ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0603; FRL 9910–00–OAR]

RIN 2060–AR88

Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing standards of performance for emissions of greenhouse gases from affected modified and reconstructed fossil fuel-fired electric utility generating units. Specifically, the EPA is proposing standards to limit emissions of carbon dioxide from affected modified and reconstructed electric utility steam generating units and from natural gas-fired stationary combustion turbines. This rule, as proposed, would continue progress already underway to reduce carbon dioxide emissions from the electric power sector in the United States.

DATES: *Comments on the proposed standards.* Comments on the proposed standards must be received on or before October 16, 2014.

Comments on the information collection request. 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 June 18, 2014, a comment to the OMB is best assured of having its full effect if the OMB receives it by July 18, 2014.

Public Hearing. In a separate action in the **Federal Register**, the EPA is proposing Clean Air Act (CAA) section 111(d) emission guidelines for existing fossil fuel-fired electric utility generating units (EGUs) and is announcing public hearings associated with that action. Because of the interconnected nature of this proposed rulemaking with the proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, we will hold joint hearings on both proposed rulemakings. Please consult the **Federal Register** document proposing Emission Guidelines for Existing Sources for information on public hearings for both actions. Additionally, information for the joint public hearings will be posted on the following Web sites: *http://www2.epa.gov/carbon-pollution-standards* and *http://www2.epa.gov/cleanpowerplan.* If any dates, times or locations of announced public hearings are changed for the proposed emission guidelines, then the public hearing dates, times and locations for this action will also change accordingly. If you would like to speak at the public hearing(s), please register by following instructions provided in the document for the emission guidelines proposed in the **Federal Register**. Please note that 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(s).

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0603, by one of the following methods:

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

Email: Send your comments by electronic mail (email) to *a-and-r-docket@epa.gov,* Attn: Docket ID No. EPA–HQ–OAR–2013–0603.

Facsimile: Fax your comments to (202) 566–9744, Attn: Docket ID No. EPA–HQ–OAR–2013–0603.

Mail: Send your comments to the EPA Docket Center, U.S. EPA, Mail Code 28221T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Attn: Docket ID No. EPA–HQ–OAR–2013–0603. Comments on the information collection provisions should be mailed 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–2013–0603. 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–2013–0603). 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* 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, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2013–0603. Clearly mark the information 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 at *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 20004. 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 World Wide Web (WWW). Following signature, a copy of this proposed rule will be posted at the following address: *http://www2.epa.gov/carbon-pollution-standards.*

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

SUPPLEMENTARY INFORMATION:

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

AEO Annual Energy Outlook
APPA American Public Power Association
BSER Best System of Emission Reduction
CAA Clean Air Act
CAP Climate Action Plan
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CFB Circulating Fluidized Bed
CH_4 Methane
CHP Combined Heat and Power
CO_2 Carbon Dioxide
DOE/NETL Department of Energy/National Energy Technology Laboratory
EGU Electric Utility Generating Unit
EO Executive Order
EPA Environmental Protection Agency
FB Fluidized Bed
FR Federal Register
GHG Greenhouse Gas
HFC Hydrofluorocarbon
HRSG Heat Recovery Steam Generator
ICR Information Collection Request
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
lb CO_2/MWh-net Pounds of CO_2 per Megawatt-hour on a net output basis
LCOE Levelized Cost of Electricity
MMBtu/h Million British Thermal Units per Hour
MPa Megapascal
MW Megawatt
MWe Megawatt Electrical
MWh Megawatt-hour
N_2 Nitrogen Gas
N_2O Nitrous Oxide
NO_X Nitrogen Oxide
NAICS North American Industry Classification System
NGCC Natural Gas Combined Cycle
NGR Natural Gas Reburning
NRC National Research Council
NRECA National Rural Electric Cooperative Association
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act
OFA Overfire Air
OMB Office of Management and Budget
PC Pulverized Coal
PFC Perfluorocarbons
$PM_{2.5}$ Particular Matter less than 2.5 micrometer in diameter
PRA Paperwork Reduction Act
psi Pounds per square inch
psig Pounds per square inch-guage
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
SBA Small Business Administration
SCC Social cost of carbon
SCPC Supercritical pulverized coal
SF_6 Sulfur Hexafluoride
SO_2 Sulfur dioxide
Tg Teragram (one trillion (10^{12}) grams)
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard
WWW Worldwide Web

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

I. General Information
A. Executive Summary
B. 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
D. Statutory Background
E. Regulatory Background
F. Stakeholder Outreach
G. Modifications and Reconstructions
III. Proposed Requirements for Modified and Reconstructed 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 GHG From Fossil Fuel-Fired EGUs
A. Rational Basis and Endangerment Finding
B. Source Categories
V. Rationale for Applicability Requirements
VI. Rationale for Emission Standards for Reconstructed Fossil Fuel-Fired Utility Boilers and IGCC Units
A. Overview
B. Identification of Best System of Emissions Reduction
C. Determination of the Level of the Standard
D. Compliance Period
VII. Rationale for Emission Standards for Modified Fossil Fuel-Fired Utility Boilers and IGCC Units
A. Introduction
B. Identification of the Best System of Emission Reduction
C. Determination of the Level of the Standard
D. Compliance Period
VIII. Rationale for Emission Standards for Reconstructed Natural Gas-Fired Stationary Combustion Turbines
A. Identification of the Best System of Emission Reduction
B. Determination of the Standards of Performance
IX. Rationale for Emission Standards for Modified Natural Gas-Fired Stationary Combustion Turbines
A. Identification of the Best System of Emission Reduction
B. Determination of the Standards of Performance
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. 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
XII. Statutory Authority

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

On June 25, 2013, in conjunction with the announcement of his Climate Action Plan (CAP), President Obama issued a Presidential Memorandum directing the EPA to issue a new proposal to address carbon pollution from new power plants by September 30, 2013, and to issue ''standards, regulations, or guidelines, as appropriate, which address carbon pollution from modified, reconstructed, and existing power plants.'' Consistent with the Presidential Memorandum, on September 20, 2013, the Administrator signed proposed carbon pollution standards for newly constructed fossil fuel-fired power plants. The proposal was published on January 8, 2014 (79 FR 1430; January 2014 proposal). Specifically, under the authority of CAA section 111(b), the EPA proposed new source performance standards (NSPS) to limit emissions of carbon dioxide (CO_2) from newly constructed fossil fuel-fired electric utility steam generating units (utility boilers and integrated gasification combined cycle (IGCC) units) and newly constructed natural gas-fired stationary combustion turbines.

In this action, under the authority of CAA section 111(b), the EPA is proposing standards of performance to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines. Specifically, the EPA is proposing standards of performance for: (1) Modified fossil fuel-fired utility boilers and IGCC units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired utility boilers and IGCC units, and (4) reconstructed natural gas-fired stationary combustion turbines. Consistent with the requirements of CAA section 111(b), these proposed standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the EPA has determined has been adequately demonstrated for each type of unit.

In a separate action, under CAA section 111(d), the EPA is proposing emission guidelines for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs. States must then submit plans to the EPA under timing set by that action.

2. Summary of the Major Provisions

The proposed standards for the affected modified and reconstructed sources are summarized below in Table 1.

TABLE 1—SUMMARY OF BSER AND PROPOSED STANDARDS FOR AFFECTED SOURCES

Affected source	BSER	Standard
Modified Utility Boilers and IGCC Units.	Most efficient generation at the affected source achievable through a combination of best operating practices and equipment upgrades.	**Co-proposed Alternative #1** 1. Source would be required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification) plus an additional 2 percent emission reduction; the emission limit will be no lower than: a. 1,900 lb CO_2/MWh-net for sources with heat input >2,000 MMBtu/h. OR b. 2,100 lb CO_2/MWh-net for sources with heat input ≤2,000 MMBtu/h.
Modified Utility Boilers and IGCC Units.	Most efficient generation at the affected source achievable through a combination of best operating practices and equipment upgrades.	**Co-proposed Alternative #2** Source would be required to meet a unit-specific emission limit dependent upon when the modification occurs. 1. Sources that modify prior to becoming subject to a CAA 111(d) plan would be required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to date of the modification) plus an additional 2 percent emission reduction; the emission limit will be no lower than: a. 1,900 lb CO_2/MWh-net for sources with heat input >2,000 MMBtu/h. OR b. 2,100 lb CO_2/MWh-net for sources with heat input ≤2,000 MMBtu/h. 2. Sources that modify after becoming subject to a CAA 111(d) plan would be required to meet a unit-specific emission limit determined by the 111(b) implementing authority from the results of an energy efficiency improvement audit.
Modified Natural Gas-Fired Stationary Combustion Turbines.	Efficient NGCC technology	1. Sources with heat input >850 MMBtu/h would be required to meet an emission limit of 1,000 lb CO_2/MWh-gross. 2. Sources with heat input ≤850 MMBtu/h would be required to meet an emission limit of 1,100 lb CO_2/MWh-gross.
Reconstructed Utility Boilers and IGCC Units.	Most efficient generating technology at the affected source.	1. Sources with heat input >2,000 MMBtu/h would be required to meet an emission limit of 1,900 lb CO_2/MWh-net. 2. Sources with heat input ≤2,000 MMBtu/h would be required to meet an emission limit of 2,100 lb CO_2/MWh-net.
Reconstructed Natural Gas-Fired Stationary Combustion Turbines.	Efficient NGCC technology	1. Sources with heat input >850 MMBtu/h would be required to meet an emission limit of 1,000 lb CO_2/MWh-gross. 2. Sources with heat input ≤850 MMBtu/h would be required to meet an emission limit of 1,100 lb CO_2/MWh-gross.

For the reasons discussed in the "Legal Memorandum"[1] supporting document in the docket for the rulemaking for CO_2 emissions from existing EGUs under CAA section 111(d), all existing sources that become modified or reconstructed sources and which are subject to a CAA section 111(d) plan at the time of the modification or reconstruction, will remain in the CAA section 111(d) plan and remain subject to any applicable regulatory requirements in the plan, in addition to being subject to regulatory requirements under CAA section 111(b).

It should be noted that the EPA intends each standard of performance proposed in this rulemaking to be severable from each other standard of performance, such that if one or more of the standards of performance were to be remanded or vacated in a court challenge, the EPA intends for the other standards to remain in effect. The EPA also intends each BSER determination or alternative determination, as applicable, for modified utility boilers and IGCC units, and for modified natural gas-fired stationary combustion turbines, to be severable from each other BSER determination. In all of these cases, the EPA believes that the standards of performance and associated best systems of emission reduction operate independently of each other.[2] The EPA also intends that the standards applicable to the units that modify after the unit is subject to a 111(d) plan are severable and that if those standards were over-turned, the standards applicable to units that modify when they are not subject to a 111(d) plan would apply to all modified sources, regardless of the timing of their modification.

The EPA is proposing that the form of the standards for modified and reconstructed natural gas-fired stationary combustion turbines be consistent with the standards for newly constructed natural gas-fired stationary combustion turbines proposed on January 8, 2014 (79 FR 1430). In that proposal, the EPA proposed standards for turbines on a gross output basis, but also took comment on standards on a net output basis. The EPA is similarly proposing standards on a gross output basis, while soliciting comment on net output based standards, in today's proposal for modified and reconstructed natural gas-fired stationary combustion turbines. To the extent that the EPA finalizes modified and reconstructed standards for stationary combustion turbines that are consistent with the standards for newly constructed stationary combustion turbines, the EPA intends to take the same approach with regards to the use of net or gross output in both final actions.

3. Costs and Benefits

As explained in the regulatory impact analysis (RIA)[3] for this proposed rule and further below, the EPA expects few units would trigger either the modification or the reconstruction provisions that we are proposing today. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative modified unit. Based on the analysis, the EPA projects that this proposed rule will result in potential CO_2 emission changes, quantified benefits, and costs for a unit that is subject to the modification provision. In this illustrative example, based on a hypothetical 500 MW coal-fired unit, we estimate costs, net of fuel savings, of $0.78 million to $4.5 million (2011$) and CO_2 reductions of 133,000 to 266,000 tons in 2025. The climate benefits from reductions in CO_2, combined with the health co-benefits from reductions in sulfur dioxide (SO_2), nitrogen oxides (NO_X), and fine particulate matter ($PM_{2.5}$), total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reduction scenario, and $35 to $65 million ($2011) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.[4]

B. Overview

1. What authority is the EPA relying on to address power plant CO_2 emissions?

The U.S. Supreme Court ruled, in *Massachusetts* v. *EPA,* that greenhouse gases (GHGs)[5] meet the definition of "air pollutant" in the CAA,[6] and premised its decision in *AEP* v. *Connecticut*[7] that the CAA displaced any federal common law right to compel reductions in CO_2 emissions from fossil fuel-fired power plants on its view that CAA section 111 applies to GHG emissions.

Congress established requirements under section 111 of the 1970 CAA to control air pollution from new stationary sources through NSPS. Specifically, as explained in greater detail in section II below, CAA section 111(b) authorizes the EPA to set "standards of performance" for new (including modified) stationary sources from listed source categories to limit emissions of air pollutants to the environment, and the EPA's implementing regulations provide that new sources include reconstructed sources.[8] Under CAA section 111(a)(1), the EPA must set these standards at the level of emission reduction that reflects the "best system of emission reduction . . . adequately demonstrated," taking into account technical feasibility, costs, and other factors.

For more than four decades, the EPA has used its authority under CAA section 111 to set cost-effective emission standards that ensure newly constructed, reconstructed and modified stationary sources use the best performing technologies to limit emissions of harmful air pollutants. In this proposal, the EPA is following the same well-established interpretation and application of the law under CAA section 111 to address GHG emissions from modified and reconstructed fossil fuel-fired electric steam generating units and natural gas-fired stationary combustion turbines.

2. What sources would be regulated by the proposed standards?

The proposed standards of performance would regulate GHG emissions from modified and reconstructed (1) fossil fuel-fired electric steam generating units—utility boilers and IGCC units—whose non-

[1] The "Legal Memorandum" supporting document is available in the rulemaking docket for the proposed emission guidelines for existing source power plants, Docket ID: EPA–HQ–OAR–2013–0602."

[2] *See K Mart Corp.* v. *Cartier, Inc.,* 486 U.S. 281, 294 (1988) (holding that a regulation was severable because the "[t]he severance and invalidation of [the subsection at issue would] not impair the function of the statute as a whole, and there [was] no indication that the regulation would not have been passed but for its inclusion.").

[3] The RIA for this proposal is presented as Chapter 9 of the RIA for the companion rulemaking for proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.

[4] For purposes of this summary, we present climate benefits from CO_2 that were estimated using the model average social cost of carbon (SCC) at a 3 percent discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5 and 5 percent, and the 95th percentile at 3 percent. Similarly, we summarize the health co-benefits in this summary at a 3 percent discount rate. We provide estimates based on additional discount rates in the RIA.

[5] Greenhouse gas pollution is the aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[6] 549 U.S. 497, 520 (2007).

[7] 131 S.Ct. 2527, 2537–38 (2011).

[8] 40 CFR part 60 subpart A

GHG emissions are regulated under 40 CFR part 60, subpart Da, and (2) natural gas-fired stationary combustion turbines, whose non-GHG emissions are regulated under 40 CFR part 60, subpart KKKK. Natural gas-fired stationary combustion turbines that supply less than one-third of their potential electric output to the grid are not subject to standards in today's proposal.

The CAA and the EPA's implementing regulations define a ''modification,'' for purposes of NSPS applicability, as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, with certain exceptions.[9]

Under the EPA's 1975 framework regulations covering CAA section 111 standards of performance, ''reconstruction'' means the replacement of components of an existing facility to an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards.[10]

3. Why is the EPA issuing this proposed rule?

GHG pollution threatens the American public's health and welfare by contributing to long-lasting changes in our climate system 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 droughts in the West and Southwest; increased frequency and severity of short-term droughts in some other U.S. regions; 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.

Unlike most other air pollutants, GHGs may persist in the atmosphere from decades to millennia, depending on the specific GHG. This special characteristic makes it crucial to act now to limit GHG emissions from fossil fuel-fired power plants, specifically emissions of CO_2, since they are the nation's largest sources of carbon pollution.

As previously noted, on June 25, 2013, President Obama issued a Presidential Memorandum directing the EPA to address carbon pollution from the power sector. As an initial step to limit carbon pollution from power plants, on January 8, 2014, the EPA published a proposed rule to limit GHG emissions from newly constructed fossil fuel-fired electric steam generating units (utility boilers and IGCC units) and newly constructed natural gas-fired stationary combustion turbines. The EPA is now taking another step to limit carbon pollution in this country by issuing a proposed rule to limit GHG emissions from modified and reconstructed fossil fuel-fired electric steam generating units and modified and reconstructed natural gas-fired stationary combustion turbines.

Although we expect that the modification and reconstruction standards of performance in this rulemaking will apply to few sources—since there have been a limited number in the past—these standards serve another important purpose that may affect a larger number of sources: Providing an incentive, and the information needed, for existing sources to structure their actions to achieve their operating and business goals without triggering the modification or reconstruction standards. For example, the modification standard encourages existing sources that undertake physical or operational changes to do so in a manner that does not increase their emission rate.

4. What is the EPA's approach to setting standards for modified and reconstructed EGUs under CAA section 111(b)?

CAA section 111(b) requires the EPA to establish standards of performance that reflect the degree of emission limitation that is 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 EPA determines has been adequately demonstrated. The text and legislative history of CAA section 111, as well as relevant court decisions identify the factors for the EPA to consider in making a BSER determination. They include, among others, whether the system of emission reduction is technically feasible, whether the costs of the system are reasonable, the amount of emissions reductions that the system would generate, and whether the standard would effectively promote further deployment or development of advanced technologies. The case law addressing section 111 makes it clear that the EPA has discretion in weighing these factors, and that as a result, the EPA may weigh them differently for different types of sources or air pollutants. See further discussion of this case law in section VI below.

For each of the standards being proposed in today's action, the EPA considered a number of alternatives and evaluated them against the factors.

The BSER we are proposing for each category of affected sources and the proposed standards of performance based on these BSER—as described immediately below—are based on that evaluation, as discussed in sections VI–IX below.

