ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 70, 71, and 98

[EPA–HQ–OAR–2013–0495; EPA–HQ–OAR–2013–0603; FRL–9930–66–OAR]

RIN 2060–AQ91

Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing new source performance standards (NSPS) under Clean Air Act (CAA) section 111(b) that, for the first time, will establish standards for emissions of carbon dioxide (CO_2) for newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (EGUs). This action establishes separate standards of performance for fossil fuel-fired electric utility steam generating units and fossil fuel-fired stationary combustion turbines. This action also addresses related permitting and reporting issues. In a separate action, under CAA section 111(d), the EPA is issuing final emission guidelines for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs.

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

ADDRESSES: The EPA has established dockets for this action under Docket ID No. EPA–HQ–OAR–2013–0495 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units) and Docket ID No. EPA–HQ–OAR–2013–0603 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units). All documents in the dockets are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center (EPA/DC), Room 3334, EPA WJC West Building, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

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

AB Assembly Bill
AEO Annual Energy Outlook
AEP American Electric Power
ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
BACT Best Available Control Technology
BDT Best Demonstrated Technology
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt-hour
Btu/lb British Thermal Units per Pound
CAA Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous Emissions Monitoring System
CFB Circulating Fluidized Bed
CH_4 Methane
CHP Combined Heat and Power
CO_2 Carbon Dioxide
CSAPR Cross-State Air Pollution Rule
DOE Department of Energy
DOT Department of Transportation
ECMPS Emissions Collection and Monitoring Plan System
EERS Energy Efficiency Resource Standards
EGU Electric Generating Unit
EIA Energy Information Administration
EO Executive Order
EOR Enhanced Oil Recovery
EPA Environmental Protection Agency
FB Fluidized Bed
FGD Flue Gas Desulfurization
FOAK First-of-a-kind
FR Federal Register
GHG Greenhouse Gas
GHGRP Greenhouse Gas Reporting Program
GPM Gallons per Minute
GS Geologic Sequestration
GW Gigawatts
H_2 Hydrogen Gas
HAP Hazardous Air Pollutant
HFC Hydrofluorocarbon
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
IRPs Integrated Resource Plans
kg/MWh Kilogram per Megawatt-hour
kJ/kg Kilojoules per Kilogram
kWh Kilowatt-hour
lb CO_2/MMBtu Pounds of CO_2 per Million British Thermal Unit
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
lb CO_2/yr Pounds of CO_2 per Year
lb/lb-mole Pounds per Pound-Mole
LCOE Levelized Cost of Electricity
MATS Mercury and Air Toxic Standards
MMBtu/hr Million British Thermal Units per Hour
MRV Monitoring, Reporting, and Verification
MW Megawatt
MWe Megawatt Electrical
MWh Megawatt-hour
MWh-g Megawatt-hour gross
MWh-n Megawatt-hour net
N_2O Nitrous Oxide
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NAS National Academy of Sciences
NETL National Energy Technology Laboratory
NGCC Natural Gas Combined Cycle
NOAK n^{th}-of-a-kind
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
O_2 Oxygen Gas
OMB Office of Management and Budget
PC Pulverized Coal
PFC Perfluorocarbon
PM Particulate Matter
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
PUC Public Utilities Commission
RCRA Resource Conservation and Recovery Act
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
RTC Response to Comments
RTP Response to Petitions
SBA Small Business Administration
SCC Social Cost of Carbon
SCR Selective Catalytic Reduction
SCPC Supercritical Pulverized Coal
SDWA Safe Drinking Water Act
SF_6 Sulfur Hexafluoride
SIP State Implementation Plan

SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
SSM Startup, Shutdown, and Malfunction
Tg Teragram (one trillion (10^{12}) grams)
Tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UIC Underground Injection Control
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USDW Underground Source of Drinking Water
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard
WGS Water Gas Shift
WWW World Wide Web

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

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

In this final action the EPA is establishing standards that limit greenhouse gas (GHG) emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and stationary combustion turbines, following the issuance of proposals for such standards and an accompanying Notice of Data Availability.

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 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.'' Pursuant to authority in section 111(b) of the CAA, on September 20, 2013, the EPA issued proposed carbon pollution standards for newly constructed fossil fuel-fired power plants. The proposal was published in the **Federal Register** on January 8, 2014 (79 FR 1430; ''January 2014 proposal'').[1] In that proposal, the EPA proposed to limit emissions of CO_2 from newly constructed fossil fuel-fired electric utility steam generating units and newly constructed natural gas-fired stationary combustion turbines.

The EPA subsequently issued a Notice of Data Availability (NODA) in which the EPA solicited comment on its initial interpretation of provisions in the Energy Policy Act of 2005 (EPAct05) and associated provisions in the Internal Revenue Code (IRC) and also solicited comment on a companion Technical Support Document (TSD) that addressed these provisions' relationship to the factual record supporting the proposed rule. 79 FR 10750 (February 26, 2014).

On June 2, 2014, the EPA proposed standards of performance, also pursuant to CAA section 111(b), 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. 79 FR 34960 (June 18, 2014) (''June 2014 proposal''). Specifically, the EPA proposed standards of performance for: (1) Modified fossil fuel-fired steam generating units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired steam generating units, and (4) reconstructed natural gas-fired stationary combustion turbines.

In this action, the EPA is issuing final standards of performance to limit emissions of GHG pollution manifested as CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units (*i.e.,* utility boilers and integrated gasification combined cycle (IGCC) units) and from newly constructed and reconstructed stationary combustion turbines. Consistent with the requirements of CAA section 111(b), these 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. These final standards are codified in 40 CFR part 60, subpart TTTT, a new subpart specifically created for CAA 111(b) standards of performance for GHG emissions from fossil fuel-fired EGUs.

In a separate action that affects the same source category, the EPA is issuing final emission guidelines under CAA section 111(d) for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs. Pursuant to those guidelines, states must submit plans to the EPA following a schedule set by the guidelines.

The EPA received numerous comments and conducted extensive outreach to stakeholders for this rulemaking. After careful consideration of public comments and input from a variety of stakeholders, the final standards of performance in this action reflect certain changes from the proposals. Comments considered include written comments that were submitted during the public comment period and oral testimony provided during the public hearing for the proposed standards.

2. Summary of Major Provisions and Changes to the Proposed Standards

The BSER determinations and final standards of performance for affected newly constructed, modified, and reconstructed EGUs are summarized in Table 1 and discussed in more detail below. The final standards for new, modified, and reconstructed EGUs apply to sources that commenced construction—or modification or reconstruction, as appropriate—on or after the date of publication of corresponding proposed standards.[2] The final standards for newly constructed fossil fuel-fired EGUs apply to those sources that commenced construction on or after the date of publication of the proposed standards, January 8, 2014. The final standards for modified and reconstructed fossil fuel-fired EGUs apply to those sources that modify or reconstruct on or after the date of publication of the proposed standards, June 18, 2014.

TABLE 1—SUMMARY OF BSER AND FINAL STANDARDS FOR AFFECTED EGUS

Affected EGUs	BSER	Final standards of performance
Newly Constructed Fossil Fuel-Fired Steam Generating Units.	Efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial carbon capture and storage (CCS).	1,400 lb CO_2/MWh-g.
Modified Fossil Fuel-Fired Steam Generating Units.	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades.	Sources making modifications resulting in an increase in CO_2 hourly emissions of more than 10 percent are 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); the emission limit will be no more stringent than: 1. 1,800 lb CO_2/MWh-g for sources with heat input >2,000 MMBtu/h. 2. 2,000 lb CO_2/MWh-g for sources with heat input ≤2,000 MMBtu/h.
Reconstructed Fossil Fuel-Fired Steam Generating Units.	Most efficient generating technology at the affected source (supercritical steam conditions for the larger; and subcritical conditions for the smaller).	1. Sources with heat input >2,000 MMBtu/h are required to meet an emission limit of 1,800 lb CO_2/MWh-g. 2. Sources with heat input ≤2,000 MMBtu/h are required to meet an emission limit of 2,000 lb CO_2/MWh-g.

[1] The EPA previously proposed performance standards for newly reconstructed fossil fuel-fired EGUs in April 2012 (77 FR 22392). In that action, the EPA proposed standards for steam generating units and natural gas-fired combustion turbines based on a single Best System of Emission Reduction determination. On January 8, 2014, the EPA withdrew that proposal (79 FR 1352).

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

TABLE 1—SUMMARY OF BSER AND FINAL STANDARDS FOR AFFECTED EGUs—Continued

Affected EGUs	BSER	Final standards of performance
Newly Constructed and Reconstructed Fossil Fuel-Fired Stationary Combustion Turbines.	Efficient NGCC technology for base load natural gas-fired units and clean fuels for non-base load and multi-fuel-fired units.[3]	1. 1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n for base load natural gas-fired units. 2. 120 lb CO_2/MMBtu for non-base load natural gas-fired units. 3. 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units.[4]

a. Fossil Fuel-Fired Electric Utility Steam Generating Units

This action establishes standards of performance for newly constructed fossil fuel-fired steam generating units[5] based on the performance of a new highly efficient SCPC EGU implementing post-combustion partial carbon capture and storage (CCS) technology, which the EPA determines to be the BSER for these sources. After consideration of a wide range of comments, technical input received on the availability, technical feasibility, and cost of CCS implementation, and publicly available information about projects that are implementing or planning to implement CCS, the EPA confirms its proposed determination that CCS technology is available and technically feasible to implement at fossil fuel-fired steam generating units. However, the EPA's final standard reflects the consideration of legitimate concerns regarding the cost to implement available CCS technology on a new steam generating unit. Accordingly, the EPA is finalizing an emission standard for newly constructed fossil fuel-fired steam generating units at 1,400 lb CO_2/MWh-g, a level that is less stringent than the proposed limitation of 1,100 lb CO_2/MWh-g. This final standard reflects our identification of the BSER for such units to be a lower level of partial CCS than we identified as the basis of the proposed standards—one that we conclude better represents the requirement that the BSER be implementable at reasonable cost.

The EPA proposed that the BSER for newly constructed steam generating EGUs was highly efficient new generating technology (*i.e.,* a supercritical utility boiler or IGCC unit) implementing partial CCS technology to achieve CO_2 emission reductions resulting in an emission limit of 1,100 lb CO_2/MWh-g.[6]

The BSER for newly constructed steam generating EGUs in the final rule is very similar to that in the January 2014 proposal. In this final action, the EPA finds that a highly efficient new supercritical pulverized coal (SCPC) utility boiler EGU implementing partial CCS to the degree necessary to achieve an emission of 1,400 lb CO_2/MWh-g is the BSER. Contrary to the January 2014 proposal, the EPA finds that IGCC technology—either with natural gas co-firing or implementing partial CCS—is not part of the BSER, but recognizes that IGCC technology can serve as an alternative method of compliance.

The EPA finds that a highly efficient SCPC implementing partial CCS is the BSER because CCS technology has been demonstrated to be technically feasible and is in use or under construction in various industrial sectors, including the power generation sector. For example, the Boundary Dam Unit #3 CCS project in Saskatchewan, Canada is a full-scale, fully integrated CCS project that is currently operating and is designed to capture more than 90 percent of the CO_2 from the lignite-fired boiler. A newly constructed, highly efficient SCPC utility boiler burning bituminous coal will be able to meet this final standard of performance by capturing and storing approximately 16 percent of the CO_2 produced from the facility. A newly constructed, highly efficient SCPC utility boiler burning subbituminous coal or dried lignite[7] will be able to meet this final standard of performance by capturing and storing approximately 23 percent of the CO_2 produced from the facility. As an alternative compliance option, utilities and project developers will also be able to construct new steam generating units (both utility boilers and IGCC units) that meet the final standard of performance by co-firing with natural gas. This final standard of performance for newly constructed fossil fuel-fired steam generating units provides a clear and achievable path forward for the construction of such sources while addressing GHG emissions and supporting technological innovation. The standard of 1,400 lb CO_2/MWh-g is achievable by fossil fuel-fired steam generating units for all fuel types, under a wide range of conditions, and throughout the United States.

We note that identifying a highly efficient new SCPC EGU implementing partial CCS as the BSER provides a path forward for new fossil fuel-fired steam generation in the current market context. Numerous studies have predicted that few new fossil fuel-fired steam generating units will be constructed in the future. These analyses identify a range of factors unrelated to this rulemaking, including low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy. The EPA recognizes that, in certain circumstances, there may be interest in building fossil fuel-fired steam generating units despite these market conditions. In particular, utilities and project developers may build new fossil fuel-fired steam generating EGUs in order to achieve or maintain fuel diversity within generating fleets, as a hedge against the possibility of natural gas prices far exceeding projections, or to co-produce both power and chemicals, including capturing CO_2 for use in enhanced oil

[3] The term ''multi-fuel-fired'' refers to a stationary combustion turbine that is physically connected to a natural gas pipeline, but that burns a fuel other than natural gas for 10 percent or more of the unit's heat input capacity during the 12-operating-month compliance period.

[4] The emission standard for combustion turbines co-firing natural gas with other fuels shall be determined at the end of each operating month based on the amount of co-fired natural gas. Units only burning natural gas with other fuels with a relatively consistent chemical composition and an emission factor of 160 lb CO_2/MMBtu or less (*e.g.,* natural gas, distillate oil, etc.) only need to maintain records of the fuels burned at the unit to demonstrate compliance. Units burning fuels with variable chemical composition or with an emission factor greater than 160 lb CO_2/MMBtu (*e.g.,* residual oil) must conduct periodic fuel sampling and testing to determine the overall CO_2 emission rate.

[5] Also referred to as just ''steam generating units'' or as ''utility boilers and IGCC units''. These are units that are covered under 40 CFR part 60, subpart Da for criteria pollutants.

[6] Using the most recent data on partial capture rates to meet an emission standard of 1,100 lb CO_2/MWh-gross, about 35 percent capture would be required at an SCPC unit and about 22 percent capture would be required at an IGCC unit.

