary basins in the onshore areas and State

²⁰⁵ DOE/NETL. (2012). *Best Practices for: Monitoring, Verification, and Accounting of CO₂ Stored in Deep Geologic Formations—2012 Update*. DOE/NETL-2012/1568. Retrieved from http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf.

²⁰⁶ The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

waters of the United States.²⁰⁷ The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO₂ storage potential across the United States. For comparison, this amount is 500 times the 2011 annual U.S. energy-related CO₂ emissions of 5.5 Gigatons (Gt).²⁰⁸

Nearly every state in the U.S. has or is in close proximity to formations with carbon storage potential including vast areas offshore.

(ii) Current availability of enhanced oil and gas recovery

Geologic storage options also include use of CO₂ in EOR, which is the injection of fluids into a reservoir to increase oil production efficiency. EOR is typically conducted at a reservoir after production yields have decreased from primary production. Fluids commonly used for EOR include brine, fresh water, steam, nitrogen, alkali solutions, surfactant solutions, polymer solutions, and CO₂. EOR using CO₂, sometimes referred to as 'CO₂ flooding' or CO₂-EOR, involves injecting CO₂ into an oil reservoir to help mobilize the remaining oil and make it available for recovery. The crude oil and CO₂ mixture is produced, and sent to a separator where the crude oil is separated from the gaseous hydrocarbons and CO₂. The gaseous CO₂-rich stream then is typically dehydrated, purified to remove hydrocarbons, recompressed, and re-injected into the oil or natural gas reservoir to further enhance recovery.

CO₂-EOR has been successfully used at many production fields throughout the U.S. to increase oil recovery. The oil and natural gas industry in the United States has over 40 years of experience of injection and monitoring of CO₂ in the deep subsurface for the purposes of enhancing oil and natural gas production. This experience provides a strong foundation for the injection and monitoring technologies that will be needed for successful deployment of CCS.

Monitoring CO₂ at EOR sites can be an important part of the petroleum reservoir management system to ensure the CO₂ is effectively sweeping the oil zone, and can be supplemented by techniques designed to detect CO₂ leakage. Recently many studies have

²⁰⁷ U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, 41 p., <http://pubs.usgs.gov/fs/2013/1386/>.

²⁰⁸ U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Summary: U.S. Geological Survey Factsheet 2013-3020, 6p. <http://pubs.usgs.gov/fs/2013/3020/>.

been conducted to better understand the fate of injected CO₂ at well-established, operational EOR sites. A large number of methods are available to monitor surface and subsurface leakage at EOR sites. Some recent studies are presented below.

- At the SACROC field in the Permian Basin, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO₂ leakage in the shallow freshwater aquifers. At the time of the study (2011), the SACROC field had injected 175 million metric tons of CO₂ over 37 years. No evidence of leakage was detected.²⁰⁹

- An extensive CO₂ leakage monitoring program was conducted by a third party (International Energy Agency Greenhouse Gas Programme) for 10 years at the Weyburn oil field in Saskatchewan, during which time over 16 million tonnes of CO₂ have been stored. A comprehensive analysis of surface and subsurface monitoring methods was conducted and resulted in a best practices manual for CO₂ monitoring at EOR sites.²¹⁰

- The Texas Bureau of Economic Geology has also been testing a wide range of surface and subsurface monitoring tools and approaches to document storage efficiency and storage permanence at a CO₂ EOR site in Mississippi.²¹¹ The Cranfield Field, under CO₂ flood by Denbury Onshore LLC, is a depleted oil and gas reservoir that injected greater than 1.2 million tons/year during the tests. The preliminary findings demonstrate the availability and effectiveness of many different monitoring techniques for tracking CO₂ underground and detecting CO₂ leakage.

The Department of Energy has conducted numerous evaluations of CO₂

²⁰⁹ K.D. Romanak, R.C. Smyth, C. Yang, S.D. Hovorka, M. Rearick, J. Lu. (2011). *Sensitivity of groundwater systems to CO₂: Application of a site-specific analysis of carbonate monitoring parameters at the SACROC CO₂-enhanced oil field*. GCCC Digital Publication Series #12-01. Retrieved from http://www.beg.utexas.edu/gccc/forum/code_xdownloadpdf.php?ID=190.

²¹⁰ Geoscience Publishing. (2012). *Best Practices for Validating CO₂ Geological Storage: Observations and Guidance from the IEAGHG Weyburn-Midale CO₂ Monitoring and Storage Project*. Brian Hitchon (Ed.).

²¹¹ Hovorka, S.D., et al. (2011). *Monitoring a large volume CO₂ injection: Year two results from SECARB project at Denbury's Cranfield, Mississippi, USA*: Energy Procedia, v. 4, Proceedings of the 10th International Conference on Greenhouse Gas Control Technologies GHGT10, September 19-23, 2010, Amsterdam, The Netherlands, p. 3478-3485. GCCC Digital Publication #11-16. Retrieved from <http://www.sciencedirect.com/science/article/pii/S1876610211004711>.

monitoring techniques at EOR pilot sites throughout the U.S. as part of the Regional Sequestration Partnership Phase II and III programs. For example, in the Illinois Basin surface and subsurface monitoring techniques were tested at three short duration CO₂ injections. At one of the Illinois Basin sites, a landowner became concerned when excessive odor in a water well was observed. The ongoing groundwater monitoring program results were used to verify the odor was from a different origin.²¹²

The EPA anticipates that many early geologic sequestration projects may be sited in active or depleted oil and gas reservoirs because these formations have been previously well characterized for hydrocarbon recovery, likely already have suitable infrastructure (e.g., wells, pipelines, etc.), and have an associated economic benefit of oil production. EOR sites including those that inject CO₂, are typically selected and operated with the intent of oil production; however, they may also be suitable for long term containment of CO₂. Although deep saline formations provide the largest CO₂ storage opportunity (2,102 to 20,043 billion metric tons), oil and gas reservoirs are currently estimated to have 226 billion metric tons of CO₂ storage resource.²¹³

CO₂-EOR is the fastest-growing EOR technique in the U.S., providing approximately 281,000 barrels of oil per day in the U.S. which equals about 6 percent of U.S. crude oil production. The vast majority of CO₂-EOR is conducted in oil reservoirs in the U.S. Permian Basin, which extends through southwest Texas and southeast New Mexico. Other U.S. states where CO₂-EOR is utilized are Alabama, Colorado, Illinois, Kansas, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Utah, and Wyoming. A well-established and expanding network of pipeline infrastructure supports CO₂-EOR in these areas. The CO₂ supply for EOR operations currently is largely obtained from natural underground formations or domes that contain CO₂. While natural sources of CO₂ comprise the majority of CO₂ supplied for EOR operations, recent developments targeting anthropogenic sources of CO₂ (e.g., ethanol plants, gas processing plants, refineries, power

plants) have expanded or led to planned expansions in existing infrastructure related to CO₂-EOR. Several hundred miles of dedicated CO₂ pipeline is under construction, planned, or proposed that would allow continued growth in CO₂ supply for EOR.

Potential sources of CO₂ for EOR continue to increase as new projects are being planned or implemented. Based on an evaluation of publicly available sources, the EPA notes there are currently twenty-three industrial source CCS projects in twelve states that are either operational, under-construction, or actively being pursued which are or will supply captured CO₂ for the purposes of EOR.²¹⁴ This further demonstrates that CCS projects associated with large point sources are occurring due to a demand for CO₂ by EOR operations. Nationally, approximately 60 million metric tons of CO₂ were received for injection at EOR operations in 2012.²¹⁵ A recent study by DOE found that the market for captured CO₂ emissions from power plants created by economically feasible CO₂-EOR projects would be sufficient to permanently store the CO₂ emissions from 93 large (1,000 MW) coal-fired power plants operated for 30 years.²¹⁶ Based on all of these factors, the EPA anticipates opportunities to utilize CO₂-EOR operations for geologic storage will continue to increase.

Based on a recent resource assessment by the DOE, the application of next generation CO₂-EOR technologies would significantly increase oil production areas, further expanding the geographic extent and accessibility of CO₂-EOR operations in the U.S.²¹⁷ Additionally, oil and gas fields now considered to be 'depleted' may resume operation because of increased availability and decreased cost of anthropogenic CO₂, and developments in EOR technology, thereby increasing the demand for and accessibility of CO₂ utilization for EOR.

The use of CO₂ for EOR can significantly lower the net cost of implementing CCS. The opportunity to sell the captured CO₂ for EOR, rather

than paying directly for its long-term storage, improves the overall economics of the new generating unit. According to the International Energy Agency (IEA), of the CCS projects under construction or at an advanced stage of planning, 70 percent intend to use captured CO₂ to improve recovery of oil in mature fields.²¹⁸

d. Examples of CCS Demonstration Projects

The following is a brief summary of some examples of currently operating or planned CO₂ capture or storage systems, including, in some cases, components necessary for coal-fired 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 slip stream of each plant's flue gas. At Warrior Run, approximately 110,000 metric tons of CO₂ per year are captured. At Shady Point 66,000 metric tons of CO₂ per year are captured. The CO₂ from both plants is used in the food processing industry.²¹⁹

At the Searles Valley Minerals soda ash plant in Trona, CA, approximately 270,000 metric tons of CO₂ per year are captured from the flue gas of a coal-fired power plant via amine scrubbing and used for the carbonation of brine in the process of producing soda ash.²²⁰

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 metric tons of CO₂ per year from the synthesis gas. The CO₂ is purified and transported via a 200-mile pipeline for use in EOR operations in the Weyburn oilfield in Saskatchewan, Canada.

In September 2009, 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 slip stream of the plant's exhaust flue gas. In May 2011, Alstom Power announced the successful operation of the chilled-

²¹² DOE/NETL. (2012). *Best Practices for: Monitoring, Verification, and Accounting of CO₂ Stored in Deep Geologic Formations—2012 Update*. DOE/NETL-2012/1568. Retrieved from http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf.

²¹³ U.S. Department of Energy National Energy Technology Laboratory (2012). *United States Carbon Utilization and Storage Atlas*, Fourth Edition.

²¹⁴ See "Documentation for the Summary of Carbon Dioxide Industrial Capture to Enhanced Oil Recovery Projects" (Docket EPA-HQ-OAR-2013-0495).

²¹⁵ "Opportunities for Utilizing Anthropogenic CO₂ for Enhanced Oil Recovery and CO₂ Storage", Michael L. Godec, Advanced Resources International, June 11, 2013 presentation at the Introduction to CO₂ EOR Workshop, <http://na2050.org/introduction-to-carbon-dioxide-enhanced-oil-recovery-co2-eor>.

²¹⁶ "Improving Domestic Energy Security and Lowering CO₂ Emissions with "Next Generation" CO₂-Enhanced Oil Recovery (CO₂-EOR)", DOE/NETL-2011/1504 (June 20, 2011).

²¹⁷ *Ibid*.

²¹⁸ Tracking Clean Energy Progress 2013, International Energy Agency (IEA), Input to the Clean Energy Ministerial, OECD/IEA 2013.

²¹⁹ Dooley, J. J., et al. (2009). *An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009*. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830.

²²⁰ IEA (2009). *World Energy Outlook 2009*, OECD/IEA, Paris.

ammonia CCS validation project. The demonstration achieved capture rates from 75 percent (design value) to as high as 90 percent, and 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 slip stream 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 would terminate its cooperative agreement with the DOE and place its plans to advance CO₂ capture and storage technology to commercial scale on hold, citing the uncertain status of U.S. climate policy as a contributor 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 metric tons of CO₂ per year. A larger scale project—the FutureGen 2.0 Project—is in advanced stages of planning in the U.S.²²¹

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 captures approximately 165,000 metric tons of CO₂ annually at a CO₂ capture rate of over 90 percent. The captured CO₂ is being permanently stored underground in a deep saline geologic formation.

Southern Company has begun construction of Mississippi Power Kemper County Energy Facility. This 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.

²²¹ In cooperation with the U.S. Department of Energy (DOE), the FutureGen 2.0 project partners will upgrade a power plant in Meredosia, IL with oxy-combustion technology to capture approximately more than 90 percent of the plant's carbon emissions. <http://www.futuregenalliance.org/>.

The captured CO₂ will be used for EOR in the Heidelberg Oil Fields in Jasper County, MS. The project is now more than 75 percent complete with start-up and operation expected to begin in 2014.

SaskPower's Boundary Dam CCS Project in Estevan, a city in Saskatchewan, Canada, is the world's largest commercial-scale CCS project of its kind. The project will fully integrate the rebuilt 110 MW coal-fired Unit #3 with available CCS technology to capture 90 percent of its CO₂ emissions. The facility is currently under construction. Performance testing is expected to commence in late 2013 and the facility is expected to be fully operational in 2014.

The Texas Clean Energy Project, a 400 MW IGCC facility located near Odessa, Texas will capture 90 percent of its CO₂, which is approximately 3 million metric tons 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. The developer expects financing to be fully arranged in 2013.

There are other CCS projects—domestic and worldwide—that are helping to further develop the CCS technology. They are noted in the DOE/NETL's Carbon Capture, Utilization, and Storage (CCUS) Database.²²² The database includes active, proposed, canceled, and terminated CCUS projects worldwide.

F. Costs

As noted, according to the D.C. Circuit case law, control costs are considered acceptable as long as they are reasonable, meaning that they can be accommodated by the industry.²²³ To determine reasonableness, the Court has looked to the amount of the control costs, whether they could be passed on to the consumer, and how much they would lead prices to increase. As we discuss below, where EOR opportunities

²²² Available at http://www.netl.doe.gov/technologies/carbon_seq/global/database/.

Information in the database regarding technologies being developed for capture, evaluation of sites for carbon dioxide (CO₂) storage, estimation of project costs, and anticipated dates of completion is sourced from publically available information. The CCUS Database provides the public with information regarding efforts by various industries, public groups, and governments towards development and eventual deployment of CCUS technology.

²²³ In addition, the EPA may consider costs through a national lens, as discussed below.

are available, the sale of captured CO₂ offers the opportunity to defray much of the costs. However, we recognize that there are places where opportunities to sell captured CO₂ for utilization in EOR operations may not be presently available. Nevertheless, as discussed below, our analysis shows that this cost structure—with and without EOR—is consistent with the D.C. Circuit's criteria for determining that costs are reasonable.

At the outset, it should be noted that even though the costs of coal-fired electricity generation—even when not incorporating CCS technology—are high when compared to the current costs of new NGCC generation, some utilities and other project developers have indicated a willingness to proceed with new fossil fuel-fired boilers and IGCC units. They have indicated the need for energy and fuel diversity. They have also indicated a skepticism regarding long-term projections for low natural gas prices and high availability. And there may be other reasons why developers have indicated a willingness to build new coal-fired plants, even if they currently do not appear to be the most economic choice.

1. Cost Estimates for Implementation of Partial CCS

The EPA has examined costs of new fossil fueled power generation options. These options are shown in Table 6 below. The costs in Table 6 are projected for new fossil generation with and without various carbon capture options. The costs for new NGCC technology are provided at two different natural gas prices: at \$6.11/MMBtu, which is reasonably consistent with current and projected prices; and at \$10/MMBtu, which would be well above current and projected natural gas prices. We also show projected costs for SCPC and IGCC units with no CCS (i.e., units that would not meet the proposed emission standard) and for those units with partial capture CCS installed such that their emissions would meet the proposed 1,100 lb CO₂/MWh standard. We have also included costs for those same units when EOR opportunities are available. We have included a "low EOR" case assuming a low EOR price of \$20 per ton of CO₂, and a "high EOR" of \$40/ton. These EOR prices are net of the costs of transportation, storage, and monitoring (TSM). We also show the projected costs for implementation of full capture CCS (i.e., 90 percent capture).

TABLE 6—LEVELIZED COST OF ELECTRICITY FOR FOSSIL FUEL ELECTRIC GENERATING TECHNOLOGIES, EXCLUDING TRANSMISSION COSTS ^{224 225}

Technology	Levelized cost of electricity (\$2011/MWh)
NGCC @ \$6.11/MMBtu	59
NGCC @ \$10.0/MMBtu	86
SCPC w/o CCS ²²⁶	92
SCPC (1,100 lb/MWh; no EOR)	110
SCPC (1,100 lb/MWh; low EOR)	96
SCPC (1,100 lb/MWh; high EOR)	88
SCPC (full, 90 percent CCS)	147
IGCC w/o CCS	97
IGCC (1,100 lb/MWh; no EOR)	109
IGCC (1,100 lb/MWh; low EOR)	101
IGCC (1,100 lb/MWh; high EOR)	97
IGCC (full, 90 percent CCS)	136

The DOE/NETL reports cite an accuracy range of –15% to +30% for the central point estimates shown in Table 6, which are based on a number of assumptions, including: an EPCM ²²⁷ contracting methodology, ISO ambient conditions, Midwest merit-shop labor costs, and a level greenfield site in the United States Midwest with no unusual characteristics (e.g., flood plain, seismic zones, environmental remediation). For specific sites that differ from this generic description, plant costs could differ from the quoted range. We have

²²⁴ These costs are derived from the following DOE/NETL studies: (1) Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010); (2) Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases” DOE/NETL–341/082312 (Aug 2012); (3) Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, DOE/NETL–2011/1498 (May 2011). Capacity factor are assumed at 85 percent.

²²⁵ These costs do not include the impact of subsidies that may potentially be available to developers of new projects that include CCS.

²²⁶ SCPC LCOE includes a 3 percent increase to the weighted average cost of capital to reflect EIA’s climate uncertainty adder (CUA).

²²⁷ Engineering, Procurement, and Construction Management.

presented that central estimate above. Also note that the 2010 DOE/NETL capital and operating costs and coal price were updated to 2011 dollars using the values from the 2012 DOE/NETL report. The value of the DOE/NETL studies lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

For an emerging technology like CCS, costs can be estimated for a “first-of-a-kind” (FOAK) plant or an “nth-of-a-kind” (NOAK) plant, the latter of which has lower costs due to the “learning by doing” and risk reduction benefits that result from serial deployments as well as from continuing research, development and demonstration projects. ²²⁸ The estimates provided in Table 6 for a new NGCC unit and for a SCPC plant without CO₂ capture are based on mature technologies and are thus NOAK costs. For plants that utilize technologies that are not yet fully mature and/or which have not yet been serially deployed in a commercial context, such as IGCC or any plant that includes CO₂ capture, the cost estimates in Table 6 represent a plant that is somewhere between FOAK and NOAK, sometimes referred to as “next-of-a-kind”, or “next commercial offering”. These cost estimates for next commercial offerings do not include the unique cost premiums associated with FOAK plants that must demonstrate emerging technologies and iteratively improve upon initial plant designs. However, these costs do utilize currently available cost bases for emerging technologies with associated process contingencies applied at the appropriate subsystem levels. It should also be noted that successful RD&D can

²²⁸ Elsewhere in this preamble, we describe the evidence that as technology matures, its costs decrease. Note also that EPA regulations of mobile source air emissions incorporate the decreasing costs of technology over time. See, e.g., “2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards—Final Rule,” 77 Fed. Reg. 62624, 62984/1 to 62985/1 (October 15, 2012) (incorporating “cost reductions, due to learning effects”).

lead to improved performance and lower costs.

Because there are a number of projects currently under development, the EPA believes it is reasonable to focus on the next-of-a-kind costs provided in Table 6. The lessons learned from design, construction and operation of those projects, as well as for that of Duke Energy’s Edwardsport IGCC (which does not include CCS) will help lower costs for future gasification facilities implementing CCS. The TCEP project and the HECA project are both in advanced stages of design and development. Summit Power, the developer of TCEP, is also pursuing a number of additional projects that would benefit from lessons learned from TCEP. These include the Captain Clean Energy Project in the United Kingdom (UK) and another poly-generation project in Texas. ²²⁹ For a new conventional PC plant implementing post-combustion CCS, the Boundary Dam project will perhaps represent a FOAK project while the W.A. Parish project may represent a second-of-a-kind project—or perhaps even a next-of-a-kind project.

Further, as discussed elsewhere in this preamble, many of the individual components of a new generation project with CCS have been previously demonstrated. For example, capturing CO₂ from a coal gasification syngas stream has been occurring for more than ten years at the Dakota Gasification facility. Experience gained at that facility can inform design and operational choices of a new IGCC implementing partial CCS.

For all these reasons, the next IGCC and SCPC facilities with CCS can be expected to be less expensive than the current FOAK projects, but more expensive than the NOAK facilities with CCS that construct when CCS has become a fully mature technology. The costs in Table 6 reflect those next-of-a-kind costs.

The EPA has also examined costs of new non-fossil fueled power generation options. These options are shown in Table 7 below.

²²⁹ <http://ghgnews.com/index.cfm/summit-even-without-uk-demo-funding-project-will-move-forward/?mobileFormat=true>.

TABLE 7—RANGE OF LEVELIZED COST OF ELECTRICITY FOR NON-FOSSIL FUEL ELECTRIC GENERATING TECHNOLOGIES, EXCLUDING TRANSMISSION COSTS^{230 231}

Technology	Levelized cost of electricity (\$2011/MWh)
Nuclear	103–114
Biomass	97–130
Geothermal	80–99
Combustion Turbine	87–116
Onshore Wind	70–97
Offshore Wind	177–289
Solar PV ²³²	109–220
Solar Thermal	184–412
Nuclear	103–114
Biomass	97–130
Geothermal	80–99

It is important to note here that both the EIA and the EPA apply a climate uncertainty adder (CUA)—represented by a three percent increase to the weighted average cost of capital—to certain coal-fired capacity types. The EIA developed the CUA to address the disconnect between power sector modeling absent GHG regulation and the widespread use of a cost of CO₂ emissions in power sector resource planning.

The CUA reflects the additional planning cost typically assigned by project developers and utilities to GHG-intensive projects in a context of climate uncertainty. The EPA believes the CUA is consistent with the industry's planning and evaluation framework (demonstrable through IRPs and PUC orders) and is therefore necessary to adopt in evaluating the cost competitiveness of alternative generating technologies.

EPA believes the CUA is relevant in considering the range of costs that power companies are willing to pay for

²³⁰ Data for non-fossil fuel-fired generation comes from DOE Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2013. Levelized Cost of Electricity (LCOE) estimates come from http://www.eia.gov/forecasts/aeo/electricity_generation.cfm. To maintain consistency with DOE/NETL estimates in Table 6, the EIA estimates provided in this table do not include transmission investment.

²³¹ The LCOE estimates in Table 7 are presented as a range that reflects EIA's view on the regional variation in local labor markets, cost and availability of fuel, and renewable resources. The capacity factor ranges for renewable non-dispatchable technologies are as follows: Wind—30 to 39 percent, Wind Offshore—33 to 42 percent, Solar PV—22 to 32 percent, and Solar Thermal—11 to 26 percent. Capacity factors for dispatchable non-fossil fueled technologies are as follows: Nuclear—90 percent, Biomass—83 percent, and Geothermal—92 percent. There is no capacity credit provided to dispatchable resources.