5. What are the BSER and the standard of performance for modified fossil fuel-fired utility boilers and IGCC units?

The EPA proposes that the BSER for modified fossil fuel-fired boilers and IGCC units is each unit's own best potential performance based on a combination of best operating practices and equipment upgrades. Specifically, the EPA is proposing unit-specific emission standards consistent with this BSER determination and is co-proposing two alternative standards for modified utility steam generating units. In the first co-proposed alternative, modified utility boilers and IGCC units would be subject to a single emission standard. Specifically, under the first co-proposed alternative, a modified source would be required to meet a unit-specific emission limit determined by the affected source's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction. The EPA has determined that this standard can be met through a combination of best operating practices and equipment upgrades. To account for facilities that have already implemented best practices and equipment upgrades, the proposal also specifies that modified facilities would not have to meet an emission standard more stringent than the corresponding standard for reconstructed EGUs. The EPA also solicits comment on whether, for units that have become subject to a CAA section 111(d) plan, the period of best historical performance should be the years from 2002 to the time when the unit becomes subject to the CAA section 111(d) plan, rather than to the time of the modification. This could address the concern that sources that make improvements to their CO_2 emission

[9] CAA Section 111(a)(4); 40 CFR 60.2, 60.14.

[10] 40 CFR 60.15(b).

rate as a result of a CAA section 111(d) plan would have lower baseline emissions from which to calculate their required rate.

It is our interpretation that, as we discuss in detail in the Legal Memorandum,[11] an existing source would continue to be subject to CAA section 111(d) requirements after it becomes a modified source, whether the modification occurs before or after the promulgation of a CAA section 111(d) plan. Therefore EPA is co-proposing that modified sources would be required to meet unit-specific emission standards that would depend on the timing of the modification. Sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposal—that is, the modified source would be required to meet a unit-specific emission limit determined by the affected source's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction (based on equipment upgrades). Sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the CAA section 111(d) implementing authority and would be based on the source's expected performance after implementation of identified unit-specific energy efficiency improvement opportunities. The BSER and standards of performance for modified fossil-fired electric utility steam generating units are discussed further in section VII of this preamble.

6. What is the BSER and standard of performance for modified natural gas-fired stationary combustion turbines?

For modified natural gas-fired stationary combustion turbines, the EPA is proposing standards of performance based on efficient Natural Gas Combined Cycle (NGCC) technology as the BSER. The emission limits proposed for these sources are 1,000 lb CO_2/MWh-gross for facilities with heat input ratings greater than 850 MMBtu/h, and 1,100 lb CO_2/MWh-gross for facilities with heat input ratings of 850 MMBtu/h or less. For sources that are subject to a CAA section 111(d) plan, the EPA is also soliciting comment on whether the sources should be allowed to elect, as an alternative to the otherwise applicable numeric standard, to instead meet a unit-specific emission standard that is determined by the CAA section 111(d) implementing authority based on implementation of identified energy efficiency improvement opportunities applicable to the source. This is discussed further in section IX of this preamble.

7. What are BSER and the standard of performance for reconstructed fossil fuel-fired utility boilers and IGCC units?

For reconstructed utility boilers and IGCC units, the EPA is proposing a standard of performance with BSER based on the most efficient generating technology for these types of units (i.e., reconstructing the boiler to use higher steam, temperature and pressure, even if the boiler was not originally designed to do so[12]). The proposed emission limit for these sources is 1,900 lb CO_2/MWh-net for sources with a heat input rating of greater than 2,000 MMBtu/h or 2,100 lb CO_2/MWh-net for sources with a heat input rating of 2,000 MMBtu/h or less. The difference in the proposed standards for larger and smaller units is based on greater availability of higher pressure/temperature steam turbines (e.g. supercritical steam turbines) for larger units. The standards could also be met through other technology options such as natural gas co-firing. This is discussed further in section VI below.

As discussed in the Legal Memorandum,[13] a reconstruction would have no effect on the applicability of an approved CAA section 111(d) plan; thus, a source that is subject to requirements in a CAA section 111(d) plan would remain subject to those requirements.

8. What are BSER and the standard of performance for reconstructed natural gas-fired stationary combustion turbines?

The EPA is proposing to find efficient NGCC technology to be the BSER for reconstructed stationary combustion turbines. Therefore, the EPA is proposing that larger units be required to meet a standard of 1,000 lb CO_2/MWh-gross and that smaller units be required to meet a standard of 1,100 lb CO_2/MWh-gross. This is discussed further in section VIII below.

A reconstruction would have no effect on the applicability of an approved CAA section 111(d) plan on the existing source; thus, a source that is subject to requirements in a CAA section 111(d) plan would remain subject to those requirements, even after reconstruction.

9. How is EPA proposing to codify the requirements?

In the January 2014 proposal of carbon pollution standards for newly constructed power plants (79 FR 1430), the EPA co-proposed two options for codifying applicable requirements for covered sources. Under the first option the EPA proposed to codify the standards of performance for the respective sources within existing 40 CFR part 60 subparts so that applicable 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. Under the second option, the EPA co-proposed to create a new subpart TTTT and to include all GHG standards of performance for covered sources in that newly created subpart.

In this action for modified and reconstructed sources, the EPA co-proposes the same two options for codifying the applicable standards. For consistency, the EPA intends—when it takes final action on this proposal and on the January 2014 proposal for newly constructed sources, respectively—to codify the standards in the same way for the sources addressed under the two proposals.

10. What is the organization and approach for this proposal?

Section II of this preamble provides a brief summary of background information on climate change impacts of GHG emissions, GHG emissions from fossil-fuel fired EGUs, the utility power sector, the statutory and regulatory background relevant to this rulemaking, and the EPA's stakeholder outreach activities. Section II also contains additional information on the regulatory and litigation history of CAA section 111.

The specific proposed requirements for modified and reconstructed sources are described in detail in section III of this preamble. The rationale for reliance on a rational basis to regulate GHG emissions from fossil fuel-fired EGUs and the rationale for the applicability requirements in today's proposal are presented in sections IV and V of this preamble, respectively. Sections VI through IX of this preamble describe the rationale for each of the proposed emission standards, including an explanation of the determination of the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units and modified fossil fuel-fired utility boilers and IGCC units, as well as for

[11] ''Legal Memorandum for Proposed Carbon Pollution Guidelines for Existing Power Plants'' Technical Support Document available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

[12] Steam with higher temperature and pressure has more thermal energy which can be more efficiently converted to electrical energy.

[13] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

reconstructed natural gas-fired stationary combustion turbines and modified natural gas-fired stationary combustion turbines. Impacts of the proposed action are described in section X of this preamble. A discussion of statutory and executive order reviews is provided in section XI of this preamble, and the statutory authority for this action is provided in section XII of this preamble.

It should be noted that this rulemaking overlaps in certain respects with two other related rulemakings: The January 2014 proposed rulemaking for CO_2 emissions from newly constructed affected EGUs, and the rulemaking for existing EGUs that the EPA is proposing at the same time as the present rulemaking. In a number of places in this preamble, the EPA cross-references parts of those two rulemakings. However, each of these three rulemakings is independent of the other two, and each has its own rulemaking docket. Accordingly, anyone who wishes to comment on any aspect of this rulemaking, including anything described by a cross-reference to one of the other two related rulemakings, should make those comments on this rulemaking.

C. Does this action apply to me?

The entities potentially affected by the proposed standards are shown in Table 2 below.

TABLE 2—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 North American Industry Classification (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, or organization, 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 (General Provisions).

II. Background

In this section,[14] we discuss climate change impacts from GHG emissions, both on public health and public welfare, present information about GHG emissions from fossil-fuel fired EGUs, describe the utility power sector and summarize the statutory and regulatory background relevant to this rulemaking. We close this section by describing stakeholder outreach and a brief history of modifications and reconstructions in the power sector.

A. Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the document known 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.[16]

1. Public Health Impacts Detailed in the 2009 Endangerment Finding [17]

Climate change caused by human emissions of GHGs threatens public health in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Other public health threats also stem from projected 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 [18]

Climate change caused by human emissions of GHGs also threatens public welfare in multiple ways. 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

[14] This background section is intended to provide the same or very similar background information as provided in the companion proposals for new sources (79 FR 1430) and existing sources (the CAA section 111(d) proposal in today's **Federal Register**). Any minor differences in phrasing between this proposal and the companion proposals are not intended to state a substantive difference.

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

[16] The January 8, 2014, preamble to the proposed GHG standards for new EGUs (79 FR 1430) and the RIA supporting that proposal include a more detailed summary of the public health and welfare impacts detailed in the 2009 Endangerment Finding, as well as a discussion of the science supporting the EPA's conclusions regarding the question of whether GHG endanger public health and welfare 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); and (3) the decision by the United States Court of Appeals for the District of Columbia Circuit in 2012 to uphold the Endangerment Finding and the Reconsideration Denial.

[17] ''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'').

[18] ''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'').

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. New Scientific Assessments

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. Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, a number of such assessments have been released. These assessments include the IPCC's 2012 ''Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation'' (SREX) and the 2013–2014 Fifth Assessment Report (AR5), the USGCRP's 2014 ''Climate Change Impacts in the United States'' (Climate Change Impacts), and the NRC's 2010 ''Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean'' (Ocean Acidification), 2011 ''Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia'' (Climate Stabilization Targets), 2011 ''National Security Implications for U.S. Naval Forces'' (National Security Implications), 2011 ''Understanding Earth's Deep Past: Lessons for Our Climate Future'' (Understanding Earth's Deep Past), 2012 ''Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future'', 2012 ''Climate and Social Stress: Implications for Security Analysis'' (Climate and Social Stress), and 2013 ''Abrupt Impacts of Climate Change'' (Abrupt Impacts) assessments.

The EPA has reviewed these new assessments and finds that the improved understanding of the climate system they present strengthens the case that GHGs endanger public health and welfare.

In addition, these assessments highlight the urgency of the situation as the concentration of CO_2 in the atmosphere continues to rise. Absent a reduction in emissions, a recent NRC assessment projected that concentrations by the end of the century would increase to levels that the Earth has not experienced for millions of years.[19] In fact, that assessment stated 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.''[20]

What this means, as stated in another NRC assessment, is 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. Therefore, emission reductions choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.[21]

Moreover, due to the time-lags inherent in the Earth's climate, the Climate Stabilization Targets assessment notes that the full warming from any given concentration of CO_2 reached will not be realized for several centuries.

The recently released USGCRP ''National Climate Assessment''[22] emphasizes that climate change is already happening now and it is happening in the United States. The assessment documents the increases in some extreme weather and climate events in recent decades, the damage and disruption to infrastructure and agriculture, and projects continued increases in impacts across a wide range of peoples, sectors, and ecosystems.

These assessments underscore the urgency of reducing emissions now: Today's emissions will otherwise lead to raised atmospheric concentrations for thousands of years, and raised Earth system temperatures for even longer. Emission reductions today will benefit the public health and public welfare of current and future generations.

Finally, it should be noted that the concentration of CO_2 in the atmosphere continues to rise dramatically. In 2009, the year of the Endangerment Finding, the average concentration of CO_2 as measured on top of Mauna Loa was 387 parts per million (ppm).[23] The average concentration in 2013 was 396 ppm. And the monthly concentration in April of 2014 was 401 ppm, the first time a monthly average has exceeded 400 ppm since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years according to ice core records.[24]

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired EGUs are by far the largest emitters of GHGs, primarily in the form of CO_2, 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 Sinks[25] (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 3 below, which presents total U.S.

[19] National Research Council, Understanding Earth's Deep Past, p. 1.

[20] Id., p.138.

[21] National Research Council, Climate Stabilization Targets, p. 3.

[22] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014 Available at *http://nca2014.globalchange.gov/*.

[23] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt.*

[24] *http://www.esrl.noaa.gov/gmd/ccgg/trends/*.

[25] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

anthropogenic emissions and sinks [26] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2012.

GHGs, including CO_2 emissions, for the years 1990, 2005 and 2012.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Teragram carbon dioxide equivalent (Tg CO_2 Eq.)] [27]

Sector	1990	2005	2012
Energy	5,260.1	6,243.5	5,498.9
Industrial Processes	316.1	334.9	334.4
Solvent and Other Product Use	4.4	4.4	4.4
Agriculture	473.9	512.2	526.3
Land Use, Land-Use Change and Forestry	13.7	25.5	37.8
Waste	165.0	133.2	124.0
Total Emissions	6,233.2	7,253.8	6,525.6
Land Use, Land-Use Change and Forestry (Sinks)	(831.3)	(1,030.7)	(979.3)
Net Emissions (Sources and Sinks)	5,402.1	6,223.1	5,546.3

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.7 percent of total 2012 GHG emissions.[28] In 2012, fossil fuel combustion by the electric power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.7 percent of all energy-related CO_2 emissions.[29] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2012.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (TG CO_2) [30]

GHG Emissions	1990	2005	2012
Total CO_2 from fossil fuel combustion EGUs	1,820.8	2,402.1	2,022.7
—from coal	1,547.6	1,983.8	1,511.2
—from natural gas	175.3	318.8	492.2
—from petroleum	97.5	99.2	18.8

C. The Utility Power Sector

Electricity in the United States is generated by a range of sources—from power plants that use fossil fuels like coal, oil, and natural gas, to non-fossil sources, such as nuclear, solar, wind and hydroelectric power. In 2013, over 67 percent of power in the U.S. was generated from the combustion of coal, natural gas, and other fossil fuels, over 40 percent from coal and over 26 percent from natural gas.[31] In recent years, though, the proportion of new renewable generation coming on line has increased dramatically. For instance, over 38 percent of new generating capacity (over 5 GW out of 13.5 GW) built in 2013 used renewable power generation technologies.[32]

Natural gas-fired EGUs typically use one of two technologies: NGCC or 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) that generates steam which is used to produce power using a steam turbine (the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Simple cycle combustion turbines 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 FB 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 or petroleum coke to form a syngas composed of carbon monoxide and hydrogen, which can be combusted in a combined cycle system to generate power.

D. Statutory Background

CAA section 111 authorizes the EPA to prescribe new source performance standards (NSPS) applicable to certain new stationary sources (including

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

[27] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012, Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[28] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[29] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[30] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[31] U.S. Energy Information Administration (EIA), ''Table 7.2b Electricity Net Generation: Electric Power Sector Electric Power Sector,'' data from April 2014 Monthly Energy Review, release date April 25, 2014. Available at: *http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m.*

[32] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following renewable energy sources: Solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.*

modified and reconstructed sources).[33] 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.'' The EPA has listed and regulated more than 60 stationary source categories under CAA section 111.[34]

Once the EPA has listed a source category, the EPA proposes and then promulgates ''standards of performance'' for ''new sources'' in the category.[35] A ''new source'' is ''any stationary source, the construction or modification of which is commenced after,'' in general, the date of the proposal.[36] 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.''[37] The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[38]

The EPA's 1975 framework regulations also provide that an existing source is considered a new source if it undertakes a ''reconstruction,'' which is the replacement of components of an existing facility to an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards.[39]

CAA 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 ''the best system of emission reduction . . . adequately demonstrated'' (BSER). The standard that the EPA develops, based on the BSER, is commonly a numeric emission 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 may select any measure or combination of measures that will achieve the emissions level of the standard.[40] In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class or size.[41]

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to establish requirements for existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the National Ambient Air Quality Standards or regulated under the CAA section 112 requirements for hazardous air pollutants. Unlike CAA section 111(b), which gives EPA direct authority to set national standards, CAA section 111(d) requires the EPA to promulgate emission guidelines directing states to develop and submit, for EPA approval, state plans that include standards of performance for the existing sources.

E. Regulatory Background

In 1971, the EPA initially included fossil fuel-fired (which includes natural gas, petroleum and coal) EGUs that use steam-generating boilers in a category that it listed under CAA section 111(b)(1)(A),[42] and the EPA promulgated the first set of standards of performance for sources in that category, which it codified in subpart D.[43] In 1977, the EPA initially included fossil fuel-fired combustion turbines in a category that the EPA listed under CAA section 111(b)(1)(A),[44] and the EPA promulgated standards of performance for that source category in 1979, which the EPA codified in subpart GG.[45]

The EPA has revised those regulations, and in some instances, has revised the codifications (that is, the 40 CFR part 60 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.[46] 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.[47] None of these subsequent rulemakings, including the revised codifications, however, constituted a new listing under CAA section 111(b)(1)(A).

The EPA promulgated amendments to subpart Da in 2006, which included new standards of performance for criteria pollutants for EGUs, but no standards of performance for GHG emissions.[48] Petitioners sought judicial review of the rule by the DC Circuit, contending, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.[49] The January 8, 2014 preamble to the proposed CO_2 standards for new EGUs[50] includes a discussion of the GHG-related litigation of the 2006 Final Rule as well as other GHG-associated litigation.

F. Stakeholder Outreach

The EPA has engaged extensively with a broad range of stakeholders and the general public regarding climate change, carbon pollution from power plants, and carbon pollution reduction opportunities. These stakeholders included industry and electric utility representatives, state and local officials, tribal officials, labor unions and non-governmental organizations.

In February and March 2011, early in the process of developing carbon pollution standards for new power plants, the EPA held five listening sessions to obtain information and input from key stakeholders and the public.

[33] CAA section 111(b)(1)(A).

[34] *See generally* 40 CFR part 60, subparts D–MMMM.

[35] CAA section 111(b)(1)(B).

[36] CAA section 111(a)(2).

[37] CAA section 111(a)(4).

[38] 40 CFR 60.2, 60.14(e).

[39] 40 CFR 60.15.

[40] CAA section 111(b)(5).

[41] CAA section 111(b)(2).

[42] 36 FR 5931 (March 31, 1971)

[43] ''Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971,'' 36 FR 24875 (December 23, 1971) codified at 40 CFR 60.40–46.

[44] 42 FR 53657 (October 3, 1977).

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

[46] 44 FR 33580 (June 11, 1979).

[47] 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (March 20, 2009).

[48] ''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 (February 27, 2006).

[49] *State of New York, et al.* v. *EPA, No. 06–1322.*

[50] 79 FR 1430.

Each of the five sessions had a particular target audience: The electric power industry, environmental and environmental justice organizations, states and tribes, coalition groups, and the petroleum refinery industry.