[7] For a summary of lignite drying technologies, see ''Techno-economics of modern pre-drying technologies for lignite-fired power plants'' available at *www.iea-coal.org.uk/documents/83436/9095/Techno-economics-of-modern-pre-drying-technologies-for-lignite-fired-power-plants,-CCC/241*; ''Drying the lignite prior to combustion in the boiler is thus an effective way to increase the thermal efficiencies and reduce the CO_2 emissions from lignite-fired power plants.''

recovery (EOR) projects.[8] As regulatory history has shown, identifying a new highly efficient SCPC EGU implementing partial CCS as the BSER in this rule is likely to further boost research and development in CCS technologies, making the implementation even more efficacious and cost-effective, while providing a competitive, low emission future for fossil fuel-fired steam generation.

The EPA is also issuing final standards for steam generating units that implement ''large modifications,'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent when compared to the source's highest hourly emissions in the previous 5 years).[9] The EPA is not issuing final standards, at this time, for steam generating units that implement ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent when compared to the source's highest hourly emissions in the previous 5 years).

The standards of performance for modified steam generating units that make large modifications are based on each affected unit's own best potential performance as the BSER. Specifically, such a modified steam generating unit will be required to meet a unit-specific CO_2 emission limit determined by that unit's best demonstrated historical performance (in the years from 2002 to the time of the modification).[10] The EPA has determined that this standard based on each unit's own best potential performance can be met through a combination of best operating practices and equipment upgrades and that these steps can be implemented cost-effectively at the time when a source is undertaking a large modification. To account for facilities that have already implemented best practices and equipment upgrades, the final rule also specifies that modified facilities will not have to meet an emission standard more stringent than the corresponding standard for reconstructed steam generating units (*i.e.,* 1,800 lb CO_2/MWh-g for units with heat input greater than 2,000 MMBtu/h and 2,000 lb CO_2/MWh-g for units with heat input less than or equal to 2,000 MMBtu/h).

The final standards for steam generating units implementing large modifications are similar to the proposed standards for such units. In the proposal, we suggested that the standard should be based on when the modification is undertaken (*i.e.,* before being subject to requirements under a CAA section 111(d) state plan or after being subject to such a plan). We also suggested that for units that undertake modifications prior to becoming subject to an approved CAA section 111(d) state plan, the standard should be its best historical performance plus an additional two percent reduction. In response to comments on the proposal, we are not finalizing separate standards that are dependent upon when the modification takes place, nor are we finalizing the proposed additional two percentage reduction.

The EPA is not promulgating final standards of performance for, and is withdrawing the proposed standards for steam generating sources that make modifications resulting in an increase of hourly CO_2 emissions of less than or equal to 10 percent (see Section XV of this preamble). As we indicated in the proposal, the EPA has been notified of very few modifications for criteria pollutant emissions from the power sector to which NSPS requirements have applied. As such, we expect that there will be few NSPS modifications for GHG emissions as well. Even so, we also recognize (and we discuss in this preamble) that the power sector is undergoing significant change and realignment in response to a variety of influences and incentives in the industry. We do not have sufficient information at this time, however, to anticipate the types of modifications, if any, that may result from these changes. In particular, we do not have sufficient information about the types of modifications, if any, that would result in increases in CO_2 emissions of 10 percent or less, and what the appropriate standard for such sources would be. Therefore, we conclude that it is prudent to delay issuing standards for sources that undertake small modifications (*i.e.,* those resulting in an increase in CO_2 emissions of less than or equal to 10 percent).

For reconstructed steam generating units, the EPA is finalizing standards based on the performance of the most efficient generating technology for these types of units as the BSER (*i.e.,* reconstructing the boiler if necessary to use steam with higher temperature and pressure, even if the boiler was not originally designed to do so).[11] The emission standard for these sources is 1,800 lb CO_2/MWh-g for large sources, (*i.e.* those with a heat input rating of greater than 2,000 MMBtu/h) or 2,000 lb CO_2/MWh-g for small sources (*i.e.,* those with a heat input rating of 2,000 MMBtu/h or less). The difference in the 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 can also be met through other non-BSER options, such as natural gas co-firing.

b. Stationary Combustion Turbines

This action also finalizes standards of performance for newly constructed and reconstructed stationary combustion turbines. In the January 2014 proposal for newly constructed EGUs, the EPA proposed that natural gas-fired stationary combustion turbines (*i.e.,* turbines combusting over 90 percent natural gas) would be subject to a standard of performance for CO_2 emissions if they are constructed for the purpose of supplying and actually annually supply to the grid (1) one-third or more of their potential electric output[12] and (2) more than 219,000 MWh,[13] based on a three-year rolling average. We refer to units that operate above the electric sales thresholds as ''base load units,'' and we refer to units that operate below these thresholds as ''non-base load units.''

In the January 2014 proposal for newly constructed combustion turbines, the EPA proposed standards for two subcategories of base load natural gas-fired stationary combustion turbines. The proposed standard for small combustion turbines (units with base load ratings less than or equal to 850 MMBtu/h) was 1,100 lb CO_2/MWh-g. The proposed standard for large combustion turbines (units with base

[8] As the EIA has stated: Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on *portfolio diversification.* While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations. *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[9] 40 CFR 60.14(h) provides that no physical change, or change in the method of operation, at an existing electric utility steam generating unit will be treated as a modification provided that such change does not increase the maximum hourly emissions above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

[10] For the 2002 reporting year the EPA introduced new automated checks in the software that integrated automated quality assurance (QA) checks on the hourly data. Thus, the EPA believes that the data from 2002 and forward are of higher quality.

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

[12] We refer to thresholds related to an EGU's actual annual electrical sales (as a fraction of potential annual output) as ''percentage electric sales criteria.''

[13] We refer to thresholds related to an EGU's actual annual electrical sales in megawatt-hours as ''total electric sales criteria.''

load ratings greater than 850 MMBtu/h) was 1,000 lb CO_2/MWh-g. The EPA did not propose standards for non-base load units.

In the June 2014 proposal for modified and reconstructed combustion turbines, the EPA solicited comment on alternative approaches for establishing applicability and subcategorization criteria, including (1) eliminating the ''constructed for the purpose of supplying'' qualifier for the total electric sales and percentage electric sales criteria, (2) eliminating the 219,000 MWh total electric sales criterion altogether, (3) replacing the fixed percentage electric sales criterion with a variable percentage electric sales criterion (*i.e.,* the sliding-scale approach[14]), and (4) eliminating the proposed small and large subcategories for base load natural gas-fired combustion turbines. These proposed applicability requirements were intended to exclude combustion turbines that are used for the purpose of meeting peak power demand, as opposed to those that are used to meet base load power demand.

In both proposals, the EPA also solicited comment on a broad applicability approach that would include non-base load natural gas-fired units (primarily simple cycle combustion turbines) and multi-fuel-fired units (primarily distillate oil-fired combustion turbines) in the general applicability of subpart TTTT. As part of the broad applicability approach, the EPA solicited comment on imposing ''no emission standard'' or establishing separate numerical limits for these two subcategories.

In this action, the EPA is finalizing a variation of the approaches put forward in the January 2014 proposal for new sources and the June 2014 proposal for modified and reconstructed sources. Based on our review of public comments related to the proposed subcategories for small and large combustion turbines and our additional data analyses, we have determined that there is no need to set two separate standards for different sizes of combustion turbines for base load natural gas-fired combustion turbines. The EPA has determined that all sizes of affected newly constructed and reconstructed stationary combustion turbines can achieve the final standards. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA is finalizing a standard of 1,000 lb CO_2/MWh-g based on efficient natural gas combined cycled (NGCC) technology as the BSER. Alternatively, owners and operators of base load natural gas-fired combustion turbines may elect to comply with a standard based on net output of 1,030 lb CO_2/MWh-n.

The EPA is eliminating the 219,000 MWh total annual electric sales criterion for non-CHP units. In addition, the EPA is finalizing the sliding-scale approach for deriving the unit-specific, percentage electric sales threshold above which a combustion turbine transitions from the subcategory for non-base load units to the subcategory for base load units. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines, the EPA is finalizing the combustion of clean fuels (natural gas with a small allowance for distillate oil) as the BSER with a corresponding heat input-based standard of 120 lb CO_2/MMBtu. This standard of performance will apply to the vast majority of simple cycle combustion turbines. The EPA is finalizing a heat input-based clean fuels standard because we have insufficient information at this time to set a uniform output-based standard that can be achieved by all new and reconstructed non-base load units.

In addition, for newly constructed and reconstructed multi-fuel-fired stationary combustion turbines, the EPA is finalizing an input-based standard of 120 to 160 lb CO_2/MMBtu based on the combustion of clean fuels as the BSER.[15] The EPA has similarly determined that it has insufficient information at this time to set a uniform output-based standard for stationary combustion turbines that operate with significant quantities of a fuel other than natural gas.

We are not promulgating final standards of performance for stationary combustion turbines that make modifications at this time. We are simultaneously withdrawing the proposed standards for modifications (see Section XV of this preamble). As we indicated in the proposal, sources from the power sector have notified the EPA of very few NSPS modifications, and we expect that there will be few NSPS modifications for CO_2 emissions as well. Moreover, our decision to eliminate the subcategories for small and large EGUs and set a single standard of 1,000 lb CO_2/MWh-g has raised questions as to whether smaller existing combustion turbines that undertake a modification can meet this standard. As a result, we have concluded that it is prudent to delay issuing standards for sources that undertake modifications until we can gather more information.

A more detailed discussion of the final standards of performance for stationary combustion turbines, the applicability criteria, and the comments that influenced the final standards is provided in Sections VIII and IX of this preamble.

3. Costs and Benefits

As explained in the regulatory impact analysis (RIA) for this final rule, available data—including utility announcements and Energy Information Administration (EIA) modeling—indicate that, even in the absence of this rule, (i) existing and anticipated economic conditions are such that few, if any, fossil fuel-fired steam-generating EGUs will be built in the foreseeable future, and (ii) utilities and project developers are expected to choose new generation technologies (primarily NGCC) that would meet the final standards and renewable generating sources that are not affected by these final standards. These projections are consistent with utility announcements and EIA modeling that indicate that new units are likely to be NGCC and that any coal-fired steam generating units built between now and 2030 would have CCS, even in the absence of this rule.[16] Therefore, based on the analysis presented in Chapter 4 of the RIA, the EPA projects that this final rule will result in negligible CO_2 emission changes, quantified benefits, and costs by 2022 as a result of the performance standards for newly constructed EGUs.[17] However, as noted earlier, for a variety of reasons, some companies may consider coal-fired steam generating units that the modeling does not anticipate. Thus, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a newly constructed coal-fired steam generating unit with partial CCS that meets the requirements of this final rule alongside the project-level costs of a newly constructed coal-fired unit without CCS. This analysis indicates that the

[14] The sliding-scale approach determines a unit-specific percentage electric sales threshold equivalent to a unit's net design efficiency (the maximum value is capped at 50 percent).

[15] Combustion turbines co-firing natural gas with other fuels shall determine fuel-based site-specific standards at the end of each operating month. The site-specific standards depend on the amount of co-fired natural gas.

[16] The EPA's Integrated Planning Model (IPM) projects no new non-compliant coal (*i.e.,* newly constructed coal-fired plants that do not meet the final standard of performance) throughout the model horizon of 2030 (there is a small amount of new coal with CCS that is hardwired into the modelling, consistent with EIA assumptions to represent units already under construction or under development).

[17] Conditions in the analysis year of 2022 are represented by a model year of 2020.

quantified benefits of the standards of performance would exceed their costs under a range of assumptions.

As explained in the RIA and further below, the EPA has been notified of few power sector NSPS modifications or reconstructions. Based on that experience, the EPA expects that few EGUs will trigger either the modification or the reconstruction provisions that we are finalizing in this action. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

B. Does this action apply to me?

The entities potentially affected by the 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 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 action. To determine whether your facility, company, business, organization, etc., would be regulated by this action, refer to Section III of this preamble for more information and examine the applicability criteria in 40 CFR 60.1 (General Provisions) and § 60.550840 of subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units). If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

C. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this final action will also be available on the Worldwide Web (WWW). Following signature, a copy of this final action will be posted at the following address: *http://www2.epa.gov/carbon-pollution-standards.*

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by December 22, 2015. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism mandating the EPA to convene a proceeding for reconsideration if the person raising an objection can demonstrate that it was impracticable to raise such objection within the period for public comment or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule. Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

E. How is this preamble organized?

This action presents the EPA's final standards of performance for newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and newly constructed and reconstructed stationary combustion turbines. Section II provides background information on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs, the utility power sector, the statutory and regulatory background relating to CAA section 111(b), EPA actions prior to this final action, and public comments regarding the proposed actions. Section III explains the EPA's authority to regulate CO_2 and EGUs, identifies affected EGUs, and describes the source categories. Section IV provides a summary of the final standards for newly constructed, modified, and reconstructed fossil fuel-fired steam generating units. Sections V through VII present the rationale for the final standards for newly constructed, modified, and reconstructed steam generating units, respectively. Sections VIII and IX provide a summary of the final standards for stationary combustion turbines and present the rationale for the final standards for newly constructed and reconstructed combustion turbines, respectively. Section X provides a summary of other final requirements for newly constructed, modified, and reconstructed fossil fuel-fired steam generating units and stationary combustion turbines. Section XI addresses the consistency of the respective BSER determinations in these rules and under the emission guidelines issued separately under CAA section 111(d). Interactions with other EPA programs and rules are described in Section XII. Projected impacts of the final action are then described in Section XIII, followed by a discussion of statutory and executive order reviews in Section XIV. Section XV addresses the withdrawal of the proposed standards for steam generating EGUs that make modifications resulting in an increase of hourly CO_2 emissions of less than or equal to 10 percent and the proposed standards for modified stationary combustion turbines. The statutory authority for this action is provided in Section XVI. We address major comments throughout this preamble and in greater detail in an accompanying response-to-comments document located in the docket.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare. We also present information about GHG emissions from fossil fuel-fired EGUs and describe the utility power sector and its changing structure. We then summarize the statutory and regulatory background relevant to this final rulemaking. In addition, we provide background information on the EPA's January 8, 2014 proposed carbon pollution standards for newly constructed fossil fuel-fired EGUs, the June 18, 2014 proposed carbon pollution standards for modified and reconstructed EGUs, and other actions associated with this final rulemaking. We close this section with a general discussion of comments and stakeholder input that the EPA received prior to issuing this final rulemaking.