²³² Costs are expressed in terms of net AC power available to the grid for the installed capacity.

generation alternatives to natural gas. To the extent that a handful of project developers are still considering coal without CCS, EPA believes, based both on the analysis the EIA undertook in developing the CUA approach and the EPA's review of IRPs,²³³ they must fall into one of two classes. The first, which is the minority, is not factoring in any form of a CUA. The second, which is the majority, assume that coal-fired power plants without CCS entail additional costs due to the risk of future regulation of CO₂. Factoring in risk associated with CO₂ suggests that these companies are, in fact, willing to pay the higher cost for coal without CCS (even if they are not actually incurring those costs today). For these reasons, EPA believes that it is appropriate to consider the cost of coal without CCS to include the CUA in the range of costs that utilities are willing to pay for alternatives to natural gas.

The EPA is requesting comment on all aspects of the CUA, including its magnitude and technology-specific application, to ensure that the EPA's supporting analysis best reflects the current standards and practices of the power sector's long-term planning process.

2. Comparison With the Costs of Other New Power Generation Options

As Tables 6 and 7 above show, while new coal-fired generation that includes CCS is more expensive than either new coal-fired generation without CCS or new NGCC generation, it is competitive with new nuclear power, which, besides natural gas combustion turbines, is the principal other option often considered for providing new base load power. It is also competitive with biomass-fired generation, which is another generation technology often considered for base load power.²³⁴ A review of utility IRPs shows that a number of companies are considering new nuclear power as an option for new base load generation capacity in lieu of new coal-fired generation with or without CCS, because, according to the IRPs, nuclear power is a cost-effective way to generate base load electricity that addresses risks associated with potential future carbon liabilities. New fossil fuel-fired generation that includes CCS serves the same basic function as new nuclear power: providing base load power with

²³³ See Technical Support Document: "Review of Electric Utility Integrated Resource Plans" (Docket EPA-HQ-OAR-2013-0495).

²³⁴ Although geothermal energy is also generally considered for base load power, it is limited in availability. The other low-GHG emitting generation listed in Table 4—solar and wind—are not used for base load.

a lower carbon footprint. New coal-fired generation that incorporates partial CCS that is sufficient to meet the CO₂ emission limitation that we are proposing in today's action (1,100 lb CO₂/MWh) would have a similar levelized cost of electricity (LCOE) as a new nuclear power plant (about \$103/MWh–\$114/MWh). This indicates that, at the proposed emission limitation of 1,100 lb CO₂/MWh, the cost of new coal-fired generation that includes CCS is reasonable today.

3. Costs of "Full Capture" CCS

As noted in Table 6, above, and discussed in the RIA²³⁵ for this rulemaking, implementation of CCS to achieve 90 percent CO₂ capture adds considerably to the LCOE from a new SCPC or IGCC unit. The LCOE for a new SCPC and a new IGCC, both without CCS, are estimated to be \$92/MWh and \$97/MWh, respectively. The corresponding costs with implementation of "full capture" CCS are \$147/MWh for the new SCPC unit and \$136/MWh for the new IGCC unit. These costs exceed what project developers have been willing to pay for other low GHG-emitting base load generating technologies (e.g., nuclear) that also provide energy diversity. For that reason alone, we do not believe that the costs of full implementation of CCS are reasonable at this time.

4. Reasonableness of Costs of Partial CCS

As noted, the current costs of coal, natural gas, and construction of coal-fired or natural gas-fired EGUs have led to little currently announced or projected new coal-fired generating capacity. This very likely reflects the large price differential between the cost of a new NGCC (cost of electricity: \$59/MWh at a natural gas price of \$6.11/MMBtu) and SCPC without CCS (cost of electricity: \$92/MWh) and IGCC without CCS (cost of electricity: \$97/MWh), coupled with a leveling of demand for electricity and the recent increase in renewable sources.

We observe that most of the industry appears to take the view that the price of natural gas will remain sufficiently low for at least a long enough period into the future that new natural-gas fired electricity generation will be less expensive than new coal-fired generation. As a result, in most cases, customers or utilities that contract for

²³⁵ Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New Fossil Fuel-Fired Electric Utility Steam Generating Units and Stationary Combustion Turbines (available in the rulemaking docket EPA-HQ-OAR-2013-0495).

new generation are doing so for natural gas-fired generation. Long-term contracts for electricity supply are commonly for a 25-year period; thus, most of the industry appears to consider contracting for new natural gas-fired generation for a 25-year period to be the most economical of their choices.

As shown in Table 6, we estimate that a new SCPC plant costs \$92/MWh, which is \$33/MWh, or about 56 percent higher than the new NGCC cost of \$59/MWh. Limiting the emission rate to 1,100 lb CO₂/MWh (which can be achieved by adding partial CCS), without sale of captured CO₂ for EOR, would add another \$18/MWh to the cost of electricity, for a total of \$110/MWh. Thus, the total additional cost to meet the proposed standard by implementing partial capture CCS (without revenues from CO₂ sales for EOR) is about half the additional cost of coal-fired generation, compared to natural-gas fired generation.

We are aware of another segment of the industry, which includes electricity suppliers who have indicated a preference for new coal-fired generation to establish or maintain fuel diversity in their generation portfolio because their customers have expressed a willingness to pay a premium for that diversity. It appears these utilities and project developers see lower risks to long-term reliance on coal-fired generation and greater risks to long-term reliance on natural gas-fired generation, compared to the rest of the industry.

We consider the costs of CCS to be reasonable for this segment of the industry as well. The additional costs of CCS for new SCPC of \$18/MWh LCOE (\$110/MWh for SCPC with partial CCS compared to \$92/MWh for SCPC without CCS) are only about half as much as the additional costs that are already needed to be incurred to develop coal-fired electricity as compared to new NGCC generation (\$92/MWh for SCPC without CCS compared to \$59 MWh for NGCC at a natural gas price of \$6.11/MMBtu). Moreover, it is possible that under these circumstances, the demand for the electricity would be inelastic with respect to the price because it may not depend on cost as much as on a demand for energy diversity. These circumstances would be similar to the *Portland Cement* (1975) case, discussed above, in which the D.C. Circuit upheld NSPS controls that increased capital and operating costs by a substantial percentage because the demand for the goods was inelastic with respect to

price, so that the industry could pass along the costs.²³⁶

In addition, we consider the costs of partial CCS to be reasonable because a segment of the industry is already accommodating them. As noted, a segment of the industry consists of the several coal-fired EGU projects that already incorporate at least partial CCS. These projects, which are each progressing, include Kemper, TCEP, and HECA. Each is an IGCC plant that expects to generate profits from the sale of products that result from coal gasification, in addition to the sale of electricity. It is true that each of these projects has received DOE grants to encourage the development of CCS technology, but we do not consider such government subsidies to mean that the costs of CCS would otherwise be unreasonable. As we noted in the original proposal for this rulemaking,²³⁷ many types of electricity generation receive government subsidies. For example, nuclear power is the beneficiary of the Price-Anderson Act, which partially indemnifies nuclear power plants against liability claims arising from nuclear incidents,²³⁸ and domestic oil and gas production,²³⁹ coal exploration and development,²⁴⁰ and renewable energy generation²⁴¹ are each the beneficiary of Federal tax incentives.

5. Opportunities to Further Reduce the Costs of Partial CCS

a. Enhanced Oil Recovery

While the reasons noted above are sufficient to justify the reasonableness of the costs of partial CCS, in most cases, we believe that the actual costs will be less. One reason is the availability of EOR. As noted, EOR is being actively used in various counties in the U.S., and CO₂ pipelines extend into those counties from, in some cases, hundreds of miles away. We consider areas in close proximity to active EOR locations, including the pipelines that extend into those locations, to be places where EOR is available.

We recognize that, at present, certain locations are far enough away from either oilfields with EOR availability or pipelines to those oil fields that any coal-fired power plants that build in

those locations would incur costs to build pipeline extensions that may render EOR non-economical. Those locations are relatively limited when legal or practical limits on building coal-fired power plants are taken into account. For example, some states with locations that are not located near EOR availability are not expected to have new coal-fired builds without CCS in any event, for legal or practical reasons. A number of States, at least in the short term, already have high reserve margins and/or have large renewable targets which push new decisions towards renewables and quick starting natural gas to provide backup to renewables over coal-fired generation.

In addition, it is important to note that coal-fired power plants that build in any particular location may serve demand in a wide area. There are many examples where coal-fired power generated in one state is used to supply electricity in other states. For instance, historically, nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah. In another example, Idaho Power, which serves customers in Idaho and Eastern Oregon, meets its demand in part from coal-fired power plants located in Wyoming and Nevada.

As a result, the geographic scope of areas in which EOR is available to defray the costs of CCS should be considered to be large. The costs provided in Table 6 show how the ability to sell CO₂ for utilization in EOR can significantly affect the overall costs of the project.

We also considered how the opportunity to sell captured CO₂ for EOR may affect the costs for new units implementing full capture CCS. We previously indicated that the costs—\$147/MWh for the new SCPC unit and \$136/MWh for the new IGCC unit—are not reasonable and we rejected that option as BSER on that basis. We estimated that the SCPC with full capture LCOE could be reduced to between \$93 and \$115/MWh (depending on selling price of the CO₂) and the IGCC with full capture could be reduced between \$91 and \$109/MWh (again, depending upon the selling price of the CO₂). These costs are similar with the reasonable costs for partial capture similar units with no opportunity to sell captured CO₂ for EOR. This indicates that in some cases (Summit's TCEP, for example), developers may determine that a new unit with full capture is economically viable. However, this factor alone does not lead us to conclude that full capture CCS should be BSER. When considered in

²³⁶ *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975).

²³⁷ 77 FR 22418/3.

²³⁸ See *Duke Power Co. v. Carolina Environmental Study Group*, 438 U.S. 59 (1978).

²³⁹ See Internal Revenue Code section 263.

²⁴⁰ See "General Explanations of the Administration's Fiscal Year 2013 Revenue Proposals," pp. 120–24. <http://www.treasury.gov/resource-center/tax-policy/Documents/General-Explanations-FY2013.pdf>.

²⁴¹ See Internal Revenue Code section 45.

conjunction with other factors, such as the cost of full CCS where EOR is not available and the fact that more projects using partial CCS than full CCS are underway, the EPA believes that partial CCS should be considered BSER.

b. Government Subsidies

In some instances, the costs of CCS can be defrayed by grants or other benefits provided by the DOE or the states. Although, for the reasons noted earlier, we consider the current costs of partial-capture CCS even without subsidization to be reasonable, the availability of these governmental subsidies supports the reasonableness of the costs.

The 2010 Interagency Task Force Report on CCS report described the DOE program as follows:

The DOE is currently pursuing multiple demonstration projects using \$3.4 billion of available budgetary resources from the American Recovery and Reinvestment Act in addition to prior year appropriations. Up to ten integrated CCS demonstration projects supported by DOE are intended to begin operation by 2016 in the United States. These demonstrations will integrate current CCS technologies with commercial-scale power and industrial plants to prove that they can be permitted and operated safely and reliably. New power plant applications will focus on integrating pre-combustion CO₂ capture, transport, and storage with IGCC technology. Power plant retrofit and industrial applications will demonstrate integrated post-combustion capture.²⁴²

DOE allocated some \$3.4 billion for 5–10 projects, and has committed \$2.2 billion for 5 projects to date. In addition, various other federal and state incentives are also available to many projects. The 2010 Interagency Task Force on CCS, in surveying all of the federal and state benefits available, concluded that the DOE grants, “plus . . . federal loan guarantees, tax incentives, and state-level drivers, cover a large group of potential CCS options.”²⁴³

In addition, regulatory programs may serve to defray the costs of CCS, including, for example, Clean Energy Standards or guaranteed electricity purchase price agreements.²⁴⁴

As noted above and in the April 2012 proposal, the need for subsidies to support emerging energy systems and new control technologies is not unusual. Each of the major types of energy used to generate electricity has been or is currently being 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 for fossil fuel-fired; as well as nuclear-, geothermal-, wind-, and solar-generated electricity.²⁴⁵

c. Expected Reductions in the Costs of CCS

The EPA reasonably projects that the costs of CCS will decrease over time as the technology becomes more widely used. Although, for the reasons noted earlier, we consider the current costs of CCS to be reasonable, the projected decrease in those costs further supports their reasonableness. The D.C. Circuit case law that authorizes determining the “best” available technology on the basis of reasonable future projections supports taking into account projected cost reductions as a way to support the reasonableness of the costs.

As noted above, the D.C. Circuit, in the 1973 *Portland Cement Ass’n v. Ruckelshaus* case, stated that the EPA, in identifying the “best system of emission reduction . . . adequately demonstrated,” may “look[] toward what may fairly be projected for the regulated future, rather than the state of the art at present. . . .”²⁴⁶ In the 1999 *Lignite Energy Council v. EPA* case, the Court elaborated:

Of course, where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture . . . but EPA may compensate for a shortage of data through the use of other qualitative methods, including the reasonable extrapolation of a technology’s performance in other industries.²⁴⁷

It is logical to read these statements in the D.C. Circuit case law to apply as well to the cost component of the “best system of emission reduction . . . adequately demonstrated.”

We expect the costs of CCS technologies to decrease for several reasons. We expect that significant additional knowledge will be gained from deployment and operation of at least two new coal-fired generation

projects that include CCS. These projects are the Southern Company’s Kemper County Energy Facility IGCC with CCS and the Boundary Dam CCS project on a conventional coal-fired power plant in Canada. They are currently under construction and are expected to commence operation next year. In addition there are several other CCS projects in advanced stages of development in the U.S. (e.g., the Texas Clean Energy Project, the Hydrogen Energy California Project, and the Future Gen project in Illinois) that may also provide additional information. In addition, research is underway to reduce CO₂ capture costs and to improve performance. The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options designed to 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 available CCS technologies would add significantly to the cost of electricity for a new pulverized coal plant, and the cost of electricity for a new advanced gasification-based plant would be increased by approximately half of the increase at a comparable PC facility. (Note that these cost increases would be less for the partial capture standard being proposed in today’s document.) 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.²⁴⁸ The large-scale CO₂ capture demonstrations that are currently planned and in some cases underway, under the 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

²⁴⁵ 77 FR 22418/3.

²⁴⁶ *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973), quoted in *Lignite Energy Council v. EPA*, 198 F.3d 930, 933–34 (D.C. Cir. 1999).

²⁴⁷ *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999). Based on this view that EPA may extrapolate from other industries, the Court in the *Lignite Energy Council v. EPA* case upheld a control technology as being “adequately demonstrated” for coal-fired industrial boilers because the technology was utilized by utility boilers.

²⁴⁸ DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap, U.S. Department of Energy National Energy Technology Laboratory, December 2010.

²⁴² Task Force Report on CCS, p. 76

²⁴³ Task Force Report on CCS, p. 76

²⁴⁴ See Center for Climate and Energy Solutions, “Financial Incentives for CCS”—available at <http://www.c2es.org/>.

gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FGSM 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,²⁴⁹ 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, reductions in financial premiums related to risk, research and development investments, and other factors have been observed over the decades.

In addition, we note that the 2010 Interagency Task Force on CCS report recognized that CCS would not become more widely available without a regulatory framework that promoted CCS or a strong price signal for CO₂. Today's action is an important component in developing that framework.

G. Promotion of Technology

It is clear that identifying partial CCS as the BSER promotes the utilization of CCS because any new fossil fuel-fired

utility boiler or IGCC unit will need to install partial capture CCS in order to meet the emission standard. Particularly because the technology is relatively new, additional utilization is expected to result in improvements in the performance technology and in cost reductions. Moreover, identifying partial capture CCS as the BSER will encourage continued research and development efforts, such as those sponsored by the DOE/NETL. In contrast, not identifying partial CCS as the BSER could potentially impede further utilization and development of CCS. It is important to promote deployment and further development of CCS technologies because they are the only technologies that are currently available or are expected to be available in the foreseeable future that can make meaningful reductions in CO₂ emissions from fossil fuel-fired utility boilers and IGCC units.

Identifying partial CCS as the BSER also promotes further use of EOR because, as a practical matter, we expect that new fossil fuel-fired EGUs that install CCS will generally make the captured CO₂ available for use in EOR operations. The use of EOR lowers costs for production of domestic oil, which promotes the important goal of energy independence.

H. Nationwide, Longer-Term Perspective

As noted, the D.C. Circuit in *Sierra Club* held:

The language of [the definition of "standard of performance" in] section 111 . . . gives EPA authority when determining the best . . . system to weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.²⁵⁰

Considering on "the national and regional levels and over time" the criteria that go into determining the "best system of emission reduction . . . adequately demonstrated" also supports identifying partial CCS as that best system because doing so would not have adverse impacts on the power sector, national electricity prices, or the energy sector.

1. Structure of the Power Sector

Identifying partial CCS as the BSER for new fossil fuel-fired utility boilers and IGCC units is consistent with the current and projected future structure of the power sector. As noted, we project that in light of the current and projected trends in coal and natural gas costs, virtually all new electric generating capacity will employ NGCC technology

or renewable energy, and very little new capacity will be coal-fired.

As noted above, the recent history of solid fossil fuel-fired projects suggest that these new coal-fired builds, if they occur, may (i) consist of an IGCC unit, including features such as sale of additional byproducts (e.g., plants such as the Texas Clean Energy Project, which intends to manufacture fertilizer products for sale and sell captured CO₂ for EOR in addition to selling electricity), use of lower cost opportunity fuels (such as petcoke proposed to be used at the Hydrogen Energy California facility) and/or rely on additional local regulatory drivers (such as California's AB-32 program which incentivizes lower CO₂ generating technologies), all of which would be designed to offset enough of the additional coal-related costs to be able to compete with natural-gas fired electricity in the marketplace; and (ii) be designed to offer fuel diversity to a group of customers that are willing to pay a premium in electricity prices (such as the Power4Georgians project in Washington County, Georgia).

Projects in the first category would by definition already include at least partial CCS and, as a result, would be affected by this rule to only a limited extent. Projects in the second category would be more affected, but developers of these projects would nevertheless have several options. They could pursue coal with CCS and possibly rely on cost savings from EOR or on their customers' willingness to pay a higher premium. Alternatively, they could choose a different generation technology (most likely natural gas). Even if they chose a different generation technology, the small number of these sources and the fact that the basic demand for electricity would still be met would limit the impact of this rule on the power sector.

2. Impacts on Nationwide Electricity Prices

Identifying partial CCS as the BSER for fossil fuel-fired utility boilers and IGCC units will not have significant impacts on nationwide electricity prices. The reason is that the additional costs of partial CCS will, on a nationwide basis, be small because no more than a few new coal-fired projects are expected, and because, as noted, at least some of these can be expected to incorporate CCS technology in any event. It should be noted that the computerized model the EPA relies on to assess energy sector and nationwide impacts—the Integrated Planing Model (IPM)—does not forecast any new coal-fired EGUs through 2020. Based on these IPM analyses, the RIA for this

²⁴⁹ These studies include: John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, 1984, vol. 9, No. 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).

²⁵⁰ *Sierra Club v. Costle*, 657 F.2d at 330.

rulemaking concludes that the proposed standard of 1,100 lb of CO₂/MWh for new fossil fuel-fired EGUs, which is based on partial CCS as the best demonstrated system, does not create any costs.

3. Energy Considerations

Identifying partial CCS as the BSER for new fossil fuel-fired utility boilers and IGCC units is consistent with nationwide energy considerations because it will not have adverse effects on the structure of the power sector, will promote fuel diversity over the long term, and will not have adverse effects on the supply of electricity.

Identifying partial CCS as the BSER will not have adverse impacts on the structure of the power sector because, as noted, for reasons related to the cost differential between natural gas-fired and coal-fired electricity, very little, if any, new coal-fired EGUs are projected to be built, and at least some of those that may be built would be expected to include CCS technology in any event.

In addition, identifying partial CCS as the BSER for coal will be beneficial to coal-fired electric generation, and therefore fuel diversity, over the long term. This is because identifying partial CCS as BSER eliminates uncertainty as to future control obligations for coal-fired capacity. Currently, any new coal-fired source that constructs without CCS faces the risk that future state or federal controls may require carbon capture, which would require the source to retrofit to CCS, which, in turn, is a more expensive proposition. This risk is heightened because power plants have expected lives of 30 to 40 years and the likelihood of future carbon limitations can be expected to remain throughout that period. Any new coal-fired source that constructs with partial-capture CCS will achieve some level of CO₂ emissions reductions, which lowers the risk of future liability, and may provide competitive advantages over higher emitting sources. Because at present, new electric generating construction is primarily natural gas-fired, benefiting new coal-fired capacity, at least over the long term, protects fuel diversity.

Moreover, even if requiring CCS adds sufficient costs to prevent a new coal-fired plant from constructing in a particular part of the country due to lack of available EOR to defray the costs, or, in fact, from constructing at all, a new NGCC plant can be built to serve the electricity demand that the coal-fired plant would otherwise serve. Thus, the present rulemaking does not prevent basic electricity demand from being met, and thus does not have an adverse effect on the supply of electricity. As

noted above, the EPA is authorized to promulgate standards of performance under CAA section 111 that may have the effect of precluding construction of sources in certain geographic locations.

4. Environmental Considerations

Identifying partial CCS as the BSER for coal-fired power plants protects the environment by preventing large amounts of CO₂ emissions from new fossil fuel-fired utility boilers and IGCC units. As noted, CCS is the only technology available at present or within the foreseeable future that provides meaningful reductions in the amount of CO₂ emissions in this sector.

I. Deference

As noted above, the D.C. Circuit has held that it will grant a high degree of deference to the EPA in determining the appropriate standard of performance. Because determining the BSER for coal-fired power plants requires balancing several factors, including on a nationwide basis and over time, the EPA's determination that partial CCS is the BSER should be granted a high degree of deference.

J. CCS and BSER in Locations Where Costs Are Too High To Implement CCS

As noted above, under CAA section 111, an emissions standard may meet the requirements of a "standard of performance" even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard. As also noted above, the EPA's analysis for this proposal indicates that coal-fired power plants that would otherwise construct in the absence of the standards in this proposal may still do so.

However, we recognize that there may be some geographic locations where EOR is not practicably available, so that in those locations, the higher costs of CCS may tilt the economics against new coal-fired construction. Even in this case, the standard would remain valid under CAA section 111, particularly because the basic demand for electricity could still be served by NGCC, which this rulemaking determines to be the "best system" for natural gas-fired power plants.

K. Compliance Period

1. 12-Operating-Month Period

Under today's proposal, sources must meet the 1,100 lb CO₂/MWh limit on a 12-operating-month rolling basis. This 12-operating-month period is important due to the inherent variability in power plant GHG emissions rates. 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.

EGU efficiency has a significant impact on the source's GHG emission rate. By comparison, efficiency has a smaller impact on the emissions rate for criteria or hazardous air pollutants (HAPs). This is because control of criteria pollutants and HAPs often involves the use of a pollution control device that results in significant reductions, often greater than 90 percent. In this situation, the performance of the specific pollution control device impacts the emissions rate much more than the EGU efficiency.

EGU efficiency can vary from month to month throughout the year. For example, high ambient temperature can negatively impact the efficiency of combustion turbine engines and steam generating units. As a result, an averaging period shorter than 12 operating-months would require us to set a standard that could be achieved under these conditions. This standard could potentially be high enough that it would not be a meaningful constraint during other parts of the year. In addition, operation at low load conditions can also negatively impact efficiency. It is likely that for some short period of time an EGU will operate at an unusually low load. A short averaging period that accounts for this operation would again not produce a meaningful constraint for typical loads.