The EPA has conducted subsequent outreach sessions: The vast majority of which occurred between September 2013 and November 2013. The agency held 11 public listening sessions; one national listening session in Washington, DC and 10 listening sessions in locations across the country. In addition to the 11 public listening sessions, the EPA has held hundreds of meetings with individual stakeholder groups, and meetings that brought together a variety of stakeholders to discuss a wide range of issues related to the electricity sector and regulation of GHGs under the CAA. The agency provided and encouraged multiple opportunities to engage with each one of the 50 states. The agency met with electric utility associations and electricity grid operators. Agency officials have engaged with labor unions and with leaders representing large and small industries. Because of the focus of the standard on the electricity sector, many of the EPA's meetings with industry have been with utilities and industry representatives directly related to the electricity sector. The agency has also met with energy industries such as coal and natural gas interests. In addition, the agency has met with companies that offer new technology to prevent or reduce carbon pollution, including companies that represent renewable energy and energy efficiency interests. The EPA has also met with representatives of energy intensive industries, such as the iron and steel and aluminum industries, to help understand the issues related to large industrial purchasers of electricity. Agency officials engaged with representatives of environmental justice organizations, environmental groups, and religious organizations.

Although this stakeholder outreach was primarily framed around the GHG emission guidelines for existing EGUs, the outreach encompassed issues relevant to this proposed rulemaking for modified and reconstructed EGUs. For example, existing EGUs would be subject to standards for modified and reconstructed EGUs should they undertake modification or reconstruction actions, and, thus it is important that we understand previous state and stakeholder experience with reducing CO_2 emissions in the power sector.

A detailed discussion of this stakeholder outreach is included in the preamble to the GHG emission guidelines for existing affected EGUs being proposed in a separate action today.

G. Modifications and Reconstructions

1. Modifications

The EPA's current regulations [51] define an NSPS ''modification'' as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, with certain exemptions.[52]

Based on current information, the EPA believes that projects may involve equipment changes to improve efficiency that could have the effect of increasing a source's maximum achievable hourly emission rate (lb CO_2/h), even while decreasing its actual output based emission rate (lb CO_2/MWh). However, based on current information, the most likely projects that could increase the maximum achievable hourly rate of CO_2 emissions would involve the installation of add-on control equipment required to meet CAA requirements for criteria and hazardous air pollutants. These increases in CO_2 emissions would generally be small and would occur as a chemical by-product of the operation of the control equipment. All of these actions, however, would be exempted from the definition of modification under the current NSPS regulations.[53]

There are, however, some actions that could potentially trigger the modification provisions of CAA section 111(b). For example, in some cases, generation from a fossil fuel-fired electric utility steam generating unit is limited not by the size of the boiler, but by other factors, such as the size of the steam turbine or limitations in the particulate control equipment that, in turn, limit the amount of coal that can be combusted. If the steam turbine or particulate control device is upgraded, more coal can be combusted in the boiler, increasing hourly emissions.

Our base of knowledge concerning the types of NSPS modifications has depended largely on self-reporting by power plants and on the enforcement actions brought against power plants. Over the lengthy history of the NSPS program, the number of modifications that we are aware of is limited.

2. Comments on the April 2012 Proposal for New Sources Related to Modifications

In the April 13, 2012 proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (77 FR 22392),[54] the EPA did not propose standards of performance for modified sources; however, it did specifically request comment on the types of modifications that may be expected and on the appropriate control measures that may be applied. The agency received a number of comments addressing standards for modified and reconstructed EGUs.[55] The EPA subsequently withdrew that proposed rulemaking.[56] While many of those comments informed today's proposal, the EPA is not responding to those comments in this rulemaking, and if members of the public wish to express views on this rulemaking they must do so in comments on this rulemaking.

Many of those comments emphasized that a standard of performance that is based on carbon capture and storage (CCS) (or partial CCS) is not appropriate for modified EGUs. Some commenters suggested that a well-designed CAA section 111(d) program could obviate the need to set separate standards of performance for modified sources. Several commenters disagreed with EPA's assertion that it lacked adequate information to propose standards for modified sources (at that time), stating that proposed standards should be based on energy efficiency measures.

3. Reconstructions

The EPA's framework regulations, interpreting the definition of ''new source'' in CAA section 111(a)(2), provide that an existing source, ''upon reconstruction,'' becomes subject to the standard of performance for new sources.[57] The regulations define reconstruction as the replacement of components of an existing facility to such an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards set forth in this part.

[51] The discussion of the EPA's regulations in this rulemaking is for background purposes only. The EPA is not re-opening, and thus is not soliciting comment on, any provision in its existing regulations.

[52] 40 CFR 60.2, 60.14.

[53] 40 CFR 60.14.

[54] The proposal was subsequently withdrawn with the publication of the January 8, 2014 proposal.

[55] The comments are available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2011–0660.

[56] 79 FR 1352.

[57] 40 CFR 60.15(a).

Thus, a reconstruction occurs if the existing source replaces components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, even if the existing source does not increase its emissions. In addition, the component replacement constitutes a reconstruction only if it is technologically and economically feasible for the source to meet the applicable standards. The purpose of the reconstruction provision is to avoid creating any regulatory incentive to perpetuate the operation of a facility, instead of replacing it at the end of its useful life with a newly constructed affected facility.

The regulations require the owner or operator of an existing source that proposes to replace components to an extent that exceeds the 50 percent level to notify the EPA and provide specified information. This information must include: The name and address of the owner or operator; the location of the existing facility; a brief description of the existing facility and the components which are to be replaced; a description of existing and proposed air pollution control equipment; an estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility; the estimated life of the existing facility after the replacements; and, a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements. The regulations require the EPA to determine, within a specified time period, whether the proposed replacement constitutes a reconstruction.[58] The determination shall be based on: The fixed capital cost in comparison to the cost to construct a comparable entirely new facility; the estimated life of the facility after the replacements compared to the life of a comparable entirely new facility; the extent to which the components being replaced cause or contribute to emissions from the facility; and any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

Historically, few EGUs have undertaken reconstructions. Because of the relative prices of coal and natural gas, and the relative costs of reconstructing an existing coal-fired EGU and constructing an entirely new NGCC unit, the EPA expects that few existing coal-fired EGUs will undertake projects that will qualify the unit to be a reconstructed source during the analysis period of this rulemaking (i.e., through 2025). The EPA also does not expect existing NGCC units to undertake reconstructions during the analysis period (i.e., through 2025) because most of them are relatively young (over 80 percent of the NGCC fleet came on-line after 2000).

While there are specific provisions in the EPA's implementing regulations at 40 CFR 60.15 on what constitutes a reconstructed source (as just described), there is not such guidance on when an existing source replaces components to such a degree that it goes beyond a reconstruction and becomes essentially a newly constructed source. Historically there has been little need to distinguish between reconstructed sources and newly constructed sources as the standards of performance are typically the same for either. However, the standards proposed in today's action are different—for reasons we explain later—and, therefore, there is a need to clearly delineate between a reconstructed source and a newly constructed source. For example, it is clear that an entirely new greenfield facility would constitute a newly constructed source. It is EPA's view that, a new unit that is built on property contiguous with an existing source—but not in the same footprint as the existing source—would also constitute a newly constructed source. And, it is EPA's view that a unit that entirely, or for all practical purposes, completely replaces an existing sources by being constructed on the replaced source's existing footprint would also constitute a newly constructed source. The EPA solicits comment on the delineation between a reconstructed source, which would be subject to standards proposed in today's action, and a newly constructed source, which would be subject to standards proposed in the January 2014 proposal (79 FR 1430), for those situations where significant equipment is being replaced (enough to exceed the reconstruction threshold) but the entire unit is not being rebuilt.

In addition, the EPA requests comment on having an upper capital cost threshold for reconstruction, such that facilities that exceed that threshold would be subject to the standard of performance for newly constructed sources. With respect to this concept, the EPA requests comment on both: (1) The idea of having an upper threshold and (2) the appropriate upper threshold. With respect to the appropriate upper threshold, EPA specifically requests comment on an upper threshold within the range of 75 to 100 percent of the cost of an entirely new and comparable facility. Finally, the EPA requests comment on whether this upper threshold should be coupled with a provision comparable to 40 CFR 60.15(b)(2) and 60.15(f)(4), such that a facility that exceeded the upper threshold would not be subject to the new construction standard if it was technologically and economically infeasible for that facility to meet the new construction standard.

4. Comments on the April 2012 Proposal for New Sources Related to Reconstructions

In the April 13, 2012 proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (77 FR 22392), the EPA did not propose standards of performance for reconstructed sources; however, it did specifically request comment on the types of reconstructions that may be expected and on the appropriate control measures that may be applied. The agency received a number of comments addressing standards for reconstructed EGUs.[59] As noted above, the agency subsequently withdrew that proposal and is not responding to those comments in this rulemaking, so that if members of the public wish to express views on this rulemaking they must do so in comments on this rulemaking.

Many of the comments on the April 13, 2012 proposal supported a delay in proposing standards for reconstructed sources. Others did not favor the delay and suggested, instead, that reconstructed sources be subject to the same standard as newly constructed sources. One commenter expressed concern that an existing source that elected to retrofit with CCS technology (perhaps in reliance on enhanced oil recovery (EOR) markets) might trigger the requirements for a reconstruction due to the high cost of CCS technology. The commenter suggested that the EPA exclude the cost of retrofitting CCS technology in order to eliminate barriers to voluntary use of that technology. Several commenters expressed concern that a reconstruction could be essentially a new plant built on a few remaining parts of an old plant. The commenters expressed concern that such reconstructed sources would face a standard that is much less stringent than a newly constructed greenfield source.

[58] 40 CFR 60.15(d)–(e).

[59] The comments are available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2011–0660.

III. Proposed Requirements for Modified and Reconstructed Sources

A. Applicability Requirements

We generally refer to fossil fuel-fired electric generating units that would be subject to an emission standard 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 proposed rule, and the criteria for being considered ''modified'' and ''reconstructed'' sources as defined under the provisions of CAA section 111 and the EPA's regulations.

The EPA is proposing generally similar applicability requirements, for purposes of this rule, that the EPA proposed in the January 2014 proposal.[60] [61] This section describes those requirements.

To be considered an EGU under subpart Da, the boiler or IGCC must be: (1) Capable of combusting more than 250 MMBtu/h heat input of fossil fuel,[62] (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 [63] (that is, to the grid), and (3) constructed for the purpose of supplying more than 25 MW net-electric output to the grid.[64] In the January 2014 proposal, we proposed to revise the third criterion to read ''more than 219,000 MWh,'' as opposed to ''25 MW,'' net-electric 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. In the January 2014 proposal, we proposed to include two additional applicability criteria specific to applicability with the GHG standards: (1) That a facility actually sells more than one-third of its potential electric output and more than 219,000 MWh to the grid on an annual basis for boilers and IGCC facilities and on a 3-year average for combustion turbines, and (2) that the GHG standards are not applicable to facilities that combust 10 percent or less fossil fuel on a 3-year average. In this proposal, we are not proposing that any of these additional applicability criteria apply for modified or reconstructed boilers or IGCC facilities. Therefore, any modified or reconstructed boiler or IGCC facility that meets the general applicability of subpart Da would also be subject to the GHG requirements. For stationary combustion turbines, we are proposing to maintain all of these criteria, along with the additional criteria specific to stationary combustion turbines, included in the January 2014 proposal: That only stationary combustion turbines that combust over 90 percent on a 3-year rolling average basis are subject to a numerical GHG standard.

We are proposing and soliciting comment on an additional amendment, not included in the January 2014 proposal, to clarify that net-electric sales, for applicability purposes, includes electricity supplied to other facilities that produce electricity to offset auxiliary loads. Without this amendment, smaller EGUs that are co-located with larger EGUs could claim that they do not meet the rule applicability criteria because their generated power is used to offset the parasitic loads of the larger facility. We are also soliciting comment if the 10 percent fossil fuel use criteria should be based on 3 consecutive calendar years or on a 3 year rolling average basis.

Consistent with the January 2014 proposal, we are proposing several additional adjustments to the way applicability is currently determined under subpart Da for purposes of modifications and reconstructions. First, we are proposing that the definition of ''potential electric output'' be revised to include ''or the design net electric output efficiency'' as an alternative to the default one-third efficiency value (i.e., the proposed definition is ''33 percent *or the design net electric output efficiency times* the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 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 electrical output capacity)'' (emphasis added)). Next, we are proposing to add ''of the thermal host facility or facilities'' to the definition of ''net-electric output'' (i.e., the proposed definition 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).

Finally, consistent with the January 2014 proposal, to avoid circumvention of the intent of the emission standards (e.g., by having auxiliary equipment provide steam to the EGU to increase the output of the EGU and not including the CO_2 emissions in determining the emission rate) and to provide additional flexibility to the regulated community through additional compliance options, 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'' in place of the existing language ''plus any integrated combustion turbines and fuel cells.'' The proposed definition would read, ''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 affected facility or auxiliary equipment''* (emphasis added). We are also proposing to add the additional language to the definition of IGCC in subpart Da (or subpart TTTT) and stationary combustion turbine in subpart KKKK (or subpart TTTT).

This action proposes to set standards only for emissions of CO_2. The pollutant we propose to regulate could also be identified as a broader suite of GHGs. However, we are not proposing to set standards for any other GHGs, such as methane (CH_4) or nitrous oxide (N_2O), because they represent less than 1 percent of total estimated GHG emissions from fossil fuel-fired electric power generating units. This is consistent with the approach that was taken in the proposed standards for newly constructed EGUs (79 FR 1430).

We are also not proposing standards for certain types of sources. These include modified and reconstructed boilers and IGCC units that were constructed for the purpose of selling one-third or less of their potential output and 219,000 MWh or less to the grid. These units are not covered under

[60] See 79 FR 1445 and 1446. Note that the statements in the January 2014 Proposal that ''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)'' are not subject to that rulemaking, 79 FR 1446, are not relevant for purposes of the present rulemaking concerning modifications and reconstructions.

[61] In the January 2014 proposal, the EPA solicited comment on whether certain applicability requirements were appropriate in light of the fact that they assumed that the source had an operating history. In this rulemaking, the affected sources that would be undertaking modifications or reconstructions do have an operating history. As a result, to the extent the solicitation of comment in the January 2014 just described may be read to identify concerns about those applicability requirements, those concerns do not apply to this rulemaking.

[62] E.g., 40 CFR 60.40Da(a)(1).

[63] 40 CFR 60.41Da (definition of (''Electric utility steam-generating unit'').

[64] *Id.*

subpart Da for any other pollutants but are rather covered as industrial boilers under subpart Db or stationary combustion turbines under subpart KKKK. We are also not proposing standards for two types of units that are currently covered under subpart KKKK for other pollutants at this time. The first type of units is stationary combustion turbines that were constructed for the purpose of selling or are selling one-third or less of their potential output or 219,000 MWh or less to the grid. These units only account for a small amount of the CO_2 emissions from fossil fuel-fired EGUs. The second type of units is modified or reconstructed non-natural gas-fired stationary combustion turbines.[65] Under the proposed approach, applicability with the NSPS for stationary combustion turbines could change on an annual basis depending on electric sales and for facilities burning fuels other than natural gas (e.g., burning backup oil).

B. Emission Standards

In this rulemaking, the EPA is proposing standards of performance for CO_2 emissions from modified and reconstructed EGUs within two categories and several subcategories of affected fossil fuel-fired EGUs.

The proposed standards of performance for the utility boiler and IGCC category are in the form of net energy output-based CO_2 emission limits expressed in units of mass of CO_2 per unit of net energy output (e.g., net electrical output plus 75 percent of the useful thermal output), specifically, in lb CO_2/MWh-net. This emission limit would apply to affected sources upon the effective date of the final action. In this document, we sometimes refer to ''net energy output'' as ''net output.''

As explained earlier, the proposed standards of performance for natural gas-fired stationary combustion turbines are in the form of a gross output-based emission limit expressed in units of mass of CO_2 per unit of gross energy output, specifically, in lb CO_2/MWh-gross. We also solicit comment on whether we should use a net output-based approach.

The proposed method to calculate compliance is the same as was proposed in the January 2014 proposal. Compliance would be calculated as the sum of the emissions for all operating hours divided by the sum of the useful energy output over a rolling 12-operating-month period. In the alternative, as in the January 2014 proposal, we solicit comment on requiring calculation of compliance on an annual (calendar year) period. *See* 79 FR 1477.

We are proposing additional amendments to the definition of useful thermal output. The current definition excludes energy used to enhance the performance of the affected facility from being considered as useful thermal output. The intent of this restriction is to clarify that thermal energy that is directly used by the affected facility to create additional output (e.g., the economizer) is not counted as useful thermal output. Without this restriction, the energy could be doubled counted—once as useful thermal output and again as electric output. This could also be interpreted to exclude thermal energy used to reduce fuel moisture (e.g., coal drying) as being useful thermal output because it enhances the performance of the affected facility. However, coal-drying could be done at a separate offsite facility by an industrial boiler prior to delivery at the power plant. In that scenario, the CO_2 emissions from the industrial boiler would not be included when the coal-fired boiler determined compliance with the proposed standards even though the overall emissions to the atmosphere could be greater than for an integrated system where the thermal energy for the drying is supplied by the power plant. Therefore, we are proposing that thermal energy used for reducing fuel moisture be counted as useful thermal output. This approach would avoid potential disincentives for integrating coal drying at power plants. We are also proposing that default useful thermal output be measured relative to standard ambient temperature and pressure (25 °C and 14.5 pounds per square inch (psi)) instead of International Organization for Standardization (ISO) conditions (15 °C and 14.7 psi). In other words, at standard ambient temperature and pressure (SATP) conditions, the amount of useful thermal energy (commonly called ''enthalpy'') is considered to be zero. The rationale behind providing a relative measurement of thermal output is so that measurements are made relative to the energy content in the makeup water. We have concluded that standard ambient conditions are more representative than ISO conditions of the energy content in the makeup water. In addition, we are proposing the combined heat and power (CHP) facilities with high energy condensate return would measure the energy in the condensate when determining the useful thermal output. In addition, we are soliciting comment on providing credit for useful thermal output in the range of two-thirds to 100 percent.