A. Climate Change Impacts From GHG Emissions

According to the National Research Council, ''Emissions of CO_2 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 CO_2 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 reduction choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.'' [18]

In 2009, based on a large body of robust and compelling scientific evidence, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1).[19] In the Endangerment Finding, the Administrator found that the current, elevated concentrations of GHGs in the atmosphere—already at levels unprecedented in human history—may reasonably be anticipated to endanger public health and welfare of current and future generations in the United States. We summarize these adverse effects on public health and welfare briefly here.

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens the health of Americans 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., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Climate change is also expected to cause more intense hurricanes and more frequent and intense storms and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders. 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

Climate change impacts touch nearly every aspect of public welfare. Among the multiple threats caused by human emissions of GHGs, climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face a multitude of increased risks, particularly from rising sea level and increases in the severity of storms. These communities face storm and flood damage to property, or even loss of land due to inundation, erosion, wetland submergence and habitat loss.

Impacts of climate change on public welfare also include threats to social and ecosystem services. Climate change is expected to result in an increase in peak electricity demand. Extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may also exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities, and 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 and Observations

Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, the climate has continued to change, with new records being set for a number of climate indicators such as global average surface temperatures, Arctic sea ice retreat, CO_2 concentrations, and sea level rise. Additionally, a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare both for current and future generations. These assessments, from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program (USGCRP), and the National Research Council (NRC), include: 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 National Climate Assessment, *Climate Change Impacts in the United States* (NCA3), 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 carefully reviewed these recent assessments in keeping with the same approach outlined in Section III.A of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, the IPCC, and the NRC of the National Academies to provide the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare. These

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

[19] ''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'').

assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review.

The findings of the recent scientific assessments confirm and strengthen the conclusion that GHGs endanger public health, now and in the future. The NCA3 indicates that human health in the United States will be impacted by ''increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks.'' The most recent assessments now have greater confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis. Both the NCA3 and the IPCC AR5 found that increasing temperature has lengthened the allergenic pollen season for ragweed, and that increased CO_2 by itself can elevate production of plant-based allergens.

The NCA3 also finds that climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting indigenous peoples' health in the United States through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards. The IPCC AR5 finds that climate change-induced warming in the Arctic and resultant changes in environment (*e.g.,* permafrost thaw, effects on traditional food sources) have significant impacts, observed now and projected, on the health and well-being of Arctic residents, especially indigenous peoples. Small, remote, predominantly-indigenous communities are especially vulnerable given their ''strong dependence on the environment for food, culture, and way of life; their political and economic marginalization; existing social, health, and poverty disparities; as well as their frequent close proximity to exposed locations along ocean, lake, or river shorelines.'' [20] In addition, increasing temperatures and loss of Arctic sea ice increases the risk of drowning for those engaged in traditional hunting and fishing.

The NCA3 concludes that children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. The IPCC AR5 indicates that children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. The IPCC finds that additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

Both the NCA3 and IPCC AR5 conclude that climate change will increase health risks facing the elderly. Older people are at much higher risk of mortality during extreme heat events. Pre-existing health conditions also make older adults susceptible to cardiac and respiratory impacts of air pollution and to more severe consequences from infectious and waterborne diseases. Limited mobility among older adults can also increase health risks associated with extreme weather and floods.

The new assessments also confirm and strengthen the conclusion that GHGs endanger public welfare, and emphasize the urgency of reducing GHG emissions due to their projections that show GHG concentrations climbing to ever-increasing levels in the absence of mitigation. The NRC assessment, *Understanding Earth's Deep Past,* projected that, without a reduction in emissions, CO_2 concentrations by the end of the century would increase to levels that the Earth has not experienced for more than 30 million years.[21] 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.'' [22] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds. As stated in the assessment, ''As Earth continues to warm, it may be approaching a critical climate threshold beyond which rapid and potentially permanent—at least on a human timescale—changes not anticipated by climate models tuned to modern conditions may occur.'' The NRC *Abrupt Impacts* report analyzed abrupt climate change in the physical climate system and abrupt impacts of ongoing changes that, when thresholds are crossed, can cause abrupt impacts for society and ecosystems. The report considered destabilization of the West Antarctic Ice Sheet (which could cause 3–4 m of potential sea level rise) as an abrupt climate impact with unknown but probably low probability of occurring this century. The report categorized a decrease in ocean oxygen content (with attendant threats to aerobic marine life); increase in intensity, frequency, and duration of heat waves; and increase in frequency and intensity of extreme precipitation events (droughts, floods, hurricanes, and major storms) as climate impacts with moderate risk of an abrupt change within this century. The NRC *Abrupt Impacts* report also analyzed the threat of rapid state changes in ecosystems and species extinctions as examples of irreversible impacts that are expected to be exacerbated by climate change. Species at most risk include those whose migration potential is limited, whether because they live on mountaintops or fragmented habitats with barriers to movement, or because climatic conditions are changing more rapidly than the species can move or adapt. While the NRC determined that it is not presently possible to place exact probabilities on the added contribution of climate change to extinction, they did find that there was substantial risk that impacts from climate change could, within a few decades, drop the populations in many species below sustainable levels, thereby committing the species to extinction. Species within tropical and subtropical rainforests such as the Amazon and species living in coral reef ecosystems were identified by the NRC as being particularly vulnerable to extinction over the next 30 to 80 years, as were species in high latitude and high elevation regions. Moreover, due to the time lags inherent in the Earth's climate, the NRC *Climate Stabilization Targets* assessment notes that the full warming from any given concentration of CO_2 reached will not be fully realized for several centuries, underscoring that emission activities today carry with them climate commitments far into the future.

Future temperature changes will depend on what emission path the world follows. In its high emission scenario, the IPCC AR5 projects that

[20] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, p. 1581.

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

[22] *Id.*, p. 138.

average global temperatures by the end of the century will likely be 2.6 degrees Celsius (°C) to 4.8 °C (4.7 to 8.6 degrees Fahrenheit (°F)) warmer than today. Temperatures on land and in northern latitudes will likely warm even faster than the global average. However, according to the NCA3, significant reductions in emissions would lead to noticeably less future warming beyond mid-century, and therefore less impact to public health and welfare.

While rainfall may only see small globally and annually averaged changes, there are expected to be substantial shifts in where and when that precipitation falls. According to the NCA3, regions closer to the poles will see more precipitation, while the dry subtropics are expected to expand (colloquially, this has been summarized as wet areas getting wetter and dry regions getting drier). In particular, the NCA3 notes that the western U.S., and especially the Southwest, is expected to become drier. This projection is consistent with the recent observed drought trend in the West. At the time of publication of the NCA, even before the last 2 years of extreme drought in California, tree ring data was already indicating that the region might be experiencing its driest period in 800 years. Similarly, the NCA3 projects that heavy downpours are expected to increase in many regions, with precipitation events in general becoming less frequent but more intense. This trend has already been observed in regions such as the Midwest, Northeast, and upper Great Plains. Meanwhile, the NRC Climate Stabilization Targets assessment found that the area burned by wildfire is expected to grow by 2 to 4 times for 1 °C (1.8 °F) of warming. For 3 °C of warming, the assessment found that 9 out of 10 summers would be warmer than all but the 5 percent of warmest summers today, leading to increased frequency, duration, and intensity of heat waves. Extrapolations by the NCA also indicate that Arctic sea ice in summer may essentially disappear by mid-century. Retreating snow and ice, and emissions of CO_2 and methane released from thawing permafrost, will also amplify future warming.

Since the 2009 Endangerment Finding, the USGCRP NCA3, and multiple NRC assessments have projected future rates of sea level rise that are 40 percent larger to more than twice as large as the previous estimates from the 2007 IPCC 4th Assessment Report due in part to improved understanding of the future rate of melt of the Antarctic and Greenland Ice sheets. The NRC *Sea Level Rise* assessment projects a global sea level rise of 0.5 to 1.4 meters (1.6 to 4.6 feet) by 2100, the NRC *National Security Implications* assessment suggests that ''the Department of the Navy should expect roughly 0.4 to 2 meters (1.3 to 6.6 feet) global average sea-level rise by 2100,'' [23] and the NRC *Climate Stabilization Targets* assessment states that an increase of 3 °C will lead to a sea level rise of 0.5 to 1 meter (1.6 to 3.3 feet) by 2100. These assessments continue to recognize that there is uncertainty inherent in accounting for ice sheet processes. Additionally, local sea level rise can differ from the global total depending on various factors. The east coast of the U.S. in particular is expected to see higher rates of sea level rise than the global average. For comparison, the NCA3 states that ''five million Americans and hundreds of billions of dollars of property are located in areas that are less than four feet above the local high-tide level,'' and the NCA3 finds that ''[c]oastal infrastructure, including roads, rail lines, energy infrastructure, airports, port facilities, and military bases, are increasingly at risk from sea level rise and damaging storm surges.'' [24] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations have stabilized (though more slowly than it would have otherwise). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting. According to the NCA, some recent research has suggested that even present day CO_2 levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the United States and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds that climate change impacts such as the rapid pace of temperature rise, coastal erosion and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the U.S. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, ''[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied.'' [25] The IPCC AR5 notes, ''Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity.'' [26]

CO_2 in particular has unique impacts on ocean ecosystems. The NRC *Climate Stabilization Targets* assessment found that coral bleaching will increase due both to warming and ocean acidification. Ocean surface waters have already become 30 percent more acidic over the past 250 years due to absorption of CO_2 from the atmosphere. According to the NCA3, this acidification will reduce the ability of organisms such as corals, krill, oysters, clams, and crabs to survive, grow, and reproduce. The NRC *Understanding Earth's Deep Past* assessment notes that four of the five major coral reef crises of the past 500 million years were caused by acidification and warming that followed GHG increases of similar magnitude to the emissions increases expected over the next hundred years. The NRC *Abrupt Impacts* assessment specifically highlighted similarities between the projections for future acidification and warming and the extinction at the end of the Permian which resulted in the loss of an estimated 90 percent of known species. Similarly, the NRC *Ocean Acidification* assessment finds that ''[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic CO_2 emissions; the rate of change exceeds any known to have occurred for at least the past

[23] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces.* The National Academies Press, p. 28.

[24] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 9.

[25] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 17.

[26] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, p. 796.

hundreds of thousands of years.'' [27] The assessment notes that the full range of consequences is still unknown, but the risks ''threaten coral reefs, fisheries, protected species, and other natural resources of value to society.'' [28]

Events outside the United States, as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences. The NRC *Climate and Social Stress* assessment concluded that it is prudent to expect that some climate events ''will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response.'' The NRC *National Security Implications* assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by human emissions of GHGs is already happening now and it is happening in the United States. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are projected to accelerate in the future. The planet warmed about 0.85 °C (1.5 °F) from 1880 to 2012. It is extremely likely (>95 percent probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66 percent probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30-year period of the last 1400 years. U.S. average temperatures have similarly increased by 1.3 to 1.9 °F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 m (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice have melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets has increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year respectively, since 2002. For context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 mm. Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s, by up to 3 °C (5.4 °F) in parts of Northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. 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, far above preindustrial concentrations of about 280 parts per million.[29] The average concentration in 2013, the last full year before this rule was proposed, was 396 parts per million. The average concentration in 2014 was 399 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years based on ice core records.[30] Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below the 1979–2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[31] And 2014 was the warmest year globally in the modern global surface temperature record, going back to 1880; this now means 19 of the 20 warmest years have occurred in the past 20 years, and except for 1998, the ten warmest years on record have occurred since 2002.[32] The first months of 2015 have also been some of the warmest on record.

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change, and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons ''why it is imprudent to delay actions that at least begin the process of substantially reducing emissions.'' [33] For example:

- The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range of adverse impacts, especially if the sensitivity of the climate to greenhouse gases is on the higher end of the estimated range.
- Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of greenhouse gas emissions do not fully manifest themselves for decades and, once manifest, many of these changes will persist for hundreds or even thousands of years.
- In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

4. Observed and Projected U.S. Regional Changes

The NCA3 assessed the climate impacts in eight regions of the United States, noting that changes in physical climate parameters such as temperatures, precipitation, and sea ice retreat were already having impacts on forests, water supplies, ecosystems, flooding, heat waves, and air quality. Moreover, the NCA3 found that future warming is projected to be much larger than recent observed variations in temperature, with precipitation likely to increase in the northern states, decrease in the southern states, and with the heaviest precipitation events projected to increase everywhere.

In the Northeast, temperatures increased almost 2 °F from 1895 to 2011, precipitation increased by about 5 inches (10 percent), and sea level rise of about a foot has led to an increase in coastal flooding. The 70 percent increase in the amount of rainfall falling in the 1 percent of the most intense events is a larger increase in extreme precipitation than experienced in any other U.S. region.

In the future, if emissions continue increasing, the Northeast is expected to experience 4.5 to 10 °F of warming by

[27] NRC, 2010: *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean.* The National Academies Press, p. 5.

[28] *Id.*

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

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

[31] Blunden, J., and D. S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1–S238.

[32] *http://www.ncdc.noaa.gov/sotc/global/2014/13.*

[33] NRC, 2011: *America's Climate Choices,* The National Academies Press.

the 2080s. This will lead to more heat waves, coastal and river flooding, and intense precipitation events. The southern portion of the region is projected to see 60 additional days per year above 90 °F by mid-century. Sea levels in the Northeast are expected to increase faster than the global average because of subsidence, and changing ocean currents may further increase the rate of sea level rise. Specific vulnerabilities highlighted by the NCA include large urban populations particularly vulnerable to climate-related heat waves and poor air quality episodes, prevalence of climate sensitive vector-borne diseases like Lyme and West Nile Virus, usage of combined sewer systems that may lead to untreated water being released into local water bodies after climate-related heavy precipitation events, and 1.6 million people living within the 100-year coastal flood zone who are expected to experience more frequent floods due to sea level rise and tropical-storm induced storm-surge. The NCA also highlighted infrastructure vulnerable to inundation in coastal metropolitan areas, potential agricultural impacts from increased rain in the spring delaying planting or damaging crops or increased heat in the summer leading to decreased yields and increased water demand, and shifts in ecosystems leading to declines in iconic species in some regions, such as cod and lobster south of Cape Cod.