On the other hand, a 12-operating-month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities. Because the 12-operating-month rolling average can be calculated each month, this form of the 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. Unlike for emissions of criteria and hazardous air pollutants, we do not believe that there are

measurable implications to health or environmental impacts from short-term higher CO₂ emission rates as long as the 12-month average emissions rate is maintained.

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

2. 84-Operating-Month Compliance Period

Under today's proposal, new fossil fuel-fired boilers and IGCC units will have the option to alternatively meet an emission standard on an 84-operating-month rolling basis.

The EPA has previously offered sources optional, longer-term emission standards that are stricter than the primary emissions standard in combination with a longer averaging period. We are proposing that this alternative emission limit should be between 1,000–1,050 lb CO₂/MWh and we are requesting comment on what the final numerical standard should be (within that range) such that the 84-operating-month standard would be as stringent as or more stringent than the 12-operating-month standard.

We are also requesting comment on an appropriate 12-operating-month standard that owners/operators electing to comply with the 84-operating-month standard would have to comply with. This standard would be numerically between the alternate 12-operating-month standard and an emissions rate of a coal-fired EGU without CCS (e.g., 1,800 lb CO₂/MWh). This shorter term standard would be more easily enforced and assure adequate emission reductions.

This 84-operating-month period offers increased operational flexibility and will tend to compensate for short-term emission excursions, which may especially occur at the initial startup of the facility and the CCS system.

L. Geologic Sequestration

1. Overview

We expect that for the immediate future, virtually all of the CO₂ captured at EGUs will be injected underground for long-term geologic sequestration at sites where enhanced oil recovery is also occurring. There is an existing regulatory framework for geologic sequestration and enhanced oil recovery activities. We intend to rely upon this existing framework to verify that the CO₂ captured from an affected unit is injected underground for long-term containment. More specifically, as discussed in Section III, the EPA is proposing to build from the existing

GHG Reporting Program 40 CFR part 98 to track that the captured CO₂ is geologically sequestered.

In addition, we recognize that types of CO₂ storage technologies other than geologic sequestration are under development (e.g. precipitated calcium carbonate, etc). EGUs may use another type of CO₂ storage technology to meet the standard, once the EPA has approved its use, including methods for reporting, monitoring, and verifying long-term CO₂ storage. We welcome comments on an appropriate mechanism for making this determination.

2. Existing Regulatory Framework for CCS

As noted, the EPA expects that for the immediate future, captured CO₂ from affected units will be injected underground for geologic sequestration at sites where EOR is occurring. Underground injection is currently the only technology available that can accommodate the large quantities of CO₂ captured at EGUs, and EOR provides an associated economic incentive and benefit. Three solid-fuel fired EGU projects incorporating CCS—Kemper, TCEP, and HECA—all include utilization of captured CO₂ for EOR.

The EPA has promulgated, or recently proposed, several rules to protect underground sources of drinking water and track the total amount of CO₂ that is supplied to the economy and injected underground for geologic sequestration. First, the EPA's 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.²⁵¹ 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 and the associated area of elevated pressure using both direct and indirect methods, as appropriate. Projects are also required to conduct 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 there is no longer a risk of

endangerment to underground sources of drinking water.

UIC Class II wells inject fluids associated with oil and natural gas production and the storage of liquid hydrocarbons. Most of the injected fluid is salt water, which is brought to the surface in the process of producing (extracting) oil and gas and subsequently re-injected. In addition, other fluids, including CO₂, are injected to enhance oil and gas production. Class II regulations include site characterization, well construction, operating, monitoring, testing, reporting, financial responsibility, and closure requirements to prevent endangerment of underground sources of drinking water. Wells that inject CO₂ underground for enhanced oil or gas recovery may be permitted as UIC Class II or Class VI wells. However, the designation of the appropriate well class depends, principally, on the risks posed or changes in the risks posed to underground sources of drinking water by a specific injection operation.

Second, the GHG Reporting Program covers sources that generate electricity (40 CFR part 98, subpart D), sources that supply CO₂ to the economy (40 CFR part 98, subpart PP) and sources that inject CO₂ underground for geologic sequestration (40 CFR part 98, subpart RR). Subpart D owners or operators of facilities that contain electricity-generating units must report emissions from electricity-generating units and all other source categories located at the facility for which methods are defined in part 98.²⁵² Owners or operators are required to collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting.

Subpart PP provides requirements for quantifying CO₂ supplied to the economy.²⁵³ Affected units that capture CO₂ to inject underground or supply offsite, are subject to all of the requirements under subpart PP of the GHG Reporting Program, which relates to suppliers of CO₂. Specifically, subpart PP requires facilities with production process unit(s) that capture a CO₂ stream for purposes of supplying CO₂ for commercial applications or that capture and maintain custody of a CO₂ stream in order to sequester or otherwise inject it underground and which meet certain applicability requirements to report the mass of CO₂ captured. CO₂ suppliers are required to

²⁵² <http://www.epa.gov/ghgreporting/reporters/subpart/d.html>.

²⁵³ <http://www.epa.gov/ghgreporting/reporters/subpart/pp.html>.

²⁵¹ http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm.

report the annual quantity of CO₂ transferred offsite and for what end use, including geologic sequestration.

Subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the amount of CO₂ received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; and report the amount of CO₂ sequestered using a mass balance approach and annual monitoring activities. The MRV plan must be submitted and approved by the EPA and revised if necessary over time according to 40 CFR 98.448(d). The subpart RR MRV plan must include five major components:

- A delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA).
- An identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO₂ through these pathways in the MMA.
- A strategy for detecting and quantifying any surface leakage of CO₂ in the event leakage occurs.
- An approach for establishing the expected baselines for monitoring CO₂ surface leakage.
- A summary of considerations made to calculate site-specific variables for the mass balance equation.

More information on the MRV plan is available in the Technical Support Document for the subpart RR final rule (75 FR 75065).

If an enhanced oil and gas recovery project holds a UIC Class VI permit, it is required to report under subpart RR. If the project holds a UIC Class II permit and is injecting a CO₂ stream underground, it is not subject to subpart RR, but the owner or operator may choose to opt-in to subpart RR. Sources reporting under subpart RR, whether they are UIC Class VI or Class II well(s), must follow the same set of requirements.

As stated in the preamble to the final subpart RR rule:

“while requirements under the UIC program are focused on demonstrating that USDWs are not endangered as a result of CO₂ injection into the subsurface, requirements under the GHG Reporting Program through 40 CFR part 98, subpart RR will enable EPA to verify the quantity of CO₂ that is geologically sequestered and to assess the efficacy of GS as a mitigation strategy. Subpart RR achieves this by requiring facilities conducting GS to develop and implement a MRV plan to detect and quantify leakage of injected CO₂ to the surface in the event leakage occurs and to report the amount of CO₂ geologically

sequestered using a mass balance approach, regardless of the class of UIC permit that a facility holds.” (75 FR 75060)

The Internal Revenue Service relies on the existing regulatory framework to verify geologic sequestration when determining eligibility of taxpayers claiming the 45Q tax credit. As stated in the preamble to the final subpart RR rule:

“EPA notes that the Internal Revenue Service (IRS) published IRS Notice 2009–83 7 to provide guidance regarding eligibility for the Internal Revenue Code section 45Q credit for CO₂ sequestration, computation of the section 45Q tax credit, reporting requirements for taxpayers claiming the section 45Q tax credit, and rules regarding adequate security measures for secure GS. As clarified in the IRS guidance, taxpayers claiming the section 45Q tax credit must follow the appropriate UIC requirements. The guidance also clarifies that taxpayers claiming section 45Q tax credit must follow the MRV procedures that are being finalized under 40 CFR part 98, subpart RR in this final rule.” (75 FR 75060)

Third, the EPA 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, into a UIC Class VI well and meet other conditions.²⁵⁴ The rationale for the rule was that any CO₂ stream that would otherwise be defined as hazardous waste, need not be managed as hazardous waste, provided it is managed under other regulatory programs that address the potential risks to human health and the environment that these materials may pose.

3. Proposal

a. Geologic Sequestration

To provide certainty and verify that CO₂ captured at an affected unit is geologically sequestered, today's action relies upon the existing regulatory framework the EPA already has in place under the GHG Reporting Program 40 CFR part 98. As discussed in the previous section, there are key subparts (i.e., subpart D, PP and RR) under 40 CFR part 98 that provide a transparent reporting and verification mechanism for EPA and the public. The EPA requires electric generating units to report CO₂ emissions under subpart D. Facilities that capture CO₂ are required to report quantities of CO₂ captured and injected on site or transferred off-site under subpart PP. Facilities that inject CO₂ underground for geologic sequestration report under subpart RR.

First, the EPA is proposing that any affected unit that employs CCS

technology which captures enough CO₂ to meet the 1,100 lb/MWh standard must report, under 40 CFR part 98, subpart RR, if the captured CO₂ is injected onsite. If the captured CO₂ is sent offsite, then the facility injecting the CO₂ underground must report under 40 CFR part 98, subpart RR. As noted above, owners and operators of projects that inject CO₂ underground and that are permitted under a UIC Class VI permit are required to comply with subpart RR. The practical impact of our proposal would be that owners and operators of projects injecting CO₂ underground that are permitted under UIC Class II and that receive CO₂ captured from EGUs to meet the proposed performance standard will also be required to submit and receive approval of a subpart RR MRV plan and report under subpart RR. This proposal does not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to EPA's UIC program under the Safe Drinking Water Act.

In order to use the GHG Reporting Program to ensure that the affected unit is sending its captured CO₂ to a site reporting under subpart RR, the EPA proposes minor modifications to subpart PP, CO₂ supply. We propose that a facility capturing CO₂ from an affected unit, and therefore subject to 40 CFR part 98, subpart PP, must provide additional information in its subpart PP annual report including (1) the electronic GHG Reporting Tool identification (e-GGRT ID) of the facility with the electric generating unit from which CO₂ was captured, and (2) the e-GGRT ID(s) for, and mass of CO₂ transferred to, each geologic sequestration site reporting under subpart RR. This proposed amendment to the GHG Reporting Program provides a transparent and consistent method to track CO₂ capture and sequestration without significantly increasing burden on the affected sources. If the affected unit does not report under 40 CFR part 98, subpart PP and comply with these proposed requirements, it will be considered in noncompliance with today's proposal.

The EPA notes that compliance with the standard of 1,100 lb CO₂/MWh is determined exclusively by the tons of CO₂ captured by the emitting EGU. The tons of CO₂ sequestered by the geologic sequestration site are not part of that calculation. However, to verify that the CO₂ captured at the emitting EGU is sent to a geologic sequestration site, we are building on existing regulatory requirements under the GHG Reporting program.

²⁵⁴ 76 FR 48073 (Aug. 8, 2011).

The EPA acknowledges that there can be downstream losses of CO₂ after capture, for example during transportation, injection or storage. Though a well selected and operated site is expected to contain CO₂ for the long-term, there is the potential for unanticipated leakage. The EPA expects these losses to be modest with incentives due to the market use of CO₂ as a purchased product. There remains an issue of whether the standard itself should be adjusted to reflect these downstream losses. The EPA is not proposing to do so. Moreover, the EPA wishes to encourage rather than discourage EOR using captured CO₂ since the practice makes CCS itself more economic and thus promotes use of the technology on which the proposed standard is based. See *Sierra Club v. Costle*, 657 F. 2d at 347 (one purpose of section 111 standards is to promote expanded use and development of technology).

We also emphasize that today's proposal does not involve regulation of any downstream recipients of captured CO₂. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO₂ (whether the captured CO₂ is sold for EOR or otherwise sequestered underground). The requirement that the emitting EGU assure that captured CO₂ is managed at an entity subject to the GHG reporting rules is thus exclusively an element of enforcement of the EGU standard. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of the proposed NSPS. The standard is a numeric value, applicable exclusively to the emitting EGU.

The approach proposed today relies on the existing GHG Reporting framework to ensure that CO₂ captured at an affected unit is transferred to a facility reporting geologic sequestration, and it does not impose any additional requirements for an affected unit to demonstrate how the captured CO₂ is transferred to a facility that is compliant with 40 CFR part 98, subpart RR. We seek comment on whether there should be such requirements and suggestions for what those might include.

b. Alternatives to Geologic Sequestration

In the development of this proposal, the EPA has identified some potential alternatives to geologic sequestration, including but not limited to CO₂ stored in precipitated calcium carbonate and certain types of cement. The EPA solicits comment on whether these and other alternatives to geologic

sequestration permanently store CO₂ (so that the stack standard is assured of achieving its object—to capture CO₂ and prevent its atmospheric release) and if they are technically available for EGUs to meet the performance standard. Consideration of how these alternatives could meet the performance standard involves understanding the ultimate fate of the captured CO₂ and the degree to which the method permanently isolates the CO₂ from the atmosphere, as well as existing methodologies to verify this permanent storage. The EPA proposes that alternatives to geologic sequestration could not be used until the EPA finalizes a mechanism to demonstrate that a non-CCS technology would result in permanent storage of CO₂. The EPA believes that the number of cases where an EGU would seek to comply with the performance standard through an alternative to CCS will be very few. However, the EPA wishes to encourage development of alternatives to geologic sequestration that could help offset the cost of CO₂ capture.

c. Drafting PSD Permits for Affected Sources Using Geologic Sequestration

In most cases, sources that are subject to this NSPS will also be a major source or major modification under PSD and required to obtain a PSD permit prior to commencing construction. A permit is the legal tool used to establish all the source limitations deemed necessary by the reviewing agency during review of the permit application, and is the primary basis for enforcement of PSD requirements. A well written permit reflects the outcome of the permit review process and clearly defines what is expected of the source. The permit must be a “stand-alone” document that: (1) Identifies the emissions units to be regulated; (2) establishes emissions standards or other operational limits to be met; (3) specifies methods for determining compliance and/or excess emissions, including reporting and recordkeeping requirements; and (4) outlines the procedures necessary to maintain continuous compliance with the emission limits.

One of the criteria that must be met to obtain a PSD permit is that the owner or operator of the facility must demonstrate that emissions from construction or operation of the facility will not cause or contribute to air pollution in excess of “any other applicable emissions standard or standard of performance under this chapter.” 42 U.S.C. 7475(a)(3)(C); see also 42 U.S.C. 7410(j). Accordingly, PSD permits for EGU sources that are subject to this NSPS will need to reflect that, at a minimum, the source will meet the

requirements of this NSPS. Compliance with the NSPS emissions standard is determined exclusively by evaluating emissions of CO₂ at the EGU.²⁵⁵

As noted in the “Implications for PSD and Title V programs” section of this preamble, some states have authority to issue PSD permits. In other cases, the EPA issues the permit. States with EPA-approved permitting programs have some discretion in making permit decisions and including the necessary conditions in the permit to ensure the enforceability of the requirements. Additionally, some states may have additional state-specific requirements (e.g., a renewable portfolio standard adopted by a state) that may affect the stringency of the emission limits for the permits issued in their states. Thus, permits for similar source types may vary from state to state depending on the permitting program of the state, and the case-specific PSD evaluation of the source under review. However, the permits for similar sources should generally contain the same basic information.

Thus, while EPA recognizes that permit conditions may vary from state to state, the EPA believes it is important to clarify the key components that should be included in a PSD permit for sources subject to the NSPS, as proposed here, and that intend to comply with the standard using geologic storage. We believe the following general condition areas of a PSD permit would adequately show that the source will not cause or contribute to air pollution in excess of this NSPS:

- A BACT emissions limit that applies to the EGU (or EGUs) at the stationary source (“EGU facility”) that does not exceed the NSPS emission limit standard using the 12-operating-month rolling average or the NSPS alternative compliance method.

- Procedures for how the EGU will demonstrate compliance with the permitted emissions limit, which, at a minimum, meet the monitoring and recordkeeping requirements defined in § 60.5355.

- A requirement that CO₂ produced by the EGU (or EGUs) is reported under Subpart PP by the permittee.

- A requirement that all CO₂ that is geologically sequestered at the site of the EGU facility is reported under subpart RR by the permittee.

- A requirement that the captured CO₂ that the permittee sends offsite of the EGU facility is transferred to an

²⁵⁵ We note that the PSD program regulates CO₂ as part of the “Greenhouse Gas” pollutant, which includes the aggregate group of the following gases: CO₂, CH₄, N₂O, SF₆, HFCs, and PFCs.

entity that is subject to the requirements of Subpart RR.

We specifically request comment on this basic framework for PSD permits that are issued for affected EGU sources that use geologic sequestration.

VIII. Rationale for Emission Standards for Natural Gas-Fired Stationary Combustion Turbines

A. Best System of Emission Reduction

The EPA evaluated several different control technology configurations as potentially representing the “best system of emissions reductions . . . adequately demonstrated” (BSER) for new natural gas-fired stationary combustion turbines: (i) The use of full or partial capture CCS; and two types of efficient generation without any CCS, including (ii) high efficiency simple cycle aeroderivative turbines; and (iii) natural gas combined cycle (NGCC) technology. We do not consider full or partial capture CCS to be BSER because of insufficient information to determine technical feasibility and because of adverse impact on electricity prices and the structure of the electric power sector. In addition, we do not consider simple cycle turbines to be BSER because they have a higher emission rate and a higher cost than NGCC technology. We do find NGCC technology to be the BSER because it is technically feasible and relatively inexpensive, its emission profile is acceptably low, and it would not adversely affect the structure of the electric power sector.

We note at the outset that currently, virtually all new sources in this category are using NGCC technology. That technology is considered to be the state of the art for this source category. Because, in this rulemaking, we are considering, and selecting, NGCC as the BSER for this category, as a matter of terminology, to avoid confusion, we generally refer to the affected sources as natural gas-fired combustion turbines, and not as NGCC sources.

1. Full and Partial CCS

To determine the BSER for natural-gas-fired stationary source combustion turbines, we evaluated full and partial CCS against the criteria. We propose to reject CCS technology as the BSER because we cannot conclude that it meets several of the key criteria.

First, it is not clear that full or partial capture CCS is technically feasible for this source category. There are significant differences between natural gas-fired combustion turbines and solid fossil fuel-fired EGUs that lead us to this conclusion. First, while some of these

turbines are used to serve base load power demand, many cycle their operation much more frequently than coal-fired power plants. It is unclear how part-load operation and frequent startup and shutdown events would impact the efficiency and reliability of CCS. We are not aware that any of the pilot-scale CCS projects have operated in a cycling mode. Similarly, none of the larger CCS projects being constructed, or under development, are designed to operate in a cycling mode. Furthermore, the CO₂ concentration in the flue gas of a natural gas combustion turbine is much lower (usually approximately 4 volume percent) than the CO₂ concentration in the flue gas stream of a typical coal-fired plant (which is approximately 16 volume percent for a SCPC or CFB unit) or the syngas of an IGCC unit (in which CO₂ can be as high as 60 volume percent). Therefore, the overall amount of CO₂ that can be captured in a CCS project is likely lower. Finally, unlike subpart Da affected facilities, where there are full-scale plants with CCS that are currently under construction or in advanced stages of development, the EPA is aware of only one demonstration project, which is an approximately 40 MW slip stream installation on a 320 MW NGCC unit.

Additional factors that make CCS more challenging for a natural gas combustion turbine compared to coal-fired EGUs include the time it would take to complete the CCS project and the water use requirements. Requiring CCS at a natural gas combustion turbine facility would potentially delay the project more than at a coal-fired EGU. Natural gas combustion turbine facilities can be constructed in about half the time required to construct a coal-fired EGU. Therefore, the time necessary to construct the carbon capture equipment and any associated pipelines to transport the CO₂ would have a relatively larger impact on a natural gas combustion turbine than a coal-fired EGU. Natural gas combustion turbines have relatively low cooling requirements for the steam condensing cooling cycle compared to coal-fired EGUs and often use dry cooling technology. The imposition of CCS would have a larger impact on water requirements for a natural gas combustion turbine facility compared to a coal-fired EGU.

Moreover, identifying partial or full CCS as the BSER for new stationary combustion turbines would have significant adverse effects on national electricity prices, electricity supply, and the structure of the power sector. Because virtually all new fossil fuel-

fired power is projected to use NGCC technology, requiring CCS would have more of an impact on the price of electricity than the few projected coal plants with CCS and the number of projects would make it difficult to implement in the short term. In addition, requiring CCS could lead some operators and developers to forego retiring older coal-fired plants and replacing them with new NGCC projects, and instead keep the older plants on line longer, which could have adverse emission impacts. Identifying CCS and BSER for combustion turbines would likely result in higher nationwide electricity prices and could adversely affect the supply of electricity, since virtually all new fossil fuel-fired power is projected to use NGCC technology.

We recognize that identifying full or partial CCS as the BSER for this source category would result in significant emissions reductions, but at present, we already consider natural gas to be a low-GHG-emitting fuel and NGCC to be a low-emitting technology. Although identifying CCS as the BSER would promote the development and implementation of emission control technology, for the reasons described, the EPA does not believe that CCS represents BSER for natural gas combustion turbines at this time.

2. Energy Efficient Generation Technology

To determine the BSER, the EPA also evaluated the use of energy efficient generation technology, including high efficiency simple cycle aeroderivative turbines.

The use of high efficiency simple cycle aeroderivative turbines does not provide emission reductions from the current state-of-the-art technology, is more expensive than the current state-of-the-art technology, and does not develop emission control technology. For these reasons, we do not consider it BSER. According to the AEO 2013 emissions rate information, advanced simple cycle combustion turbines have a base load rating CO₂ emissions rate of 1,150 lb CO₂/MWh, which is higher than the base load rating emission rates of 830 and 760 lb CO₂/MWh for the conventional and advanced NGCC model facilities, respectively.

In the April 2012 proposal, we identified NGCC as the BSER for this source category, and proposed a standard of 1,000 lb/MWh. We stated:

[A] NGCC facility is the best system of emission reduction for new base load 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 different elevations and ambient temperatures), operational characteristics, and sizes.²⁵⁶

The same information supports our current proposal. As described above, NGCC has a lower cost of electricity than simple cycle turbines at intermediate and high capacity factors. In addition, NGCC has an emissions rate that is approximately 25 percent lower than the most efficient simple cycle facilities. Therefore, the use of a heat recovery steam generator in combination with a steam turbine to generate additional electricity is a cost effective control for intermediate and high capacity factor stationary combustion turbines. Therefore, BSER for intermediate and high capacity factor stationary combustion turbines is the use of modern high efficiency NGCC technology.