1. Emission Standards for Modified Utility Boilers and IGCC Units

The EPA is proposing that affected modified utility boilers and IGCC units must meet a standard of performance based on the source's best potential performance, achieved through a combination of best operating practices and equipment upgrades, as the BSER. The EPA is co-proposing two alternative standards of performance. In the first alternative, modified sources would be required to meet a unit-specific numeric emission standard that is 2 percent lower than the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs.

Based on analysis of existing data, the EPA has determined that this standard can be met through a combination of best operating practices and equipment upgrades. In an analysis to determine opportunities for heat rate improvement in the U.S. coal-fired utility power fleet, the EPA found that a total of 6 percent improvement, on average, can be achieved through two types of measures: Best operating practices that have the potential to improve heat rate, on average, by 4 percent, and equipment upgrades that have the potential to improve heat rate, on average, by an additional 2 percent.[66] The EPA also proposes that the unit-specific emission rates that would apply to affected modified utility boilers and IGCC units would be no more stringent (i.e., no lower) than 1,900 lb CO_2/MWh-net for units with a heat input rating greater than 2,000 MMBtu/h, and no more stringent (i.e., no lower) than 2,100 lb CO_2/MWh-net for units with a heat input rating of 2,000 MMBtu/h or less. These proposed constraints on the stringency of unit-specific emission rate standards are consistent with the emission rate standards proposed in today's action for reconstructed utility boilers and IGCC units—based on the EPA's review and analysis of the emissions from the best available generating technology. The EPA is soliciting comment on whether the most stringent standard for modified steam generating units should take into account the current steam cycle of the

[65] 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).

[66] Additional detail can be found in the Technical Support Document: ''GHG Abatement Measures'' (Chapter 2: Heat Rate Improvement at Existing Coal-fired EGUs), available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

facility. For example, should large subcritical steam generating units have a most stringent standard that is less stringent (i.e., greater than) 1,900 lb CO_2/MWh-net, which is based on the use of a supercritical steam cycle.

As we discuss in the Legal Memorandum[67], existing sources that are subject to requirements under an approved CAA section 111(d) plan would remain subject to those requirements after undertaking a modification or reconstruction. Therefore, we are co-proposing a second alternative—that modified sources would be required to meet a unit-specific numeric emission standard that would be dependent on the timing of the modification relative to the adoption of a CAA section 111(d) plan that covers the source. Specifically, the EPA proposes that sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposed alternative—that is, the modified source would be required to meet a unit-specific emission limit determined by the affected source's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction. Sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the CAA section 111(b) implementing authority and would be based on the source's expected performance after implementation of identified unit-specific energy efficiency improvement opportunities. We seek comment on all aspects of these co-proposals, including whether the CAA section 111(b) implementing authority would determine the unit-specific emission limit, even when the implementing authority is a state, as opposed to the EPA.

In addition, we solicit comment on alternative ways to determine the best potential performance at affected modified utility boilers and IGCC units. Specifically, we are requesting comment on whether the unit-specific numerical emission standard should be based on the single best annual emission rate (for the years 2002 to the year when the modification occurs) or the best three consecutive year average emission rate. We also solicit comment on whether there are circumstances where it would not be appropriate to require that the best historical emission rate be made 2 percent more stringent, or where some other increment of additional stringency should be required.

The EPA also seeks comment on including an additional compliance option for modified utility boilers and IGCC units. Specifically, we seek comment on including uniform emission standards that are similar to the standards proposed for reconstructed utility boilers and IGCC units. Specifically, we seek comment on a standard of 1,900 lb CO_2/MWh-net for modified supercritical sources with a heat input rating of greater than 2,000 MMBtu/h and a standard of 2,100 lb CO_2/MWh-net for all modified subcritical sources and for modified supercritical sources with a heat input rating of 2,000 MMBtu/h or less. The EPA further seeks comment on whether this option should be available only to sources that modify before becoming subject to an approved CAA section 111(d) plan or to all modified boilers and IGCC units, regardless of the timing of the modification.

The EPA further solicits comment on whether, in the case of modified utility boilers and IGCC units subject to a CAA section 111(d) plan, there are any circumstances in which the emission limit should be calculated by not including the 2 percent additional emission reduction based on equipment upgrades. This may, for example, be appropriate in cases where the state plan requires heat rate improvements which improve on the source's historical performance, or where the source has recently implemented aggressive measures to improve its operating efficiency, and as a result, the additional 2 percent improvement may be unnecessary or not reasonable.

The EPA also solicits comment on requiring modified utility boilers and IGCC units subject to a CAA section 111(d) plan to take, as their unit-specific emission rate, the lower of (1) the emission rate they are subject to under the CAA section 111(d) plan, or (2) the emission rate that is 2 percent less than the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs. Similarly, the EPA solicits comment on whether modified utility boilers and IGCC units subject to a CAA section 111(d) plan could be evaluated on a case-by-case basis to determine whether, as their CAA section 111(b) standard, they should continue to be subject to the CAA section 111(d) requirements to which they are subject. One method of doing this might be through a delegation of the EPA's CAA section 111(b) authority over that source to the state administering the applicable CAA section 111(d) plan. Under this option the modified utility boilers and IGCC units would be considered to be only ''new sources'' under 111(a)(2).

The EPA further seeks comment on whether the time period of the unit's best demonstrated performance should be limited to the years from 2002 to the time that the unit becomes subject to a CAA section 111(d) plan—rather than to the date that the modification occurs. The EPA also seeks comment on whether the time period for best historic performance should be from 2002 to the date of modification—unless the source can provide evidence of significant heat rate improvements that have already been implemented, in which case the time period would be from the year of the first heat rate improvement to the modification.

The EPA also seeks comment on whether, and under what circumstances, a modified utility boiler or IGCC unit that modifies prior to becoming subject to a CAA section 111(d) plan should also be allowed to meet a emission limit that is determined from the results of an energy assessment or audit. The EPA also requests comment on whether this approach should be limited to sources that may have voluntarily, or for any other reason, implemented energy efficiency measures in the time period between 2002 and the date of the modification and whether those sources should be required to provide evidence of those energy efficiency improvements.

The EPA also solicits comment on whether we should—as we have proposed in this action—have different standards of performance for modified utility boilers and IGCC units depending on whether a CAA section 111(d) plan has been submitted (or a federal plan promulgated). On the one hand, a CAA section 111(d) plan may not necessarily impose obligations on a particular unit. On the other hand, such a plan may impose significant obligations on a particular source, and if that source modifies, it may not be as well positioned to implement additional controls. A state, in developing a CAA section 111(d) plan, may choose to confer with its sources to determine whether any expect to modify, and, if any do, to take that into account in developing the state plan.

2. Emission Standards for Modified Natural Gas-Fired Stationary Combustion Turbines

For affected modified natural gas-fired stationary combustion turbines, this action proposes standards of performance that are based on efficient NGCC technology as the BSER. The emission limits proposed for these

[67] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

sources are 1,000 lb CO_2/MWh-gross for facilities with heat input ratings greater than 850 MMBtu/h, and 1,100 lb CO_2/MWh-gross for facilities with heat input ratings of 850 MMBtu/h or less.[68]

In the companion rulemaking proposing emission guidelines under CAA section 111(d) for CO_2 emissions from existing affected EGUs, the EPA is proposing that an existing source that becomes subject to requirements under CAA section 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction. This is also discussed in greater detail in the Legal Memorandum.[69] Under this interpretation, a modified or reconstructed source would be subject to both (1) the CAA section 111(d) requirements that it had previously been subject to and (2) the modified source or reconstructed source standard under CAA section 111(b) proposed in this rulemaking.

The EPA also solicits comment on an optional alternative method for calculating the emission limit that would be applicable to an affected modified natural gas-fired stationary combustion turbine after that unit becomes subject to a CAA section 111(d) plan. The EPA specifically seeks comment on the option of allowing the affected source to meet a unit-specific emission limit that is determined by the CAA section 111(b) implementing authority from an assessment to identify energy efficiency improvement opportunities for the affected source.

3. Emission Standard for Reconstructed EGUs

Reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating that is greater than 2,000 MMBtu/h would be required to meet a standard of 1,900 lb CO_2/MWh-net. Reconstructed fossil fuel-fired utility boilers and IGCC units with a heat input rating that is 2,000 MMBtu/h or less would be required to meet a standard of 2,100 lb CO_2/MWh-net.

Reconstructed natural gas-fired stationary combustion turbines with a heat input rating greater than 850 MMBtu/h would be required to meet a standard of 1,000 lb CO_2/MWh-gross. Reconstructed combustion turbines with a heat input rating of 850 MMBtu/h or less would be required to meet a standard of 1,100 lb CO_2/MWh-gross.

While the EPA is proposing these standards of performance, we are also taking comment on a range of potential emission limits. Specifically, we solicit comment on the following emission limit ranges:

(1) For reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating that is greater than 2,000 MMBtu/h, a range of 1,700–2,100 lb CO_2/MWh-net;

(2) for reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating of 2,000 MMBtu/h or less, a range of 1,900–2,300 lb CO_2/MWh-net;

(3) for reconstructed stationary combustion turbines with a heat input rating greater than 850 MMBtu/h, a range of 950–1,100 lb CO_2/MWh-gross; and

(4) for reconstructed stationary combustion turbines with a heat input rating of 850 MMBtu/h or less, a range of 1,000–1,200 lb CO_2/MWh-gross.

We also solicit comment on whether: (1) The standards for utility boilers and IGCC units should be subcategorized by primary fuel type, (2) the small utility boiler and IGCC unit subcategory should be limited to utility boilers so that all IGCC units would be in the large subcategory regardless of size, or if there are sufficient alternate compliance technologies (e.g., co-firing natural gas) that the small unit subcategory is unnecessary and should be eliminated so that those sources would be required to meet the same emission standard as large utility boilers and IGCC units, and (3) an annual short-term performance test should be required for stationary combustion turbines in addition to the 12-operating-month rolling average standard. Requiring an initial and annual short term compliance test that is numerically more stringent than the 12-operating-month standard for modified and reconstructed stationary combustion turbines would insure that efficient stationary combustion turbines are installed and properly maintained. The less stringent 12-month rolling average standard would be set at a level that would account for operating conditions where the emission rate is higher than design conditions.

4. Net Output

We are proposing standards for modified and reconstructed units as net output emission rates. We are also requesting comment on using either gross output standards or adjusted gross output based standards in the final rule.[70]

C. Startup, Shutdown and Malfunction Requirements

We are proposing the standards in this rule apply at all times, including during periods of startup and shutdown. This section provides a summary of the requirements.

1. Startups and Shutdowns

Consistent with *Sierra Club* v. *EPA*,[71] 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, which are included in the compliance calculation as periods of partial load. 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 electric 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, during which fuel is combusted and emissions monitors are not out of control, in addition to 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, the impact of these periods on the total average is expected to be minimal.

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 ''any sudden, infrequent, and not reasonably preventable failure of air pollution control 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 operation 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

[68] 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.

[69] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

[70] In the January 8, 2014 proposal for new sources, we proposed standards as gross output emission rates, *See* 79 FR 1447 and 1448. In the rulemaking for existing sources that we are proposing concurrently with this rulemaking, we are proposing emission guidelines that call for state standards as net output emission rates (but seek comment on gross output-based emission rates).

[71] 551 F.3d 1019 (D.C. Cir. 2008).

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. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels EPA to consider such events in setting standards based on the ''best system of emission reduction.'' The ''application of the best system of emission reduction'' is more appropriately understood to include units operating in such a way as to avoid malfunctions.

Further, accounting for malfunctions in setting emission standards 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, emissions during a malfunction event can be significantly higher than emissions at any other time of source operation and thus accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing, non-malfunctioning source. It is reasonable to interpret CAA section 111 to avoid such a result. The EPA's approach to malfunctions is consistent with CAA 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 undertake 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 (containing the definition of malfunction).

Further, to the extent the EPA files an enforcement action against a source for violation of an emission standard, the source can raise any and all defenses in that enforcement action and at federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

In several prior rules, the EPA had included an affirmative defense to civil penalties for violations caused by malfunctions in an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, in ensuring adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included the affirmative defense to provide a more formalized approach and more regulatory clarity. *See Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); *but see Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of ''upsets beyond the control of the permit holder''). Under the EPA's regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the U.S. Court of Appeals for the District of Columbia Circuit vacated such an affirmative defense in one of the EPA's CAA section 112(d) regulations. *NRDC* v. *EPA,* No. 10–1371, 2014 U.S. App. LEXIS 7281 (D.C. Cir. April 18, 2014) (vacating affirmative defense provisions in CAA section 112(d) rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts lies exclusively with the courts, not the EPA. Specifically, the Court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' '' *See also id.* at *21 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.'').[72] In light of *NRDC,* the EPA is not including a regulatory affirmative defense provision in this rulemaking. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate. Further, as the DC Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. *Cf.id.* at *24. (stating that arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same logic applies to EPA administrative enforcement actions.

D. Continuous Monitoring Requirements

We are proposing the same monitoring requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR 1450 and 1451.

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

[72] The court's reasoning in *NRDC* focuses on civil judicial actions. The court noted that ''EPA's ability to determine whether penalties should be assessed for Clean Air Act violations extends only to administrative penalties, not to civil penalties imposed by a court.'' *Id.*

measure CO_2 concentration, stack gas flow rate, and (if needed) stack gas moisture content in accordance with 40 CFR part 75, in order to determine hourly CO_2 mass emissions rates (tons/h).

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 CO_2 mass emissions rates using Equation G–4 in Appendix G to 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 to part 75.

In addition to requiring monitoring of the CO_2 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 40 CFR 75.53(g) and (h). Further, all monitoring systems used to determine the CO_2 mass emission rates would have to be certified according to section 75.20 and section 6 of part 75, Appendix A within the 180-day window of time allotted under section 75.4(b), and would be required to meet the applicable on-going quality assurance procedures in Appendices B and D to part 75.

The proposed rule would require only those operating hours in which valid data are collected and recorded for all of the parameters in the CO_2 mass emission rate equation to be used for compliance purposes. Additionally for EGUs using CO_2 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.

Certain variations from and additions to the basic Part 75 monitoring would be required and are detailed in the January 2014 proposal (*See* 79 FR 1451).

Special compliance provisions for units with common stack or multiple stack configurations, consistent with section 60.13(g), would be required and are detailed in the January 2014 proposal (see 79 FR 1451).

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 CO_2 mass emissions. EGU owners or operators would have the option to use backup monitoring systems, as provided in sections 75.10(e) and 75.20(d), to help meet this proposed data capture requirement.

We are proposing two additional amendments to the monitoring requirements. First, we are proposing that measurements of electricity output (both gross and net) be measured using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Second, we are proposing that hours with no gross generation or where the gross generation is less than the auxiliary loads be reported as zero instead of a negative value.

Steam is the most common type of useful thermal output for NSPS purposes. The amount of useful energy flowing in a steam header is measured with the following components: a flow meter (to determine the volumetric flow rate of steam in cubic meters per hour or the mass flow rate in kilograms per hour), a thermocouple or resistance temperature detector (to determine the temperature of the steam), and an electromechanical transmitter (to determine the pressure of the steam). The accuracy of the measurement of useful thermal energy calculation is the product of the accuracies of the flow, temperature, and pressure measurements. The January 2014 proposal includes requirements for the measurement of useful thermal output from CHP systems, but does not include associated specifications for quality assurance of the underlying flow, temperature, and pressure measurements. The EPA is considering and soliciting comment on requiring that manufacturers' maintenance recommendations be followed and include, at a minimum, annual inspection and calibration requirements for the flow meters, thermocouples or resistance temperature detectors (RTDs), and electromechanical transmitters used to acquire the steam flow rates and properties integral to calculation of useful thermal output.

The EPA is soliciting information on: (1) The technologies that are appropriate for continuous monitoring of useful thermal output, and (2) whether the EPA should specify the technologies to be used. For example, should technology choices be limited to ultrasonic, coriolis, averaging pitot tube with 2 differential pressure cells, or shedding vortex since they appear to be the most accurate? The EPA is also soliciting information on the costs of operating these systems, including ongoing maintenance, calibration intervals, and other quality assurance costs. Finally, with regard to the quality assurance requirements for continuous monitoring of useful thermal output, the EPA is soliciting comment on the appropriate ASTM, ANSI, or ASME standards (e.g., ASME PTC 4–2013, ASME PTC 19.5–2004 and ASME MFC–6–2013) that should be incorporated by reference into the final standards of performance. This would be an alternative to specifying technologies in order to ensure monitoring data are of sufficient quality for demonstrating compliance with the proposed efficiency standards.

E. Emissions Performance Testing Requirements

We are proposing the same emissions performance testing requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR 1451.

In accordance with section 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 section 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). 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 section 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.

F. Continuous Compliance Requirements

We are proposing the same continuous compliance requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal.

This section provides a summary of the requirements. For additional detail, see 79 FR 1451.

Today's proposed rule specifies that compliance with the 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 CO_2 mass emissions rate.

The proposed rule specifies that the first operating month included in the initial 12-operating-month compliance period would be the month in which reporting of emissions data is required to begin under section 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 CO_2 mass emissions values by the total gross output for the 12-operating-month period. Affected EGUs would continue to be subject to the standards and maintenance requirements in the CAA section 111 regulatory general provisions contained in 40 CFR part 60, subpart A.

G. Notification, Recordkeeping and Reporting Requirements

We are proposing the same notification, recordkeeping and reporting requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR 1451 and 1452.

Today's proposed rule would require an EGU owner or operator to comply with the applicable notification requirements in sections 60.7(a)(1) and (a)(3), section 60.19 and section 75.61. 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 CO_2 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 CO_2 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 CO_2 mass emissions and gross output for each operating month. Records would be kept of the calculations performed to determine the average CO_2 mass emission rate (kg/MWh) and the percentage of valid CO_2 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).

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 Emissions Collection and Monitoring Plan System (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 CO_2 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 that quarterly electronic ''excess emissions'' reports be submitted using ECMPS, within 30 days after the end of each quarter. Reporting the percentage of valid CO_2 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.