In the Southeast, average annual temperature during the last century cycled between warm and cool periods. A warm peak occurred during the 1930s and 1940s, followed by a cool period, and temperatures then increased again from 1970 to the present by an average of 2 °F. There have been increasing numbers of days above 95 °F and nights above 75 °F, and decreasing numbers of extremely cold days since 1970. Daily and five-day rainfall intensities have also increased, and summers have been either increasingly dry or extremely wet. Louisiana has already lost 1,880 square miles of land in the last 80 years due to sea level rise and other contributing factors.

The Southeast is exceptionally vulnerable to sea level rise, extreme heat events, hurricanes, and decreased water availability. Major consequences of further warming include significant increases in the number of hot days (95 °F or above) and decreases in freezing events, as well as exacerbated ground-level ozone in urban areas. Although projected warming for some parts of the region by the year 2100 is generally smaller than for other regions of the United States, projected warming for interior states of the region is larger than coastal regions by 1 °F to 2 °F. Projections further suggest that there will be fewer tropical storms globally, but that they will be more intense, with more Category 4 and 5 storms. The NCA identified New Orleans, Miami, Tampa, Charleston, and Virginia Beach as being specific cities that are at risk due to sea level rise, with homes and infrastructure increasingly prone to flooding. Additional impacts of sea level rise are expected for coastal highways, wetlands, fresh water supplies, and energy infrastructure.

In the Northwest, temperatures increased by about 1.3 °F between 1895 and 2011. A small average increase in precipitation was observed over this time period. However, warming temperatures have caused increased rainfall relative to snowfall, which has altered water availability from snowpack across parts of the region. Snowpack in the Northwest is an important freshwater source for the region. More precipitation falling as rain instead of snow has reduced the snowpack, and warmer springs have corresponded to earlier snowpack melting and reduced streamflows during summer months. Drier conditions have increased the extent of wildfires in the region.

Average annual temperatures are projected to increase by 3.3 °F to 9.7 °F by the end of the century (depending on future global GHG emissions), with the greatest warming expected during the summer. Continued increases in global GHG emissions are projected to result in up to a 30 percent decrease in summer precipitation. Earlier snowpack melt and lower summer stream flows are expected by the end of the century and will affect drinking water supplies, agriculture, ecosystems, and hydropower production. Warmer waters are expected to increase disease and mortality in important fish species, including Chinook and sockeye salmon. Ocean acidification also threatens species such as oysters, with the Northwest coastal waters already being some of the most acidified worldwide due to coastal upwelling and other local factors. Forest pests are expected to spread and wildfires to burn larger areas. Other high-elevation ecosystems are projected to be lost because they can no longer survive the climatic conditions. Low lying coastal areas, including the cities of Seattle and Olympia, will experience heightened risks of sea level rise, erosion, seawater inundation and damage to infrastructure and coastal ecosystems.

In Alaska, temperatures have changed faster than anywhere else in the United States. Annual temperatures increased by about 3 °F in the past 60 years. Warming in the winter has been even greater, rising by an average of 6 °F. Arctic sea ice is thinning and shrinking in area, with the summer minimum ice extent now covering only half the area it did when satellite records began in 1979. Glaciers in Alaska are melting at some of the fastest rates on Earth. Permafrost soils are also warming and beginning to thaw. Drier conditions have contributed to more large wildfires in the last 10 years than in any previous decade since the 1940s, when recordkeeping began. Climate change impacts are harming the health, safety, and livelihoods of Native Alaskan communities.

By the end of this century, continued increases in GHG emissions are expected to increase temperatures by 10 to 12 °F in the northernmost parts of Alaska, by 8 to 10 °F in the interior, and by 6 to 8 °F across the rest of the state. These increases will exacerbate ongoing arctic sea ice loss, glacial melt, permafrost thaw and increased wildfire, and threaten humans, ecosystems, and infrastructure. Precipitation is expected to increase to varying degrees across the state. However, warmer air temperatures and a longer growing season are expected to result in drier conditions. Native Alaskans are expected to experience declines in economically, nutritionally, and culturally important wildlife and plant species. Health threats will also increase, including loss of clean water, saltwater intrusion, sewage contamination from thawing permafrost, and northward extension of diseases. Wildfires will increasingly pose threats to human health as a result of smoke and direct contact. Areas underlain by ice-rich permafrost across the state are likely to experience ground subsidence and extensive damage to infrastructure as the permafrost thaws. Important ecosystems will continue to be affected. Surface waters and wetlands that are drying provide breeding habitat for millions of waterfowl and shorebirds that winter in the lower 48 states. Warmer ocean temperatures, acidification, and declining sea ice will contribute to changes in the location and availability of commercially and culturally important marine fish.

In the Southwest, temperatures are now about 2 °F higher than the past century, and are already the warmest that region has experienced in at least 600 years. The NCA notes that there is evidence that climate change-induced warming on top of recent drought has influenced tree mortality, wildfire frequency and area, and forest insect outbreaks. Sea levels have risen about 7 or 8 inches in this region, contributing to inundation of Highway 101 and back up of seawater into sewage systems in the San Francisco area.

Projections indicate that the Southwest will warm an additional 5.5 to 9.5 °F over the next century if emissions continue to increase. Winter snowpack in the Southwest is projected to decline (consistent with the record lows from this past winter), reducing the reliability of surface water supplies for cities, agriculture, cooling for power plants, and ecosystems. Sea level rise along the California coast will worsen coastal erosion, increase flooding risk for coastal highways, bridges, and low-lying airports, pose a threat to groundwater supplies in coastal cities such as Los Angeles, and increase vulnerability to floods for hundreds of thousands of residents in coastal areas. Climate change will also have impacts on the high-value specialty crops grown in the region as a drier climate will increase demands for irrigation, more frequent heat waves will reduce yields, and decreased winter chills may impair fruit and nut production for trees in California. Increased drought, higher temperatures, and bark beetle outbreaks are likely to contribute to continued increases in wildfires. The highly urbanized population of the Southwest is vulnerable to heat waves and water supply disruptions, which can be exacerbated in cases where high use of air conditioning triggers energy system failures.

The rate of warming in the Midwest has markedly accelerated over the past few decades. Temperatures rose by more than 1.5 °F from 1900 to 2010, but between 1980 and 2010, the rate of warming was three times faster than from 1900 through 2010. Precipitation generally increased over the last century, with much of the increase driven by intensification of the heaviest rainfalls. Several types of extreme weather events in the Midwest (*e.g.,* heat waves and flooding) have already increased in frequency and/or intensity due to climate change.

In the future, if emissions continue increasing, the Midwest is expected to experience 5.6 to 8.5 °F of warming by the 2080s, leading to more heat waves. Though projections of changes in total precipitation vary across the regions, more precipitation is expected to fall in the form of heavy downpours across the entire region, leading to an increase in flooding. Specific vulnerabilities highlighted by the NCA include long-term decreases in agricultural productivity, changes in the composition of the region's forests, increased public health threats from heat waves and degraded air and water quality, negative impacts on transportation and other infrastructure associated with extreme rainfall events and flooding, and risks to the Great Lakes including shifts in invasive species, increases in harmful algal blooms, and declining beach health.

High temperatures (more than 100 °F in the Southern Plains and more than 95 °F in the Northern Plains) are projected to occur much more frequently by mid-century. Increases in extreme heat will increase heat stress for residents, energy demand for air conditioning, and water losses. North Dakota's increase in annual temperatures over the past 130 years is the fastest in the contiguous U.S., mainly driven by warming winters. Specific vulnerabilities highlighted by the NCA include increased demand for water and energy, changes to crop-growth cycles and agricultural practices, and negative impacts on local plant and animal species from habitat fragmentation, wildfires, and changes in the timing of flowering or pest patterns. Communities that are already the most vulnerable to weather and climate extremes will be stressed even further by more frequent extreme events occurring within an already highly variable climate system.

In Hawaii, other Pacific islands, and the Caribbean, rising air and ocean temperatures, shifting rainfall patterns, changing frequencies and intensities of storms and drought, decreasing baseflow in streams, rising sea levels, and changing ocean chemistry will affect ecosystems on land and in the oceans, as well as local communities, livelihoods, and cultures. Low islands are particularly at risk.

Rising sea levels, coupled with high water levels caused by tropical and extra-tropical storms, will incrementally increase coastal flooding and erosion, damaging coastal ecosystems, infrastructure, and agriculture, and negatively affecting tourism. Ocean temperatures in the Pacific region exhibit strong year-to-year and decadal fluctuations, but since the 1950s, they have exhibited a warming trend, with temperatures from the surface to a depth of 660 feet rising by as much as 3.6 °F. As a result of current sea level rise, the coastline of Puerto Rico around Rincón is being eroded at a rate of 3.3 feet per year. Freshwater supplies are already constrained and will become more limited on many islands. Saltwater intrusion associated with sea level rise will reduce the quantity and quality of freshwater in coastal aquifers, especially on low islands. In areas where precipitation does not increase, freshwater supplies will be adversely affected as air temperature rises.

Warmer oceans are leading to increased coral bleaching events and disease outbreaks in coral reefs, as well as changed distribution patterns of tuna fisheries. Ocean acidification will reduce coral growth and health. Warming and acidification, combined with existing stresses, will strongly affect coral-reef fish communities. For Hawaii and the Pacific islands, future sea surface temperatures are projected to increase 2.3 °F by 2055 and 4.7 °F by 2090 under a scenario that assumes continued increases in emissions. Ocean acidification is also taking place in the region, which adds to ecosystem stress from increasing temperatures. Ocean acidity has increased by about 30 percent since the pre-industrial era and is projected to further increase by 37 percent to 50 percent from present levels by 2100.

The NCA also discussed impacts that occur along the coasts and in the oceans adjacent to many regions, and noted that other impacts occur across regions and landscapes in ways that do not follow political boundaries.

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired EGUs are by far the largest emitters of GHGs among stationary sources in the U.S., primarily in the form of CO_2. Among fossil fuel-fired EGUs, coal-fired units are by far the largest emitters. This section describes the amounts of these emissions and places these amounts in the context of the U.S. Inventory of Greenhouse Gas Emissions and Sinks [34] (the U.S. GHG Inventory).

The EPA implements a separate program under 40 CFR part 98 called the Greenhouse Gas Reporting Program [35] (GHGRP) that requires emitting facilities that emit over certain threshold amounts of GHGs to report their emissions to the EPA annually. Using data from the GHGRP, this section also places emissions from fossil fuel-fired EGUs in the context of the total emissions reported to the GHGRP from facilities in the other largest-emitting industries.

The EPA prepares the official U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate

[34] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013", Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[35] U.S. EPA Greenhouse Gas Reporting Program Dataset, see *http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.*

Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sector. It provides the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks [36] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2013.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR (MILLION METRIC TONS CARBON DIOXIDE EQUIVALENT (MMT CO_2e)) [37] [38]

Sector	1990	2005	2013
Energy[39]	5,290.5	6,273.6	5,636.6
Industrial Processes and Product Use	342.1	367.4	359.1
Agriculture	448.7	494.5	515.7
Land Use, Land-Use Change and Forestry	13.8	25.5	23.3
Waste	206.0	189.2	138.3
Total Emissions	6,301.1	7,350.2	6,673.0
Land Use, Land-Use Change and Forestry (Sinks)	(775.8)	(911.9)	(881.7)
Net Emissions (Sources and Sinks)	5,525.2	6,438.3	5,791.2

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.3 percent of total 2013 GHG emissions.[40] In 2013, fossil fuel combustion by the utility power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.3 percent of all energy-related CO_2 emissions.[41] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005, and 2013.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (MMT CO_2) [42]

GHG emissions	1990	2005	2013
Total CO_2 from fossil fuel-fired EGUs	1,820.8	2,400.9	2,039.8
—from coal	1,547.6	1,983.8	1,575.0
—from natural gas	175.3	318.8	441.9
—from petroleum	97.5	97.9	22.4

In addition to preparing the official U.S. GHG Inventory to present comprehensive total U.S. GHG emissions and comply with commitments under the UNFCCC, the EPA collects detailed GHG emissions data from the largest emitting facilities in the U.S. through its GHGRP. Data collected by the GHGRP from large stationary sources in the industrial sector show that the utility power sector emits far greater CO_2 emissions than any other industrial sector. Table 5 below presents total GHG emissions in 2013 for the largest emitting industrial sectors as reported to the GHGRP. As shown in Table 4 and Table 5, respectively, CO_2 emissions from fossil fuel-fired EGUs are nearly three times as large as the total reported GHG emissions from the next ten largest emitting industrial sectors in the GHGRP database combined.

TABLE 5—DIRECT GHG EMISSIONS REPORTED TO GHGRP BY LARGEST EMITTING INDUSTRIAL SECTORS (MMT CO_2e) [43]

Industrial sector	2013
Fossil Fuel-Fired EGUs	2,039.8
Petroleum Refineries	176.7
Onshore Oil & Gas Production	94.8
Municipal Solid Waste Landfills	93.0
Iron & Steel Production	84.2
Cement Production	62.8
Natural Gas Processing Plants	59.0
Petrochemical Production	52.7
Hydrogen Production	41.9
Underground Coal Mines	39.8
Food Processing Facilities	30.8

[36] Sinks are physical units or processes that store GHGs, such as forests or underground or deep sea reservoirs of CO_2.

[37] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[38] 1 metric ton (tonne) is equivalent to 1,000 kilograms (kg) and is equivalent to 1.1023 short tons or 2,204.62 pounds (lb).

[39] The energy sector includes all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions.

[40] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[41] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15, 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[42] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013'', Report EPA 430–R–15–004, United States Environmental Protection Agency, April 15 2015. *http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.*

[43] U.S. EPA Greenhouse Gas Reporting Program Dataset as of August 18, 2014. *http://ghgdata.epa.gov/ghgp/main.do.*

It should be noted that the discussion above concerned all fossil fuel-fired EGUs. Steam generators emitted 1,627 MMT CO_2e and combustion turbines emitted 401 MMT CO_2e in 2013.[44]

C. The Utility Power Sector

1. Modern Electric System Trends

The EPA includes a background discussion of the electricity system in the Clean Power Plan (CPP) rulemaking, which is the companion rulemaking to this rule that promulgates emission guidelines for states to use in regulating emissions of CO_2 from existing fossil fuel-fired EGUs. Readers are referred to that rulemaking. The following discussion of electricity sector trends is of particular relevance for this rulemaking.