B. Determination of the Standards of Performance

Multiple commenters on the April 2012 proposal stated the proposed standard of 1,000 lb CO₂/MWh for combined cycle facilities in the April 2012 proposal was too stringent and should be increased to a minimum of 1,100 lb CO₂/MWh. Commenters explained that the increased use of renewable energy for electricity generation will require combined cycle facilities to startup, shutdown, cycle, and operate at part-load more frequently than they currently do, and that this more cyclical operation necessarily entails a higher emission rate. The commenters stated that the recent historical emissions data that the EPA relied on for the original proposal does not account for these likely operational changes. Additional reasons given justifying a higher standard include the deterioration of efficiencies over time, the need for flexibility to use distillate oil as a backup fuel, the operation of combined cycle facilities in simple cycle mode, the fact that combined cycle facilities located at high elevations and/or in locations with high ambient temperatures are less efficient, and the fact that smaller combined cycle facilities are inherently less efficient than larger facilities. On the other hand, other commenters stated that the final standard should be lower than proposed on grounds that the best performing facilities are operating below the

original proposed standard. Multiple commenters also stated that the EPA should evaluate additional CEMS data to determine the appropriate standard.

In light of these comments, we have reviewed the CO₂ emissions data from 2007 to 2011 for natural gas-fired (non-CHP) combined cycle units that commenced operation on or after January 1, 2000, and that reported complete electric generation data, including output from the steam turbine, to the EPA. A more detailed description of this emissions data analysis is included in a technical support document in the docket for this rulemaking. These 307 NGCC units are diverse in location, age, capacity, and operating profile. Based on these data, we propose to subcategorize the turbines into the same two size-related subcategories currently in subpart KKKK for standards of performance for the combustion turbine criteria pollutants. These subcategories are based on whether the design heat input rate to the turbine engine is either less than or equal to 850 MMBtu/h or greater than 850 MMBtu/h. We further propose to establish different standards of performance for these two subcategories.

This subcategorization has a basis in differences in several types of equipment used in the differently sized units, which affect the efficiency of the units. Large-size combustion turbines use industrial frame type combustion turbines and may use multiple pressure or steam reheat turbines in the heat recovery steam generator (HRSG) portion of a combined cycle facility. Multiple pressure HRSGs employ two or three steam drums that produce steam at multiple pressures. The availability of multiple pressure steam allows the use of a more efficient multiple pressure steam turbine, compared to a single pressure steam turbine. A steam reheat turbine is used to improve the overall efficiency of the generation of electricity. In a steam reheat turbine, steam is withdrawn after the high pressure section of the turbine and returned to the boiler for additional heating. The superheated steam is then returned to the intermediate section of the turbine, where it is further expanded to create electricity. Although HRSGs with steam reheat turbines are more expensive and complex than HRSGs without them, steam reheat turbines offer significant reductions in CO₂ emission rates. In contrast, small-size combustion turbines frequently use aeroderivative turbine engines instead of industrial frame design turbines. While there is not a strict definition for an aeroderivative turbine, at least parts

of aeroderivative turbines are derived from aircraft engines. Aeroderivative and frame turbines use different combustor designs, lubrication oil systems, and bearing designs. While aeroderivative turbines are typically more expensive than industrial frame turbines, they are generally more compact, lighter, are able to start up and shut down more quickly, and handle rapid load changes more easily than industrial frame turbines. Due to their higher simple cycle efficiencies, they have traditionally been used more for peak and intermittent purposes rather than base power generation. However, combined cycle facilities based on aeroderivative combustion turbines are available. Due to the higher efficiency of the simple cycle portion of an aeroderivative turbine based combined cycle facility, the HRSG portion would contribute relatively less to the overall efficiency than a HRSG in a frame turbine based combined cycle facility. Therefore, adding a multiple steam pressure and/or a reheat steam turbine to the HRSG would be relatively more expensive to an aeroderivative turbine based combined cycle facility compared to a frame based combined cycle facility. Consequently, multiple pressure steam and reheat steam turbine HRSG are not widely available for aeroderivative turbine based combined cycle facilities. In addition, since aeroderivative turbine engines have faster start times and change load more quickly than frame turbines, aeroderivative turbine based combined cycle facilities are more likely to run at part load conditions and to potentially bypass the HRSG and run in simple cycle mode for short periods of time than industrial frame turbine based combined cycle facilities.

Because of these differences in equipment and inherent efficiencies of scale, the smaller capacity NGCC units (850 MMBtu/h and smaller) available on the market today are less efficient than the larger units (larger than 850 MMBtu/h). According to the data in the EPA's Clean Air Markets Division database, which contains information on 307 NGCC facilities, there is a 7 percent difference in average CO₂ emission rate between the small- and large-size units. This relative difference is consistent with what would be predicted when comparing the efficiency values reported in *Gas Turbine World* of small and large combined cycle designs.²⁵⁷ Fourteen of the study NGCC facilities evaluated using the Clean Air Markets data have heat input rates of less than or equal to 850 MMBtu/h, and the

²⁵⁶ 77 FR 22414/1.

²⁵⁷ *Gas Turbine World*—2012 GTW Handbook.

remaining 293 are above 850 MMBtu/MWh. Two of the small combined cycle facilities had a maximum 12-operating-month rolling average emissions rate equal to or greater than 1,000 lb CO₂/MWh and one had a maximum 12-operating-month rolling average emissions rate equal to or greater than 1,100 lb CO₂/MWh. Twenty three of the large turbines had at least one occurrence of a 12-operating-month rolling average emissions rate greater than or equal to 1,000 lb CO₂/MWh and forty four had at least one occurrence of a 12-operating-month rolling average emissions rate greater than or equal to 950 lb CO₂/MWh. Therefore, because over 90 percent of small and large existing NGCC facilities are currently operating below the emission rates of 1,100 lb CO₂/MWh and 1,000 lb CO₂/MWh, respectively, these rates are considered BSER for new NGCC facilities in those respective subcategories. These values represent the emission rates that a modern high efficiency NGCC facility located in the U.S. would be able to maintain over its life.

To further evaluate the impact of the proposed rule we reviewed the GHG BACT permits for eight recently permitted NGCC facilities. Of these facilities, seven are larger than 850 MMBtu/h, and one is smaller. The seven larger facilities all have emission rates below 1,000 lb/MWh, and as low as 880 lb/MWh. The single smaller facility, which is 400 MMBtu/h, has a permitted emissions rate of 1,100 lb CO₂/MWh. The GHG BACT permit limits are higher than the base load rating emissions rates because they take into account actual operating conditions.

We are requesting comment on a range of 950 to 1,100 lb CO₂/MWh (430 to 500 kg CO₂/MWh) for the large turbine subcategory and 1,000 to 1,200 lb CO₂/MWh (450 to 540 kg CO₂/MWh) for the small turbine subcategory.

IX. 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. Commenters have raised questions regarding whether this rule will have implications for regulations and permits written under the CAA PSD preconstruction permit program and the CAA Title V operating permit program.

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. Likewise,

today's rulemaking does not have implications for the Tailoring Rule thresholds established with respect to sources subject to title V requirements. Furthermore, this proposal does not have any direct applicability on the determination of Best Available Control Technology (BACT) for existing EGUs that require PSD permits to authorize a major modification of the EGU. Finally, this proposal does have some implications for Title V fees, but EPA is proposing action to address those implications as discussed below.

B. Applicability of Tailoring Rule Thresholds Under the PSD Program

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.²⁵⁸ Commenters have queried whether under the EPA's PSD regulations, promulgation of a section 111 standard of performance for 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) if the State cannot do so promptly, the EPA will assess whether to 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 the final rule that the EPA is proposing today.

In the alternative, if the Tailoring Rule thresholds would not continue to apply

when the EPA promulgates requirements under CAA section 111, then the EPA would assess whether to 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 the final rule that EPA is proposing today.

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 BACT. States that are authorized by the EPA to administer 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 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 undertakes construction and to a "major modification." 40 CFR 51.166(a)(7)(i) and (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

²⁵⁸ "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.

applicability provisions is that PSD applies to a “major stationary source.”

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” 40 CFR 51.166(b)(49) to include any pollutant that is subject to any standard promulgated under section 111 of the Act. 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 NSPS trigger provision in 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 of the final Tailoring Rule, 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”).²⁵⁹

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.”

Even so, to clarify and confirm that the Tailoring Rule thresholds apply to the section 111 prong of the definition of regulated NSR pollutant, in this

²⁵⁹ 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 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 create any additional type of PSD trigger.

proposed rulemaking, the EPA is proposing to add new provisions to the NSPS regulations, although not the PSD regulations, to make explicit that the NSPS trigger provision in the PSD regulations incorporates the Tailoring Rule thresholds.²⁶⁰ Under these new provisions, to the extent that promulgation of section 111 requirements for GHGs triggers PSD requirements for GHGs, it does so only for GHGs emitted at or above the Tailoring Rule thresholds.

The EPA requests that all States with approved SIP PSD programs that apply to GHGs indicate during the comment period on this rule whether, (i) in light of EPA’s interpretation that the Tailoring Rule thresholds continue to apply even when the EPA promulgates the first NSPS for GHGs, and (ii) assuming that EPA finalizes the added provisions to the section 111 regulations proposed today, 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 will assess whether to propose a rule shortly after the close of the comment period, 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 the final rule that the EPA is proposing today. Such a rule would be comparable to what we call the SIP PSD Narrowing Rule that EPA promulgated in December, 2010.²⁶¹ The EPA may finalize such a narrowing rule at the same time that it finalizes this NSPS rule.

C. Implications for BACT Determinations Under PSD

New major stationary sources and major modifications at existing major stationary sources are required by the CAA to, among other things, obtain a permit under the PSD program before commencing construction. A source is subject to PSD by way of its proposed construction and the effect of the construction and operation of the new equipment on emissions. The emission thresholds that define PSD applicability can be found in 40 CFR parts 51 and 52 and are discussed briefly in the above section.

As mentioned above, sources that are subject to PSD must obtain a

²⁶⁰ The Tailoring Rule thresholds themselves are not at issue in this rulemaking.

²⁶¹ “Limitation of Approval of Prevention of Significant Deterioration Provisions Concerning Greenhouse Gas Emitting-Sources in State Implementation Plans; Final Rule,” 75 FR 82536 (December 30, 2010).

preconstruction permit that contains emission limitations based on application of Best Available Control Technology for each regulated NSR pollutant. The BACT requirement is set forth in section 165(a)(4) of the CAA, and in EPA regulations under 40 CFR parts 51 and 52. These provisions require that BACT determinations be made on a case-by-case basis after consideration of the record in each case. CAA section 169(3) defines BACT as an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

Furthermore, this definition in the CAA specifies that “[i]n no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of the Act.” This has historically been interpreted to mean that BACT cannot be less stringent than any applicable standard of performance under the NSPS. See e.g. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, p. 20–21 (March 2011). Thus, upon completion of an NSPS, EPA reads the CAA to mean that the NSPS establishes a “BACT Floor” for PSD permits issued to affected facilities covered by an NSPS. It is important to note that a proposed NSPS does not establish the BACT Floor for affected facilities seeking a PSD permit. This is explained on page 25 of EPA’s PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011):

In cases where a NSPS is proposed, the NSPS will not be controlling for BACT purposes since it is not a final action and the proposed standard may change, but the record of the proposed standard (including any significant public comments on EPA’s evaluation) should be weighed when considering available control strategies and achievable emission levels for BACT determinations made that are completed before a final standard is set by EPA. However, even though a proposed NSPS is not a controlling floor for BACT, the NSPS is an independent requirement that will apply to an NSPS source that commences construction after an

NSPS is proposed and carries with it a strong presumption as to what level of control is achievable. This is not intended to limit available options to only those considered in the development of the NSPS. (p.25)

However, once an NSPS is finalized, then the standard applies to any new source or modification that meets the applicability of the NSPS and has not commenced construction as of the date of the proposed NSPS.

It is also important to keep in mind that BACT is a case-by-case review that considers a number of factors, and the fact that a minimum control requirement is established by EPA through an NSPS does not mean that a more stringent control cannot be chosen by the permitting agency. The EPA’s PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) discusses considerations (e.g., technical feasibility, economic impacts and other costs, and environmental and energy impacts) when evaluating BACT for CO₂, as well as other greenhouse gases.

Under this proposed NSPS, an affected facility is a new EGU. In this rule we are not proposing standards for modified or reconstructed sources. However, since both a new and existing power plant can add new EGUs to increase generating capacity, this NSPS will apply to both a new, greenfield EGU facility or an existing facility that adds EGU capacity by adding a new EGU that is an affected facility under this NSPS. While this latter scenario can be considered the modification of existing sources under PSD, this proposed NSPS will not apply to modified or reconstructed sources as those terms are defined under part 60. Thus, this NSPS would not establish a BACT floor for sources that are modifying an existing EGU, for example, by adding new steam tubes in an existing boiler or replacing blades in their existing combustion turbine with a more efficient design.

Furthermore, our analysis for this proposed NSPS considers only the extent to which particular pollution control techniques are BSER for new units, and does not evaluate whether such techniques also qualify as BSER for modified or reconstructed sources under Part 60 or are otherwise achievable methods for reducing GHG emission from such sources considering economic, environmental, and energy impacts. Therefore, we do not believe that the content of this rule has any direct applicability on the determination of BACT for any part 60 modified or reconstructed sources obtaining a PSD permit.

D. 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 the definition of “subject to regulation.” The EPA 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. The 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 CO_{2e} basis.

75 FR 31583.

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 applicability 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 applicable 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.

Note that we propose to move the definition of "Greenhouse gases" currently within the definitions of "Subject to regulation" in 40 CFR 70.2 and 71.2 to a definition within 70.2 and 71.2 to promote clarity in the regulations.

E. Implications for Title V Fee Requirements for GHGs

The issuance of the final EGU GHG NSPS will trigger certain requirements related to title V fees for GHG emissions under 40 CFR parts 70 and 71. States (and approved local and tribal permitting authorities) will be required to include GHG emissions in determining whether they collect adequate fees, if the state relies on the "presumptive minimum" approach to demonstrating fee adequacy. In addition, sources subject to federal permitting under part 71 will be required to include GHG emissions in calculating their annual permit fee.²⁶² The EPA is proposing changes to the title V rules to limit the impact of the requirements that would otherwise occur under the existing rules, provide flexibility to the states to ensure sufficient funding for their programs, and to ensure that the requirements are consistent with the Clean Air Act.

These requirements would be triggered because the regulation of GHGs under section 111 for the first time through the issuance of the EGU GHG NSPS would make GHGs a "regulated air pollutant," as defined under 40 CFR parts 70 and 71, a "regulated pollutant (for presumptive fee calculation)" as defined under part 70 and a "regulated pollutant (for fee calculation)" as defined under part 71.

²⁶² Also, we understand several states may have fee requirements that are structured with similar definitions that would result in GHGs being added to the list of air pollutants that are subject to title V fees.

Under the current part 70, regulation of GHGs under section 111 through the issuance of any NSPS would result in GHGs being added to the list of air pollutants used in "presumptive minimum" fee calculations. Also, in EPA's part 71 permit program, and possibly in certain state part 70 programs, issuance of a NSPS standard would result in GHGs being added to the list of air pollutants that are subject to fee payment by sources. This effect of adding GHGs to certain title V fee requirements was not discussed in the original proposal for the EGU GHG NSPS; however, several public comments were raised on this issue, and a number of related issues, during the public comment period on the original proposal for the EGU GHG NSPS.

In this re-proposal of the EGU GHG NSPS, we discuss this issue for GHGs related to title V fees and propose rule amendments that will enable permitting authorities to collect fees as needed to support their programs, and to avoid excessive and unnecessary fees. We also respond to and clarify some related issues raised by commenters on the original proposal.

In summary, we are proposing to exempt GHGs from the presumptive fee calculation, yet account for the costs of GHG permitting program costs through a cost adjustment to ensure that fees will be collected that are sufficient to cover the program costs. We are also proposing that permitting agencies that do not use the presumptive fee approach can continue to demonstrate that their fee structures are adequate to implement their title V programs.

Prior to explaining our proposal in more detail, the following discussion provides background on the fee requirements of the title V rules, what those fees cover in terms of agencies' program implementation, what additional activities agencies might be expected to have to undertake as a result of GHGs becoming "regulated pollutants" under the NSPS, what the GHG Tailoring Rule said about title V fees, background on title V fees in the context of the original proposal for the EGU GHG NSPS, and existing limitations on the collection of GHG fees.

1. Background

a. The Title V Rules

Title V is implemented through 40 CFR parts 70 and 71. Part 70 defines the minimum requirements for state, local and tribal (state) agencies to develop, implement and enforce a title V operating permit program; these programs are developed by the state and

the state submits a program to EPA for a review of consistency with part 70. There are about 112 approved part 70 programs in effect, with about 15,000 part 70 permits currently in effect. (See Appendix A of 40 CFR part 70 for the approval status of each state program). Part 71 is a federal permit program run by the EPA, primarily where there is no part 70 program in effect (e.g., in Indian country, the federal Outer Continental Shelf and for offshore Liquefied Natural Gas terminals).²⁶³ There are about 100 part 71 permits currently in effect (most are in Indian country).

b. The Fee Requirements of Title V

Section 502(b)(3)(A) of the Act requires owners or operators of all sources subject to permitting to "pay an annual fee, or the equivalent over some other period, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program." Section 502(b)(3)(B) of the Act generally sets forth the methods for determining whether a permitting authority is collecting sufficient fees in total to cover the costs of the program. First, under the "presumptive minimum" approach set forth in section 502(b)(3)(B)(i), a state can satisfy the requirement by showing that "the program will result in the collection, in the aggregate, from all sources subject to [the program] of an amount not less than \$25 per ton of each regulated pollutant, or such other amount as the Administrator may determine adequately reflects the reasonable costs of the permit program." The statute further provides that emissions in excess of 4,000 tpy for any one pollutant need not be included in the calculation, and that the initial fee rate (\$25 per ton) shall be adjusted for inflation.²⁶⁴ See section 502(b)(3)(B)(iii)-(v). Also, section 502(b)(3)(B)(ii) of the Act sets forth a definition of "regulated pollutant" for purposes of the presumptive fee calculation that includes, in part, each pollutant regulated under section 111 of the Act, such as any pollutants regulated under any NSPS, which would make GHG a "regulated pollutant" based on our proposal for the EGU GHG NSPS. Each of the title V rules that implement title V contains a definition of "regulated air

²⁶³ In some circumstances, EPA may delegate authority for part 71 permitting to another permitting agency, such as a tribal agency or a state. The EPA has entered into delegation agreements for certain part 71 permitting activities with at least one tribal agency. There are currently no states that do not have an approved part 70 program; thus, there is no need for EPA to delegate part 71 permitting authority to any state at this time.

²⁶⁴ The current corresponding part 70 fee rate, adjusted for inflation, is approximately \$47 per ton.

pollutant”²⁶⁵ (at 40 CFR 70.2 and 71.2) that tracks the Act definition of “regulated pollutant.” The “regulated air pollutant” definition is used in the regulatory text for application and other purposes and it is relevant for fee purposes because it is cross-referenced as the starting point for two fee-related definitions: “regulated pollutant (for presumptive fee calculation)”²⁶⁶ in 40 CFR 70.2 and “regulated pollutant (for fee calculation)”²⁶⁷ in 40 CFR 71.2.

Alternatively, if a state does not wish to show it collects an amount of fees at least equal to the presumptive minimum amount, section 502(b)(3)(B)(iv) provides that a program may be approved if the state demonstrates that it collects sufficient fees to cover the costs of the program, even if that amount is below the presumptive minimum.

The presumptive fee approach of the statute is reflected in the part 70 regulations for those states that wish to use it for fee adequacy purposes. In addition, for the federal part 71 permitting program, which the EPA implements directly, the EPA has adopted rules to ensure that it collects adequate fees, consistent with the statute. These statutory requirements for fees are reflected in 40 CFR 70.9 and 71.9, respectively.

Although the Clean Air Act and part 70 require that a title V permit program must collect sufficient fees to cover the costs of the program, neither the Act nor part 70 specifies the details of how those fees must be charged to particular sources in their fee schedules. The part 70 regulations specifically provide, at 40 CFR 70.9(b)(3), that a “state program’s fee schedule may include emission fees, application fees, service fees or other types of fees, or any combination thereof.” Many states use emission fees and other types of fees in combination in their fee schedules and we understand that some state fee schedules are structured such that they would result in GHG fees being required when GHGs are regulated under any NSPS. For example, states may have chosen for convenience sake to use the

“regulated pollutant (for presumptive fee calculation)” definition of part 70, or a similar state definition, to identify the pollutants subject to fees as part of their fee schedule. For part 71, the EPA chose to promulgate an emissions-based fee schedule that uses the definition of “regulated pollutants (for fee calculation)” to identify the pollutants subject to fees, and thus, part 71 is structured such that GHG fees would be required when GHGs are regulated under any NSPS.

State fee schedules charge emissions-based fees that range from about \$15 to \$100 or more per ton for each air pollutant for which they charge a fee, while part 71 charges about \$48 per ton,²⁶⁸ effective for calendar year 2013, for each of the “regulated pollutants (for fee calculation).” See 40 CFR 71.9(c)(1). Most part 70 and part 71 programs require sources to pay the fees on an annual basis, initially with the submittal of its permit application, and thereafter, on the anniversary of application submittal. See 40 CFR 70.9(a), 71.9(e).

Section 502(b)(3)(A) of the CAA broadly requires permit fees “sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program” including the reasonable costs of: “(i) reviewing and acting upon any application for such a permit, (ii) implementing and enforcing the terms and conditions of any such permit (not including any court costs or other costs associated with any enforcement action), (iii) emissions and ambient monitoring, (iv) preparing generally applicable regulations, or guidance, (v) modeling, analyses, and demonstrations, and (vi) preparing inventories and tracking emissions.” These statutory requirements were incorporated into the regulations at 40 CFR 70.9(b)(1) and 71.9(b), EPA has provided detailed guidance on EPA’s interpretation of this list of activities in several memoranda,²⁶⁹ and these activities have been considered in the context of the ICR development and renewal process for part 70 and 71.

²⁶⁸ Note that the part 71 fee rate and the part 70 presumptive fee rate are slightly different because the part 71 rate was set based on an analysis that showed that the EPA needed slightly more than the presumptive minimum to collect sufficient revenue to fund the program.

²⁶⁹ For example, see “Reissuance of Guidance on Agency Review of State Fee Schedules for Operating Permits Programs Under Title V”; from John S. Seitz, Director, Office of Air Quality Planning and Standards, to Air Division Directors, Regions I–X; August 4, 1993; available at <http://www.epa.gov/region07/air/title5/t5memos/fees.pdf>.

c. How EPA Addressed Title V Fees in the Tailoring Rule

The GHG Tailoring Rule concerned when sources are required to obtain permits under prevention of significant deterioration (PSD) and title V due to emissions of GHGs. (See Prevention of Significant Deterioration and Title V Greenhouse Tailoring Rule; Final Rule [the Tailoring Rule]; 75 FR 31514, June 3, 2010.) GHGs became subject to regulation as a result of the Light Duty Vehicle Rule (75 FR 25234, May 7, 2010), and the Tailoring Rule established emissions thresholds for purposes of PSD and title V. Neither the Light Duty Vehicle Rule nor the Tailoring Rule made any changes that would cause GHGs to meet the definition of “regulated air pollutant,” or related fee definitions in the title V regulations. The EPA has promulgated no other standards that would trigger fee requirements for GHGs in title V programs.