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

A. Rational Basis and Endangerment Finding

In the January 2014 proposal, the EPA proposed that, in order to regulate GHG from newly constructed fossil fuel-fired EGUs, the EPA needed a rational basis, but that CAA section 111 did not require an endangerment finding. The EPA further proposed that even if CAA section 111 did require such a finding, the EPA's rational basis would qualify as one. The EPA expects to finalize the January 2014 proposal by the time that it finalizes this proposed rulemaking for affected modified and reconstructed fossil fuel-fired EGUs, and in that event, the EPA would not be required to further address the rational basis or endangerment finding in this rulemaking.

However, because this rulemaking is a separate action from the January 2014 proposal, the EPA is making the same proposal—that the EPA has a rational basis for this rulemaking, and that no endangerment finding is required, but that if one is, the EPA's rational basis would qualify as one—which it made in the January 2014 proposal. *See* 79 FR 1452 through 1456.

B. Source Categories

This proposal addresses the same two source categories—fossil fuel-fired steam generating units (utility boilers and IGCC units) and natural gas-fired stationary combustion turbines—that were addressed by the January 2014 proposal. In the January 2014 proposal, the EPA included a proposal and co-proposal for the treatment of the two affected source categories, and for how the regulatory requirements applicable to these source categories would be codified in 40 CFR part 60. Specifically, the EPA proposed to create subcategories within each category, and to codify the regulatory requirements for each subcategory in 40 CFR part 60, subparts Da and KKKK, respectively. In addition, the EPA co-proposed to combine the two categories for purposes of regulating the CO_2 emissions, and to codify all the CO_2 regulatory requirements in a new subpart, TTTT.

As noted, the EPA expects to finalize the January 2014 proposal by the time that it finalizes this proposed rulemaking for modified and reconstructed fossil fuel-fired EGUs. It is the EPA's intent that the approach for categorization and codification will be the same in the final action for this proposal as is finalized for the January 2014 proposal. However, because this rulemaking is a separate action from the January 2014 proposal, the EPA is making the same proposal and co-proposal with regard to categories and codification for modified and reconstructed sources that it made with regard to new construction sources in the January 2014 proposal. That is, the EPA proposes to create subcategories within each category and to codify the regulatory requirements in 40 CFR part 60, subparts Da and KKKK, respectively; and in addition, the EPA co-proposes to combine the two categories for purposes of regulating CO_2 emissions, and to codify all the CO_2 regulatory requirements in a new subpart TTTT. *See* 79 FR 1452 through 1454.

V. Rationale for Applicability Requirements

The rationale for several of the proposed applicability requirements for modified and reconstructed sources is the same as that in the January 2014 proposal. This section provides a summary of the rationale for these requirements along with rationale for differences with the applicability included in the January 2014 proposal. In addition, we are soliciting comment on multiple alternative approaches to the applicability criteria.

The following four proposed applicability criteria are consistent with the January 2014 proposal. First, this proposal includes within the definition of a utility boiler, IGCC unit, and stationary combustion turbine that is 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. Also consistent with the January 2014 proposal, we are considering including in the definition of the affected facility co-located non-emitting energy generation equipment included in the facility operating permit but that is not integrated into the operation of the affected facility.

Second, 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. 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.

Third, we are proposing to apply the one-third sales criterion on a rolling 3-year basis instead of an annual basis for stationary combustion turbines for multiple reasons. First, extending the period to 3 years would ensure that the CO_2 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. Second, only 0.2 percent of existing simple cycle turbines had a 3-year average capacity factor of greater than one-third between 2000 and 2012. We are soliciting comment on ways to address potential complications resulting from having different time periods for applicability and the actual emission standard. For example, a stationary combustion turbine that runs at a 60 percent capacity factor for years one and two but only a 5 percent capacity factor on year three would meet the proposed applicability requirements for all 3 years (since applicability is determined on a 3-year rolling average basis). However, the emission standard is on a 12-month rolling average basis and if the hours of operation on year three are even and spread out in each month the facility likely operated at low loads and may have difficulty achieving the proposed standard. This could be further complicated if the facility burned fuels other than natural gas during year 3 since the 90 percent natural gas applicability would still apply even though other fuels were burned during the emissions standard period.

Finally, 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. 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.

The rationale for following applicability criteria is different from the January 2014 proposal. To clarify that existing boiler and IGCC facilities would continue to be included in CAA section 111(d) state programs regardless of their actual electric sales or fossil fuel use, we are deleting the criteria to be considered an EGU. These criteria include that the facility must (1) actually sell one-third of their potential electric output and 219,000 MWh on an annual basis and (2) the applicability exemption for facilities, than burn fossil fuel for 10 percent or less of the heat input during a 3-year rolling average period. The sales criteria exemption was intended to exempt low capacity factor facilities since they would have additional difficulties meeting the standards in the January 2014 proposal. However, the proposed standards for boilers and IGCC facilities in this rulemaking are less stringent and are achievable by low capacity factor facilities, so the applicability exemption would not be applicable. The low fossil use exemption was designed to exempt facilities that are capable of combusting fossil fuel, but burn primarily non fossil fuels. These facilities (e.g., wood-fired EGUs) typically are inherently less efficient than fossil fuel-fired EGUs, and we are soliciting comment on if we should subcategorize boilers and IGCC facilities where fossil fuel consists of 10 percent or less of the heat input during. In the event we establish a subcategory, should the heat input be determined on an annual or 3-year rolling period and should the standard be an alternate numerical limit or ''no emission standard.''

In the January 2014 proposal, we also solicit comment on various issues concerning, and different approaches to, the applicability requirements for steam generating units and combustion turbines.[73] For additional detail, see 79 FR 1459 through 1461. We are soliciting comment on additional approaches to address potential unintended negative environmental impacts and to address issues concerning how the general applicability of the CAA section 111(b) NSPS potentially impacts the CAA section 111(d) rulemaking, since only EGUs that would be included under the CAA section 111(b) applicability if they were newly constructed, modified or reconstructed are included in the state CAA section 111(d) goals.

In the January 2014 proposal, we proposed a dual electric sales applicability criterion for stationary combustion turbines of 219,000 MWh and 33 percent sales of potential electric output on a 3-year rolling average basis. In addition, we specifically solicited comment on a range of 20 to 40 percent sales of potential electric output. However, the dual electric sales applicability could potentially result in

[73] Requests for comment in the January 2014 proposal regarding the appropriateness of certain applicability requirements that are based on a source's operations do not apply to this proposed rulemaking. Whereas newly constructed sources would not have a history of operating, in this rulemaking, the affected sources that would be undertaking modifications or reconstructions do have an operating history.

the installation, modification or reconstruction of smaller, less efficient simple cycle combustion turbines rather than larger, more efficient simple cycle combustion turbines. For simple cycle combustion turbines that are smaller than approximately 70 MW, the 219,000 MWh sales would be the determining criteria for whether the facility is subject to an emission standard. Smaller EGUs can sell over one-third of their potential electric output and still not be subject to a GHG emission standard. This could potentially place larger, more efficient simple cycle combustion turbines at a disadvantage since they would be limited to selling less (e.g., one-third) of their potential electric output. This could result in higher GHG emissions, and we are soliciting comment on approaches to minimize this outcome. One approach we are considering is changing the ''one-third potential electric output'' sales criteria to ''the design net efficiency times the potential electric output'' for simple cycle combustion turbines. This would have the effect of allowing the most efficient larger simple cycle combustion turbines currently available to sell approximately 38 percent of their potential electric output on a 3-year rolling average before an emission standard would apply. The smallest aeroderivative stationary combustion turbine designs have efficiencies of approximately 30 percent or greater, but these combustion turbine engines are smaller in size and the 219,000 MWh sales limit would still be the controlling criterion. Lower efficiency industrial frame turbines have efficiencies of approximately 28 percent. Therefore, in this approach, applicability with an emission standard would in general increase the electric sales criteria for the larger, more efficient aeroderivative simple cycle combustion turbines and decrease it larger, less efficient industrial frame simple cycle turbines. We are soliciting comment on if this change would be sufficient to avoid the potential adverse environmental impact mentioned previously or if a multiplication factor, such as 1.1 (we are soliciting comment on an appropriate factor), should be applied to the design net efficiency to determine the percent sales applicability criterion. The percent electric sales criterion would read, for example, ''1.1 times the design net efficiency times the potential electric output'' for simple cycle combustion turbines. The result of this approach is that the most efficient simple cycle turbines would be able to sell approximately 42 percent of their potential electric output prior to becoming subject to a GHG standard. Conversely, the least efficient simple cycle turbines would be limited to selling 31 percent of their potential electric output prior to becoming subject to a GHG standard. The 42 percent sales criterion is approximately equivalent to allowing 4,000 hours of operation on a 3-year average at 90 percent load before a GHG standard would apply. We are also soliciting comment on eliminating the additional 219,000 MWh sales criterion for stationary combustion turbines so that stationary combustion turbines would be subject to a GHG emission standard once they sell the specified percentage of potential electric output to the grid. This would eliminate any incentive to install multiple smaller, less efficient stationary combustion turbines rather than fewer larger, more efficient stationary combustion turbines. This approach would recognize the environmental benefit of installing more efficient simple cycle turbines regardless of size. However, this change could also potentially cover a larger percentage of industrial combined heat and power facilities. We are therefore soliciting comment on if the 219,000 MWh electric sales criterion should only be eliminated for non-CHP stationary combustion turbines. As an alternative, we are soliciting comment on an applicability exemption, and the criteria for that exemption, for highly efficient CHP facilities.

We are also soliciting comment on whether the percent sales of potential electric output is sufficient to account for the potential increased use of simple cycle combustion turbines due to the expected increased percentage of electricity generated from renewable generation in the future. Due to the intermittent nature of some renewable technologies, such as wind and solar, the electric grid must be balanced by using some type of quick response backup generation or rapid reductions in load. The EPA is soliciting comment on the extent to which simple cycle combustion turbines will be used to support additional renewable generation. We also solicit comment on the ability, relative costs and overall GHG emissions of energy storage systems (e.g., utility battery stations or flywheels) and on demand response programs to balance demand and generation from renewable electricity generation.

In addition, some of the initial feedback we received in public comments[74] on the January 2014 proposal suggests that the emissions data that the EPA used in developing the natural gas-fired stationary combustion turbine standards do not completely account for degradation in performance over the entire life of an NGCC. Also, commenters noted that NGCC units are expected to operate differently in the future due to the increased percentage of power generated from renewable sources, such as wind and solar. In addition, initial feedback suggested that the size distinction between large and small stationary combustion turbines should be adjusted.

The EPA is soliciting comment on whether a separate standard should be established for load-following (i.e., intermediate capacity factor) NGCC EGUs. The more stringent standard would apply only during periods of high annual capacity factors and a less stringent standard would apply during periods of intermediate load (e.g., when electric sales are between 33 to 60 percent of the potential electric output). This approach addresses two potential issues with the standards in the January 2014 proposal. First, certain NGCC units are designed to be highly efficient when operated as load-following units, but these design characteristics reduce the efficiency at base load. Conversely, the NGCC units with the highest base load design efficiencies are not necessarily as efficient as NGCC designed and intended to be used as load-following EGUs. Therefore, a full-load efficiency performance test would not necessarily result in the lowest CO_2 emissions in practice. Second, NGCC units operating as load-following EGUs are inherently less efficient than NGCC units operating at base load. Establishing a standard that varies with load would assure that NGCC units that are operated as base load units are as efficient as possible and still account for inherent lower efficiencies at part-load conditions.

We are requesting comment on a full range of alternatives for low capacity factor stationary combustion turbines and/or simple cycle combustion turbines to the general applicability thresholds we proposed in the January 2014 proposal. This includes soliciting comment on whether we should: Establish a separate numerical limit for low capacity factor stationary combustion turbines and/or simple cycle combustion turbines; exempt all such units; set a higher capacity factor threshold applicable to all simple cycle turbines; establish a variable capacity

[74] All public comments on the January 2014 proposal are available in the rulemaking docket, Docket ID: EPA–HQ–OAR–2013–0495.

factor that would allow more efficient, lower emitting turbines to run and be permitted for longer periods of operation (e.g., a higher capacity factor for the most efficient turbines being progressively lowered for lower efficiency turbines); or establish a CO_2 emission limitation in the form of an annual tonnage cap based on allowable emissions from smaller, less efficient units that do not exceed the 33 percent and 219,000 MWh thresholds regardless of hours operated. The EPA is considering all these options in its treatment of simple cycle combustion turbines and solicits comments on the merits of these options or variations of them. The EPA intends—when it takes final action on this proposal and on the January 2014 proposal for newly constructed sources—to finalize the same standards and applicability criteria for newly constructed, modified and reconstructed natural gas-fired stationary combustion turbines.

Consistent with the January 2014 proposal, the EPA is proposing the size distinction between large and small combustion turbines be a base load heat input rating of the combustion turbine engine of 850 MMBtu/h. As explained in the January 2014 proposal, this distinction is consistent with the criteria pollutant NSPS for stationary combustion turbines, which was based on the largest aeroderivative turbine design available at the time. However, incremental adjustments have been made to aeroderivative designs and the base load rating of the largest aeroderivative turbines now exceeds 850 MMBtu/h. The EPA is soliciting comment on increasing the size distinction between large and small stationary combustion turbines to 900 MMBtu/h to account for larger aeroderivative designs or to 1,000 MMBtu/h to account for future incremental increases in base load ratings. Alternately, the EPA is soliciting comment on increasing the size distinction to between 1,300 to 1,800 MMBtu/h. There are currently no combined cycle combustion turbines offered with turbine engine base load rating between those sizes.

VI. Rationale for Emission Standards for Reconstructed Fossil Fuel-Fired Utility Boilers and IGCC Units

A. Overview

In this section, we explain our rationale for emission standards for reconstructed fossil fuel-fired utility boiler and IGCC units, which are based on our proposal that the most efficient generating technology is the BSER for these types of units.

CAA section 111(b)(1)(B) authorizes the EPA to promulgate ''standards of performance'' for new sources, including modified and reconstructed sources. The CAA directs that standards of performance must consist of emission limits that are based on the ''best system of emission reduction . . . adequately demonstrated,'' taking into account cost and other factors. In this manner, CAA section 111 provides that the EPA's central task is to identify the BSER.

Over a 40-year period, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit or Court) has issued a number of decisions interpreting this CAA provision, including its component elements.[75] Consistent with this case law, the EPA determines the best demonstrated system based on the following key considerations, among others:

- The system of emission reduction must be technically feasible.
- The EPA must consider the amount of emissions reductions that the system would generate.
- The costs of the system must be reasonable. The 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.[76]
- The EPA must also consider that CAA section 111 is designed to promote the deployment, development and implementation of technology.[77] [78]

Other considerations are also important, including that the 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, the 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. The EPA discussed the CAA requirements and Court interpretations of the BSER at length in the January 2104 proposal, 79 FR 1462 through 1467, and incorporates by reference that discussion in this rulemaking.

It should be noted at the outset that the EPA determined that reconstructions are a type of construction, and therefore subject to CAA section 111(b), as part of the 1975 framework regulations, and the EPA is not re-opening that determination.[79] The EPA also defined reconstructions in those regulations, and the EPA is not reopening that definition in this rulemaking. These provisions have two main specifications: (1) That reconstruction occurs upon replacement of components if the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct an entirely new comparable facility, and, (2) that it is technologically and economically feasible for the facility to comply with the applicable standards of performance after the replacements. 40 CFR 60.15. These reconstruction provisions have not been amended since originally promulgated in 1975, and have been implemented for numerous source categories.

B. Identification of Best System of Emissions Reduction

The EPA evaluated seven different control technology configurations as potentially representing the BSER for reconstructed fossil fuel-fired boiler and IGCC EGUs: (1) The use of partial CCS, (2) conversion to (or co-firing with) natural gas, (3) the use of CHP, (4) hybrid power plants (5) reductions in generation associated with dispatch changes, renewable generation, and

[75] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Portland Cement Association* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011).

[76] As discussed in the January 2014 Proposal, the D.C. Circuit's case law formulates the cost consideration in various ways: The costs must not be ''exorbitant [ ]'', *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), *see Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999); ''greater than the industry could bear and survive,'' *Portland Cement Association* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975); or ''excessive'' or ''unreasonable.'' *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981). In the January 2014 Proposal, EPA stated that ''these various formulations of the cost standard . . . are synonymous,'' and, for convenience, EPA used ''reasonableness'' as the formulation. EPA takes the same approach in this proposal.

[77] See discussion of case law and legislative history in the January 2014 proposal. 79 FR 1430, 1465 (cols.1–2) (January 8, 2014).

[78] It should be noted that in one of the earliest cases, *Essex Chemical Corp.* v. *Ruckelshaus,* in 1973, the Court stated that because the standard must be ''achievable,'' the emission limits must be technically feasible, and added that ''[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 427. This case law may be read to treat technical feasibility as the measure for whether the standard of performance is ''achievable,'' not as a criteria for whether the system of emission reduction is the ''best system of emission reduction . . . adequately demonstrated.'' However, for convenience, we may refer to technical feasibility as another of the criteria for the BSER.

[79] 40 FR 58417–58418, December 16, 1975 (final NSPS modification, notification, and reconstruction provisions).

demand side energy efficiency,(6) efficiency improvements achieved through the use of the most efficient generation technology, and (7) efficiency improvements achieved through a combination of best operating practices and equipment upgrades.[80]

We discuss each of these alternatives below, and explain why we propose that for reconstructed fossil fuel-fired boiler and IGCC EGUs the most efficient generating technology qualifies as the BSER.

1. Partial CCS

We considered the implementation of partial CCS as the BSER at affected reconstructed utility boilers and IGCC units. In the January 2014 proposal (79 FR 1430), the EPA found that, for new units, partial CCS has been adequately demonstrated and is technically feasible; it can be implemented at costs that are not unreasonable; it provides meaningful emission reductions; its implementation will serve to promote further development and deployment of the technology; and it would not have a significant impact on nationwide energy prices. The EPA also noted in the January 2014 proposal that most of the relatively few new projects that are in the development phase are already planning to implement CCS, so that partial CCS was consistent with current industry trends.