The electricity sector is undergoing a period of intense change. Fossil fuels—such as coal, natural gas, and oil—have historically provided a large percentage of electricity in the U.S., with smaller amounts being provided by other types of generation, including nuclear and renewables such as wind, solar, and hydroelectric power. Coal has historically provided the largest percentage of fossil-fuel generation.[45] In recent years, the nation has seen a sizeable increase in renewable generation such as wind and solar, as well as a shift from coal to natural gas.[46] In 2013, fossil fuels supplied 67 percent of U.S. electricity, but renewables made up 38 percent of the new generation capacity (over 5 GW out of 13.5 GW).[47] From 2007 to 2014, use of lower- and zero-carbon energy sources has grown, while other major energy sources such as coal and oil have experienced declines. Renewable electricity generation, including from large hydro-electric projects, grew from 8 percent to 13 percent over that time period.[48] Between 2000 and 2013, approximately 90 percent of new power generation capacity built in the U.S. has come in the form of natural gas or renewable energy facilities.[49] In 2015, the U.S. Energy Information Administration (EIA) projected the need for 28.4 GW of additional base load or intermediate load generation capacity through 2020, with approximately 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity already in development.[50]

The change in the resource mix has accelerated in recent years, but wind, solar, other renewables, and energy-efficiency resources have been reliably participating in the electric sector for a number of years. This rapid development of non-fossil fuel resources is occurring as much of the existing power generation fleet in the U.S. is aging and in need of modernization and replacement.[51] For example, the average age of U.S. coal steam units in 2015 is 45 years.[52] In its *2013 Report Card for America's Infrastructure,* the American Society for Civil Engineers noted that ''America relies on an aging electrical grid and pipeline distribution systems, some of which originated in the 1880s.'' [53] While there has been an increased investment in electric transmission infrastructure since 2005, the report also found that ''ongoing permitting issues, weather events, and limited maintenance have contributed to an increasing number of failures and power interruptions.''[54] However, innovative technologies have increasingly entered the electric energy space, helping to provide new answers to how to meet the electricity needs of the nation. These new technologies can enable the nation to answer not just questions as to how to reliably meet electricity demand, but also how to meet electricity demand reliably and cost-effectively[55] with the lowest possible emissions and the greatest efficiency.

Natural gas has a long history of meeting electricity demand in the U.S. with a rapidly growing role as domestic supplies of natural gas have dramatically increased. Natural gas net generation increased by approximately 36 percent between 2004 and 2014.[56] In 2014, natural gas accounted for approximately 27 percent of net generation.[57] The EIA projects that this demand growth will continue, with its *Annual Energy Outlook 2015* (AEO 2015) reference case forecasting that natural gas will produce 31 percent of U.S. electric generation in 2040.[58]

Renewable sources of electric generation also have a history of meeting electricity demand in the U.S. and are expected to have an increasing role going forward. A series of energy crises provided the impetus for renewable energy development in the early 1970s. The OPEC oil embargo in 1973 and oil crisis of 1979 caused oil price spikes, more frequent energy shortages, and significantly affected the national and global economy. In 1978, partly in response to fuel security concerns, Congress passed the Public Utilities Regulatory Policies Act (PURPA) which required local electric utilities to buy power from qualifying facilities (QFs).[59] QFs were either cogeneration facilities [60] or small

[44] These figures are based on data for EGUs in the Acid Rain Program plus additional ones that report to the EPA under the Regional Greenhouse Gas Initiative.

[45] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from April 2014 Monthly Energy Review, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

[46] U.S. Energy Information Administration, ''Table 7.2b Electricity Net Generation: Electric Power Sector'' data from April 2014 Monthly Energy Review, release data April 25, 2014, *available at http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.*

[47] 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.*

[48] Bloomberg New Energy Finance and the Business Council for Sustainable Energy, *2015 Factbook: Sustainable Energy in America,* at 16 (2015), *available at http://www.bcse.org/images/2015%20Sustainable%20Energy%20in%20America%20Factbook.pdf.*

[49] Energy Information Administration, *Electricity: Form EIA–860 detailed data* (Feb. 17, 2015), *available at http://www.eia.gov/electricity/data/eia860/.*

[50] EIA, *Annual Energy Outlook for 2015 with Projections to 2040,* Final Release, *available at http://www.eia.gov/forecasts/AEO/pdf/0383(2015).* The AEO numbers include projects that are under development and model-projected nuclear, coal, and NGCC projects.

[51] Quadrennial Energy Review, *http://energy.gov/epsa/quadrennial-energy-review-qer.*

[52] We calculated the average age of coal steam units based on the NEEDS inventory, and included units with planned retirements in 2015–2016. *See http://www.epa.gov/airmarkets/documents/ipm/needs_v514.xlsx.*

[53] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/.*

[54] American Society for Civil Engineers, *2013 Report Card for America's Infrastructure* (2013), *available at http://www.infrastructurereportcard.org/energy/.*

[55] Business Council for Sustainable Energy Comments in Docket Id. No. EPA–HQ–OAR–2013–0602 at 2 (Nov. 19, 2014).

[56] U.S. Energy Information Administration (EIA), *Electric Power Monthly: Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2004–December 2014* (2015), *available at http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_1.*

[57] *Id.*

[58] The AEO 2015 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, and resource assumptions. U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at 24–25 (2015), *available at http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.*

[59] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

[60] Cogeneration facilities utilize a single source of fuel to produce both electricity and another form of energy such as heat or steam. Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

generation resources that use renewables such as wind, solar, biomass, geothermal, or hydroelectric power as their primary fuels.[61] Through PURPA, Congress supported the development of more renewable energy generation in the U.S. States have taken a significant lead in requiring the development of renewable resources. In particular, a number of states have adopted renewable portfolio standards (RPS). As of 2013, 29 states and the District of Columbia have enforceable RPS or similar laws.[62] In its AEO 2015 Reference case, the EIA found that renewable energy will account for 38 percent of the overall growth in electricity generation from 2013 to 2040.[63] The AEO 2015 Reference case forecasts that the renewables share of U.S. electricity generation will grow from 13 percent in 2013 to 18 percent in 2040.[64]

Price pressures caused by oil embargoes in the 1970s also brought the issues of conservation and energy efficiency to the forefront of U.S. energy policy.[65] This trend continued in the early 1990s. Some state regulatory commissions and utilities supported energy efficiency through least-cost planning, with the National Association of Regulatory Utility Commissioners (NARUC) ''adopting a resolution that called for the utility's least cost plan to be the utility's most profitable plan.'' [66] Energy efficiency has been utilized to meet energy demand to varying levels since that time. As of April 2014, 25 states [67] have ''enacted long-term (3+ years), binding energy savings targets, or energy efficiency resource standards (EERS).'' [68] Funding for energy efficiency programs has grown rapidly in recent years, with budgets for electric efficiency programs totaling $5.9 billion in 2012.[69]

Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a reliable supply of power at a reasonable cost.

2. Fossil Fuel-Fired EGUs Regulated by this Action, Generally

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 then 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 or steam cycle). 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 synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power.

3. Technological Developments and Costs

Natural gas prices have decreased dramatically and generally stabilized in recent years as new drilling techniques have brought additional supply to the marketplace and greatly increased the domestic resource base. As a result, natural gas prices are expected to be competitive for the foreseeable future, and EIA modeling and utility announcements confirm that utilities are likely to rely heavily on natural gas to meet new demand for electricity generation. On average, as discussed below, the cost of generation from a new natural-gas fired power plant (a NGCC unit) is expected to be significantly lower than the cost of generation from a new coal-fired power plant.[70]

Other drivers that may influence decisions to build new power plants are increases in renewable energy supplies, often due to state and federal energy policies. As previously discussed, many states have adopted RPS, which require a certain portion of electricity to come from renewable energy sources such as solar or wind. The federal government has also offered incentives to encourage further deployment of other forms of electric generation including renewable energy sources and new nuclear power plants.

Reflecting these factors, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2020, along with renewable energy, nuclear power, and a limited amount of coal with CCS.[71]

While EIA data shows that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2030, a few coal-fired units still remain as viable projects at various advanced stages of construction and development. One new coal facility that has essentially completed construction,

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[61] Casazza, J. and Delea, F., *Understanding Electric Power Systems,* IEEE Press, at 220–221 (2d ed. 2010).

[62] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with Projections to 2040,* at LR–5 (2014).

[63] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at E–12 (2015).

[64] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2015 with Projections to 2040,* at 24–25(2015).

[65] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities,* at 1 (2007). Congress passed legislation in the 1970s that jumpstarted energy efficiency in the U.S. For example, President Ford signed the Energy Policy and Conservation Act (EPCA) of 1975—the first law on the issue. EPCA authorized the Federal Energy Administration (FEA) to ''develop energy conservation contingency plans, established vehicle fuel economy standards, and authorized the creation of efficiency standards for major household appliances.'' Alliance to Save Energy, *History of Energy Efficiency,* at 6 (2013) (citing Anders, *''The Federal Energy Administration,''* 5; Energy Policy and Conservation Act, S. 622, 94th Cong. (1975–1976)), *available at https://www.ase.org/sites/ase.org/files/resources/Media%20browser/ee_commission_history_report_2–1–13.pdf.*

[66] Edison Electric Institute, *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities,* at 1 (2007), *available at http://www.eei.org/whatwedo/PublicPolicyAdvocacy/State Regulation/Documents/Making_Business_Energy_Efficiency.pdf.*

[67] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04-2014.pdf.* ACEEE did not include Indiana (EERS eliminated), Delaware (EERS pending), Florida (programs funded at levels far below what is necessary to meet targets), Utah, or Virginia (voluntary standards) in its calculation.

[68] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards (EERS)* (2014), *available at http://aceee.org/files/pdf/policy-brief/eers-04–2014.pdf.*

[69] American Council for an Energy-Efficient Economy, *The 2013 State Energy Efficiency Scorecard,* at 17 (Nov. 2013), *available at http://aceee.org/sites/default/files/publications/researchreports/e13k.pdf.*

[70] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015 *http://www.eia.gov/forecasts/aeo/electricity_generation.html.*

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

Southern Company's Kemper County Energy Facility, deploys IGCC with partial CCS. Additionally, another project, Summit Power's Texas Clean Energy Project (TCEP), which will deploy IGCC with CCS, continues as a viable project.[72] The EIA modeling projects that coal-fired power generation will remain the single largest portion of the electricity sector beyond 2030. The EIA modeling also projects that few, if any, new coal-fired EGUs will be built in this decade and that those that are built will have CCS.[73] Continued progress on these projects is consistent with the EIA modeling that suggests that a small number of coal-fired power plants may be constructed. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand growth, and increases in the supply of renewable energy. We recognize, however, that a variety of factors may come into play in a decision to build new power generation, and we want to ensure that there are standards in place to make sure that whatever fuel is utilized is done so in a way that minimizes CO_2 emissions, as Congress intended with CAA section 111.[74]

4. Energy Sector Modeling

Various energy sector modeling efforts, including projections from the EIA and the EPA, forecast trends in new power plant construction and utilization of existing power plants that are consistent with the above-described technological developments and costs. The EIA's annual report, the AEO, forecasts the structure of and developments in the power sector. These reports are based on economic modeling that reflects existing policy and regulations, such as state RPS programs and federal tax credits for renewables.[75] The current report, AEO 2015:[76] (i) Shows that a modest amount of coal-fired power plants that are currently under construction are expected to begin operation in the next several years (referred to as ''planned''); and (ii) projects in the reference case[77] that a very small amount of new (''unplanned'') conventional coal-fired capacity, with CCS, will come online after 2012 and through 2037 in response to federal and state incentives. According to the AEO 2015, the vast majority of new generating capacity during this period will be either natural gas-fired or renewable sources. Similarly, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2030.[78]

Specifically, the AEO 2015 projects 30.3 GW of additional base load or intermediate load generation capacity through 2020 (this includes projects that are under development—*i.e.,* being constructed or in advance planning—and model-projected nuclear, coal, and NGCC projects). The vast majority of this new electric capacity (20.4 GW) is already under development (under construction or in advanced planning); it includes about 0.7 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 14.2 GW of new NGCC capacity. The EPA believes that most current fossil fuel-fired projects are already designed to meet limits consistent with this rule (or they have already commenced construction and are thus not subject to these final standards). The AEO 2015 also projects an additional 9.9 GW of new base load capacity additions, which are model-projected (unplanned). This consists of 7.7 GW of new NGCC capacity, 1.2 GW of new geothermal capacity, 0.7 GW of new hydroelectric capacity, and 0.3 GW of new coal equipped with CCS (incentivized with some government funding). Therefore, the AEO 2015 projection suggests that the new power generation capacity added through 2020 is expected to already meet the final emissions standards without incurring further control costs. This is also true during the period from 2020 through 2030, where new model-projected (unplanned) intermediate and base load capacity is expected to be compliant with the standards without incurring further control costs (*i.e.,* an additional 31.3 GW of NGCC and no additional coal, for a total, from 2015 through 2030, of 39 GW of NGCC and 0.3 GW of coal with CCS).

Under the EIA projections, existing coal-fired generation will remain an important part of the mix for power generation. Modeling from both the EIA and the EPA project that coal-fired generation will remain the largest single source of electricity in the U.S. through 2040. Specifically, in the EIA's AEO 2015, coal will supply approximately 40 percent of all electricity in the electric power sector in both 2020 and 2025.

The EPA modeling using the Integrated Planning Model (IPM), a detailed power sector model that the EPA uses to support power sector regulations, also shows limited future construction of new coal-fired power plants under the base case.[79] The EPA's projections from IPM can be found in the RIA.