The GHG Tailoring Rule addressed the possible need for states and the EPA to charge fees for GHG emissions based on the burdens imposed under the Tailoring Rule for states to incorporate GHGs into permits or to issue permits to sources based on GHG emissions. We did not revise the part 70 rules to require fees for GHGs, although we did clarify that states have the option of charging fees to recover the costs of permitting related to GHGs. Also, we did not revise part 71 to require GHG fees, and we stated that we would review the need for additional fees to cover program costs for GHGs over time. (See 75 FR 31526 and 31584.) We retained this approach in last year’s Step 3 Tailoring Rule. (See Prevention of Significant Deterioration and Title V Greenhouse Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations, (Step 3 of the Tailoring Rule), 77 FR 41051, July 12, 2012).

d. Title V Fees in the Previous EGU GHG NSPS Proposal

The previous EGU GHG NSPS proposal did not discuss any title V fee issues related to regulating GHGs under a section 111 standard; however, several public commenters (two state agencies and one industry group) raised several concerns or asked for clarification on a number of issues related to title V fees during the public comment period. Two of these commenters requested clarification as to whether the issuance of the EGU GHG NSPS would make either GHGs or CO₂ subject to regulation such that title V fee requirements would be triggered for either of these

²⁶⁵ The definition includes any pollutant that is subject to any standard promulgated under section 111 of the Act.

²⁶⁶ 40 CFR 70.2 defines *regulated pollutant (for presumptive fee calculation)* to include any regulated air pollutant except carbon monoxide, any pollutant that is a regulated air pollutant solely because it is a Class I or II substance subject to a standard promulgated under or established by title VI of the Act and any pollutant that is a regulated air pollutant solely because it is subject to a standard or regulation under section 112(r) of the Act.

²⁶⁷ 40 CFR 71.2 defines *regulated pollutant (for fee calculation)* the same as *regulated pollutant (for presumptive fee calculation)* in 40 CFR 70.2.

pollutants. One commenter requested clarification on whether fees are required for “regulated NSR pollutants,” such as GHG. One commenter questioned whether the rationale of the Tailoring Rule for deferring fees for GHGs would also apply to the EGU GHG NSPS. Finally, one commenter asked us to clarify if a state could refrain from charging a fee for CO₂ (based on the issuance of the EGU GHG NSPS) if the state otherwise generates a fee sufficient to meet the “program support requirements” of title V. Note that we address the substance of several of these comments related to title V fees in section B of this portion of the proposal.

e. Unique Characteristics of GHGs Relative to Fees

There are a number of provisions in part 70 and part 71 and characteristics of GHGs that are relevant to any discussion related to charging fees for GHGs. First, it should be noted that GHG are emitted in extremely high quantities relative to other air pollutants, such as the criteria pollutants, which are typically emitted by combustion sources that also emit GHGs. A review of emission factors in EPA’s AP-42 shows that GHGs are typically emitted in quantities as much as one thousand or more times higher than CO or NO_x and many other pollutants as a product of combustion for a given mass of fuel.²⁷⁰ Thus, we expect that charging fees for GHGs at the same rate (in dollars per ton) as other regulated air pollutants would lead to fee revenue that would be excessive, far beyond the reasonable costs of the program. Even though most part 70 and 71 programs cap total fees at 4,000 tons per air pollutant per year²⁷¹ we note that the total GHG fee for a particular source under the current part 71 rule could still be significant, up to about \$194,000 per year for GHGs alone, if GHGs are charged at the same rate as for other “regulated pollutants (for fee calculation).”²⁷²

Second, unlike other pollutants, GHGs can be estimated in two ways: by mass or by CO₂ equivalent (CO₂e). While the title V permitting threshold

for the Tailoring Rule was established at 100,000 CO₂e and 100 tpy mass, the fee provisions of part 70 and 71, and we believe the fee provisions of the majority, if not all, state programs, charge fees on a mass (per ton), rather than on a CO₂e,²⁷³ basis. See 40 CFR 70.9(b)(2)(i) and 40 CFR 71.9(c)(1).

2. Response to Comments on Fees From the Previous EGU GHG NSPS Proposal

In response to concerns raised by commenters, and because response to certain of these issues will help to provide a better proposal, we respond to several of these comments at this time. In response to the question as to whether CO₂ or GHGs would be regulated by the EGU GHG NSPS, we clarify that GHG would be regulated under section 111 of the Act and that this does not affect the applicability thresholds previously established for PSD and title V in the Tailoring Rule. First, the EPA considers the pollutant being regulated by the NSPS for the purposes of PSD and title V to be GHG, rather than CO₂. Thus, under this interpretation, this NSPS has not caused CO₂ to be treated as a “regulated air pollutant” under the third prong of the definition of “regulated air pollutant” contained in 40 CFR 70.2 and 71.2, which includes “[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act,” because it causes GHG, rather than CO₂, to be the “regulated air pollutant.” Second, although EPA’s PSD regulations provide that regulation of GHGs under CAA section 111 triggers PSD applicability, the Tailoring Rule thresholds for GHG continue to apply for major source applicability for both the PSD and Title V permitting programs.²⁷⁴ In addition, we are proposing regulatory text in section 60.46Da(f) and section 60.4315(b) to make clear that for purposes of PSD and title V, greenhouse gases (not carbon dioxide) is the pollutant subject to a standard promulgated under section 111.

In response to the comment inquiring whether the rationale of the Tailoring

Rule remains relevant for deferring action on fees, we are proposing several revisions to the part 70 and part 71 regulations in response to the proposed regulation of GHGs under section 111, while retaining the general approach that we described in the Tailoring Rule. At the time of the promulgation of the Tailoring Rule, there were no section 111 standards (or other standards) that had been promulgated that would have resulted in title V fee requirements being triggered for GHGs. Thus, the rationale we use now is necessarily different than the rationale we used for the Tailoring Rule fee discussion. If the commenter is referring to the requests of certain state agencies in their comments on the Tailoring Rule for the EPA to set a presumptive fee of GHGs, we are responding to that request in this proposal by proposing to set a presumptive fee cost adjustment. If the commenter is referring to the fee flexibility afforded by 40 CFR 70.9(b)(3), we respond that we are not proposing to revise that regulatory provision. A state commenter generally asked us if it could refrain from requiring a fee for CO₂ (or GHG) if it could show that it can otherwise generate a fee sufficient to meet the “program support requirements” of title V. The response to this comment is yes, based on the following analysis. Title V requires permitting authorities to collect fees from sources that are “sufficient to cover all reasonable (direct and indirect) costs required to develop and administer [title V] programs.”²⁷⁵ States have adopted various fee schedules to meet this requirement. 40 CFR 70.9(b)(3) allows a State program’s fee schedule to include emissions fees, application fees, service-based fees or other types of fees, or any combination thereof, to meet the requirements of the collection and retention of revenues sufficient to cover the permit program costs. Further, states are not required to calculate fees on any particular basis or in the same manner for all part 70 sources or for all regulated air pollutants, provided that they collect a total amount of fees sufficient to meet the program support requirements. This flexibility is also true for states that use the presumptive minimum approach to demonstrate they would collect sufficient fees to fund the program. In the final Tailoring Rule (75 FR 31584, June 3, 2010), we did not change our fee regulations to require title V fees for GHGs or require new fee demonstrations from states related to permitting GHGs, and we have retained

²⁷⁰ See AP-42, Compilation of Air Pollution Emission Factors, Volume I, Stationary and Area Sources, Fifth Edition. For example, for external combustion of bituminous and subbituminous coals, see table 1.1–3 for NO_x and CO emission factors and table 1.1–20 for CO₂ emissions factors.

²⁷¹ Consistent with the option afforded states at 40 CFR 70.9(b)(2)(ii)(B) and the EPA’s fee schedule at 40 CFR 71.9(c)(5).

²⁷² Note that most sources that emit GHGs, particularly major sources of GHG, also emit other regulated air pollutants subject to fees; thus, they would pay significant title V fees even if a fee for GHGs is not charged.

²⁷³ The term “tpy CO₂ equivalent emissions” (or “CO₂e”) is defined within the definition of “subject to regulation” in 40 CFR 70.2 and 71.2. The definitions read, in relevant part, “[CO₂e] shall represent an amount of GHGs emitted, and shall be computed by multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas’s associated global warming potential published at Table A–1 to subpart A of part 98 of this chapter—Global Warming Potentials, and summing the resultant value for each to compute a tpy CO₂e.”

²⁷⁴ We have clarified these points further in a memorandum added to the docket for this rulemaking (“PSD Threshold Memorandum,” dated May 8, 2012). See document number EPA–HQ–OAR–2011–0660–7602.

²⁷⁵ The fee provisions are set forth in CAA section 502(b)(3) and in our regulations at 40 CFR 70.9 and 71.9.

the same policies for the purposes of the recent Step 3 rule (77 FR 41051, July 12, 2012). In the final Tailoring Rule, we recommended that each state, local or tribal program review its resource needs for GHGs and determine if the existing fee approaches would be adequate. If those approaches were not adequate, we suggested that they should be proactive in raising fees to cover the direct and indirect costs of the program or develop other alternative approaches to meet the shortfall. Therefore, we agree with the commenter that consistent with 40 CFR 70.9(b)(3), if a state generates fees “sufficient to meet the program support requirements,” without charging fees based on GHG emissions, then a fee does not have to be charged specifically for GHGs.²⁷⁶ Thus, this proposal does not seek to revise fee schedule flexibility for states and instead focuses on revising the presumptive minimum fee provisions under part 70 to more appropriately account for GHG program costs. This notice does not propose any new requirements for states that do not use the presumptive approach to establish adequacy of fees.

3. Today’s Proposal To Address GHGs in Title V Fees

In this part of the preamble we explain and solicit comment on options to address the title V fee issues raised by the proposed regulation of GHGs under this NSPS. In sum, we propose to exempt GHGs from the presumptive fee calculation, yet account for the costs of GHG permitting through a cost adjustment to ensure that fees will be collected that are sufficient to cover the program costs. We request comment on these proposals, particularly from state, local, and tribal permitting agencies, and particularly with respect to which approach would be most appropriate, feasible, and workable and result in fees that would be adequate to cover the direct and indirect costs of permitting GHGs. We also invite comments on ways to improve this proposal and/or address this issue in other ways consistent with the same principles, concerns, and statutory authority that we have described for this proposal.

a. Exemption of GHGs From Presumptive Fee Calculation

For the reasons discussed earlier in this proposal, we propose to exempt GHGs from the definition of “regulated pollutant (for presumptive fee calculation)” in 40 CFR 70.2 in order to

²⁷⁶ Conversely, where a state cannot show that sufficient fees are being collected, the state would need to modify its fee schedule (which could, but need not, involve charging fees for GHG emissions).

exclude GHGs from being subject to the statutory fee rate set for the presumptive minimum fee calculation of 40 CFR 70.9(b)(2)(i). Pursuant to the authority of section 502(b)(3)(B)(i), we are proposing to determine that utilizing the statutory fee rate for GHGs would be inappropriate because it would result in excessive fees, far above the reasonable costs of a program. We are proposing a significantly smaller cost adjustment for GHGs to reflect the program costs related to GHGs.

We have estimated the cost of permitting GHGs associated with the Tailoring Rule thresholds in an economic analysis performed for the Tailoring Rule and in several documents related to Information Collection Request (ICR) requirements for part 70 and 71, and we believe these analyses provide a basis for estimating the costs related to GHG permitting for the typical permitting authority. Thus, we propose to revise 40 CFR 70.9(b)(2)(i) to add a GHG cost adjustment to account for the GHG permitting program costs.

b. Addition of a GHG Cost Adjustment to the Presumptive Minimum Fee Calculation

We propose to revise the presumptive minimum fee provisions of part 70 to add a GHG cost adjustment to account for the typical GHG permitting program costs that may not already be covered by the existing presumptive minimum fee provisions of parts 70 and 71. The current presumptive minimum fee provisions of the title V rules implements the statutory mandate to collect fees that are sufficient to cover the direct and indirect GHG program costs. Since we are not proposing to charge fees for GHGs at the statutory rate (\$25 per ton, adjusted for inflation) due to concerns raised by permitting authorities and others about this resulting in excessive fees, we may need an alternative presumptive minimum fee to recover any costs related to GHGs that would not otherwise be covered by the presumptive minimum fee that is calculated based on emissions of regulated air pollutants, excluding GHGs. We estimated certain incremental GHG program costs that would not be covered under the context of the Tailoring Rule, but we did not revise our permit rule to reflect those costs at that time. We are aware that the EGU NSPS may further increase permitting authority costs above the levels that would be covered by presumptive minimum fee provisions that exclude GHGs, but we are also concerned that accounting for GHGs using the statutory rate would result in excessive calculation of costs. Thus, to address

these concerns, we are proposing two alternative options to adjust the presumptive minimum fee provisions of the regulations, including a modest additional cost for each GHG-related activity of certain types that a permitting authority would process over the period covered by the presumptive minimum fee calculation, and a modest additional increase in the per ton rate used in the presumptive minimum calculation. We are also soliciting comment on an option that would calculate no additional costs for GHGs.

When we promulgate step 4 of the Tailoring Rule, and depending on EPA’s proposal(s) and final action(s) there, we may revisit the GHG cost adjustment and potentially revise it, taking into account any changes in permitting authority costs for GHGs related to the obligations for permitting authorities under that rulemaking.

In addition, as a general matter, the presumptive minimum adjustments for part 70 we propose for GHGs are based, in part, on information concerning permitting authority burden (in hours) and cost (in dollars) contained in the Information Collection Request (ICR) renewal for part 70²⁷⁷ approved by the Office of Management and Budget on October 3, 2012 for the 36 month period of October 31, 2012 through September 30, 2015. Also, this information is consistent with, and updates, burden and cost information in the Regulatory Impact Assessment (RIA) for the Tailoring Rule²⁷⁸ and an ICR change request for the GHG Tailoring Rule (EPA ICR Number 1587.11), which was approved by OMB at the time of the promulgation of the Tailoring Rule²⁷⁹. These assumptions are relevant at least through step 3 of the implementation of the Tailoring Rule. The supporting statement for the ICR renewal for part 70 sets forth our estimate of the three-year and annual incremental burden related to certain activities performed by permitting authorities under the Tailoring Rule. (See Supporting Statement for the part 70 state Operating Permits Program, document number EPA-HQ-OAR-2004-0016-0023). The information in the supporting statement is designed to be a directionally correct assessment of costs, and thus, may serve as a starting point for considerations of

²⁷⁷ The most recent part 70 ICR renewal is identified as EPA ICR number 1587.12 and the ICR for part 70 has been assigned OMB control number 2060-0243.

²⁷⁸ Regulatory Impact Analysis for the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Final Report, May 2010.

²⁷⁹ The ICR change request form for the Tailoring Rule was based on the assumptions made in the RIA for the Tailoring Rule.

the possible range of costs to consider when proposing adjustments to the presumptive minimum fee provisions of part 70 to appropriately account for GHG permitting program costs.

First, we are proposing to adjust the presumptive minimum fee to account for GHG costs by adding a cost for each GHG-related activity of certain types that a permitting authority may perform over the period covered by a presumptive minimum fee calculation. Additional information supporting this approach may be found in part in Table 12 of the supporting statement (in the ICR) summarizing the permitting authority burden for particular GHG-related permitting activities. Table 12 in the ICR shows certain incremental burden assumptions for certain activities related to GHG permitting program costs in the form of an hourly burden for each activity that a permitting authority may process. Based on observations regarding permitting activities since the Tailoring Rule, we have adapted these assumptions for the purposes of this option and included certain activities with a somewhat different description than we used in the table in the ICR in an attempt to more accurately reflect the types of permitting activities that have occurred in the GHG permit program. In addition, by making these clarifying changes, we are trying to more closely track the language in the CAA and parts 70 and 71 regarding the specific of the permit process. We are proposing to include three general activities in this proposed option: (1) "GHG completeness determination (for initial permits or for updated applications)" at 43 hours, (2) "GHG evaluation for a modification or related permit action" at 7 hours, and (3) "GHG evaluation at permit renewal" at 10 burden hours.²⁸⁰ The GHG cost

²⁸⁰ A completeness determination is the first step performed by the permitting authority once a permit application is received. This step is generally more time consuming for an initial permit application compared to other permit applications because this is the initial evaluation leading to the drafting and issuance of the permit for the first time. Because GHG permitting is in the early stages of implementation and EPA is in the early stages of issuing new applicable requirements for GHGs, we believe permitting authorities will experience additional burdens related to GHGs as part of this initial completeness determination. Thus, the first item, "GHG completeness determination (for initial permit or update application)" reflects these additional burdens for completeness determinations related to GHGs. This item would also cover subsequent application updates related to an initial application. See, e.g., 40 CFR 70.5(a)(2). The second item, "GHG evaluation for a permit modification or related permitting action" applies where a permitting authority undertakes an evaluation of whether a permit modification involves any GHG-related requirements. This might also occur, for example, where a synthetic or true minor application is submitted and the permitting

adjustment for the presumptive fee would be calculated under this approach by multiplying the burden hours for each activity by the cost of staff time (in \$ per hour), including wages, benefits, and overhead, as determined by the state for the particular activities undertaken. We also solicit comment on the specific burden hours we propose for these GHG-related activities. The proposed burden hours for the three activities above were not directly discussed in the ICR or directly subject to public comment in that context. We believe this proposal would benefit from state input on the burden hour assumptions for the activities identified and we solicit comment the burden hour assumptions and on additional GHG-related permitting activities that should be added to the list.

We are also co-proposing an alternative option under which we would increase the fee rate used in the presumptive minimum calculation for each regulated air pollutant, excluding GHGs. This option would rely primarily on data concerning the state burdens of permitting GHGs through step 3 of the tailoring rule found in the Information Collection Request (ICR) for part 70. This suggests that when looking at Tailoring Rule burden in isolation, that GHG permitting increases permitting authority burden by about 7 percent above the baseline burden,²⁸¹ which would be multiplied by the presumptive minimum fee rate in effect to calculate the revised presumptive fee rate to account for GHG. Under this approach, the new presumptive minimum fee effective for the current period would be \$50.00 per ton for each regulated pollutant (for presumptive fee calculation).²⁸² Several states suggested

authority needs to undertake a GHG related analysis to determine if it affects the existing title V permit. The third item, "GHG evaluation at permit renewal" applies where the permitting authority receives a renewal application that is not coupled with any facility modifications. The EPA suggests this language because it is more closely tied to the specific work to be performed by permitting authorities consistent with statutory and regulatory obligations.

²⁸¹ The baseline costs in the supporting statement for the ICR were the costs of permitting looking at all activities except for those related to the GHG tailoring rule and certain other recent rule changes. Table 14 of the supporting statement shows a permitting authority burden of 102,122 hours for implementing the GHG tailoring rule and 1,414,293 hours of baseline permitting authority burden, and Table 15 shows a permitting authority cost of \$5.5 million for implementing the GHG tailoring rule and \$76.4 million for the baseline permitting program.

²⁸² At the current rate for part 70 of \$46.73, this would result in a GHG fee adjustment of about \$3.27, or a new rate of \$50.00 per ton for each regulated pollutant (for presumptive fee calculation).

an approach similar to this in comments on the Tailoring Rule, however, their comments assumed we would not be exempting GHGs from the definition of regulated pollutants (for presumptive fee calculation), as we are proposing today. We solicit comment on the appropriateness of the 7 percent fee increase for the presumptive minimum fee we propose to account for the GHG permitting costs for permitting authorities under this alternative option. We are particularly interested in state input on whether this level should be higher or lower than we propose.

The two options we co-propose for adjusting the presumptive minimum fee to account for the costs of GHG permitting are similar in that we believe they would both result in about the same amount of additional fee revenue being collected. For the first option, we took the assumptions approved into the ICR and adapted them somewhat so that they more accurately reflect the actual implementation experience of permitting authorities related to GHGs. On the second, alternative option, we used the ICR estimate to determine the relative contribution of GHG tailoring rule costs to the total costs of title V permitting and we assume these relative costs will hold true in any particular state that uses the presumptive minimum fee approach to demonstrating fee adequacy. The two options differ in that the first option calculates the GHG adjustment to the presumptive fee minimum by determining the number of actual GHG-related activities they have performed for a period, while the second option calculates the GHG adjustment by increasing the presumptive fee rate for non-GHG pollutants by a set ratio to reflect average expected costs. The first approach requires a state to track the number of activities of these types it is performing and is thus more burdensome to calculate, although it may more accurately reflect the actual costs. The second approach is simpler to calculate and predictable but is less directly tied to actual implementation experience in a particular state.

We also solicit comment on whether we need to revise the presumptive minimum calculation provisions to account for GHGs costs if we exempt GHGs from the calculation of the presumptive minimum fee. The basis for this option would be that because most GHG sources that would be subject to title V permitting, whether due to GHGs or due for other reasons under the proposed NSPS and applicability provisions of the permitting rules (see 40 CFR 70.3 and 71.3) would have actual emissions of other regulated air

pollutants subject to fees, and thus the cost of permitting these sources may be adequately accounted for without charging any additional fees specifically based on emissions of GHGs. We also note that support for this approach can be found in the current OMB-approved ICR for part 70, tables 14, 15 and 18, where the cost of permitting for permitting authorities is summarized, considering the effects of several recent EPA rulemakings that were conducted since the last ICR update.

This proposal does not directly affect those states that do not rely on the presumptive minimum fee approach to show fee adequacy; however, non-presumptive fee states are still required to charge sufficient fees to recover all reasonable direct and indirect program costs. Part 70 allows the EPA to review state fee programs at any time to determine if they are collecting fees sufficient to cover their costs, whether or not states rely on the presumptively minimum fee approach. We are not requiring any additional detailed fee submittals from states at this time based on these proposed changes.

Some states may conclude that they wish to revise their part 70 programs in response to this proposal either to revise their state fee schedules to prevent any possible collection of excessive fees (e.g., if they require any regulated pollutant subject to a section 111 standard to pay a fee) or to charge additional fees to sources because their presumptive minimum fee target has increased. We solicit comment on the most expeditious means for EPA to approve title V program revisions across the states once this proposal is finalized.

There may be other viable options consistent with statutory and regulatory authority, principles, and concerns, in addition to those we have described in this proposal. For example, states have previously commented on establishing a separate, lower presumptive fee per ton of GHG emissions). The EPA invites states, local, and/or Tribal authorities to provide more refined data and/or information surrounding the unique costs associated with permitting GHG sources under this proposed rule, and other fee options such data supports. Notably, the regulatory text included today represents only one option on which comments are solicited. The EPA is providing full regulatory text only for this option because it represents the most novel approach. The EPA is also soliciting comment on other viable approaches described herein, but considers the discussion provided herein to provide an adequate basis for public comment. The EPA notes that the

final rule may be based on any of the approaches described in the preamble.

c. Revisions to the Part 71 Fee Schedule

As part of the promulgation of the final part 71 rule, the EPA performed a detailed analysis of the costs of developing and implementing the program and reviewed the inventory of emissions of regulated pollutants (for fee calculation) to determine the appropriate emission fee that would be sufficient to recover all direct and indirect programs costs—we set the fee at \$32 per ton, adjusted for inflation, times the emissions of regulated pollutant (for fee calculation). (See Federal Operating Programs Fees, Revised Cost Analysis, February 1996; legacy docket A-93-51, document number II-A-3.)