Partial CCS has been demonstrated at some existing EGUs. It has been demonstrated at a large pilot scale (e.g., 20 MW or greater) at two facilities: At Southern Company's Plant Barry and at AEP's Mountaineer Power Plant. A full scale, 110 MW project is currently being retrofitted at SaskPower's Boundary Dam coal-fired EGU in Canada and is expected to begin operation in 2014. Another large scale retrofit project (240 MW) is in advanced stages of project development at NRG Energy's WA Parish facility. There are also a number of smaller examples of CCS retrofits on coal-fired power plants.[81]

However, the EPA does not, at present, have sufficient information about costs to propose that partial CCS is the BSER for reconstructed utility boilers and IGCC units. Utility boilers are numerous and diverse in size and configuration, and the EPA does not have sufficient information about the range of specific configurations that would be necessary to estimate the cost of partial CCS, on either a source-specific basis or an industry-wide basis. In particular, retrofitting a plant with partial CCS would entail integrating the carbon capture equipment with the affected unit's steam cycle (or with an external source of steam or heat) in order to release the captured CO_2 and regenerate the solvent or sorbent. The cost of a retrofit would depend on many site-specific details, including the space available for the capture equipment, and the EPA lacks information on such details for a significant portion of the industry.

Therefore, the EPA does not propose to find that partial CCS is the BSER for CO_2 emissions from reconstructed fossil fuel-fired utility boilers and IGCC units.

2. Conversion to or Co-Firing With Natural Gas

While conversion to or co-firing with natural gas in a utility boiler is a technically feasible option to reduce CO_2 emission rates, it is an inefficient way to generate electricity compared to use of an NGCC and the resultant CO_2 reductions are relatively expensive. The EPA found costs for natural gas co-firing to range from approximately $83/ton to $150/ton of CO_2 avoided.[82] Even for cases where the natural gas could be co-fired without any capital investment or impact on the performance of the affected facility (e.g., an existing IGCC facility that already has a sufficient natural gas supply), the costs of CO_2 reduction would still be approximately $75/ton of CO_2 avoided. Therefore, we are not proposing natural gas co-firing as part of the BSER for modified or reconstructed steam generating units.

However, we specifically solicit comment on whether natural gas reburning (NGR) and/or similar technologies[83] should be included as part of the BSER for reconstructed utility boilers and IGCC units. NGR is a combustion technology in which a portion of the main fuel heat input is diverted to locations above the burners, creating a secondary combustion zone called the reburn zone. In NGR, the secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. Overfire air (OFA) is added above the reburn zone to complete burnout. As flue gas passes through the reburn zone, part of the NO_X formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen (N_2). With NGR at 15 and 20 percent of the heat input to a coal-fired boiler, the CO_2 emission rate would be reduced by 6 percent and 8 percent, respectively. In addition to reducing CO_2 emissions, a potential financial benefit of NGR compared to natural gas co-firing is the generation of additional NO_X reductions. These reductions could reduce costs a source is currently paying for compliance with NO_X requirements, including operations and maintenance costs associated with existing controls such as selective catalytic reduction systems and/or the cost of emission allowances under certain pollution control programs.

The EPA also requests comment on whether there are other factors or technologies related to co-firing that reduce its cost, and whether for these or other reasons, co-firing should be considered as BSER for reconstructed fossil fuel-fired electric utility steam generating units.

3. CHP

CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP reduces air pollution and greenhouse gas emissions. CHP has lower emission rates and can be more economic than separate electric and thermal generation. However, not all potentially modified and reconstructed utility boilers and IGCC units are located close enough to thermal hosts to economically or efficiently use the recovered thermal energy. Therefore, we are not proposing to find that CHP is the BSER for reconstructed utility boilers and IGCC units or stationary combustion turbines.

4. Hybrid Power Plant

Hybrid power plants combine two or more forms of energy input into a single facility with an integrated mix of complementary generation methods. While there are multiple types of hybrid power plants, the most relevant type for this proposal is the integration of solar energy (e.g., concentrating solar thermal with or without photovoltaic generation) with a fossil fuel-fired EGU.

[80] Note that we also evaluated these seven different technology configurations as potentially representing BSER for modified utility boilers and IGCC units. The subsequent discussion of each of these is also applicable for that evaluation as well.

[81] Technical Support Document, ''Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs,'' available in rulemaking docket ID: EPA–HQ–OAR–2013–0495.

[82] Chapter 2, GHG Abatement Measures Technical Support Document, available in Docket EPA–HQ–OAR–2013–0602.

[83] Fuel lean gas reburning (FLGR™), also known as controlled gas injection, similar to NGR. In FLGR™, natural gas is injected above the main combustion zone at a lower temperature zone than in NGR and avoids creating a fuel-rich zone and maintains overall fuel-lean conditions. The FLGR™ technology is reported to achieve NO_X control comparable to NGR using less than 10% natural gas heat input without the requirement for OFA. At a 10 percent heat input reburn rate, the CO_2 emission rate of a coal-fired EGU would be reduced by 4 percent.

Both coal-fired and NGCC EGUs have demonstrated the technical feasibility of integrating concentrating solar thermal energy for use in boiler feed water heating, preheating makeup water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps. While hybrid power plants can reduce the CO_2 emission rate by several percent compared to similar non-hybrid power plants, not all modified and reconstructed EGUs may have the space or meteorological conditions to generate enough solar thermal energy to successfully convert to a hybrid power plant. Solar thermal facilities require abundant sunshine and significant land area and the EPA does not have sufficient information about the range of specific configurations that would be necessary to estimate the cost of implementation, on either a source-specific basis or an industry-wide basis. We solicit comment on whether hybrid power plant technology is broadly applicable to modified and reconstructed EGUs and on the costs of integrating non-emitting generation.

Our understanding is that one of the benefits of hybrid fossil EGUs is decreased incremental cost of the non-emitting (e.g., solar thermal) generated electricity due to the ability to use equipment (e.g., HRSG, steam turbine, condenser, etc.) already included at the fossil fuel-fired EGU, as well as improvement of the electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces steam at relatively low temperatures and pressures and the conversion efficiency of the thermal energy in the steam to electricity is relatively low. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HRSG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low grade steam produced by the solar thermal facility improves the relative conversion efficiencies of the solar thermal to electricity process. The primary incremental costs of the non-emitting solar thermal generation in a hybrid power plant is the costs of the mirrors, additional piping, and a steam turbine that is 10 to 20 percent larger than a comparable fossil only EGU to accommodate the additional steam load during sunny hours.

We specifically solicit comment on an alternate, but similar, approach for modified and reconstructed fossil fuel-fired EGUs to integrate lower emitting generation. The recovered thermal energy from natural gas-fired combustion turbines, fuel cells, or other combustion technology could be used to reheat or preheat boiler feed water (minimizing the steam that is otherwise extracted from the steam turbine), preheat makeup water and combustion air, produce steam for use in the steam turbine or to power the boiler feed pumps, or use the exhaust directly in the boiler to generate steam. In theory, this could lower generation costs as well the GHG emissions rate for a coal-fired EGU. However, at this time we do not have sufficient information on the costs or technical feasibility of this approach to include it as the BSER for reconstructed fossil fuel-fired utility boilers.

5. Reductions in Generation Associated With Dispatch Changes, Renewable Generation, and Demand Side Energy Efficiency

In the companion proposal in today's **Federal Register**, which proposes emission guidelines for existing fossil fuel-fired EGUs, the EPA considered numerous measures that can and are being implemented to improve emission rates and to limit overall CO_2 emissions from fossil fuel-fired EGUs. The EPA grouped those measures into four main categories, or ''building blocks.'' The EPA proposed that each of the building blocks represents a method of CO_2 emission reduction at existing fossil fuel-fired EGUs that, when combined with the other building blocks, represent the ''best system of emission reduction . . . adequately demonstrated'' for existing fossil-fuel-fired EGUs under a 111(d) program. The building blocks are:

1. Lowering the carbon intensity of generation at individual affected EGUs (e.g., through heat rate improvements);
2. Reducing emissions of the most carbon-intensive affected EGUs to the extent that this can be accomplished cost-effectively by shifting generation to less carbon-intensive existing NGCC units, including NGCC units that are under construction;
3. Reducing emissions of carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by expanding the amount of new, lower (or no) carbon-intensity generation; and,
4. Reducing emissions of carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by increasing demand-side energy efficiency.

In this rulemaking, we are, in effect, utilizing building block one—lowering the carbon intensity of generation at individual affected EGUs through heat rate improvements—as part of the BSER determination for modified units, but we are not proposing that building blocks two, three, or four are components of the BSER determination. We solicit comment on whether building blocks two, three and four would be appropriate in light of the fact that, unlike the CAA section 111(d) emission guidelines proposal, which will result in state plans that cover all existing sources, this proposal will result in a federal rule that covers only those sources that modify or reconstruct. We note that it is not possible in advance to determine which sources will do so. We solicit comment on any additional considerations that the EPA should take into account in the applicability of building blocks two, three and four in the BSER determination.

6. Efficiency Improvements Achieved Through the Use of the Most Efficient Generation Technology

We also considered whether the proposed emission limit for reconstructed fossil fuel-fired utility boilers and IGCC units should be based on the performance of the most efficient generation technology available, which we believe is a supercritical pulverized coal (SCPC) or supercritical circulating fluidized bed (CFB) boiler for large sources, and subcritical for small sources. We propose to find that these technologies meet the criteria for the BSER.[84]

a. Technical Feasibility

The use of supercritical steam conditions has been demonstrated by many facilities since the 1960s for both large and small EGUs. In fact, the world's first commercial supercritical pressure EGU was the 125 MW Philo Unit 6 that commenced operation in 1957. Currently commercially available materials capable of tolerating steam conditions of 30 megapascal (MPa) (4,350 psi) and 605 °C (1,120 °F) have been demonstrated at coal-fired EGUs. In addition, even though the majority of recently constructed coal-fired EGUs use a single steam reheat cycle, the use of a dual steam reheat cycle has been demonstrated by multiple facilities as technically feasible. For a facility to be considered reconstructed for NSPS purposes, the boiler itself would have to be substantially refurbished. As part of a reconstruction, an owner/operator would be able to replace the steam tubing and other necessary equipment to allow the use of the best demonstrated steam cycle. Therefore, this option is technically feasible.

[84] Note that the discussion of efficiency improvements in this section is limited to reconstructed utility boilers and IGCC units. We discussed efficiency improvements for modifications below.

It should be noted that this approach identifies as the BSER changes in production technology that would result in fewer emissions, and not add-on technology that would control emissions. The kraft pulp mill NSPS (40 CFR part 60, subpart BB) is an example in which different equipment design (rather than add-on control) is the BSER for a modification or reconstruction.

b. CO_2 Reductions

The U.S. Department of Energy National Energy Technology Laboratory (DOE/NETL) has estimated that a new SCPC boiler using subbituminous coal would emit 7 percent less CO_2 per MWh than a comparable subcritical boiler. Therefore, we estimate that this standard will result in reduction in emissions of at least 7 percent when compared to the expected emissions of a reconstructed EGU using subcritical steam conditions. Smaller EGUs often use relatively low steam parameters and increasing the steam parameters to the maximum subcritical steam parameters reduces the CO_2 emissions rate. The average steam pressure and temperature for small EGUs that were reported to the information collection request associated with the Mercury and Air Toxics Standards rulemaking is 11 MPa (1,630 pounds per square inch guage (psig)) and 527 °C (980 °F) and 40 percent have no steam reheat. Increasing the steam pressure to 20 MPa (2,900 psig) and 568 °C (1,054 °F) would reduce the CO_2 emission rate by 6 percent. In addition, the use of a single steam reheat cycle reduces the CO_2 emission rate by 10 percent compared to an equivalent EGU without a steam reheat cycle.

While the percent reduction in CO_2 emissions rate using efficiency improvements achieved through the use of the most efficient generation technology is less than could be achieved by a number of the other alternatives for the BSER that the EPA considered, as noted above, those other alternatives do not meet other criteria for the BSER. Efficiency improvements achieved through the use of the most efficient generation technology do achieve the greatest emission reductions of any of the remaining alternatives that the EPA is considering.

c. Costs, Structure of the Energy Sector

DOE/NETL has estimated, based on the levelized cost of electricity (LCOE), that the capital costs of a SCPC EGU are approximately 3 percent more than a comparable subcritical EGU. In fact, the reduced fuel costs are significant enough that the overall cost to generate electricity is actually lower for a SCPC EGU compared to a subcritical EGU. Therefore, the emission reductions are considered cost effective for larger EGUs.

For smaller boilers, less than approximately 200 MW, it is the understanding of the EPA that manufacturers of steam turbines do not currently offer turbines that have been thermodynamically optimized to use supercritical steam conditions. Instead, for smaller applications, they would typically adapt their larger turbines for the application. The resulting designs have a higher cost premium than larger supercritical steam turbines and do not take full advantage of the potential efficiency improvements and the benefits of using a supercritical steam cycle are reduced. Therefore, for smaller reconstructed EGUs the EPA has determined that the BSER is the use of highest available subcritical steam conditions. The maximum viable subcritical steam parameters are 21 MPa (3,000 psi) and 570 °C (1,060 °F). The EPA specifically solicits comment on the efficiency benefits and the costs of using supercritical steam conditions for smaller EGU designs. Modern materials are widely available that can tolerate the maximum subcritical steam parameters. Therefore, we anticipate the incremental cost of increasing steam parameters within subcritical conditions is low. We solicit comment on these costs.

Designating the most efficient generation technology as the BSER for reconstructed 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 the use of efficient generation will, on a nationwide basis, be small because few reconstructed coal-fired projects are expected and because at least some of these reconstructions can be expected to incorporate the most efficient generation technology even in the absence of a standard.

For the same reason, designation of the most efficient generation technology as the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units will not have adverse effects on the structure of the power sector, will not impact fuel diversity, and will not have adverse effects on the supply of electricity.

d. Incentive for Technological Innovation

As noted above, the case law makes clear that the EPA is to consider the effect of its selection of BSER on technological innovation or development, but that the EPA also has the authority to weigh this factor along with the other ones. When it comes to the selection of the BSER, the EPA recognizes that reconstructed sources face inherent constraints that newly constructed greenfield sources do not; as a result, reconstructed sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, identifying the most efficient generation technology as the BSER promotes the further extension of that technology throughout the industry.

While some of the other options that the EPA considered in determining the BSER for reconstructed utility boilers and IGCC units would have led to greater opportunities for technology advancement, for the reasons discussed above, those other options did not meet other criteria. While the proposed standard is based on the use of the best available steam cycle, other energy efficiency measures will likely be developed and used (improved economizers, etc.) and these technologies will be transferrable to other EGUs.

7. Efficiency Improvements Achieved Through a Combination of Best Operating Practices and Equipment Upgrades

The EPA also considered whether a combination of best operating practices and equipment upgrades would qualify as the BSER for a reconstruction. These measures are discussed in greater detail in Section VII of this preamble. A reconstruction, because it occurs only when an owner/operator spends more than 50 percent of the cost of a replacement unit, generally entails fundamental decisions about what type of unit to rebuild. For example, one reconstruction occurred following an explosion at the boiler and resulted in a rebuild of the entire unit including both the boiler and the accompanying steam turbine.

Because a reconstruction generally entails rebuilding the unit, operating practices and equipment upgrades are not applicable as BSER. Those entail smaller scale changes to the unit that may be expected to be rebuilt anyway. In addition, the emission reductions that could be achieved through best operating practices and equipment upgrades are smaller than the most efficient generation technology.

C. Determination of the Level of the Standard

Once the EPA has determined that a particular system or technology represents BSER, the EPA must establish an emission standard based on that system or technology. To determine an achievable emission standard, we reviewed the emission rate information submitted by owners/operators of coal-fired EGUs to the EPA's Clean Air Markets Division. For reconstructed fossil fuel-fired boiler and IGCC EGUs, the EPA proposes to find that the best available steam cycle—which qualify as the BSER—supports a standard of 1,900 lb CO_2/MWh-net for large EGUs (i.e., those with heat input greater than 2,000 MMBtu/h), and 2,100 lb CO_2/MWh-net for small EGUs (i.e., those with a heat input 2,000 MMBtu/h or less). The DOE/NETL estimates that an IGCC unit emission rate is comparable to those achieved by a supercritical coal-fired EGU. Therefore, for both technologies, these levels of the standard are based on the emission performance that can be achieved by a large pulverized or CFB coal unit using supercritical steam conditions and a small unit using subcritical steam conditions.

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 the Technical Support Document (TSD),[85] we are soliciting comment on a range of 1,700 to 2,100 lb CO_2/MWh-net for large units and 1,900 to 2,300 lb CO_2/MWh-net for small units. An emission rate of 1,700 lb CO_2/MWh-net could potentially be met by an EGU using advanced ultra-supercritical steam conditions.[86]

We are not currently considering a standard more stringent than 1,700 lb CO_2/MWh-net for large units. Available information indicates that an EGU facility could not meet a standard of 1,600 lb CO_2/MWh-net based on the use of an advanced ultra-supercritical steam cycle, and instead would be required to implement partial CCS, co-fire approximately 40 percent natural gas directly in the boiler, or integrate non emitting or lower emitting technology in the facility's design (i.e., a hybrid power plant). We are not currently considering a standard more stringent than 1,900 lb CO_2/MWh-net for small units because available information indicates that a small EGU facility could only meet a standard of 1,800 lb CO_2/MWh-net burning bituminous coal and using the best available subcritical steam cycle. Modified facilities burning other coal types would be required to implement partial CCS, co-fire approximately 10 percent natural gas directly in the boiler, or integrate non-emitting or lower emitting technology in the facility's design (i.e., a hybrid power plant).

We are not currently considering a standard less stringent than 2,100 lb CO_2/MWh-net for large units because at that level, the NSPS would not necessarily promote the use of the best available steam cycle. At an emissions rate of 2,200 lb CO_2/MWh, large EGUs would not be required to use efficient generation technologies (e.g., they could use subcritical steam conditions). We are not currently considering a standard less stringent than 2,300 lb CO_2/MWh-net for small units because at that level, the NSPS would not necessarily promote the use of the best available steam conditions because many smaller subcritical units are operating well below 2,300 lb CO_2/MWh-net.

D. Compliance Period

The EPA is proposing that sources would be required to meet the proposed standards on a 12 operating-month rolling basis. The proposed compliance period requirements and rationale are the same as in the January 2014 proposal. This section provides a summary of the rationale. For additional detail, see 79 FR 1481 and 1482.