5. Integrated Resource Plans

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

The EPA has reviewed publicly available IRPs from a range of companies (*e.g.,* varying in size, location, current fuel mix), and these plans are generally consistent with both EIA and EPA modeling projections.[80] These IRPs indicate that companies are focused on demand-side management programs to lower future electricity demand and are mostly reliant on a mix of new natural gas-fired generation and renewable energy to meet increased load demand and to replace retired generation capacity.

Notwithstanding this clear trend towards natural gas-fired generation and renewables, many of the IRPs highlight the value of fuel diversity and include options to diversify new generation capacity beyond natural gas and renewable energy. Several IRPs indicate that companies are considering new nuclear generation, including either traditional nuclear power plants or small modular reactors, and a smaller number are considering new coal-fired generation capacity with and without CCS technology. Based on public comments and on the information contained in these IRPs, the EPA acknowledges that a small number of

[72] ''Odessa coal-to-gas power plant to break ground this year'', Houston Chronicle (April 1, 2015).

[73] This projection is for business as usual and does not account for the proposed or final CO_2 emission standard. Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal-fired power plants beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations.

[74] These sources received federal assistance under EPAct 2005. See Section III.H.3.g below. However, none of the constraints in that Act affect the discussion in the text above, since that discussion does not relate to technology use or emissions reduction by these sources.

[75] *http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm.*

[76] Energy Information Administration's Annual Energy Outlook for 2015, Final Release available at *http://www.eia.gov/forecasts/aeo/index.cfm.*

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

[78] Annual Energy Outlook 2010, 2011, 2012, 2013, 2014 and 2015.

[79] *http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.*

[80] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

new coal-fired power plants may be built in the near future. While this outcome would be contrary to the economic modeling predictions, the agency understands that economic modeling may not fully reflect the range of factors that a particular company may consider when evaluating new generation options, such as fuel diversification. Further, it is possible that some of this potential new coal-fired construction may occur because developers are able to design projects with specific business plans, such as the cogeneration of chemicals, which allow the source to provide competitively priced electricity in specific geographic regions.

D. Statutory Background

The U.S. Supreme Court ruled in *Massachusetts* v. *EPA* that GHGs [81] meet the definition of ''air pollutant'' in the CAA,[82] and premised its decision in *AEP* v. *Connecticut,*[83] 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.

CAA section 111 authorizes and directs the EPA to prescribe new source performance standards (NSPS) applicable to certain new stationary sources (including newly constructed, modified and reconstructed sources).[84] 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.[85] The EPA listed the two source categories at issue here in the 1970s—listing fossil fuel-fired electric steam generating units in 1971 [86] and listing combustion turbines in 1977.[87]

Once the EPA has listed a source category, the EPA proposes and then promulgates ''standards of performance'' for ''new sources'' in the category.[88] A ''new source'' is ''any stationary source, the construction or modification of which is commenced after,'' in general, final standards applicable to that source are promulgated or, if earlier, proposed.[89] 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.'' [90] The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[91]

The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered to be 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.[92]

CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions . . . achievable through the application of the best system of emission reduction which [considering cost, non-air 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, reflecting the performance of the BSER, is commonly a numeric emission limit, expressed as a numeric performance level that can either be normalized to a rate of output or input (*e.g.,* tons of pollution per amount of product produced—a so-called rate-based standard), or expressed as a numeric limit on mass of pollutant that may be emitted (*e.g.,* 100 ug/m^3—parts per billion). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance.[93] Rather, sources generally may select any measure or combination of measures that will achieve the emissions level of the standard.[94] In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class, or size.[95]

The text and legislative history of CAA section 111, as well as relevant court decisions, identify the factors that the EPA is to consider in making a BSER determination. The system of emission reduction must be technically feasible, the costs of the system must be reasonable, and the emission standard that the EPA promulgates based on the system of emission reduction must be achievable. In addition, in identifying a BSER, the EPA must consider the amount of emissions reductions attributable to the system, and must also consider non-air quality health and environmental impacts and energy requirements. The case law addressing CAA section 111 makes it clear that the EPA has discretion in weighing costs, amount of emission reductions, energy requirements, and impacts of non-air quality pollutants, and may weigh them differently for different types of sources or air pollutants. We note that under the case law of the D.C. Circuit, another factor is relevant for the BSER determination: Whether the standard would effectively promote further deployment or development of advanced technologies. Within the constraints just described, the EPA has discretion in identifying the BSER and the resulting emission standard. See generally Section III.H below.

For more than four decades, the EPA has used its authority under CAA section 111 to set cost-effective emission standards which ensure that newly constructed, reconstructed, and modified stationary sources use the best performing technologies to limit emissions of harmful air pollutants. In this final action, the EPA is following the same well-established interpretation and application of the law under CAA section 111 to address GHG emissions from newly constructed, reconstructed, and modified fossil fuel-fired power plants. For each of the standards in this final action, the EPA considered a number of alternatives and evaluated them against the statutory factors. The BSER for each category of affected EGUs and the standards of performance based on these BSER are based on that evaluation.

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

[82] 549 U.S. 497, 520 (2007).

[83] 131 S.Ct. 2527, 2537–38 (2011).

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

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

[86] 36 FR 5931 (March 31, 1971).

[87] 42 FR 53657 (October 3, 1977).

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

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

[90] CAA section 111(a)(4); See also 40 CFR 60.14 concerning what constitutes a modification, how to determine the emission rate, how to determine an emission increase, and specific actions that are not, by themselves, considered modifications.

[91] 40 CFR 60.2, 60.14(e).

[92] 40 CFR 60.15.

[93] CAA section 111(b)(5) and (h).

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

[95] CAA section 111(b)(2); see also *Lignite Energy Council* v. *EPA,* 198 F. 3d 930, 933 (D.C. Cir. 1999).

E. Regulatory Background

In 1971, the EPA initially included fossil fuel-fired EGUs (which includes natural gas, petroleum and coal) that use steam-generating boilers in a category that it listed under CAA section 111(b)(1)(A),[96] and promulgated the first set of standards of performance for sources in that category, which it codified in subpart D.[97] 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),[98] and the EPA promulgated standards of performance for that source category in 1979, which the EPA codified in subpart GG.[99]

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.[100] 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.[101] 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 did not include specific standards of performance for CO_2 emissions.[102] Petitioners sought judicial review of the rule, contending, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.[103] The January 8, 2014 preamble to the proposed CO_2 standards for new EGUs [104] includes a discussion of the GHG-related litigation of the 2006 Final Rule as well as other GHG-associated litigation.

F. Development of Carbon Pollution Standards for Fossil Fuel-Fired Electric Utility Generating Units

On April 13, 2012, the EPA initially proposed standards under CAA section 111 for newly constructed fossil fuel-fired electric utility steam generating units. 77 FR 22392 (''April 2012 proposal''). The EPA withdrew that proposal (79 FR 1352 (January 8, 2014)), and, on the same day, proposed the standards addressed in this final rule. 79 FR 1430 (''January 2014 proposal''). Specifically, the EPA proposed standards under CAA section 111 to limit emissions of CO_2 from newly constructed fossil fuel-fired electric utility steam generating units and newly constructed natural gas-fired stationary combustion turbines.

In support of the January 2014 proposal, on February 26, 2014, the EPA published a notice of data availability (NODA) (79 FR 10750). Through the NODA and an associated technical support document, *Effect of EPAct05 on Best System of Emission Reduction for New Power Plants,* the EPA solicited comment on its interpretation of the provisions in the Energy Policy Act of 2005 (EPAct05),[105] including how the provisions may affect the rationale for the EPA's proposed determination that partial CCS is the best system of emission reduction adequately demonstrated for fossil fuel-fired electric utility steam generating units.

On June 18, 2014, the EPA proposed 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 (79 FR 34960; June 2014 proposal). Specifically, the EPA proposed standards of performance for: (1) Modified fossil fuel-fired electric utility steam generating units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired electric utility steam generating units, and (4) reconstructed natural gas-fired stationary combustion turbines.

G. Stakeholder Engagement and Public Comments on the Proposals

1. Stakeholder Engagement

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, non-governmental organizations and many others.

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. 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 conducted subsequent outreach prior to the June 2014 proposals of standards for modified and reconstructed EGUs and emission guidelines for existing EGUs, as well as during the public comment periods for the proposals. Although this stakeholder outreach was primarily framed around the GHG emission guidelines for existing EGUs, the outreach encompassed issues relevant to this rulemaking and provided an opportunity for the EPA to better understand previous state and stakeholder experience with reducing CO_2 emissions in the power sector. In addition to 11 public listening sessions, the EPA 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 met with electric utility associations and electricity grid operators. Agency officials engaged with labor unions and with leaders representing large and small industries. The agency also met with energy industries, such as coal and natural gas interests, as well as with representatives of energy-intensive industries, such as

[96] 36 FR 5931 (March 31, 1971).

[97] ''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.

[98] 42 FR 53657 (October 3, 1977).

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

[100] 44 FR 33580 (June 11, 1979).

[101] 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (March 20, 2009).

[102] ''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).

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

[104] 79 FR 1430, 1444.

[105] See Section III.H.3.g below. The Energy Policy Act of 2005 (EPAct05) was signed into law by President George W. Bush on August 8, 2005. EPAct05 was intended to address energy production in the United States, including: (1) Energy efficiency; (2) renewable energy; (3) oil and gas; (4) coal; (5) Tribal energy; (6) nuclear matters and security; (7) vehicles and motor fuels, including ethanol; (8) hydrogen; (9) electricity; (10) energy tax incentives; (11) hydropower and geothermal energy; and (12) climate change technology. *www2.epa.gov/laws-regulations/summary-energy-policy-act.*

the iron and steel, and aluminum industries, to better understand the potential concerns of large industrial purchasers of electricity. In addition, the agency met with companies that offer new technology to prevent or reduce carbon pollution. The agency provided and encouraged multiple opportunities for engagement with state, local, tribal, and regional environmental and energy agencies. The EPA also met with representatives of environmental justice organizations, environmental groups, public health professionals, public health organizations, religious organizations, and other community stakeholders.

The EPA received more than 2.5 million comments submitted in response to the original April 2012 proposal for newly constructed fossil fuel-fired EGUs. Because the original proposal was withdrawn, the EPA instructed commenters that wanted their comments on the April 2012 proposal to be considered in connection with the January 2014 proposal to submit new comments to the EPA or to re-submit their previous comments. We received more comments in response to the January 2014 proposal, as discussed in the section below.

The EPA has given stakeholder input provided prior to the proposals, as well as during the public comment periods for each proposal, careful consideration during the development of this rulemaking and, as a result, it includes elements that are responsive to many stakeholder concerns and that enhance the rule. This preamble and the Response-to-Comments (RTC) document summarize and provide the agency's responses to the comments received.

2. Comments on the January 2014 Proposal For Newly Constructed Fossil Fuel-Fired EGUs

Upon publication of the January 8, 2014 proposal for newly constructed fossil fuel-fired EGUs, the EPA provided a 60-day public comment period. On March 6, 2014, in order to provide the public additional time to submit comments and supporting information, the EPA extended the comment period by 60 days, to May 9, 2014, giving stakeholders over 120 days to review, and comment upon, the January 2014 proposal, as well as the NODA. A public hearing was held on February 6, 2014, with 159 speakers presenting testimony.

The EPA received more than 2 million comments on the proposed standards for newly constructed fossil fuel-fired EGUs from a range of stakeholders that included industry and electric utility representatives, trade groups, equipment manufacturers, state and local government officials, academia, environmental organizations, and various interest groups. The agency received comments on a range of topics, including the determination that a new highly-efficient steam generating EGU implementing partial CCS was the BSER for such sources, the level of the CO_2 standard based on implementation of partial CCS, the criteria that define which newly constructed natural gas-fired stationary combustion turbines will be subject to standards, the establishment of subcategories based on combustion turbine size, and the rule's potential effects on the Prevention of Significant Deterioration (PSD) preconstruction permit program and Title V operating permit program.

3. Comments on the June 2014 Proposal For Modified and Reconstructed Fossil Fuel-Fired EGUs

Upon publication of the June 18, 2014 proposal for modified and reconstructed fossil fuel-fired EGUs, the EPA offered a 120-day public comment period—through October 16, 2014. The EPA held public hearings in four locations during the week of July 28, 2014. These hearings also addressed the EPA's June 18, 2014 proposed emission guidelines for existing fossil fuel-fired EGUs (reflecting the connections between the proposed standards for modified and reconstructed sources and the proposed emission guidelines). A total of 1,322 speakers testified, and a further 1,450 attended but did not speak. The speakers were provided the opportunity to present data, views, or arguments concerning one or both proposed actions.

The EPA received over 200 comments on the proposed standards for modified and reconstructed fossil fuel-fired EGUs from a range of stakeholders similar to those that submitted comments on the January 2014 proposal for newly constructed fossil fuel-fired EGUs (*i.e.,* industry and electric utility representatives, trade groups, equipment manufacturers, state and local government officials, academia, environmental organizations, and various interest groups). The agency received comments on a range of topics, including the methodology for determining unit-specific CO_2 standards for modified steam generating units and the use of supercritical boiler conditions as the basis for the CO_2 standards for certain reconstructed steam generating units. Many of the comments regarding modified and reconstructed natural gas-fired stationary combustion turbines are similar to the comments regarding newly constructed combustion turbines described above (*e.g.,* applicability criteria and subcategories based on turbine size).

III. Regulatory Authority, Affected EGUs and Their Standards, and Legal Requirements

In this section, we describe our authority to regulate CO_2 from fossil fuel-fired EGUs. We also describe our decision to combine the two existing categories of affected EGUs—steam generators and combustion turbines—into a single category of fossil fuel-fired EGUs for purposes of promulgating standards of performance for CO_2 emissions. We also explain that we are codifying all of the requirements in this rule for new, modified, and reconstructed affected EGUs in new subpart TTTT of part 60 of Title 40 of the Code of Federal Regulations. In addition, we explain which sources are and are not affected by this rule, and the format of these standards. Finally, we describe the legal requirements for establishing these emission standards.