For part 71, we also propose to exempt GHGs from the definition of regulated pollutant (for fee calculation), which is similar to the definition of regulated pollutants (for presumptive fee calculation) used in part 70, for the same reasons we have explained for part 70. In addition, for the same reasons we explained for part 70, we are proposing two options for revising the fee schedule of 40 CFR 71.9(c) to ensure that we continue to recover sufficient fees to fully fund the part 71 GHG permitting program. The bases for the options were described in more detail earlier in this proposal with respect to part 70 proposals and those also apply here to part 71.

First, the EPA (or delegate agency) burden hour assumptions we propose for each GHG-related permitting activity under part 71 are the same as we are proposing for states under the presumptive minimum fee provisions of part 70.²⁸³ This option would rely on the following information. The labor rate assumption we propose for the EPA (or delegate agency) staff time under part 71 is the average hourly rate we assumed in the supporting statement for the recent part 71 ICR renewal of \$52 per hour in 2011 dollars, including wages, benefits and overhead costs. We propose to determine the GHG fee adjustment for each GHG permitting program activity by multiplying the burden hour assumption we propose by the EPA (or delegate agency) labor rate

²⁸³ See the supporting statement for the ICR renewal for part 71 approved by the Office of Management and Budget on June 13, 2012 for the 36 month period of June 30, 2012 through May 31, 2015. The ICR renewal for part 71 is identified as EPA ICR number 1713.10 and the ICR for part 71 has been assigned OMB control number 2060-0336. The assumptions of this part 71 ICR renewal for GHG burden are identical to those used for the part 70 ICR. See Table 12 of the part 71 supporting statement.

we propose. Thus, for example, we propose a set fee to be paid by sources for each “completeness determination (for new permit or updated application)” of \$364 (7 hours times \$52 per hour for the current period). Also, we propose to charge, for simplicity sake, the same set fees for GHG activities, whether performed by the EPA, a delegate agency, or by the EPA with contractor assistance. The appropriate set fees for all GHG permitting program activities performed for the source would be added to the traditional fee that is determined based on emissions of each regulated pollutant (for fee calculation) to determine the total fee for the source.

The second option we propose for part 71 is to increase the emission fee by a modest amount for each regulated air pollutant, excluding GHGs. For simplicity sake, we propose to charge the same adjustment under this option that we propose for part 70, or 7 percent, which would be multiplied by annual part 71 fee in effect to calculate the revised fee rate.²⁸⁴ The rationale for this approach is described in more detail earlier in this preamble during the part 70 discussion.

We also solicit comment on whether we could exclude GHG emissions from the calculation of the annual part 71 fee for reasons similar to those we explained for part 70 (e.g., because permitting costs can be covered by the existing part 71 permit fee).

X. Impacts of the Proposed Action ²⁸⁵

A. What are the air impacts?

As explained in the Regulatory Impact Analysis (RIA) for this proposed rule, available data indicate that, even in the absence of this rule, existing and anticipated economic conditions will lead electricity generators to choose new generation technologies that would meet the proposed standard without installation of additional controls. Therefore, based on the analysis presented in Chapter 5 of the RIA, the EPA projects that this proposed rule will result in negligible CO₂ emission changes, quantified benefits, and costs by 2022.²⁸⁶

²⁸⁴ At the current rate for part 71 of \$48.33, this would result in a GHG fee adjustment of \$3.38, or a new rate of \$51.71 per ton for each regulated pollutant (for fee calculation).

²⁸⁵ Note that EPA does not project any difference in the impacts between the alternative to regulate sources under subparts Da and KKKK versus regulating them under new subpart TTTT.

²⁸⁶ Conditions in the analysis year of 2022 are represented by a model year of 2020.

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, the EPA believes that electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in its absence, because of existing and expected market conditions. In addition, the EPA does 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. However, because some companies may choose to construct coal or other fossil fuel-fired units, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS.

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 2022. The owners of newly built electric generating units will likely choose technologies that meet these standards even in the absence of this proposal due to existing economic conditions as normal business practice. Likewise, the EPA believes this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. 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 meet a particular performance standard, this rulemaking reduces uncertainty and may enhance the prospects for new coal-fired generation and the deployment of CCS, and thereby promote energy diversity.

XI. 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.

Measurement. We are requesting comment on requiring the use of the following procedures that increase the precision of GHG measurements:

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 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.

e. An ambient air argon concentration of 0.93 percent²⁸⁷ and a molecular weight of 39.9 lb/lb-mol in calculating the dry gas molecular weight.

f. A value for pi of 3.14159 when calculating the effective area for circular stacks.

g. A daily calibration drift cap no greater than 0.3 percent CO₂ for CO₂ CEMS.

h. A maximum relative accuracy specification of 2.5 percent for both CO₂ and flow rate measurement CEMS.

i. Method 3B of 40 CFR part 60 in addition to Method 3A, for CO₂ concentration measurement and for molecular weight determination during CEMS relative accuracy determinations or for performance testing.

Coal refuse. In the original proposal, we requested comment on subcategorizing EGUs that burn over 75 percent coal refuse on an annual basis. Multiple commenters supported the exemption, citing numerous environmental benefits of remediating coal refuse piles. Other commenters disagreed with any exemption, specifically citing the N₂O emissions from fluidized bed boilers (coal refuse-fired EGUs typically use fluidized bed technology). Due to the environmental benefits of remediating coal refuse piles cited by commenters, the limited amount of coal refuse, and that a new coal refuse-fired EGU would be located in close proximity to the coal refuse pile, we are continuing to consider establishing a subcategory for coal refuse-fired EGUs and are requesting additional comments. Specifically, we are requesting additional information on the net environmental benefits of coal refuse-fired EGUs, and in the event we do establish a coal refuse-fired subcategory, what the emissions standard for that subcategory should be (i.e., should it be based on a lower amount of partial CCS or on highly efficient generation alone, without the use of CCS). One commenter on the original proposal stated that existing coal refuse piles are naturally combusting at a rate of 0.3 percent annually. We are requesting comment

²⁸⁷ <http://www.physicalgeography.net/fundamentals/7a.html>.

on assuming this rate of natural combustion and the proper approach to accounting for naturally occurring emissions from coal refuse piles.

Compressed Air Energy Storage (CAES) Facilities. CAES technology is an energy storage technology that involves two steps. Air is compressed by electric motor driven compressors during off-peak electricity demand hours and stored in a storage media (e.g., an underground cavern). Electricity is then generated during peak electricity demand periods by releasing the high-pressure air, heating the air with natural gas, and expanding it through sequential turbines (expanders), which drive an electrical generator. Since natural gas is combusted in the stationary combustion turbine, a new CAES would potentially have to comply with one of the proposed emissions standards. However, based on anticipated capacity factors for new CAES facilities, it is our understanding that the proposed one-third electric sales of potential electric output applicability criteria would exempt new CAES facilities from the proposed emission standards. The EPA is requesting comment on whether this assumption is accurate. In the event that this is not the case, the EPA is considering and requesting comment on if new source review is the appropriate mechanism to establish site specific GHG requirements for CAES facilities and, if so, whether the EPA should exempt stationary combustion turbines at CAES facilities from the proposed CO₂ emission standards. We have concluded this could be appropriate since we expect only a limited number of new CAES facilities, and the use of stored energy complicates the determination of compliance with the proposed emission standards.

District Energy. District energy systems produce steam, hot water or chilled water at a central facility. The steam, hot water or chilled water is then distributed through pipes to individual consumers for space heating, domestic hot water heating and air conditioning. As a result, individual consumers served by a district energy system do not need their own heating, water heating or air conditioning systems. Even though with the proposed definition of net-electric output it is unlikely that a district energy system would be subject to an emissions standard, we are considering and requesting comment on an appropriate method to recognize the environmental benefit of district energy systems. The steam or hot water distribution system of a district energy system located in urban areas, college and university

campuses, hospitals, airports, and military installations eliminates the need for multiple, smaller boilers at individual buildings. A central facility typically has superior emission controls and consists of a few larger boilers facilitating more efficient operation than numerous separate smaller individual boilers. However, when the hot water or steam is distributed, approximately two to three percent of the thermal energy in the water and six to nine percent of the thermal energy in the steam is lost, reducing the net efficiency advantage. To recognize the net environmental benefit of district energy systems compared to multiple smaller heating and cooling systems, we are requesting comment on whether it is appropriate to adjust the measured thermal output from district energy systems when calculating the emissions rate used for compliance purposes. For example, if thermal energy from central district energy systems is approximately 5 percent more efficient than thermal energy supplied by multiple smaller heating and cooling systems, the measured thermal output would be divided by 0.95 (e.g., 100 MMBtu/h of measured steam would be 105 MMBtu/h when determining the emissions rate). This approach would be similar to the proposed approach to how the electric output for CHP is considered when determining regulatory compliance and is consistent with the approach in the proposed amendments to the combustion turbine NSPS (77 FR 52554). We request that comments include technical analysis of the net benefits in support of any conclusions on an appropriate adjustment factor.

Emergency conditions. We are requesting comment on excluding electricity generated as a result of a grid emergency declared by the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator from counting as net sales when determining applicability as an EGU. For example, under this approach, if grid voltage drops below acceptable levels and the affected facility is the only facility with available capacity, then electricity generated during this period would not count for applicability purposes. While the proposed 3 year average electric sales applicability provides significant flexibility for simple cycle turbines, we are considering including the emergency conditions exemption to allow facilities designed with the intent to sell less than one-third of their potential electric output to continue to generate electricity during a grid emergency without such generation

counting towards the one-third sales applicability criterion. In the original 1979 electric utility NSPS rulemaking (44 FR 33580), the EPA recognized that emergency periods do occur from unplanned EGU outages, transmission outages or surging customer demand loads. Such occurrences may require that all available operable EGUs interconnected to the electrical grid supply power to the grid. Provisions were added to 40 CFR part 60, subpart Da to address emergency conditions when continued operation of an EGU with a malfunctioning flue gas desulfurization (FGD) system is acceptable and not considered a violation of the SO₂ emissions standard. These conditions require that all available capacity from the power company's other EGUs is being used and all available purchase power from interconnected power companies is being obtained. In this case, the EPA concluded that the broader benefits of operating the power plant with the malfunctioning FGD system to generate electrical power during emergency conditions in order to ensure uninterrupted electricity supply to the public outweigh any adverse impacts from a short-term increase in SO₂ emission to the atmosphere from the power plant. The definition for a system emergency we are considering is "any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected facility to operate to avert loss of load."

Initial Design Efficiency Test. We are considering and requesting comment on requiring an initial performance test for stationary combustion turbines in addition to the 12-operating-month rolling average standard. Requiring an initial compliance test that is numerically more stringent than the annual standard for new combined cycle facilities would insure that the most efficient stationary combustion turbines are installed. The less stringent 12-month rolling average standard would be set at a level that would take into account actual operating conditions.

Integrated Equipment. The proposed affected facility definitions include the traditional generating unit "plus any integrated equipment that provides electricity or useful thermal output."

For example, the definition of a steam generating unit for GHG purposes, “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 equipment that provides electricity or useful thermal output to either the boiler or to power auxiliary equipment” (emphasis added). We are considering and requesting comment on also including in the definition of the affected facility co-located non-emitting energy generation equipment that is not integrated into the operation of the affected facility. This approach would provide additional flexibility, lower compliance costs, and recognize the environmental benefit of non-emitting sources of electricity and not limit options to integrated solar thermal. The definition would include the additional language “or co-located non-emitting energy generation included in the facility operating permit.” For example, the definition of a steam generating unit for GHG purposes would be expanded to read, “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 equipment that provides electricity or useful thermal output to either the boiler or to power auxiliary equipment or co-located non-emitting energy generation included in the facility operating permit” (emphasis added). This would permit the use of co-located photovoltaic solar power, wind turbines, and other non-emitting energy generation as means for achieving compliance with the emission standards. Since integrated solar thermal is primarily a feasible option only for facilities that operate daily (e.g., thermal energy from the solar thermal is used in the steam cycle generated from the combustion of fossil fuels), this approach would expand options for more intermittent intermediate load generators to efficiently integrate non-emitting energy generation into their design.

Other GHGs. Today’s proposed rule would require continuous measurement of CO₂ from fossil fuel-fired EGUs. Other GHGs, such as CH₄ and N₂O are not included in the proposed emission standards and are also not required to be measured and reported by affected EGUs as part of today’s proposal, even though their 100-year global warming

potential is 21 to 310 times greater than that of CO₂, because their emissions from EGUs are believed to be negligible when compared to CO₂ emissions. We request comment on the appropriateness, technique, and frequency (one-time or periodic, but not continuous) of measurement and reporting of CH₄ and N₂O emissions from fossil fuel-fired EGUs as part of the proposed emissions standard. Receipt of this data would enhance understanding of total GHG emissions from EGUs and could aid future policy decisions regarding whether these GHGs should be included in a revised emission standard, as part of 8-year NSPS review and potential revision cycle.

Violations. We are proposing that the calculation of the number of daily violations within an averaging period be determined using the following methodology. If, for any 12- or 84-operating month period, the source’s emission rate exceeds the standard, the number of daily violations in the 12- or 84-operating-month averaging period would be the number of operating days in that period. However, if a violation occurs directly following the previous 12-operating-month or 84-operating-month averaging period, daily violations would not double count operating days that were determined as violations under the previous averaging period. For example, assume that a facility operates 10 days out of each month for 12 months from January 1, Year 1 to December 31, Year 1, and exceeds the emissions standard during that 12-month period. The violation for this January-December Year 1 period would constitute 120 daily violations. If the facility operated 20 days the following month, which would be January, Year 2, and was still in excess of the emissions standard over the period from February, Year 1 to January, Year 2, then 20 additional daily violations would result, for a total of 140 daily violations. We are requesting comment on this determination of daily violations for owners/operators that exceeds either a 12-operating-month or 84-operating-month standard.

XII. 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 51735, 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 Fossil Fuel-Fired Electric Utility Steam Generating Units and Stationary Combustion Turbines.

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). The EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this proposal. However, because some companies may choose to construct coal or other fossil fuel-fired units, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS.

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 the EPA ICR number 2465.02.

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 emissions and downtime, every 3 months.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 60, subparts Da and KKKK or subpart TTTT 60.5530. 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 reasonably preventable, and not caused by poor maintenance 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 affirmative defense, 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 \$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.

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 this rule applies only to sources built in the future. Of the number of excess emissions events that may be reported by source operators, only a small number would be expected to result from a malfunction, and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert an 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 Da and subpart KKKK or 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 quarterly summary reports which include reporting of emissions and downtime. All burden estimates are in 2010 dollars. Average burden hours per response are estimated to be 8 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-2013-0495. 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 the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after January 8, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by February 7, 2014. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

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 8 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 8—POTENTIALLY REGULATED CATEGORIES AND ENTITIES ^a

Category	NAICS Code	Examples of potentially regulated entities
Industry	221112	Fossil fuel electric power generating units.
State/Local Government	^b 221112	Fossil fuel electric power generating units owned by municipalities.

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

^b 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). 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, prior to the April 13, 2012 proposal (77 FR 22392), the EPA determined to seek early input from representatives of small entities while formulating the provisions of the 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.

While formulating the provisions of this proposed regulation, the EPA also

considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392). We invite comments on all aspects of the proposal and its impacts, including potential adverse impacts, on small entities.

D. Unfunded Mandates Reform Act

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). 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 prior to the April 13, 2012 proposal (77 FR 22392). 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.

While formulating the provisions of this proposed regulation, the EPA also considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392).

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. Prior to the April 13, 2012 proposal (77 FR 22392), 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. While formulating the provisions of this proposed regulation, the EPA also considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392). In the spirit of EO 13132, and consistent with the 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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). 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. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, EPA consulted with tribal officials in developing this action. Because the EPA is aware of Tribal interest in this proposed rule, prior to the April 13, 2012 proposal (77 FR 22392), the EPA offered consultation with tribal officials early in the process of developing the 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.

While formulating the provisions of this proposed regulation, the EPA also considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392).

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 action is not subject to EO 13045 because it is based solely on technology performance.

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 proposes to use 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.

This proposed rule limits GHG emissions from new fossil fuel-fired EGUs by establishing national emission standards for CO₂. The EPA has determined that this proposed rule would not result in disproportionately high and adverse human health or environmental effects on minority, low-

income, and indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income or indigenous populations.

XIII. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects

40 CFR Part 60

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

40 CFR Part 70

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

40 CFR Part 71

Environmental Protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

40 CFR Part 98

Environmental protection, Greenhouse gases and monitoring, Reporting and recordkeeping requirements.

Dated: September 20, 2013.

Gina McCarthy,
Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60, 70, 71, and 98 of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

- 2. Section 60.46Da is added to read as follows:

§ 60.46Da Standards for carbon dioxide (CO₂).

(a) Your affected facility is subject to this section if construction commenced after [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**], and the affected facility meets the conditions specified in paragraphs (a)(1) and (a)(2) of this section, except as specified in paragraph (b) of this section.

(1) The affected facility combusts fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years.

(2) The affected facility supplies more than one-third of its potential electric output and more than 219,000 MWh net-electric output to a utility power distribution system for sale on an annual basis.

(b) The following EGUs are not subject to this section:

(1) The proposed Wolverine EGU project described in Permit to Install No. 317–07 issued by the Michigan Department of Environmental Quality, Air Quality Division, effective June 29, 2011 (as revised July 12, 2011).

(2) The proposed Washington County EGU project described in Air Quality Permit No. 4911–303–0051–P–01–0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**].

(3) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**].

(c) As owner or operator of an affected facility subject to this section, you shall not cause to be discharged into the atmosphere from the affected facility any gases that contain CO₂ in excess of the emissions limitation specified in either paragraphs (c)(1) or (c)(2) of this section.

(1) 500 kilograms (kg) of CO₂ per megawatt-hour (MWh) of gross energy output (1,100 lb CO₂/MWh) on a 12-operating month rolling average basis; or

(2) 480 kg of CO₂ per MWh of gross energy output (1,050 lb CO₂/MWh) on an 84-operating month rolling average basis.

(d) You must make compliance determinations at the end of each operating month, as provided in

paragraphs (d)(1) and (d)(2) of this section. For the purpose of this section, operating month means a calendar month during which any fossil fuel is combusted in the affected facility.

(1) If you elect to comply with the CO₂ emissions limitation in paragraph (c)(1) of this section, you must determine compliance monthly by calculating the average CO₂ emissions rate for the affected facility at the end of each 12-operating month period that includes, as the last month, the month for which you are determining compliance.

(2) If you elect to comply with the CO₂ emissions limitation in paragraph (c)(2) of this section, you must determine compliance monthly by calculating the average CO₂ emissions rate for the affected facility at the end of each 84-operating month period that includes, as the last month, the month for which you are determining compliance.

(e) You must conduct an initial compliance determination with the CO₂ emissions limitation for your affected facility within 30 days after accumulating the required number of operating months for the compliance period with which you have elected to comply (i.e., 12-operating months or 84-operating months). The first operating month included in this compliance period is the month in which emissions reporting is required to begin under § 75.64(a) of this chapter.

(f) You must monitor and collect data to demonstrate compliance with the CO₂ emissions limitation according to the requirements in paragraphs (f)(1) through (4) of this section.

(1) You must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(2) You must measure the hourly CO₂ mass emissions from each affected facility using the procedures in paragraphs (f)(2)(i) through (vii) of this section, except as provided in paragraph (f)(3) of this section.

(i) You must install, certify, operate, maintain, and calibrate a CO₂ continuous emission monitoring system (CEMS) to directly measure and record CO₂ concentrations in your affected facility's exhaust gases that are emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. If you measure CO₂ concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter.

(ii) For each monitoring system used to determine the CO₂ mass emissions,

you must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices B and D to part 75 of this chapter.

(iii) You must use a laser device to measure the dimensions of each exhaust gas stack or duct at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, you must make measurements of the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, you must make measurements of each dimension (i.e., depth and width) at three or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, you must repeat these measurements at the new location.

(iv) You can only use unadjusted exhaust gas volumetric flow rates to determine the hourly CO₂ mass emissions from the affected facility; you must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(v) If you choose to use Method 2 in Appendix A-1 to this part to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, you must use a calibrated Type-S pitot tube or pitot tube assembly. You must not use the default Type-S pitot tube coefficient.

(vi) If two or more affected facilities share a common exhaust gas stack and are subject to the same CO₂ emissions limitation in paragraph (c) of this section, you may monitor the hourly CO₂ mass emissions at the common exhaust gas stack rather than monitoring each affected facility separately.

(vii) If the exhaust gases from the affected facilities are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you choose to monitor in the ducts), you must monitor the hourly CO₂ mass emissions and the "stack operating time" (as defined in § 72.2 of this chapter) at each stack or duct separately.

(3) As an alternative to complying with paragraph (f)(2) of this section, for affected facilities that do not combust any solid fuel, you may determine the hourly CO₂ mass emissions by using Equation G-4 in Appendix G to part 75 of this chapter according to the requirements specified in paragraphs (f)(3)(i) and (f)(3)(ii) of this section.

(i) You must implement the applicable procedures in Appendix D to part 75 of this chapter to determine hourly unit heat input rates (MMBtu/h),

based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(ii) You may determine site-specific carbon-based F-factors (F_c) using Equation F-7b in section 3.3.6 of Appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G-4 nomenclature.

(4) You must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the gross electric output from the affected facility, and you must meet the requirements specified in paragraphs (f)(4)(i) and (ii) of this section, as applicable.

(i) If your affected facility is a combined heat and power unit as defined in § 60.42Da, you must also install, calibrate, maintain, and operate meters to continuously determine and record the total useful recovered thermal energy. For process steam applications, you must install, calibrate, maintain, and operate meters to continuously determine and record steam flow rate, temperature, and pressure. If your affected facility has a direct mechanical drive application, you must submit a plan to the Administrator or delegated authority for approval of how gross energy output will be determined. Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(ii) If two or more affected facilities have steam generating units that serve a common electric generator, you must apportion the combined hourly gross electric output to each individual affected facility using a plan approved by the Administrator (e.g., using steam load or heat input to each affected facility). Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(g) You must demonstrate compliance with the CO₂ emissions limitation using the procedures specified in paragraphs (g)(1) and (2) of this section.

(1) You must calculate the CO₂ mass emissions rate for your affected facility using the calculation procedures in paragraphs (g)(1)(i) through (v) of this section with the hourly CO₂ mass emissions and gross energy output data determined and recorded according to the procedures in paragraph (f) of this section for each operating hour in the applicable compliance period (i.e., 12-

operating months or 84-operating months).

(i) You must only use operating hours in the compliance period for which you have valid data for all the parameters you use to determine the hourly CO₂ mass emissions and gross output data. You must not use operating hours which use the substitute data provisions of part 75 of this chapter for any of the parameters in the calculation. For the compliance determination calculation, you must obtain valid hourly values for a minimum of 95 percent of the

operating hours in the applicable compliance period.