The 12-operating-month averaging period being proposed is important because of 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. 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. The EPA proposes that it is not necessary to have a shorter averaging period for CO_2 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 measureable implications to health or environmental impacts from short-term higher CO_2 emission rates as long as the 12-month average emissions rate is maintained.

VII. Rationale for Emission Standards for Modified Fossil Fuel-Fired Utility Boilers and IGCC Units

A. Introduction

In this section we explain our rationale for proposing, as the ''best system of emission reduction . . . adequately demonstrated'' for modified fossil fuel-fired utility boiler and IGCC EGUs, a combination of best operating practices and equipment upgrades.

We include in this discussion: (1) Our rationale for rejecting other alternatives as BSER, (2) a description of efficiency improvements achieved through a combination of best operating practices and equipment upgrades and our rationale for selecting it as BSER, and (3) our rationale for co-proposed alternative standards of performance based on this BSER (including varying the standard depending upon whether the affected source would be subject to a CAA section 111(d) plan (or promulgated federal plan) for CO_2).

B. Identification of the Best System of Emission Reduction

1. Options Considered

For the same reasons explained above for reconstructed fossil fuel-fired boiler and IGCC EGUs, the EPA is not proposing the following options to be BSER for modified fossil fuel-fired utility boiler and IGCC units: (1) The use of partial CCS, (2) conversion to (or co-firing with) natural gas, (3) the use of CHP, (4) Hybrid Power Plants, and (5)

[85] ''Best System of Emissions Reduction (BSER) for Reconstructed Electric Utility Steam Generating Units (EGUs) and Integrated Gasification Combined Cycle Facilities (IGCC)'' Technical Support Document available in the rulemaking docket (EPA–HQ–OAR–2013–0603).

[86] Advanced ultra-supercritical steam conditions are 700–760 °C (1,290–1,400 °F) and 36 MPa (5,000 psi).

reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency.

In this section, we evaluate two other options for BSER: (1) Efficiency improvements achieved through the use of the most efficient generation technology, and (2) efficiency improvements achieved through a combination of best operating practices and equipment upgrades.

2. Use of the Most Efficient Generation Technology

We considered whether the BSER for modified fossil fuel-fired utility boilers and IGCC units should be based on the performance of the most efficient generation technology available, which we believe is a supercritical [87] unit (i.e., a SCPC or supercritical CFB boiler) for large sources, and a subcritical unit for small sources. However, as was previously noted, the existing fleet of fossil fuel-fired steam-generating boilers is numerous and diverse in size and configuration (including steam parameters), and the EPA does not have sufficient information about the range of configurations that would be necessary to estimate the cost of upgrading the steam cycle (switching to higher grade of materials in the furnace, replacement of the steam drum and conversion to a once through design, etc.) and auxiliary equipment to the most efficient generating technology. For a given boiler design, steam pressures and temperatures are limited by the properties of the materials (boiler tubes, etc.) and cannot be increased without replacing those components. We do not have sufficient information on the number of components that would need to be replaced or on the costs of replacing individual components. Furthermore, we recognize that, in at least some cases, requiring a unit to meet levels achievable by a supercritical unit, when it was not originally designed to do so, could require significant modifications to both the boiler and turbine that could start to approach the replacement cost for the unit.

Unlike in the case of reconstruction explained above, it is the understanding of the EPA that modifications do not typically involve the type of boiler rebuilding that would make this an option with reasonable cost. Consequently, the EPA does not propose to find that the use of the most efficient generation technology meets the criteria for the BSER for a uniform nationwide standard of performance.

3. Best Operating Practices and Equipment Upgrades

The second option that EPA considered for modified fossil fuel-fired utility boilers and IGCC units is a combination of best operating practices and equipment upgrades. Best operating practices includes both operating the unit in the most efficient manner for a given operating condition and replacing worn components in a timely manner. Equipment upgrades involve replacing existing components with upgraded ones or a more extensive overhaul of major equipment (turbine or boiler). We propose to find that this option meets the criteria for BSER for these EGUs.

In addition, we are co-proposing two alternative standards of performance reflective of this BSER. In the first co-proposed alternative, all modified utility boilers and IGCC units will be required to meet a unit-specific emission standard. In the second co-proposed alternative, modified sources will be required to meet unit-specific emission limits that will depend on whether the affected unit undertakes the modification before it becomes subject to a CAA section 111(d) state plan (or promulgated federal plan), or after it becomes subject to such a plan. Each variation of the BSER meets the criteria, which we discuss next. We describe the variations in more detail in the section concerning the standards of performance, which follows the discussion of the criteria.

a. Technical Feasibility

A wide range of studies have been performed evaluating the opportunity to improve the heat rate (or efficiency) [88] of an existing power plant without upgrading to the most efficient generation technology available. These studies are summarized in Chapter 2 of the TSD, ''GHG Abatement Measures'' [89] which explains that, while the studies are different in the level of detail and assumptions, the results of the studies overall suggest that the U.S. coal-fired EGU existing fleet is theoretically capable of achieving heat rate improvements ranging from 9 to 15 percent.

Many of the detailed engineering studies describe a wide range of opportunities to improve heat rate including improvements to the: (1) Materials handling equipment at the plant, (2) economizer, (3) boiler control systems, (4) soot blowers, (5) air heaters, (6) steam turbine, (7) feed water heaters, (8) condenser, (9) boiler feed pumps, (10) induced draft (ID) fans, (11) emission controls, and (12) water treatment systems.

As the studies show, these types of upgrades have been made at a wide range of power plants, demonstrating their technical feasibility.

b. CO_2 Reductions

This approach would achieve reasonable reductions in CO_2 emissions from the affected modified units as those units will be required to meet an emission standard that is consistent with more efficient operation. In light of the limited opportunities for emission reductions from retrofits, these reductions are adequate.

c. Costs

The EPA reviewed the engineering studies available in the literature and selected the Sargent & Lundy 2009 study [90] as the basis for its assessment of heat rate improvement potentials from equipment and system upgrades. We focused on thirteen heat rate improvement methods discussed by Sargent & Lundy and listed in Table 2–13 of the ''GHG Abatement Measures'' TSD. We used the average of the estimated costs (in $/kW) for each method to develop the cost-ranked list of heat rate improvement methods (listed by costs from lowest to highest in the table). The first nine items in Table 2–13 contribute about 15 percent of the total average $/kW cost for all items. We believe it is reasonable to consider those nine no-cost and low-cost heat rate improvement methods as belonging in the category of what has been described above as best practices. The remaining four methods are higher cost heat rate improvement opportunities that we believe properly fall into the category discussed here as equipment or system upgrades. Using an average of the ranges of potential Btu improvements estimated by Sargent & Lundy for the

[87] 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 improves the efficiency of a steam turbine converting thermal energy to electricity, which in turn leads to increased efficiency and a lower emission rate.

[88] The heat rate is a common way to measure EGU efficiency. As the efficiency of a fossil fuel-fired EGU is increased, less fuel is burned per kilowatt-hour (kWh) generated by the EGU. This results in a corresponding decrease in CO_2 and other air pollutant emissions. Heat rate is expressed as the number of British thermal units (Btu) or kilojoules (kJ) that are required to generate 1 kWh of electricity. Lower heat rates are associated with more efficient fossil fuel-fired EGUs.

[89] Chapter 2: Heat Rate Improvement at Existing Coal-fired EGUs, Available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2013–0603.

[90] Coal-fired Power Plant Heat Rate Reductions, SL–009597 Final Report, January 2009. Available in the rulemaking docket and at *http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.*

four upgrade methods, equipment or system upgrades could provide a 4 percent heat rate improvement if all were applied on an EGU that has not already made those upgrades.

The 2009 Sargent & Lundy study included an estimated range of heat rate improvement, and the associated range of capital cost for each heat rate improvement method, for units ranging in size from 200 MW to 900 MW. If the methods and unit sizes are combined, as though they were all applied on a single EGU, the range of Sargent & Lundy estimated Btu reductions (412 to 1,205 Btu) resulted in associated combined capital costs in the range of $40–150/kW. The wide ranges of estimated Btu reductions and capital costs are indicative of the wide range of real differences in the many details of site specific EGU designs, fuel types, age, size, ambient conditions, current physical condition, etc. The EPA's analysis, therefore, assumed $100/kW as a representative combined heat rate improvement capital cost to achieve whatever Btu reduction is possible at an average site.

The EPA heat rate improvement analysis resulted in the following summary conclusions:

• Some degree of heat rate improvement is already economic for high heat rate—high coal cost EGUs.

• If a fleet-wide average 6 percent heat rate is technically feasible, it would also be economic on the basis of fuel savings alone, before consideration of the value of the associated CO_2 emission reductions, on a fleet-wide basis at today's coal prices if the associated average capital cost is about $75/kW or less.

• Even at a capital cost of $100/kW and an Integrated Planning Model (IPM) projected 2020 coal price of $2.62/MMBtu, the fleet-wide cost of CO_2 reduction via 6 percent heat rate improvement would be a relatively low $7.7/tonne of CO_2 avoided.

Based on this assessment, the EPA determines that the unit-specific emission limit based on historical best performance (which captures the good operating practice at the unit) coupled with an additional 2 percent reduction (which captures minimum opportunities for additional heat rate improvements from equipment and system upgrades) can be achieved at reasonable cost.

The EPA's modeling tools do not allow projection of any specific number of utility boilers and IGCC units that are expected to trigger the NSPS modification provision. As discussed below, however, the EPA believes there are likely to be few. Hence, a unit-specific standard of performance will not have significant impacts on nationwide electricity prices or on the structure of the nation's energy sector.

d. Incentive for Technological Development

As noted previously, the case law makes clear that the EPA is to consider the effect of its selection of the BSER on technological innovation or development, but that the EPA also has the authority to weigh this factor, along with the various other factors. With the selection of emissions controls, modified sources face inherent constraints that newly constructed greenfield and even reconstructed sources do not; as a result, modified sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, the proposed standards promote technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

C. Determination of the Level of the Standard

Once the EPA has determined that a particular system or technology represents BSER, the EPA must establish an emission standard based on that technology.

Because the existing fossil fuel-fired steam-generating boilers are numerous and diverse in size and configuration—and because the EPA has no way to predict which of those sources may modify—developing a single standard for all modified utility boilers or IGCC units is challenging. The EPA considered a sub-categorization approach, but, as is detailed in Chapter 2 of the TSD, ''GHG Abatement Measures,'' analysis of available data did not support a number of potential sub-categorization options—such as unit size, type or age—that intuitively seemed logical.

In this action, the EPA is co-proposing two alternative standards of performance for modified utility boilers and IGCC units. In the first co-proposed alternative, all modified sources would meet a unit-specific emission limit. In the second co-proposed alternative, the modified source would be required to meet a unit-specific emission limit that will depend on the timing of the modification.

For utility boilers or IGCC units undertaking modifications, the EPA is proposing that the BSER has two components: (1) That the source operates consistently with its own best demonstrated historical performance; and (2) that the source implements other available heat rate improvement measures including upgrading of some components of the unit. Specifically, for the first co-proposed alternative, a modified utility boiler or IGCC unit would be required to maintain an emission rate that equals the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs, multiplied by 98 percent (i.e., a 2 percent further reduction), but not to be more stringent than the emission limit that would be applicable to the source if it were a reconstructed source. Consistent with the heat rate improvement analysis in the CAA section 111(d) proposal, we selected 2002 to assure we captured the impacts of maintenance cycles and year to year natural variability in CO_2 emission rate performance to capture the best historical performance. We solicit comment on whether we should select a year prior to or subsequent to 2002 for purposes of determining the best historical emission rate.

As mentioned, the EPA is also co-proposing standards of performance that are dependent on the timing of the modification. Specifically, a source that modifies prior to becoming subject to a CAA section 111(d) plan would be required to meet an emission limit that is determined using the same methodology described in the first co-proposed alternative. The modified utility boiler or IGCC unit would be required to maintain an emission rate that equals the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs, multiplied by 98 percent (i.e., a 2 percent further reduction based on equipment upgrades), but not to be more stringent than the emission limit applicable to a corresponding reconstructed source. The EPA is proposing that units undertaking modifications after they become subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that is determined by the CAA section 111(d) implementing authority from an assessment to identify energy efficiency improvement opportunities for the affected source. This standard is informed by the fact that, as we discuss in the Legal Memorandum,[91] these sources would remain subject to the requirements of the CAA section 111(d) plan even after modifying.

The EPA also solicits comment on whether the period of best historical performance should be the years from

[91] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–20913–0602.

2002 to the time when the unit becomes subject to the CAA section 111(d) plan, rather than to the time of the modification.

We are considering different standards applicable before and after a source becomes subject to a CAA section 111(d) plan because we are concerned that, as a result of implementation of state plans, the additional 2 percent efficiency improvement may be unachievable for a substantial number of sources that make efficiency improvements as part of a CAA section 111(d) plan. Specifically, we are concerned that where a state imposes efficiency improvements on a source, or where a source undertakes efficiency improvements to comply with the state plan, it will have already attained the maximum level of efficiency improvement that is achievable for that unit. As a result, the source would be unable to undertake additional improvements to meet the highest level of efficiency plus the additional 2 percent reduction (based on equipment upgrades) that we are considering. We recognize that in some states, CAA section 111(d) plans may require no or limited efficiency improvements on a specific unit. In such cases, we expect such a unit to be able to achieve the standard we are considering for sources that modify prior to becoming subject to a CAA section 111(d) plan. Accordingly, for such sources, we anticipate that the audit process that we are considering will result in an emission rate consistent with the highest level of efficiency plus 2 percent (based on equipment upgrades) that we are considering for sources that modify prior to becoming subject to a state plan.

For this co-proposal, the EPA is proposing that the date for determining whether a unit is subject to a CAA section 111(d) plan is the date that the plan is initially submitted to the EPA. Although a state's plan is still subject to the EPA's approval, we believe this represents a reasonable point to determine that a source is subject to a CAA section 111(d) plan, because at that point the operator would know what requirements the source would have to meet, and would have confirmation of the state's intention to submit that plan to meet the requirements of CAA section 111(d). We are also taking comment on a range of other dates including: June 30, 2016 (the original state plan submission deadline), the date that the state promulgates its rule, the date the EPA approves the rule, and January 1, 2020 (the proposed initial compliance date for state plans).

For a source modifying after a CAA section 111(d) plan becomes applicable, a unit-specific emission standard will be determined by the CAA section 111(d) implementing authority from the results of an energy efficiency audit to identify technically feasible heat rate improvement opportunities at the affected source.

An energy efficiency audit, or assessment, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. An energy audit is a process that involves a thorough examination of potential savings from energy efficiency improvements, pollution prevention, and productivity improvement. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. Besides reducing operating and maintenance costs, improving energy efficiency results in decreased fuel use which results in a corresponding decrease in emissions. Such an energy assessment requirement is included in the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR part 63, subpart DDDDD).

We propose that the energy assessment would include, at a minimum, the following elements:

1. A visual inspection of the facility to identify steam leaks or other sources of reduced efficiency;
2. a review of available engineering plans and facility operation and maintenance procedures and logs; and
3. a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

We propose that the energy assessment be conducted by energy professionals or engineers that have expertise in evaluating energy systems. We specifically request comment on: (1) Whether energy assessor certification should be required; (2) if certification were required, what the basis of the certification should be; and (3) whether there are organizations that provide certification of specialists in evaluating energy systems. We propose that the CAA section 111(d) implementing authority will determine a unit-specific emission limit based on the results of the energy efficiency audit and we also request comment on: (1) Whether the rule should require implementation of identified energy efficiency improvements; and (2) if implementation were required, what the determining factor(s) for requiring the improvements should be. Finally, we request comment on: (1) Whether an energy efficiency audit recently completed (e.g., within 3 years of the modification) that meets or is amended to meet the rule's energy audit requirements can be used to satisfy the energy efficiency audit requirement and, in such instances, whether energy assessor approval and qualification requirements should be waived; and (2) whether facilities that operate under an energy management program compatible to ISO 50001 [92] that includes the affected units can be used to satisfy the energy efficiency audit requirement.

The EPA also seeks comment on whether, and under what circumstances, the energy audit methodology—i.e., determining the emission limit from the results of the energy audit—should be an option for sources that modify before becoming subject to a CAA section 111(d) plan. In particular, the EPA seeks comment on whether the audit methodology should be an option for all units that modify, prior to becoming subject to a CAA section 111(d) plan, or if it should be an option for sources that provide evidence that significant energy efficiency improvements were implemented after 2002 but before the modification.

D. Compliance Period

The EPA is proposing that sources would be required to meet the proposed standards on a 12 operating-month rolling basis. The compliance period requirements and rationale being proposed for modified boilers and IGCC units are the same as the requirements and rationale being proposed for reconstructed utility boilers and IGCC units (see section VII.D. of this preamble), as well as the compliance period requirements and rationale in the January 2014 proposal. For additional detail, see 79 FR 1481 and 1482.

VIII. Rationale for Emission Standards for Reconstructed Natural Gas-Fired Stationary Combustion Turbines

A. Identification of the Best System of Emission Reduction

The EPA evaluated three different control technology configurations as potentially representing the "best system of emissions reductions . . .

[92] ISO 50001 is a specification created by the International Organization for Standardization (ISO) for an energy management system. The standard specifies the requirements for establishing, implementing, maintaining and improving an energy management system, whose purpose is to enable an organization to follow a systematic approach in achieving continual improvement of energy performance, including energy efficiency, energy security, energy use and consumption.

adequately demonstrated'' for reconstructed natural gas-fired stationary combustion turbines: (1) NGCC technology with CCS, (2) NGCC technology by itself, and (3) high efficiency simple cycle aeroderivative turbines.

1. NGCC Technology With CCS

We are not proposing to find that CCS technology is the BSER for reconstructed natural gas-fired stationary combustion turbines for the same reasons we are not proposing to find that CCS technology is the BSER for steam-generating units: an owner/operator of an existing source that is undertaking reconstruction has challenges not faced when building a new NGCC unit because the existing unit may be located at a site with space constraints that would make installation of CCS problematic. We do not have sufficient information about the universe of existing sources to be able to determine the costs of CCS, in light of these space constraints.