A. Authority To Regulate Carbon Dioxide From Fossil Fuel-Fired EGUs

The EPA's authority for this rule is CAA section 111(b)(1). CAA section 111(b)(1)(A) requires the Administrator to establish a list of source categories to be regulated under section 111. A category of sources is to be included on the list ''if in [the Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health and welfare.'' This determination is commonly referred to as an ''endangerment finding'' and that phrase encompasses both the ''causes or contributes significantly'' component and the ''endanger public health and welfare'' component of the determination. Then, for the source categories listed under section 111(b)(1)(A), the Administrator promulgates, under section 111(b)(1)(B), ''standards of performance for new sources within such category.''

In this rule, the EPA is establishing standards under section 111(b)(1)(B) for source categories that it has previously listed and regulated for other pollutants and which now are being regulated for an additional pollutant. Because of this, there are two aspects of section 111(b)(1) that warrant particular discussion.

First, because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to affected EGUs in order to establish standards of performance for the CO_2 emissions from those sources. Under the plain language of CAA section

111(b)(1)(A), an endangerment finding is required only to list a source category. Further, though the endangerment finding is based on determinations as to the health or welfare impacts of the pollution to which the source category's pollutants contribute, and as to the significance of the amount of such contribution, the statute is clear that the endangerment finding is made with respect to the source category; section 111(b)(1)(A) does not provide that an endangerment finding is made as to specific pollutants. This contrasts with other CAA provisions that do require the EPA to make endangerment findings for each particular pollutant that the EPA regulates under those provisions. E.g., CAA sections 202(a)(1), 211(c)(1), and 231(a)(2)(A); *see also American Electric Power Co. Inc.,* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011) (''[T]he Clean Air Act directs the EPA to establish emissions standards for *categories* of stationary sources that, 'in [the Administrator's] judgment,' 'caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.' § 7411(b)(1)(A).'') (emphasis added).

Second, once a source category is listed, the CAA does not specify what pollutants should be the subject of standards from that source category. The statute, in section 111(b)(1)(B), simply directs the EPA to propose and then promulgate regulations ''establishing federal standards of performance for new sources within such category.'' In the absence of specific direction or enumerated criteria in the statute concerning what pollutants from a given source category should be the subject of standards, it is appropriate for the EPA to exercise its authority to adopt a reasonable interpretation of this provision. *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 843–44 (1984).[106]

The EPA has previously interpreted this provision as granting it the discretion to determine which pollutants should be regulated. *See* Standards of Performance for Petroleum Refineries, 73 FR 35838 (June 24, 2008) (concluding that the statute provides ''the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under section 111(b)(1)(B)'' and citing cases). Further, in directing the Administrator to propose and promulgate regulations under section 111(b)(1)(B), Congress provided that the Administrator should take comment and then finalize the standards with such modifications ''as he deems appropriate.'' The D.C. Circuit has considered similar statutory phrasing from CAA section 231(a)(3) and concluded that ''[t]his delegation of authority is both explicit and extraordinarily broad.'' *National Assoc. of Clean Air Agencies* v. *EPA,* 489 F.3d 1221, 1229 (D.C. Cir. 2007).

In exercising its discretion with respect to which pollutants are appropriate for regulation under section 111(b)(1)(B), the EPA has in the past provided a rational basis for its decisions. See *National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (court discussed, but did not review, the EPA's reasons for not promulgating standards for oxides of nitrogen (NO_X), sulfur dioxide (SO_2) and CO from lime plants); Standards of Performance for Petroleum Refineries, 73 FR at 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries as part of that rule). Though these previous examples involved the EPA providing a rational basis for not setting standards for a given pollutant, a similar approach is appropriate where the EPA determines that it should set a standard for an additional pollutant for a source category that was previously listed and regulated for other pollutants.

In this rulemaking, the EPA has a rational basis for concluding that emissions of CO_2 from fossil fuel-fired power plants, which are the major U.S. source of GHG air pollution, merit regulation under CAA section 111. As noted, in 2009, the EPA made a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare, and in 2010, the EPA denied petitions to reconsider that finding. The EPA extensively reviewed the available science concerning GHG pollution and its impacts in taking those actions. In 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the finding and the denial of petitions to reconsider.[107] In addition, assessments from the NRC, the IPCC, and other organizations published after 2010 lend further credence to the validity of the Endangerment Finding. No information that commenters have presented or that the EPA has reviewed provides a basis for reaching a different conclusion. Indeed, current and evolving science discussed in detail in Section II.A of this preamble is confirming and enhancing our understanding of the near- and longer-term impacts emissions of CO_2 are having on Earth's climate and the adverse public health, welfare, and economic consequences that are occurring and are projected to occur as a result.

Moreover, the high level of GHG emissions from fossil fuel-fired EGUs makes clear that it is rational for the EPA to regulate GHG emissions from this sector. EGUs emit almost one-third of all U.S. GHGs and comprise by far the largest stationary source category of GHG emissions; indeed, as noted above, the CO_2 emissions from fossil fuel-fired EGUs are almost three times as much as the emissions from the next ten source categories combined. Further, the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year. See, *e.g.,* Section V.K below (noting that even the difference in CO_2 emissions between a highly efficient SCPC and the same unit meeting today's standard of performance can amount to hundreds of thousands of tons each year). These facts provide a rational basis for regulating CO_2 emissions from affected EGUs.

Some commenters have argued that the EPA is required to make a new endangerment finding before it may regulate CO_2 from EGUs. We disagree, for the reasons discussed above. Moreover, as discussed in the January 2014 proposal,[108] even if CAA section 111 required the EPA to make endangerment and cause-or-contribute significantly findings as prerequisites for this rulemaking, then, so far as the ''CO_2 endangers public health and welfare'' component of an endangerment finding is concerned, the information and conclusions described above should be considered to constitute the requisite endangerment finding. Similarly, so far as a cause-or-contribute significantly finding is concerned, the information and conclusions described above should be considered to constitute the requisite finding. The EPA's rational basis for regulating CO_2 under CAA section 111 is based primarily on the analysis and conclusions in the EPA's 2009 Endangerment Finding and 2010 denial of petitions to reconsider that Finding, coupled with the subsequent assessments from the IPCC and NRC that describe scientific developments since those EPA actions. In addition, we have reviewed comments presenting other scientific information to

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

[107] *Coalition for Responsible Regulation* v. *EPA,* 684 F.3d 102, 119–126 (D.C. Circuit 2012).

[108] 79 FR 1430, 1455–56 (January 8, 2014).

determine whether that information has any meaningful impact on our analysis and conclusions. For both the endangerment finding and the rational basis, the EPA focused on public health and welfare impacts within the United States, as it did in the 2009 Finding. The impacts in other world regions strengthen the case because impacts in other world regions can in turn adversely affect the United States or its citizens.

More specifically, our approach here—reflected in the information and conclusions described above—is substantially similar to that reflected in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider. The D.C. Circuit upheld that approach in *Coalition for Responsible Regulation* v. *EPA,* 684 F.3d 102, 117–123 (D.C. Cir. 2012) (noting, among other things, the ''substantial . . . body of scientific evidence marshaled by EPA in support of the Endangerment Finding'' (id. at 120); the ''substantial record evidence that anthropogenic emissions of greenhouse gases 'very likely' caused warming of the climate over the last several decades'' (id. at 121); ''substantial scientific evidence . . . that anthropogenically induced climate change threatens both public health and public welfare . . . [through] extreme weather events, changes in air quality, increases in food- and water-borne pathogens, and increases in temperatures'' (id.); and ''substantial evidence . . . that the warming resulting from the greenhouse gas emissions could be expected to create risks to water resources and in general to coastal areas. . . .'' (id.)). The facts, unfortunately, have only grown stronger and the potential adverse consequences to public health and the environment more dire in the interim. Accordingly, that approach would support an endangerment finding for this rulemaking.[109]

Likewise, if the EPA were required to make a cause-or-contribute-significantly finding for CO_2 emissions from the fossil fuel-fired EGUs as a prerequisite to regulating such emissions under CAA section 111, the same facts that support our rational basis determination would support such a finding. As shown in Tables 3 and 4 in this preamble, fossil fuel-fired EGUs are very large emitters of CO_2. All told, these fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions, and are responsible for almost three times as much as the emissions from the next ten stationary source categories combined. The CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year, and the CO_2 emissions from even a single NGCC unit may amount to one million or more tons per year. It is not necessary in this rulemaking for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution; under any reasonable threshold or definition, the emissions from combustion turbines and steam generators are a significant contribution. Indeed, these emissions far exceed in magnitude the emissions from motor vehicles, which have already been held to contribute to the endangerment. See *Coalition for Responsible Regulation,* 684 F. 3d at 121 (''substantial evidence'' supports the EPA's determination ''that motor-vehicle emissions of greenhouse gases contribute to climate change and thus to the endangerment of public health and welfare'').[110]

B. Treatment of Categories and Codification in the Code of Federal Regulations

As discussed in the January 2014 proposal of carbon pollution standards for newly constructed EGUs (79 FR 1430) and above, in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to CAA section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories and codified those standards, at various times, in 40 CFR part 60, subparts D, Da, GG, and KKKK.

In the January 2014 proposal of carbon pollution standards for newly constructed EGUs (79 FR 1430) and the June 2014 proposal of carbon pollution standards for modified and reconstructed EGUs (79 FR 34960), the EPA proposed separate standards of performance for new, modified, and reconstructed sources in the two categories. The EPA took comment on combining the two categories into a single category solely for purposes of the CO_2 emissions from new, modified, and reconstructed affected EGUs. In addition, the EPA proposed codifying the standards of performance in the same Da and KKKK subparts that currently contain the standards of performance for other pollutants from those sources addressed in the NSPS program, but co-proposed codifying all the standards of performance for CO_2 emissions in a new 40 CFR part 60, subpart TTTT.

In this rule, the EPA is combining the steam generator and combustion turbine categories into a single category of fossil fuel-fired electricity generating units for purposes of promulgating standards of performance for GHG emissions. Combining the two categories is reasonable because they both provide the same product: Electricity services. Moreover, combining them in this rule is consistent with our decision to combine them in the CAA section 111(d) rule for existing sources that accompanies this rule. In addition,

[109] Nor does the EPA consider the cost of potential standards of performance in making this Finding. Like the Endangerment Finding under section 202(a) at issue in *State of Massachusetts* v. *EPA,* 549 U.S. 497 (2007) the pertinent issue is a scientific inquiry as to whether an endangerment to public health or welfare from the relevant air pollution may reasonably be anticipated. Where, as here, the scientific inquiry conducted by the EPA indicates that these statutory criteria are met, the Administrator does not have discretion to decline to make a positive endangerment finding to serve other policy grounds. Id. at 532–35. In this regard, an endangerment finding is analogous to setting national ambient air quality standards under section 109(b), which similarly call on the Administrator to set standards that in her ''judgment'' are ''requisite to protect the public health''. The EPA is not permitted to consider potential costs of implementation in setting these standards. *Whitman* v. *American Trucking Assn's,* 531 U.S. 457, 466 (2001); see also *Michigan* v. *EPA,* U.S. (no. 14–46, June 29, 2015) slip op. pp. 10–11 (reiterating *Whitman* holding). The EPA notes further that section 111(b)(1) contains no terms such as ''necessary and appropriate'' which could suggest (or, in some contexts, require) that costs may be considered as part of the finding. Compare CAA section 111(n)(1)(A); see *State of Michigan,* slip op. pp. 7–8. The EPA, of course, must consider costs in determining whether a best system of emission reduction is adequately demonstrated and so can form the basis for a section 111(b) standard of performance, and the EPA has carefully considered costs here and found them to be reasonable. See section V. H. and I. below. The EPA also has found that the rule's quantifiable benefits exceed regulatory costs under a range of assumptions were new capacity to be built. RIA chapter 5 and section XIII.G below. Accordingly, this endangerment finding would be justified if (against our view) it is both required, and (again, against our view) costs are to be considered as part of the finding.

[110] The ''air pollution'' defined in the Endangerment Finding is the atmospheric mix of six long-lived and directly emitted greenhouse gases: Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). See 74 FR 66496 at 66497. The standards of performance adopted in the present rulemaking address only one component of this air pollution: CO_2. This is reasonable, given that CO_2 is the air pollutant emitted in the largest volume by the source category, and which is (necessarily) emitted by every affected EGU. There is, of course, no requirement that standards of performance address each component of the air pollution which endangers. Section 111(b)(1)(A) requires the EPA to establish ''standards of performance'' for listed source categories, and the definition of ''standard of performance'' in section 111(a)(1) does not specify which air pollutants must be controlled. See also Section III.G below explaining that CH_4 and N_2O emissions represent less than 1 percent of total estimated GHG emissions (as CO_2e) from fossil fuel-fired electric power generating units.

many of the monitoring, reporting, and verification requirements are the same for both source categories, and, as discussed next, we are codifying all requirements in a single new subpart of the regulations; as a result, combining the two categories into a single category will reduce confusion. It should be noted that in this rule, we are not combining the two categories for purposes of standards of performance for other air pollutants.

Because these two source categories are pre-existing listed source categories and the EPA will not be subjecting any additional sources in the categories to CAA regulation for the first time, the combination of these two categories is not considered a new source category subject to the listing requirements of CAA section 111(b)(1)(A). As a result, this final rule does not list a new category under CAA section 111(a)(1)(A), nor does this final rule revise either of the two source categories. Thus, the EPA is not required to make a new endangerment and contribution finding for the combination of the two categories,[111] although as discussed in the previous section, the evidence strongly supports such findings. Thus, the EPA has found, in the alternative, that this category of sources contributes significantly to air pollution which may be reasonably anticipated to endanger public health and welfare.

C. Affected Units

We generally refer to fossil fuel-fired electric generating units that would be subject to a CAA section 111 emission standard as ''affected'' or ''covered'' sources, units, facilities or simply as EGUs. An EGU is any boiler, IGCC unit, or combustion turbine (in either simple cycle or combined cycle configuration) that meets the applicability criteria. Affected EGUs include those that commenced construction after January 8, 2014, and meet the specified applicability criteria and, for modifications and reconstructions, EGUs that commenced those activities after June 18, 2014, and meet the specified applicability criteria.

To be considered an EGU, the unit must: (1) Be capable of combusting more than 250 MMBtu/h (260 GJ/h) heat input of fossil fuel; [112] and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[113] However, we are not finalizing CO_2 standards for certain EGUs. The EGUs that are not covered by the standards we are finalizing in this rule include: (1) Non-fossil fuel units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) combined heat and power (CHP) units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh or less, whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to subpart Eb of this part; and (6) commercial or industrial solid waste incineration units subject to subpart CCCC of this part.