(ii) You must calculate the total CO₂ mass emissions by summing all of the valid hourly CO₂ mass emissions values for the applicable compliance period. If exhaust gases from the affected facility are emitted to the atmosphere through multiple stacks or ducts, you must calculate the total CO₂ mass emissions for the affected facility by summing the total CO₂ mass emissions from each of the individual stacks or ducts.

(iii) For each operating hour of the compliance period used in paragraph (g)(1)(ii) of this section to calculate the total CO₂ mass emissions, you must determine the affected facility's corresponding hourly gross energy output using the appropriate definitions in § 60.42Da and paragraph (k) of this section and using the procedure specified in paragraphs (g)(3)(iii)(A) through (D) of this section.

(A) Calculate P_{gross} for your affected facility using the following equation:

$$P_{gross} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW}}{T} + 0.75 \times [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where: a

P_{gross} = Gross energy output of your affected facility in megawatt-hours in MWh.

(Pe)_{ST} = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

(Pe)_{CT} = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

(Pe)_{IE} = Electric energy output plus mechanical energy output (if any) of your affected facility's integrated equipment that provides electricity or mechanical energy to the affected facility or auxiliary equipment in MWh.

(Pe)_{FW} = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. This term is not applicable to IGCC facilities.

(Pt)_{PS} = Useful thermal energy output of steam measured relative to ISO conditions that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected facility. This term is calculated using the equation specified in paragraph (g)(3)(iii)(B) of this section in MWh.

(Pt)_{HR} = Hourly useful thermal energy output measured relative to ISO conditions from heat recovery that is used for applications other than steam generation or performance enhancement of the affected facility in MWh.

(Pt)_{IE} = Useful thermal energy output relative to ISO conditions from any integrated equipment that provides thermal energy to the affected facility or auxiliary equipment in MWh.

T = Electric Transmission and Distribution Factor.

T = 0.95 for a combined heat and power affected facility where at least on an annual basis 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal energy output on a rolling 3 year basis.

T = 1.0 for all other affected facilities.

(B) If applicable to your affected facility, calculate (Pt)_{PS} using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{3.6 \times 10^9}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions in Joules per kilogram (J/kg) (or Btu/lb).

3.6 × 10⁹ = Conversion factor (J/MWh) (or 3.413 × 10⁶ Btu/MWh).

(C) For an operating hour in which there is no gross electric load, but there is mechanical or useful thermal output, you must still determine the gross energy output for that hour. In addition, for an operating hour in which there is no useful output, you must still determine the hourly gross CO₂ emissions for that hour.

(D) If hourly CO₂ mass emissions are determined for a common stack, you must determine the hourly gross energy output (electric, thermal, and/or mechanical, as applicable) by summing the hourly loads for the individual affected facility and you must express the operating time as "stack operating hours" (as defined in § 72.2 of this chapter).

(iv) You must calculate the total gross energy output by summing the hourly gross energy output values for the affected facility determined from paragraph (g)(1)(iii) of this section for all of the operating hours in the applicable compliance period.

(v) You must calculate the CO₂ mass emissions rate for the applicable compliance period interval by dividing the total CO₂ mass emissions value from paragraph (g)(1)(ii) of this section by the total gross energy output value from paragraph (g)(1)(iv) of this section.

(2) You must determine compliance with the CO₂ emissions limitation in paragraph (c) of this section is determined as specified in paragraphs (g)(2)(i) and (ii) of this section using the CO₂ mass emissions rate for your affected facility that you determined in paragraph (g)(1) of this section.

(i) If the CO₂ mass emissions rate for your affected facility is less than or equal to the CO₂ emissions limitation applicable to your affected facility, then your affected facility is in compliance with the CO₂ emissions limitation. If you attain compliance with the CO₂ emissions limitation at a common stack for two or more affected facilities subject to the same CO₂ emissions limitation, each affected facility sharing the stack is in compliance with the CO₂ emissions limitation.

(ii) If the CO₂ mass emissions rate for the affected facility is greater than the CO₂ emissions limitation in paragraph (c) of this section applicable to the affected facility, then the affected facility has excess CO₂ emissions.

(h) You must prepare and submit notifications and reports according to paragraphs (h)(1) through (4) of this section.

(1) You must prepare and submit the notifications in §§ 60.7(a)(1) and (a)(3) and 60.19, as applicable to your affected facility.

(2) You must prepare and submit notifications in § 75.61 of this chapter, as applicable to your affected facility.

(3) You must submit electronic quarterly reports according to the requirements specified in paragraphs (h)(3)(i) through (iii) of this section.

(i) Initially, after you have accumulated the required number of operating months for the CO₂ emission limitation compliance period that you have chosen to comply with (i.e., 12-operating months or 84-operating months), you must submit a report for

the calendar quarter that includes the final (12th- or 84th) operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter no later than 30 days after the end of the quarter.

(ii) In each quarterly report you must include the information in paragraphs (h)(3)(ii)(A) through (E) of this section.

(A) The CO₂ emission limitation compliance period with which you have chosen to comply.

(B) Any months in the calendar quarter that you are not counting as operating months.

(C) For each operating month in the calendar quarter, the corresponding average CO₂ mass emissions rate for the applicable compliance period interval that you determined according to paragraph (g) of this section.

(D) The percentage of valid CO₂ mass emission rates in each compliance period (i.e., the total number of valid CO₂ mass emission rates in that period divided by the total number of operating hours in that period, multiplied by 100 percent).

(E) Any operating months in the calendar quarter with excess CO₂ emissions.

(iii) In the final quarterly report of each calendar year you must include the following:

(A) Net electric output sold to an electric grid over the calendar year; and

(B) The potential electric output of the facility.

(iv) You must submit each electronic report using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the EPA Office of Atmospheric Programs.

(4) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(5) If your affected unit uses geologic sequestration to meet the applicable emissions limit, you must report in accordance with the requirements of 40 CFR Part 98, subpart PP and either:

(i) if injection occurs onsite, report in accordance with the requirements of 40 CFR Part 98, subpart RR, or

(ii) if injection occurs offsite, transfer the captured CO₂ to a facility or facilities that reports in accordance with the requirements of 40 CFR Part 98, subpart RR.

(i) For each affected electric utility stream generating unit, you must maintain records according to paragraphs (i)(1) through (i)(8) of this section.

(1) You must comply with the applicable recordkeeping requirements

and maintain records as required under subpart F of part 75 of this chapter.

(2) You must maintain records of the calculations you performed to determine the total CO₂ mass emissions for each operating month, and the averages for each compliance period interval (i.e., 12-operating months or 84-operating months, as applicable to the CO₂ emissions limitations).

(3) You must maintain records of the applicable data recorded and calculations performed that you used to determine the gross energy output for each operating month.

(4) You must maintain records of the calculations you performed to determine the percentage of valid CO₂ mass emission rates in each compliance period.

(5) You must maintain records of the calculations you performed to assess compliance with each applicable CO₂ emissions limitation in paragraph (c) of this section.

(6) Your records must be in a form suitable and readily available for expeditious review.

(7) You must maintain each record for 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record except those records required to demonstrate compliance with an 84-operating month compliance period. You must maintain records required to demonstrate compliance with an 84-operating month compliance period for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(8) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. You may maintain the records off site and electronically for the remaining year(s) as required by this subpart.

(j) *PSD and Title V Thresholds for Greenhouse Gases.*

(1) For purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from new affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from new affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the

pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from new affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from new affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

(k) For purposes of this section, the following definitions apply:

Gross energy output means:

(i) Except as provided under paragraph (ii) of this definition, for electric utility steam generating units, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) minus any electricity used to power the feedwater pumps plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application);

(ii) For electric utility steam generating unit combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of thermal output on a rolling 3 year basis, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) minus any electricity used to power the feedwater pumps, that difference divided by 0.95, plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application);

(iii) Except as provided under paragraph (ii) of this definition, for a IGCC electric utility generating unit, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) plus 75 percent of the useful

thermal output measured relative to ISO conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application);

(iv) For IGCC electric utility generating unit combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of thermal output on a rolling 3 year basis, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) divided by 0.95, plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application);

IGCC facility is an integrated gasification combined cycle electric utility steam generating unit, which means an electric utility combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the facility during operation.

Net-electric output means:

(i) Except as provided under paragraph (ii) of this definition, the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis, or

(ii) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of thermal output, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities on a calendar year basis.

Potential electric output means:

(i) Either 33 percent or the design net electric output efficiency, at the election of the owner/operator of the affected facility,

(ii) Multiplied by the maximum design heat input capacity of the steam generating unit,

(iii) Divided by 3,413 Btu/KWh,

(iv) Divided by 1,000 kWh/MWh, and

(v) Multiplied by 8,760 h/yr.

(vi) For example, a 35 percent efficient steam generating unit with a 100 MW (341 MMBtu/h) fossil-fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to either the boiler or auxiliary equipment.

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

■ 3. Section 60.4305 is amended by adding paragraph (c) to read as follows:

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

* * * * *

(c) For purposes of regulation of greenhouse gases, the applicable provisions of this subpart affect your stationary combustion turbine if it meets the applicability conditions in paragraphs (c)(1) through (c)(5) of this section.

(1) Commenced construction after [DATE OF PUBLICATION IN THE FEDERAL REGISTER];

(2) Has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h);

(3) Combusts fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years.

(4) Combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis; and

(5) Was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis.

■ 4. Section 60.4315 is revised to read as follows:

§ 60.4315 What pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are nitrogen oxides (NO_x), sulfur dioxide (SO₂), and greenhouse gases.

(b)(1) The greenhouse gases regulated by this subpart consist of carbon dioxide (CO₂).

(2) *PSD and Title V Thresholds for Greenhouse Gases.*

(i) For purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected stationary combustion turbine, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(ii) For purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected stationary combustion turbines, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(iii) For purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected stationary combustion turbines, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(iv) For purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected stationary combustion turbines, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

■ 5. Section 60.4326 is added to read as follows:

§ 60.4326 What CO₂ emissions standard must I meet?

You must not discharge from your affected stationary combustion turbine into the atmosphere any gases that contain CO₂ in excess of the applicable CO₂ emissions standard specified in Table 2 of this subpart.

■ 6. Section 60.4333 is amended by adding paragraph (c) to read as follows:

§ 60.4333 What are my general requirements for complying with this subpart?

* * * * *

(c) If you own or operate an affected stationary combustion turbine subject to a CO₂ emissions standard in § 60.4326, you must make compliance determinations on a 12-operating month rolling average basis, and you must determine compliance monthly by calculating the average CO₂ emissions rate for the affected stationary

combustion turbine at the end of each 12-operating month period.

■ 7. Section 60.4373 is added under undesignated center heading “Monitoring” to read as follows:

§ 60.4373 How do I monitor and collect data to demonstrate compliance with my CO₂ emissions standard using a CO₂ CEMS?

(a) You must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(b) You must measure the hourly CO₂ mass emissions from each affected stationary combustion turbine using the procedures in paragraphs (b)(1) through (5) of this section, except as provided in paragraph (c) of this section.

(1) You must install, certify, operate, maintain, and calibrate a CO₂ continuous emission monitoring system (CEMS) to directly measure and record CO₂ concentrations in the stationary combustion turbine exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. If you measure CO₂ concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter.

(2) For each monitoring system that you use to determine the CO₂ mass emissions, you must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices B and D to part 75 of this chapter.

(3) You must use a laser device to measure the dimensions of each exhaust gas stack or duct at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, you must make measure of the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, you must measure each dimension (i.e., depth and width) at three or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, you must repeat these measurements at the new location.

(4) You must use unadjusted exhaust gas volumetric flow rates only to determine the hourly CO₂ mass emissions from the affected stationary combustion turbine; you must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(5) If you chose to use Method 2 in Appendix A–1 to this part to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, you must use a calibrated Type-S pitot tube or pitot tube assembly. You must not use the default Type-S pitot tube coefficient.

(c) As an alternative to complying with paragraph (b) of this section, you may determine the hourly CO₂ mass emissions by using Equation G–4 in Appendix G to part 75 of this chapter according to the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) You must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly unit heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) You may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of Appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(d) You must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the gross electric output from the affected stationary combustion turbine. If the affected stationary combustion turbine is a CHP stationary combustion turbine, you must also install, calibrate, maintain, and operate meters to continuously determine and record the total useful recovered thermal energy. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record steam flow rate, temperature, and pressure. If the affected stationary combustion turbine has a direct mechanical drive application, you must submit a plan to the Administrator or delegated authority for approval of how gross energy output will be determined. Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(e) If two or more affected stationary combustion turbines serve a common electric generator, you must apportion the combined hourly gross output to the individual stationary combustion turbines using a plan approved by the Administrator (e.g., using steam load or heat input to each affected stationary combustion turbine). Your plan shall ensure that you install, calibrate, maintain, and operate meters to

continuously determine and record each component of the determination.

(f) In accordance with § 60.13(g), if two or more stationary combustion turbines that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard under § 60.4326, you may monitor the hourly CO₂ mass emissions at the common stack in lieu of monitoring each stationary combustion turbine separately. If you choose this option, the hourly gross load (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual stationary combustion turbines and you must express the operating time as “stack operating hours” (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.4326 at the common stack, each stationary combustion turbine sharing the stack is in compliance.

(g) In accordance with § 60.13(g), if the exhaust gases from a stationary combustion turbine that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you chose to monitor in the ducts), you must monitor the hourly CO₂ mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct separately. In this case, you determine compliance with the applicable emissions standard in § 60.4326 by summing the CO₂ mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the unit.

■ 8. Section 60.4374 is added under undesignated center heading “Monitoring” to read as follows:

§ 60.4374 How do I demonstrate compliance with my CO₂ emissions standard and determine excess emissions?

(a) You must calculate the CO₂ mass emissions rate for your affected stationary combustion turbine by using the hourly CO₂ mass emissions and total gross output data determined and recorded according to the procedures in § 60.4373 for the compliance period for the CO₂ emissions standard applicable to the affected stationary combustion turbine, and the calculation procedures in paragraphs (a)(1) through (a)(5) of this section.

(1) You must only use operating hours in the compliance period for the compliance determination calculation for which you obtained valid data for all

parameters you used to determine the hourly CO₂ mass emissions and gross output data, are used for the compliance determination calculation. You must not include operating hours in which you used the substitute data provisions of part 75 of this chapter for any of the parameters in the calculation. For the compliance determination calculation, you must obtain valid hourly CO₂ mass emission values for a minimum of 95 percent of the operating hours in the compliance period.

(2) You must calculate the total CO₂ mass emissions by summing the hourly CO₂ mass emissions values for the affected stationary combustion turbine determined to be valid according to the conditions specified in paragraph (a)(1) of this section for all of the operating hours in the applicable compliance period.

(3) For each operating hour of the compliance period used in paragraph (a)(2) of this section to calculate the total CO₂ mass emissions, you must

determine the affected stationary combustion turbine's corresponding hourly gross output (P_{gross}) by applying the appropriate definitions in §§ 60.4420 and 60.4421 of this subpart and according to the procedures specified in paragraphs (a)(3)(i) and (iv) of this section.

(i) Calculate P_{gross} for your affected stationary combustion turbine using the following equation:

$$P_{gross} = \frac{(Pe)_{CT} + (Pe)_{ST} + (Pe)_{IE}}{T} + 0.75 \times [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{gross} = Gross energy output of your affected stationary combustion turbine in megawatt-hours in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbines in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected stationary combustion turbine's integrated equipment that provides electricity to the affected facility or auxiliary equipment in MWh.

$(Pt)_{PS}$ = Useful thermal energy output of steam relative to ISO conditions that is used for applications that do not generate additional electricity, produce mechanical energy output, enhance the performance of the affected facility. Calculated using the equation specified in paragraph (a)(3)(ii) of this section in MWh.

$(Pt)_{HR}$ = Useful thermal energy output relative to ISO conditions from heat recovery that is used for applications other than steam generation or performance enhancement of the affected facility in MWh.

$(Pt)_{IE}$ = Useful thermal energy output relative to ISO conditions from any integrated equipment that provides input to the affected facility or auxiliary equipment in MWh.

T = Electric Transmission and Distribution Factor.

T = 0.95 for a CHP stationary combustion turbine where at least on an annual basis 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal energy output on a rolling 3 year basis.

T = 1.0 for all other affected stationary combustion turbines.

(ii) If applicable to your affected stationary combustion turbine, calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{3.6 \times 10^9}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions in Joules per kilogram (J/kg) (or Btu/lb).

3.6×10^9 = Conversion factor (J/MWh) (or 3.413×10^6 Btu/MWh).

(iii) You must determine the hourly gross energy output for each operating hour in which there is no electric output, but there is mechanical output or useful thermal output. In addition you must determine the hourly gross CO₂ emissions for each operating hour in which there is no useful output.

(iv) In the case for which compliance is demonstrated according to § 60.4373(f) for affected stationary combustion turbines that vent to a common stack, then you must calculate the hourly gross energy output (electric, mechanical, and/or thermal, as applicable) by summing the hourly gross energy output you determined for each of your individual affected stationary combustion turbines that vent to the common stack; and you must express the operating time as "stack operating hours" (as defined in § 72.2 of this chapter).

(4) You must calculate the total gross output for the affected stationary combustion turbine's compliance period by summing the hourly gross output values for the affected stationary combustion turbine determined from paragraph (a)(2) of this section for all of the operating hours in the applicable compliance period.

(5) You must calculate the CO₂ mass emissions rate for the affected stationary combustion turbine by dividing the total CO₂ mass emissions value as calculated according to the requirements of paragraph (a)(2) of this section by the total gross output value as calculated according to the requirements of paragraph (a)(4) of this section.

(b) If the CO₂ mass emissions rate for the affected stationary combustion turbine determined according to the procedures specified in paragraph (a) of this section is less than or equal to the CO₂ emissions standard in Table 2 of this subpart applicable to the affected stationary combustion turbine, then your affected stationary combustion turbine is in compliance with the emissions standard. If the average CO₂ mass emissions rate is greater than the CO₂ emissions standard in Table 2 of this subpart applicable to the affected stationary combustion turbine, then your affected stationary combustion turbine has excess CO₂ emissions.

■ 9. Section 60.4375 is amended by revising the section heading to read as follows:

§ 60.4375 What reports must I submit to comply with my NO_x and SO₂ emissions limits?

* * * * *

■ 10. Section 60.4376 is added to read as follows:

§ 60.4376 What notifications and reports must I submit to comply with my CO₂ emissions standard?

(a)(1) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (a)(3) and 60.19, as applicable to your affected stationary combustion turbine.

(2) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected stationary combustion turbine.

(b) You must prepare and submit reports according to paragraphs (b)(1) through (d) of this section, as applicable.

(1) For stationary combustion turbines that are required, by § 60.4333(c), to conduct initial and on-going compliance determinations on a 12-operating month rolling average basis for the standard in § 60.4326, you must submit electronic quarterly reports as follows. After you

have accumulated the first 12-operating months for the affected stationary combustion turbine, you must submit a report for the calendar quarter that includes the 12th-operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report, you must include the following information, as applicable:

(i) Each rolling average CO₂ mass emissions rate for which the last (12th) operating month in a 12-operating month compliance period falls within the calendar quarter. You must calculate each average CO₂ mass emissions rate according to the requirements of § 60.4374. You must report the dates (month and year) of the 1st and 12th-operating months in each compliance period for which you performed a CO₂ mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter with excess CO₂ emissions;

(iii) The percentage of valid CO₂ mass emission rates (as defined in § 60.4374) in each 12-operating month compliance period described in paragraph (b)(2)(i) of this section (i.e., the total number of valid CO₂ mass emission rates in that period divided by the total number of operating hours in that period, multiplied by 100 percent); and

(iv) The CO₂ emissions standard (as identified in Table 2 of this subpart) with which your affected stationary combustion turbine is complying.

(3) The final quarterly report of each calendar year must contain the following:

(i) Net electric output sold to an electric grid over the 4 quarters of the calendar year; and

(ii) The potential electric output of the stationary combustion turbine.

(c) You must submit all electronic reports required under paragraph (b) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

(d) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

■ 11. Section 60.4391 is added to read as follows:

§ 60.4391 What records must I maintain to comply with my CO₂ emissions limits?

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

(b) You must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(c) You must keep records of the calculations you performed to determine the total CO₂ mass emissions for:

(1) Each operating month (for all affected units);

(2) Each compliance period, including, as applicable, each 12-operating month compliance period.

(d) You must keep records of the applicable data recorded and calculations performed that you used to determine your affected stationary combustion turbine's gross output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO₂ mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO₂ mass emissions standard in § 60.4326.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h)(1) Your records must be in a form suitable and readily available for expeditious review.

(2) You must keep each record for 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record to demonstrate compliance with a 12-operating month emissions standard.

(3) 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 § 60.7. You may keep the records off site and electronically for the remaining year(s) as required by this subpart.

■ 12. Section 60.4395 is revised to read as follows:

§ 60.4395 When must I submit my reports?

All of your reports required under § 60.7(c) must be postmarked by the 30th day after the end of each 6-month period, except as specified in § 60.4376

■ 13. Section 60.4421 is added to read as follows:

§ 60.4421 What definitions with respect to CO₂ emissions apply to this subpart?

As used in this subpart:

Base load rating means 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel (heat input from duct burners is not included).

Excess emissions means a specified averaging period over which either:

(1) The CO₂ emissions rate of your affected stationary combustion turbine exceeds the applicable emissions standard in Table 2 of this subpart or § 60.4330; or

(2) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross energy output means:

(1) The gross electric or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) or integrated equipment plus any useful thermal output measured relative to ISO conditions (except for GHG calculations in § 60.4374 as only 75 percent credit is given) that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

(2) For a CHP stationary combustion turbine where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a rolling 3-year basis, the sum of the gross electric or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions (except for GHG calculations in § 60.4374 as only 75 percent credit is given) that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

Net-electric output means:

(1) The gross electric sales to the utility power distribution system minus purchased power on a 3 calendar year rolling average basis; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a 3 calendar year rolling average basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal

host facility or facilities on a three calendar year rolling average basis.

Operating month means a calendar month during which any fuel is combusted in the affected stationary combustion turbine.

Potential electric output means 33 percent or the design electric output efficiency on a net output basis (at the election of the owner/operator of the affected facility) multiplied by the base load rating (expressed in MMBtu/h) of the stationary combustion turbine, multiplied by 10⁶ Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000

kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient stationary combustion turbine with a 100 MW (341 MMBtu/h) fossil-fuel heat input capacity would have a 310,000 MWh 12-month potential electric output capacity).

Stationary combustion turbine means all equipment, including but not limited to the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems, heat recovery system, steam turbine, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any

ancillary components and sub-components plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

■ 14. Table 2 to Subpart KKKK of Part 60 is added to read as follows:

TABLE 2 TO SUBPART KKKK OF PART 60—CARBON DIOXIDE EMISSION LIMITS FOR STATIONARY COMBUSTION TURBINES

[Note: all numerical values have a minimum of 2 significant figures]

Affected stationary combustion turbine	CO ₂ Emission standard
Stationary combustion turbine that has a design heat input to the turbine engine of greater than 250 MW (850MMBtu/h).	450 kilograms (kg) of CO ₂ per megawatt-hour (MWh) of gross output (1,000 lb/MWh) on a 12-operating month rolling average.
Stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h) and equal to or less than 250 MW (850MMBtu/h).	500 kg of CO ₂ per MWh of gross output (1,100 lb CO ₂ /MWh) on a 12-operating month rolling average.