2. NGCC Technology

For the reasons explained below, we find NGCC technology to be BSER for reconstructed natural gas-fired stationary combustion turbines.

a. Technical Feasibility

NGCC technology is widely used in the power sector today. There are hundreds of NGCCs in the U.S. and in other countries.

b. Emission Reductions

NGCC technology is the most efficient technology for natural-gas fired stationary combustion turbines. It has an emission rate that is approximately 25 percent lower than the most effective main alternative technology, which is the simple cycle combustion turbine.

c. Cost

NGCC technology is one of the lowest cost forms of baseload and intermediate load electricity generation. Even in the case of a simple cycle turbines that operates at a capacity factor of greater than one-third, the cost of replacement with a NGCC unit is likely to be cost effective based on consideration of fuel savings alone. In the proposal for newly constructed sources (79 FR 1459), we explained that at capacity factors of greater than 20 percent, the LCOE of a combined cycle unit would be less than the LCOE of a simple cycle turbine. Because the cost of adding a HRSG to a simple cycle turbine is less than the cost of building a full combined cycle unit, the same holds true with a comparison of replacing a simple cycle turbine and upgrading it to a combined cycle turbine. Furthermore, if the owner/operator of a simple cycle turbine wishes to make a modification, they could do so—without having to comply with the requirements of this proposal—by maintaining an average annual capacity factor of less than one-third. As we explained in the proposal, few simple cycle turbines operate at an annual capacity factor of greater than one-third. (79 FR 1459)

d. Incentive for Technology Innovation

We recognize that because NGCC technology is already the state of the art technology, and is widely used, for natural gas stationary combustion turbines, identifying this technology as the BSER may not provide significant incentive for technology innovation. However, we are according less weight to this factor in this case because we consider this technology to be highly efficient and because the only more stringent alternative—CCS—is one that we are not proposing to identify as BSER, for reasons discussed above.

3. High Efficiency Simple Cycle Aeroderivative Turbines

The use of high efficiency simple cycle aeroderivative turbines does not provide emission reductions when compared to the NGCC technology. According to the Annual Energy Outlook (AEO) 2013 emissions rate information, advanced simple cycle combustion turbines have a base load rating CO_2 emissions rate of 1,150 lb CO_2/MWh-gross, which is higher than the base load rating emission rates of 830 and 760 lb CO_2/MWh-gross for the conventional and advanced NGCC model facilities, respectively. In addition, simple cycle technology is more expensive than NGCC technology; and it does not further develop or promote use of the most advanced emission control technology. For these reasons, we do not find it to be the BSER for reconstructed natural gas-fired stationary combustion turbines.

B. Determination of the Standards of Performance

The proposed standards of performance for reconstructed natural gas-fired stationary combustion turbines, which are based on BSER being efficient NGCC technology, are consistent with those that were proposed for newly constructed natural gas-fired stationary combustion turbine sources, as described in the January 2014 proposal (79 FR 1430). The EPA intends—when it takes final action on this proposal and on the January 2014 proposal for newly constructed sources, respectively—to finalize the same standards for newly constructed, modified and reconstructed natural gas-fired stationary combustion turbines. The EPA solicits comment on this approach and on any reasons why these sources should not have consistent standards.

In the January 2014 proposal, the EPA indicated that it had reviewed the CO_2 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 the emissions data analysis is included in a TSD in the docket for that rulemaking [93] and is also included in the docket for this proposal.

Consistent with the January 2014 proposal, the EPA proposes 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 850 MMBtu/h or less, 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. Because of these differences in equipment and inherent efficiencies of scale, the smaller capacity NGCC units (850 MMBtu/h and smaller) are less efficient than the larger units (larger than 850 MMBtu/h). We are proposing standards of performance of 1,000 lb CO_2/MWh-gross for the large units and 1,100 lb CO_2/MWh-gross for the small units; and we are requesting comment on a range of 950 to 1,100 lb CO_2/MWh-gross for the large turbine subcategory and 1,000 to 1,200 lb CO_2/MWh-gross for the small turbine subcategory.

IX. Rationale for Emission Standards for Modified Natural Gas-Fired Stationary Combustion Turbines

A. Identification of the Best System of Emission Reduction

We believe that the analysis above with regards to reconstructed natural gas-fired stationary combustion turbines is also applicable to modified natural gas-fired stationary combustion

[93] ''Standard of Performance for Natural Gas-Fired Combustion Turbines'' Technical Support Document, Docket ID: EPA–HQ–OAR–2013–0495.

turbines.[94] The only potential difference that the EPA has identified is consideration of cost because the actions that could trigger modification are less extensive changes at the facility. We have considered four different scenarios that could trigger the modification provisions: (1) Modification of an older (e.g., pre-2000) combined cycle unit, (2) modification of a newer (e.g., a built in 2000 or later) combined cycle unit, (3) upgrading of a simple cycle turbine to a combined cycle unit, and, (4) modification to a simple cycle turbine other than upgrading to a combined cycle unit. As described below, in each of these cases, we believe that NGCC is cost-effective.

1. Modifications to an Older (e.g., Pre-2000) Combined Cycle Unit

Because the performance of combined cycle technology has improved so significantly since 2000, we believe that upgrading to current technology is likely to be cost effective when one considers a combination of fuel savings, and performance benefits (the ability to start up the unit more quickly and operate more efficiently over a wider range of loads).

2. Modifications to a Newer Combined Cycle Unit

These modifications are likely to be made to return the unit to close to its original operating performance, would be consistent with the requirements of today's proposal, and are not likely to significantly increase the cost of the project.

3. Upgrading a Simple Cycle Turbine to a Combined Cycle Unit

These modifications would be made to upgrade the efficiency of the unit, are consistent with the requirements of today's proposal, and are not likely to significantly increase the cost of the project.

4. Modifications to a Simple Cycle Turbine Other Than Upgrading to Combined Cycle

As was noted above—and in the proposal for newly constructed sources—when operating at higher capacity factors, the use of combined cycle technology instead of simple cycle technology pays for itself in fuel savings alone.

For these reasons, we find the use of NGCC technology to be BSER for modified natural gas-fired combustion turbines.

B. Determination of the Standards of Performance

We propose that the same standards of performance described above for reconstructed natural gas-fired stationary combustion turbines are also appropriate for modified natural gas-fired stationary combustion turbines.

We are requesting comment on a range of 950 to 1,100 lb CO_2/MWh-gross (430 to 500 kg CO_2/MWh) for the large turbine subcategory and 1,000 to 1,200 lb CO_2/MWh-gross (450 to 540 kg CO_2/MWh) for the small turbine subcategory.

For sources that are subject to a CAA section 111(d) plan, the EPA is also soliciting comment on whether the sources should be allowed to elect, as an alternative to the otherwise applicable numeric standard, to meet a unit-specific emission standard, determined by the CAA 111(d) implementing authority, based on implementation of identified energy efficiency improvement opportunities applicable to the source.

X. Impacts of the Proposed Action [95]

As explained in the RIA for this proposed rule, the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions that we are proposing today. Because the EPA is aware of a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the EPA expects that this proposed rule will result in potential CO_2 emission changes, quantified benefits, and costs for a unit that was subject to the modification provision. In this illustrative example based on a hypothetical 500 MW coal-fired unit, we estimate costs, net of fuel savings, of $0.78 million to $4.5 million (2011$) and CO_2 reductions of 133,000 to 266,000 tons in 2025. The combined climate benefits from reductions in CO_2 and health co-benefits from reductions in SO_2, NO_X, and $PM_{2.5}$ total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reductions scenario and $35 to $65 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.[96]

A. What are the air impacts?

As explained immediately above, the EPA expects few modified or reconstructed EGUs in the period of analysis. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the impacts for a hypothetical unit that triggered the modification provision. For this illustrative example, we estimate CO_2 reductions of 133,000 to 266,000 tons in 2025. Additionally, we estimate co-reductions of SO_2, NO_X, and $PM_{2.5}$.

B. What are the energy impacts?

This proposed rule is not anticipated to have significant impacts on the supply, distribution, or use of energy. As previously stated, the EPA expects few reconstructed or modified EGUs in the period of analysis and the nationwide cost impacts to be minimal as a result.

C. What are the compliance costs?

The EPA believes this proposed rule will have minimal compliance costs associated with it, because, as previously stated, the EPA expects few modified or reconstructed EGUs in the period of analysis. Because the EPA is aware of a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the EPA estimates compliance costs, net of fuel savings, of $0.78 to $4.5 million (2011$) in 2025 for a hypothetical unit that triggered the modification provisions.

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

As previously explained, the special characteristics of GHGs make it important to take action 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 fuel-fired power plants emit more GHG emissions than any other stationary source category in the U.S.

This proposed rule would limit GHG emissions from modified fossil fuel-

[94] Technical Support Document ''Standard of Performance for Natural Gas-Fired Combustion Turbines'' available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2013–0603.

[95] Note that the 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.

[96] For purposes of this summary, we present climate benefits from CO_2 that were estimated using the model average SCC at a 3 percent discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5 and 5 percent, and the 95th percentile at 3 percent. Similarly, we summarize the health co-benefits in this synopsis at a 3 percent discount rate. We provide estimates based on additional discount rates in the RIA.

fired electric utility steam generating units (utility boilers and IGCC units) to levels consistent with the unit's best potential performance. GHG emissions from reconstructed utility boilers and IGCC units would be limited to levels consistent with modern, efficient generating technology (e.g., supercritical steam cycles). While the EPA expects few units to trigger the modification or reconstruction provisions, this proposed rule would limit GHG emissions from any modified and reconstructed stationary combustion turbines to levels consistent with modern, efficient natural gas combined cycle technology. As a result, this 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?

As previously stated, the EPA anticipates few units will trigger the proposed modification or reconstruction provisions. For this reason, the proposed standards will result in minimal emission reductions, costs, or quantified benefits by 2025. There are no macroeconomic or employment impacts expected as a result of these proposed standards.

F. What are the benefits of the proposed standards?

As previously stated, the EPA anticipates few units will trigger the proposed modification or reconstruction provisions. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the combined climate benefits from reductions in CO_2 and health co-benefits from reductions in SO_2, NO_X, and $PM_{2.5}$ total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reductions scenario and $35 to $65 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.[97]

XI. 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 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 OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to the 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 Chapter 9 of the Regulatory Impact Analysis for Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.

As explained in the RIA for this proposed rule, in the period of analysis (through 2025) the EPA anticipates few sources will trigger either the modification or the reconstruction provisions proposed. Because there have been a few units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit that is included in Chapter 9 of the RIA.

B. Paperwork Reduction Act

This proposed action is not expected to impose an information collection burden under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). As previously stated, the EPA expects few modified or reconstructed EGUs in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines will take actions that would constitute modifications or reconstructions as defined under the EPA's NSPS regulations. Accordingly, this proposed action is not anticipated to impose any information collection burden over the 3-year period covered by this Information Collection Request (ICR). We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed. 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 ICR document prepared by the EPA has been assigned the EPA ICR number 2465.03.

The EPA intends to codify the standards of performance in the same way for both this proposed action and the January 2014 proposal for newly constructed sources and is proposing the same recordkeeping and reporting requirements that were included in the January 2014 proposal.[98] See 79 FR 1498 and 1499. Although not anticipated, if an EGU were to modify or reconstruct, this proposed action would impose minimal information collection burden on affected sources beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. The 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 potential energy metering modifications to comply with net energy output based emission limits proposed in this action and certain reporting costs, which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there would be 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.

Although, as stated above, the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions that we are proposing, if an EGU were to modify or reconstruct during the 3-year period covered by this ICR, it is likely that an EGU's energy metering equipment would need to be

[97] For purposes of this summary, we present climate benefits from CO_2 that were estimated using the model average social cost of carbon (SCC) at a 3 percent discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5 percent and 5 percent, and the 95th percentile at 3 percent. Similarly, we summarize the health co-benefits in this synopsis at a 3 percent discount rate. We provide estimates based on additional discount rates in the RIA.

[98] The information collection requirements in the January 2014 proposal have been submitted for approval to the OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The ICR document prepared by the EPA for the January 2014 proposal has been assigned the EPA ICR number 2465.02.

modified to comply with proposed net energy output based CO_2 emission limits. Specifically, the EPA estimates that it would take approximately 3 working months for a technician to retrofit existing energy metering equipment to meet the proposed net energy output requirements. In addition, after modifications are made that enable a facility to measure net energy output, each EGU's Data Acquisition System (DAS) would need to be upgraded to accommodate reporting of net energy output rate based emissions. A modified or reconstructed EGU would be required to prepare a quarterly summary report, which includes reporting of emissions and downtime, every 3 months. The reporting burden for such a unit (averaged over the first 3 years after the effective date of the standards) is estimated to be $17,217 and 205 labor hours. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data. Average burden hours per response are estimated to be 47.3 hours and the average number of annual responses over the 3-year ICR period is 4.33 per year. 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–2013–0603. Submit any comments related to the ICR to the EPA and OMB. See **ADDRESSES** section at the beginning of this proposed rule 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 June 18, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by July 18, 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 with less than 750 employees.);

(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.

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.

The EPA expects few modified utility boilers, IGCC units, or stationary combustion turbines in the period of analysis. An NSPS modification is defined as a physical or operational change that increases the source's maximum achievable hourly rate of emissions. The EPA does not believe that there are likely to be EGUs that will take actions that would constitute modifications as defined under the EPA's NSPS regulations.

Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, the RIA for this proposed rule includes an illustrative analysis of the costs and benefits for a representative unit.

Based on the analysis, the EPA estimates that this proposed rule could result in CO_2 emission changes, quantified benefits, or costs for a hypothetical unit that triggered the modification provision. However, we do not anticipate this proposed rule would impose significant costs on those sources, including any that are owned by small entities.

In addition, the EPA expects few reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Reconstruction occurs when a single project replaces components or equipment in an existing facility and exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Due to the limited data available on reconstructions, it is not possible to conduct a representative illustrative analysis of what costs and benefits might result from this proposal in the unlikely case that a unit were to reconstruct. However, based on the low number of previous reconstructions and the BSER determination based on the most efficient available generating technology, we would expect this proposal to result in no significant CO_2 emission changes, quantified benefits, or costs for NSPS reconstructions. Accordingly, there are no anticipated economic impacts as a result of the proposed standards for reconstructed EGUs.

Nevertheless, the EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives). As summarized in section II.G. of this preamble, the EPA has conducted an unprecedented amount of stakeholder outreach. As part of that outreach, agency officials participated in many meetings with individual utilities as well as meetings with electric utility associations. Specifically, the EPA Administrator, Gina McCarthy, participated in separate meetings with both the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA). The meetings brought together leaders of the rural cooperatives and public power utilities from across the country. The Administrator discussed and exchanged information on the unique challenges, in particular the financial structure, of NRECA and APPA member utilities. A detailed discussion of the stakeholder outreach is included in the preamble to the emission guidelines for existing affected electric utility generating units being proposed in a separate action.

In addition, as described in the RFA section of the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1499 and 1500), the EPA conducted outreach to representatives of small entities while formulating the provisions of the proposed standards. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources.

While formulating the provisions of this proposed rule, the EPA considered the input provided over the course of the stakeholder outreach. We invite comments on all aspects of this proposal and its impacts, including potential 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. As previously stated, the EPA expects few modified or reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Accordingly, 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 among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for newly constructed EGUs. This outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources. As described in the UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1500 and 1501), the EPA consulted with the following 10 national organizations representing state and local elected officials: (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. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs.

While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see section II.G. of this preamble).

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 Executive Order 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.

However, as described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources. The EPA engaged 10 national organizations representing state and local elected officials. The UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1500 and 1501) includes a description of the consultation. In addition, on February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see section II.G. of this preamble). In the spirit of Executive Order 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 reconstructed and modified 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 would only affect existing sources such as the three coal-fired EGUs located in Indian country, if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. However, as previously stated the EPA expects few modified or reconstructed EGUs in the period of analysis. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, the EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in carbon pollution standards for the power sector, prior to proposal of GHG standards for newly constructed power plants, 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 newly constructed, reconstructed, modified, and existing sources. The Consultation and Coordination with Indian Tribal Governments discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1501) includes a description of that consultation.

During development of this proposed regulation, consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of both the NSPS for modified and reconstructed EGUs and emission guidelines for existing EGUs and offered consultation. No tribes have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013, and to which tribes were invited. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on July 25, 2013, and December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency. Additional detail regarding this stakeholder outreach is included in the preamble to the emission guidelines for existing affected electric utility generating units being proposed in a separate action today. The EPA also held a series of listening sessions prior to proposal of GHG standards for newly constructed power plants. Tribes participated in a session on February 17, 2011, with the state agencies, as well as in a separate session with tribes on April 20, 2011.

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

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

The EPA interprets Executive Order 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 Executive Order 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 Executive Order 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. As previously stated, the EPA expects few reconstructed or modified EGUs in the period of analysis and impacts on emissions, costs or energy supply decisions for the affected electric utility industry to be minimal as a result.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995 (Public Law No. 104–113; 15 U.S.C. 272 note) directs the EPA to use VCS in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS 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: ASTM D388–12 (Standard Classification of Coals by Rank), ASTM D396–13c (Standard Specification for Fuel Oils), ASTM D975–14 (Standard Specification for Diesel Fuel Oils), D3699–13b (Standard Specification for Kerosene), D6751–12 (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), ASTM D7467–13 (Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)), and ANSI C12.20 (American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes). The EPA is proposing use of Appendices A, 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 modified and reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) and stationary combustion turbines by establishing national emission standards for CO_2. 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 does not affect the level of protection provided to human health or the environment. As previously stated, the EPA expects few modified or reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis.

XII. 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 in 40 CFR Part 60

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

Dated: June 2, 2014.

Gina McCarthy,

Administrator.

Proposed Rule Amendment With Changes

The Environmental Protection Agency proposed rule amending 40 CFR parts 60, 70, 71, and 98, which was published at 79 FR 1430, January 8, 2014, proposed amendments to the regulatory text of 40 CFR part 60, subparts Da and KKKK, and, as an alternative to amending subparts Da and KKKK, to create a new subpart (40 CFR part 60, subpart TTTT) to include GHG standards for newly constructed EGUs. To facilitate understanding the amendments being proposed in this proposal, we are providing a Technical Support Document in the docket for this rulemaking in track changes that shows the proposed amendments considering the amendments proposed in the January 8, 2014, **Federal Register** publication.

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