■ 15. Table 3 to Subpart KKKK of Part 60 is added to read as follows:

TABLE 3 TO SUBPART KKKK OF PART 60—APPLICABILITY OF SUBPART A GENERAL PROVISIONS TO STATIONARY COMBUSTION TURBINE CO₂ EMISSIONS STANDARDS IN SUBPART KKKK

General provisions citation	Subject of citation	Applies to subpart KKKK	Explanation
§ 60.1	Applicability	Yes.	Only the requirements to submit the notification in § 60.7(a)(1) and (a)(3).
§ 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.	
§ 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.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes.	

■ 16. 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

Sec.

Applicability

60.5508 What is the purpose of this subpart?

60.5509 Am I subject to this subpart?

Emission Standards

60.5515 What greenhouse gases are regulated by this subpart?

60.5520 What CO₂ emissions standard must I meet?

General Compliance Requirements

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

60.5530 Affirmative defense for violation of emission standards 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 with my CO₂ emissions standard and determine excess emissions?

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 maintain?

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 my affected facility?

60.5575 Who implements and enforces this subpart?

60.5580 What definitions apply to this subpart?

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 a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after [DATE OF PUBLICATION IN THE FEDERAL REGISTER].

§ 60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the subpart applies to any steam generating unit, IGCC, or stationary combustion turbine that commences construction after [DATE OF PUBLICATION IN THE FEDERAL REGISTER] that meets the relevant applicability conditions in paragraphs (a)(1) and (a)(2) of this section.

(1) A steam generating unit or IGCC that has a design heat input greater than 73 MW (250MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, and was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electric output to a utility distribution system on an annual basis.

(2) A stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis, and was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical

output to a utility distribution system on a 3 year rolling average basis.

(b) You are not subject to the requirements of this subpart if your affected facility meets any one of the conditions specified in paragraphs (b)(1) through (b)(5) of this section.

(1) The proposed Wolverine EGU project described in Permit to Install No. 317-07 issued by the Michigan Department of Environmental Quality, Air Quality Division, effective June 29, 2011 (as revised July 12, 2011).

(2) The proposed Washington County EGU project described in Air Quality Permit No. 4911-303-0051-P-01-0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE FEDERAL REGISTER].

(3) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE FEDERAL REGISTER].

(4) Your affected facility is a municipal waste combustor unit that is subject to subpart Eb of this part.

(5) Your affected facility is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

Emission Standards

§ 60.5515 What greenhouse gases are regulated by this subpart?

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

(b) *PSD and Title V Thresholds for Greenhouse Gases.*

(1) For purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to

regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

§ 60.5520 What CO₂ emissions standard must I meet?

For each affected facility subject to this subpart, you must not discharge from the affected facility stack into the atmosphere any gases that contain CO₂ in excess of the applicable CO₂ emissions standard specified in Table 1 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 emission standards in this subpart that apply to your affected facility at all times. However, you must make a compliance determination only at the end of the applicable operating month, as provided in paragraphs (a)(1) and (2) of this section.

(1) For each affected facility subject to a CO₂ emissions standard based on a 12-operating month rolling average, you must determine compliance monthly by calculating the average CO₂ emissions rate for the affected facility at the end of each 12-operating month period.

(2) For each affected facility subject to a CO₂ emissions standard based on an 84-operating month rolling average, you must determine compliance monthly by calculating the average CO₂ emissions rate for the affected facility at the end of each 84-operating month period.

(b) At all times you must operate and maintain each affected facility, including associated equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and

records, review of reports required by this subpart, and inspection of the facility.

(c) You must conduct an initial compliance determination for your affected facility for the applicable emissions standard in § 60.5520, according to the requirements in this subpart, within 30 days after the end of the initial compliance period for the CO₂ emissions standards applicable to your affected facility (i.e., 12-operating months or 84-operating months). The first operating month included in this compliance period is the month in which emissions reporting is required to begin under § 75.64(a) of this chapter.

§ 60.5530 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 60.5520, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

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

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

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

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

(2) Repairs were made as expeditiously as possible when the violation occurred;

(3) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable;

(4) If the violation 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 possible steps were taken to minimize the impact of the violation on

ambient air quality, the environment, and human health;

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

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

(8) At all times, the affected source 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 violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report is due after the initial occurrence of the exceedance of the standard in § 60.5520, and on the same quarterly reporting schedule as in § 60.5555 (which may be the end of any applicable averaging period). If such quarterly report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the following quarterly report required in § 60.5555(a).

Monitoring and Compliance Determination Procedures

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

(a) You must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(b) You must measure the hourly CO₂ mass emissions from each affected facility using the procedures in paragraphs (b)(1) through (5) of this section, except as provided in paragraph (c) of this section.

(1) You must install, certify, operate, maintain, and calibrate a CO₂ continuous emission monitoring system (CEMS) to directly measure and record CO₂ concentrations in the affected facility exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. If you measure CO₂ concentration on a dry basis, you must also install, certify,

operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter.

(2) For each monitoring system you use to determine the CO₂ mass emissions, you must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices B and D to part 75 of this chapter.

(3) You must use a laser device to measure the dimensions of each exhaust gas stack or duct at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, you must measure the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, you must measure each dimension (i.e., depth and width) at three or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, you must repeat these measurements at the new location.

(4) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO₂ mass emissions from the affected facility; you must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(5) If you choose to use Method 2 in Appendix A–1 to this part to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, you must use a calibrated Type-S pitot tube or pitot tube assembly. You must not use the default Type-S pitot tube coefficient.

(c) If your affected facility exclusively combusts liquid fuel and/or gaseous fuel as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO₂ mass emissions by using Equation G–4 in Appendix G to part 75 of this chapter according to the requirements in paragraphs (c)(1) and (2) of this section.

(1) You must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly unit heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) You may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(d) You must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the gross electric output from the affected facility. If the affected facility is a CHP facility, you must also install, calibrate, maintain, and operate meters to continuously determine and record the total useful recovered thermal energy. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record steam flow rate, temperature, and pressure. If the affected facility has a direct mechanical drive application, you must submit a plan to the Administrator or delegated authority for approval of how gross energy output will be determined. Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(e) If two or more affected facilities serve a common electric generator, you must apportion the combined hourly gross output to the individual affected facilities using a plan approved by the Administrator (e.g., using steam load or heat input to each affected EGU). Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(f) In accordance with § 60.13(g), if two or more affected facilities that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard under § 60.5520, you may monitor the hourly CO₂ mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross

load (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected facility and you must express the operating time as “stack operating hours” (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected facility sharing the stack is in compliance.

(g) In accordance with § 60.13(g), if the exhaust gases from an affected facility that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO₂ mass emissions and the “stack operating time” (as defined in § 72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in § 60.5520 by summing the CO₂ mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the affected facility.

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

(a) You must calculate the CO₂ mass emissions rate for your affected facility by using the hourly CO₂ mass emissions and total gross output data determined and recorded according to the procedures in § 60.5535 for each operating hour in the compliance period for the CO₂ emissions standard applicable to the affected facility (i.e., 12- or 84-operating month rolling average period), and the calculation

procedures in paragraphs (a)(1) through (a)(5) of this section.

(1) You can only use operating hours in the compliance period for the compliance determination calculation if valid data are obtained for all parameters you used to determine the hourly CO₂ mass emissions and the gross output data are used for the compliance determination calculation. You must not include operating hours in which you used the substitute data provisions of part 75 of this chapter for any of those parameters in the calculation. For the compliance determination calculation, you must obtain valid hourly CO₂ mass emission values for a minimum of 95 percent of the operating hours in the compliance period for the CO₂ emissions standard applicable to the affected facility.

(2) You must calculate the total CO₂ mass emissions by summing the valid hourly CO₂ mass emissions values for all of the operating hours in the applicable compliance period.

(3) For each operating hour of the compliance period that you used in paragraph (a)(2) of this section to calculate the total CO₂ mass emissions, you must determine the affected facility’s corresponding hourly gross output according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected facility. For an operating hour in which there is no gross electric load, but there is mechanical or useful thermal output, you must still determine the gross output for that hour. In addition, for operating hours in which there is no useful output, you still need to determine the CO₂ emissions for that hour.

(i) Calculate P_{gross} for your affected facility using the following equation:

$$P_{gross} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW}}{T} + 0.75 \times [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where: a

P_{gross} = Gross energy output of your affected facility in megawatt-hours in MWh.

(Pe)_{ST} = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

(Pe)_{CT} = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

(Pe)_{IE} = Electric energy output plus mechanical energy output (if any) of your affected facility’s integrated equipment that provides electricity or mechanical energy to the affected facility or auxiliary equipment in MWh.

(Pe)_{FW} = Electric energy used to power boiler feedwater pumps at steam generating

units in MWh. Not applicable to stationary combustion turbines or IGCC facilities.

(Pt)_{PS} = Useful thermal energy output of steam measured relative to ISO conditions that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected facility. Calculated using the equation specified in paragraph (g)(3)(iii)(B) of this section in MWh.

(Pt)_{HR} = Hourly useful thermal energy output measured relative to ISO conditions from heat recovery that is used for applications other than steam generation or performance enhancement of the affected facility in MWh.

(Pt)_{IE} = Useful thermal energy output relative to ISO conditions from any integrated equipment that provides thermal energy to the affected facility or auxiliary equipment in MWh.

T = Electric Transmission and Distribution Factor.

T = 0.95 for a combined heat and power affected facility where at least on an annual basis 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal energy output on a rolling 3 year basis.

T = 1.0 for all other affected facilities.

(ii) If applicable to your affected facility, you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{3.6 \times 10^9}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions in Joules per kilogram (J/kg) (or Btu/lb).

3.6×10^9 = Conversion factor (J/MWh) (or 3.413×10^6 Btu/MWh).

(4) You must calculate the total gross output for the affected facility's compliance period by summing the hourly gross output values for the affected facility that you determined from paragraph (a)(2) of this section for all of the operating hours in the applicable compliance period.

(5) You must calculate the CO₂ mass emissions rate for the affected facility by dividing the total CO₂ mass emissions value calculated according to the procedures in paragraph (a)(2) of this section by the total gross output value calculated according to the procedures in paragraph (a)(4) of this section.

(b) If the CO₂ mass emissions rate for your affected facility that you determined according to the procedures specified in paragraph (a) of this section is less than or equal to the CO₂ emissions standard in Table 1 of this subpart applicable to the affected facility, then your affected facility is in compliance with the emissions standard. If the average CO₂ mass emissions rate is greater than the CO₂ emissions standard in Table 1 of this subpart applicable to the affected facility, then your affected facility has excess CO₂ emissions.

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (a)(3) and 60.19, as applicable to your affected facility.

(b) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected facility.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected facilities that are required by § 60.5525 to conduct initial and on-going compliance determinations on a 12- or 84-operating

month rolling average basis for the standard in § 60.5520 you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected facility (or, the first 84-operating months for an affected facility electing to comply with the 84-operating month standard), you must submit a report for the calendar quarter that includes the twelfth (or eighty-fourth) operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO₂ mass emissions rate for which the last (12th or eighty-fourth) operating month in a 12- or 84-operating month compliance period falls within the calendar quarter. You must calculate each average CO₂ mass emissions rate according to the procedures in § 60.5540. You must report the dates (month and year) of the first and twelfth (or eighty-fourth) operating months in each compliance period for which you performed a CO₂ mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter you must identify each operating month in the calendar quarter with excess CO₂ emissions;

(iii) The percentage of valid CO₂ mass emission rates (as defined in § 60.5540) in each 12- or 84-operating month compliance period described in paragraph (a)(1)(i) of this section (i.e., the total number of valid CO₂ mass emission rates in that period divided by the total number of operating hours in that period, multiplied by 100 percent); and

(iv) The CO₂ emissions standard (as identified in Table 1 of this subpart) with which your affected facility is complying.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Gross electric output sold to an electric grid over the 4 quarters of the calendar year; and

(ii) The potential electric output of the facility.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(d) If your affected unit employs geologic sequestration to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) if injection occurs onsite, report in accordance with the requirements of 40 CFR part 98, subpart RR, or

(2) if injection occurs offsite, transfer the captured CO₂ to a facility or facilities that reports in accordance with the requirements of 40 CFR part 98, subpart RR.

§ 60.5560 What records must I maintain?

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

(b) You must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(c) You must keep records of the calculations you performed to determine the total CO₂ mass emissions for:

(1) Each operating month (for all affected units);

(2) Each compliance period, including, as applicable, each 12-operating month compliance period and the 84-operating month compliance period.

(d) You must keep records of the applicable data recorded and calculations performed that you used to determine your affected facility's gross output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO₂ mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO₂ mass emissions standard in § 60.5520.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

§ 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 maintain each record for 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record except those records required to demonstrate

compliance with an 84-operating month compliance period. You must maintain records required to demonstrate compliance with an 84-operating month compliance period for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. You may maintain the records off site and electronically for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570 What parts of the General Provisions apply to my affected facility?

Notwithstanding any other provision of this chapter, certain parts of the General Provisions in §§ 60.1 through 60.19, listed in Table 2 of this subpart, do not apply to your affected facility.

§ 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 Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580 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, *baseload* means 100 percent of the design heat input capacity of the simple cycle portion of the stationary combustion turbine at ISO conditions (heat input from duct burners is not included).

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 facility means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power facility or CHP facility, (also known as "cogeneration") means an electric generating unit that that use a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal energy from the same primary energy source.

Distillate oil means fuel oils that contain no more than 0.05 weight percent nitrogen 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).

Excess emissions means a specified averaging period over which the CO₂ emissions rate is higher than the applicable emissions standard located in Table 1 of this subpart.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC facilities, the gross electric or direct mechanical output from both the unit (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

(2) For electric utility steam generating units, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application);

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of thermal output on a rolling 3 year basis, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to

IGCC facilities), that difference divided by 0.95, plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or IGCC facility means a combined cycle stationary combustion 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, startup and commissioning, shutdown, 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.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal energy, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a

gaseous state under ISO conditions. 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:

(1) The gross electric sales to the utility power distribution system minus purchased power on a three calendar year rolling average basis; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a 3 calendar year rolling average basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities on a three calendar year rolling average basis.

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Operating month means a calendar month during which any fuel is combusted in the affected facility at any time.

Potential electric output means 33 percent or the design electric output efficiency on a net output basis multiplied by the maximum design heat input capacity (expressed in MMBtu/h) of the steam generating unit, multiplied by 10⁶ Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected facility with a 100 MW (341 MMBtu/h) fossil-fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under

moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

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 electric generation, mechanical output at the affected facility, or to enhance the performance of the affected facility. 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—CO₂ EMISSION STANDARDS

[NOTE: all numerical values have a minimum of 2 significant figures]

Affected facility	CO ₂ Emission standard
Stationary combustion turbine that has a base load rating heat input to the turbine engine of greater than 250 MW (850MMBtu/h).	450 kilograms (kg) of CO ₂ per megawatt-hour (MWh) of gross output (1,000 lb/MWh) on a 12-operating month rolling average.
Stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h) and equal to or less than 250 MW (850MMBtu/h).	500 kg of CO ₂ per MWh of gross output (1,100 lb CO ₂ /MWh) on a 12-operating month rolling average.

TABLE 1 TO SUBPART TTTT OF PART 60—CO₂ EMISSION STANDARDS—Continued

[NOTE: all numerical values have a minimum of 2 significant figures]

Affected facility	CO ₂ Emission standard
Steam generating unit	500 kg of CO ₂ per MWh of gross energy output (1,100 lb CO ₂ /MWh) on a 12-operating month rolling average basis; or 480 kg of CO ₂ per MWh of gross energy output (1,050 lb CO ₂ /MWh) on an 84-operating month rolling average basis.
Integrated gasification combined cycle (IGCC) facility	500 kg of CO ₂ per MWh of gross energy output (1,100 lb CO ₂ /MWh) on a 12-operating month rolling average basis; or 480 kg of CO ₂ per MWh of gross energy output (1,050 lb CO ₂ /MWh) on an 84-operating month rolling average basis.

TABLE 2 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.	
§ 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.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes.	

PART 70—STATE OPERATING PERMIT PROGRAMS

■ 17. The authority citation for part 70 continues to read as follows:

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

■ 18. Section 70.2 is amended:

■ a. By adding in alphabetical order the definition of “Greenhouse gases,”

■ b. By revising the introductory text, removing “or” from the end of paragraph (2), adding “or” to the end of paragraph (3), and adding paragraph (4) to the definition of “Regulated pollutant (for presumptive fee calculation),” and

■ c. By revising paragraph (1) to the definition of “Subject to regulation.”

The revision and additions read as follows:

§ 70.2 Definitions.

* * * * *

Greenhouse gases (GHGs) means the air pollutant defined in § 86.1818–12(a) of this chapter as the aggregate group of

six greenhouse gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

* * * * *

Regulated pollutant (for presumptive fee calculation), which is used only for purposes of § 70.9(b)(2), means any regulated air pollutant except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

Subject to regulation * * *

(1) Greenhouse gases shall not be subject to regulation unless, as of July 1, 2011, the GHG emissions are at a stationary source emitting or having the potential to emit 100,000 tpy CO₂ equivalent emissions.

* * * * *

■ 19. Section 70.9 is amended by revising paragraph (b)(2)(i), and by

adding paragraph (b)(2)(v) to read as follows:

§ 70.9 Fee determination and certification.

* * * * *

(b) * * *

(2)(i) The Administrator will presume that the fee schedule meets the requirements of paragraph (b)(1) of this section if it would result in the collection and retention of an amount not less than \$25 per year [as adjusted pursuant to the criteria set forth in paragraph (b)(2)(iv) of this section] times the total tons of the actual emissions of each regulated pollutant (for presumptive fee calculation) emitted from part 70 sources and any GHG cost adjustment required under paragraph (b)(2)(v) of this section.

* * * * *

(v) *GHG cost adjustment.* The amount calculated in paragraph (b)(2)(i) of this section shall be increased by the GHG cost adjustment determined as follows:

For each activity identified in the following table, multiply the number of activities performed by the permitting authority by the burden hours per activity, and then calculate a total number of burden hours for all activities. Next, multiply the burden hours by the average cost of staff time, including wages, employee benefits and overhead.

Activity	Burden hours per activity
GHG completeness determination (for initial permit or updated application)	43
GHG evaluation for a modification or related permit action	7
GHG evaluation at permit renewal	10

PART 71—FEDERAL OPERATING PERMIT PROGRAMS

■ 20. The authority citation for part 71 continues to read as follows:

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

■ 21. Section 71.2 is amended:

■ a. By adding in alphabetical order the definition of “Greenhouse gases,”

■ b. By removing “or” from the end of paragraph (2), adding “or” to the end of paragraph (3), and adding paragraph (4) to the definition of “Regulated pollutant (for fee calculation),” and

■ c. By revising paragraph (1) of the definition of “Subject to regulation.”

The revisions and additions read as follows:

§ 71.2 Definitions.

* * * * *

Greenhouse gases (GHGs) means the air pollutant defined in § 86.1818–12(a) of this chapter as the aggregate group of six greenhouse gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

* * * * *

Regulated pollutant (for fee calculation), which is used only for purposes of § 71.9(c), means any “regulated air pollutant” except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

Subject to regulation * * *

(1) Greenhouse gases shall not be subject to regulation unless, as of July 1, 2011, the GHG emissions are at a stationary source emitting or having the

potential to emit 100,000 tpy CO₂ equivalent emissions.

* * * * *

■ 22. Section 71.9 is amended by:

■ a. Revising paragraphs (c)(1), (c)(2)(i), (c)(3), and (c)(4), and

■ b. Adding paragraph (c)(8).

The revisions and additions read as follows:

§ 71.9 Permit fees.

* * * * *

(c) * * *

(1) For part 71 programs that are administered by EPA, each part 71 source shall pay an annual fee which is the sum of:

(i) \$32 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(ii) Any GHG fee adjustment required under paragraph (c)(8) of this section.

(2) * * *

(i) Where the EPA has not suspended its part 71 fee collection pursuant to paragraph (c)(2)(ii) of this section, the annual fee for each part 71 source shall be the sum of:

(A) \$24 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(B) Any GHG fee adjustment required under paragraph (c)(8) of this section.

* * * * *

(3) For part 71 programs that are administered by EPA with contractor assistance, the per ton fee shall vary depending on the extent of contractor involvement and the cost to EPA of contractor assistance. The EPA shall establish a per ton fee that is based on the contractor costs for the specific part 71 program that is being administered, using the following formula: Cost per ton = $(E \times 32) + [(1 - E) \times \$ C]$

Where *E* represents EPA’s proportion of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E$ represents the contractor’s effort, and *C* represents the contractor assistance cost on a per ton basis. *C* shall be computed by using the following formula: $C = [B + T + N]$ divided by 12,300,000

Where *B* represents the base cost (contractor costs), where *T* represents travel costs, and where *N* represents nonpersonnel data management and tracking costs. In addition, each part 71 source shall pay a GHG fee adjustment

for each activity as required under paragraph (c)(8) of this section.

(4) For programs that are delegated in part, the fee shall be computed using the following formula: Cost per ton = $(E \times 32) + (D \times 24) + [(1 - E - D) \times \$ C]$

Where *E* and *D* represent, respectively, the EPA and delegate agency proportions of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E - D$ represents the contractor’s effort, and *C* represents the contractor assistance cost on a per ton basis. *C* shall be computed using the formula for contractor assistance cost found in paragraph (c)(3) of this section and shall be zero if contractor assistance is not utilized. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

* * * * *

(8) *GHG fee adjustment.* The annual fee shall be increased by a GHG fee adjustment for any source that has initiated an activity listed in the following table since the fee was last paid. The GHG fee adjustment shall be equal to the set fee provided in the table for each activity that has been initiated since the fee was last paid:

Activity	Set fee
GHG completeness determination (for initial permit or updated application)	\$2,236
GHG evaluation for a permit modification or related permit action ..	364
GHG evaluation at permit renewal	520

* * * * *

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 23. The authority citation for part 98 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart PP—Suppliers of Carbon Dioxide

■ 24. Section 98.426 is amended by adding paragraph (h) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(h) If you capture a CO₂ stream from an electricity generating unit that is subject to subpart D of this part and transfer CO₂ to any facilities that are subject to subpart RR of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the facility that is subject to subpart D of this part,

(2) Report each facility identification number associated with the annual GHG

reports for each facility that is subject to subpart RR of this part to which CO₂ is transferred, and

(3) Report the annual quantity of CO₂ in metric tons that is transferred to each

facility that is subject to subpart RR of this part.

■ 25. Section 98.427 is amended by adding paragraph (d) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(d) Facilities subject to § 98.426(h) must retain records of CO₂ in metric tons that is transferred to each facility that is subject to subpart RR of this part.
[FR Doc. 2013-28668 Filed 12-27-13; 8:45 am]

BILLING CODE 6560-50-P