D. Units Not Covered by This Final Rule

As described in the previous section, the EPA is not issuing standards of performance for certain types of sources—specifically, dedicated non-fossil fuel-fired (*e.g.,* biomass) units and industrial CHP units, as well as certain projects under development. This section discusses these sources and our rationale for not issuing standards for them. Because the rationale applies to both steam generating units and combustion turbines, we are describing it here rather than in the separate steam generating unit and combustion turbine discussions. We discuss the proposed applicability criteria, the topics where the agency solicited comment, a brief summary of the relevant comments, and the rationale for the final applicability approach for these sources.

1. Dedicated Non-fossil Fuel Units

The proposed applicability for newly constructed EGUs included those that primarily combust fossil fuels (*e.g.,* coal, oil, and natural gas). The proposed applicability criteria were that affected units must burn fossil fuels for more than 10 percent of the unit's total heat input, on average, over a 3-year period.[114] Under the proposed approach, applicability under the final NSPS for CO_2 emissions could have changed on an annual basis depending on the composition of fuel burned. We solicited comment on several aspects of the proposed applicability criteria for non-fossil fuel units. Specifically, we solicited comment on a broad applicability approach that would include non-fossil fuel-fired units as affected units, but that would impose an alternate standard when the unit fires fossil fuels for 10 percent or less of the heat input during the 3-year applicability-determination period. We solicited comment on whether, if such a subcategory is warranted, the applicability-determination period for the subcategory should be 1-year or a 3-year rolling period. We also solicited comment on whether the standard for such a subcategory should be an alternate numerical limit or ''no emission standard.''

While the proposed exemption applied to all non-fossil fuels, most commenters focused on biomass-specific issues. Many commenters supported an exclusion for biomass-fired units that fire no more than 10 percent fossil fuels. Some commenters suggested that the exclusion for biomass-fired units should be raised to a 25 percent fossil fuel-use threshold.

Many commenters supported the proposed 3-year averaging period for the fossil fuel-use criterion because it provides greater flexibility for operators to use fossil fuels when supply chains for the primary non-fossil fuels are disrupted, during unexpected malfunctions of the primary non-fossil fuel handling systems, or when the unit's maximum generating capacity is required by system operators for reliability reasons. Many commenters supported the 3-year averaging period because it is consistent with the final requirements under the EPA's Mercury and Air Toxics Standards (MATS) and would allow non-fossil fuel-fired units to use some fossil fuels for flame stabilization without triggering applicability. Some commenters requested that the EPA clarify the method an operator should use during the first 3 years of operations to determine if a particular unit will meet the 10 percent fossil fuel-use threshold. Others asked whether or not an affected facility has a compliance obligation during the first 3-year period and, if an

[111] See, *e.g., American Trucking Assn's* v. *EPA,* 175 F.3d 1027, 1055, rev'd on other grounds sub. nom. *Whitman* v. *Am. Trucking Assn's,* 531.U.S. 457 (because fine particulate matter ($PM_{2.5}$) was already included as a sub-set of the listed pollutant particulate matter, it was not a new pollutant necessitating a new listing).

[112] We refer to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

[113] We refer to the capability to supply 25 MW net to the grid as the ''total electric sales criterion.''

[114] We refer to the fraction of heat input derived from fossil fuels as the ''fossil fuel-use criterion.''

affected facility does not meet the 10 percent fossil fuel-use threshold during several 12-month periods during the first 3 years, whether compliance calculations would be required for such 12-month periods. Other commenters had concerns with the 3-year averaging period, stating that a source would no longer be subject to the NSPS if it fell below the threshold for any of the applicability metrics that the EPA proposed to calculate on a 3-year (or, in some cases, annual) basis. They argued that this would create a situation in which no one would know whether a particular plant will be subject to the standards until years after the emissions had already occurred. Some commenters were concerned that plants operating near the threshold could move in and out of the regulatory system, which would provide complications for compliance, enforcement, and permitting.

After considering these comments, the EPA has concluded that the proposed fossil fuel-use criterion based on the actual amount of fossil fuel burned is not an ideal approach to determine applicability. As commenters pointed out, facilities, permitting authorities, and the public would not know when construction is commenced whether a facility will be subject to the final NSPS, and after operation has commenced, a unit could move in and out of applicability each year. The intent of this rulemaking is to establish CO_2 standards for fossil fuel-fired EGUs, not for non-fossil fuel-fired EGUs. Therefore, to simplify compliance and establish CO_2 standards for only those sources which we set out to regulate, we are finalizing a fossil fuel-use criterion that will exempt dedicated non-fossil units. Specifically, units that are capable of burning 50 percent or more non-fossil fuel are exempt from the final standards so long as they are subject to a federally enforceable permit that limits their use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis. This approach establishes clear applicability criteria and avoids the prospect of units moving in and out of applicability based on their actual fuel use in a given year. Consistent with the applicability approach in the steam generating unit criteria pollutant NSPS, subpart Da, the final fossil fuel-use criterion does not include ''constructed for the purpose of'' language. Therefore, an owner or operator could change a unit's applicability in the future by seeking a modification of the unit's permit conditions. A unit with the appropriate permit limitation will not be subject to the requirements in this rulemaking. Similarly, an existing unit that takes a permit limitation restricting fossil-fuel use would no longer be an affected unit for the purposes of 111(d) state plans. This is consistent with our intent to reduce GHG emissions from fossil fuel-fired EGUs.

We considered using either an annual or 3-year average for calculating compliance with the final fossil fuel-use criterion. Ultimately, we concluded that an annual average would provide sufficient flexibility for dedicated non-fossil units to combust fossil fuels for flame stabilization and other ancillary purposes, while maintaining consistency with the 12-month compliance periods used for most permit limitations. A 3-year average potentially would allow units to combust a significant quantity of fuels in a given year, leading to higher CO_2 emissions, so long as they curtailed fossil-fuel use in a later year. This would defeat the purpose of the criterion, which is to exempt dedicated non-fossil units only. Finally, we are finalizing the 10 percent fossil-fuel use threshold in relation to a unit's heat input capacity rather than its actual heat input, which is consistent with past approaches we have taken under the industrial boiler criteria pollutant NSPS.

2. Industrial CHP Units

Another approach to generating electricity is the use of CHP units. A CHP unit can use a boiler, combustion turbine, reciprocating engine, or various other generating technologies to generate electricity and useful thermal energy in a single, integrated system. CHP units are generally more efficient than conventional power plants because the heat that is normally wasted in a conventional power generation cooling system (*e.g.,* cooling towers) is instead recovered as useful thermal output. While the EPA did propose some applicability provisions specific to CHP units (*e.g.,* subtract purchased power of adjacent facilities when determining total electric sales), in general, the proposed applicability criteria for electric-only units and CHP units were similar. The intent of the proposed total and percentage electric sales criteria was to cover only utility CHP units, not industrial CHP units. To the extent that the proposal's applicability provisions would have the effect of covering industrial CHP units, we solicited comment on an appropriate applicability exemption, and the criteria for that exemption, for highly efficient CHP facilities.

Many commenters supported the exclusion of CHP units as a means of encouraging capital investments in highly efficient and reliable distributed generation technologies. These commenters recommended that the EPA adopt an explicit exemption for CHP units at facilities that are classified as industrial (*e.g.,* gas-fired CHPs within SIC codes 2911—petroleum refining, 13—oil and gas extraction, and other industrial SIC codes as appropriate). They also stated that the EPA should exclude CHP units that have an energy savings of 10 percent or more compared to separate heat and power. One commenter suggested that the final rule should cover only industrial-commercial-institutional CHP units that supply, on a net basis, more than two-thirds of their potential combined thermal and electric energy output and more than 450,000 MWh net-electric output to a utility power distribution system on an annual basis for five consecutive calendar years. The commenter also suggested that CHP units which have total thermal energy production that approaches or exceeds their total electricity production should be exempted.

Other commenters suggested exempting CHP units by fuel type or based on the definition of potential electric output. For example, some commenters suggested modifying the percentage electric sales threshold to be based on net system efficiency (including useful thermal output) rather than the rated net-electric-output efficiency. They also suggested that the applicability criteria should use a default efficiency of 50 percent for CHP units. Some commenters suggested that a CHP unit should not be considered an affected EGU if 20 percent or more of its total gross or net energy output consisted of useful thermal output on a 3-year rolling average basis. Other commenters said that highly efficient CHP units that achieve an overall efficiency level of 60 to 70 percent or higher should be excluded from applicability.

The intent of this rulemaking is to cover only utility CHP units, because they serve essentially the same purpose as electric-only EGUs (*i.e.,* the sale of electricity to the grid). Industrial CHP units, on the other hand, serve a different primary purpose (*i.e.,* providing useful thermal output with electric sales as a by-product). With these facts in mind and after considering the comments, the EPA has concluded that it is appropriate to consider two factors for the final CHP exemption: (1) Whether the primary purpose of the CHP unit is to provide useful thermal output rather than electricity and (2) whether the CHP unit is highly efficient and thus achieves environmental benefits.

We rejected many of the approaches suggested by the commenters because they did not achieve one or both of the factors we identified. Specifically, the EPA has concluded that SIC code classification is not a sufficient indicator of the purpose (*i.e.,* it does not correlate to useful thermal output) or environmental benefits (*i.e.,* efficiency) of a unit. Further, an exemption based on SIC code could result in circumvention of the intended applicability. For example, this approach would allow a new EGU to locate near an industrial site, provide a trivial amount of useful thermal output to that site, sell electricity to the grid, and nonetheless avoid applicability. Similarly, increasing the electric sales criteria to two-thirds of potential electric output and 450,000 MWh would essentially amount to a blanket exemption that tells us nothing about the primary purpose or efficiency of the unit.

On the other hand, exemptions based on useful thermal output being greater than 20 percent of total output, thermal output being greater than electric output, or overall design efficiency value would identify whether the primary purpose of a unit is to generate thermal output, but they would not recognize the environmental benefits of highly efficient CHP units. While overall efficiency may appear to be a good indicator of environmental benefits, this is not always the case with CHP units. Overall efficiency is a function of both efficient design and the power to heat ratio (the amount of electricity relative to the amount of useful thermal output). For example, boiler-based CHP units tend to produce large amounts of useful thermal output relative to electric output and tend to have high overall efficiencies. For units producing primarily useful thermal output, the equivalent separate heat and power efficiency (*i.e.,* the theoretical overall efficiency if the electricity and useful thermal output were produced by a stand-alone EGU and stand-alone boiler) would approach that of a stand-alone boiler (*e.g.,* 80 percent). However, combustion turbine-based CHP units tend to produce relatively equal amounts of electricity and useful thermal output. In this case, the equivalent separate heat and power efficiency would be closer to 65 percent. Therefore, an exemption based on overall efficiency is not an indication of the fuel savings a CHP unit will achieve relative to separate heat and power. Further, this approach would encourage the development of CHP units that just meet the efficiency exemption criterion and would still cover many combustion turbine-based industrial CHP units. Conversely, while an exemption based on fuel savings relative to separate heat and power would recognize the environmental benefit of highly efficient CHP units, it would not consider the primary purpose of the CHP unit.

In the end, the EPA has concluded that maintaining the proposed percentage electric sales criterion with two adjustments addresses both factors with which we are concerned. First, we are changing the definition of ''potential electric output'' to be based on overall net efficiency at the maximum electric production rate, instead of just electric-only efficiency. Second, we are changing the percentage electric sales criterion to reflect the sliding scale, which is the overall design efficiency, calculated at the maximum useful thermal rating of the CHP unit (*e.g.,* a CHP unit with a extraction condensing steam turbine would determine the efficiency at the maximum extraction/bypass rate), of the unit multiplied by the unit's potential electric output instead of one-third of potential electric output as proposed. This approach recognizes the primary purpose of industrial CHP units by providing a more generous percentage electric sales exemption to CHP units with high thermal output. As described previously, CHP units with high thermal loads tend to be more efficient and will therefore have a higher allowable percentage electric sales. By amending both the definition of ''potential electric output'' and the electric sales threshold, we assure that CHP units that primarily produce useful thermal output are exempted as industrial CHP units even if they are selling all of their electric output to the grid. As the relative amount of electricity generated by the CHP unit increases, efficiency will generally decrease, thus limiting allowable electric sales before applicability is triggered. This approach also recognizes the environmental benefits of increased efficiency by encouraging industrial CHP units to be designed as efficiently as possible to take advantage of the higher electric sales permitted by the sliding scale.

In conclusion, a CHP unit will be an affected source unless it is subject to a federally enforceable permit that limits annual total electric sales to less than or equal to the unit's design efficiency multiplied by its potential electric output or 219,000 MWh,[115] whichever is greater. This final applicability criterion will only cover CHP units that condense a significant portion of steam generated by the unit and use the electric power generated as a result of condensing that steam to supply electric power to the grid. CHP facilities that do not have a condensing steam turbine (*e.g.,* combustion turbine-based CHP units without a steam turbine and boiler-based systems with a backpressure steam turbine) would generally not be physically capable of selling enough electricity to meet the applicability criterion, even if they sold 100 percent of the electricity generated and did not subtract out the electricity used by the thermal host(s). The EPA has concluded that this is appropriate because these sources are industrial by design and provide mostly useful thermal output.

CHP facilities with a steam extraction condensing steam turbine will determine their potential electric output based on their efficiency on a net basis at the maximum electric production rate at the base load heat input rating (*e.g.,* the CHP is condensing as much steam as possible to create electricity instead of using it for useful thermal output). We have concluded that it is necessary for CHP units with extraction condensing steam turbines to calculate their potential electric output at the maximum condensing level to avoid circumvention of the applicability criteria. For example, to avoid applicability a CHP unit could locate next to an industrial host and have the capability of selling significant quantities of useful thermal output without ever actually intending to supply much, if any, useful thermal output to the industrial host. If we calculated the potential electric output at the maximum level of thermal output, this type of CHP unit could operate at full condensing mode at base load conditions for the entire year and still not exceed the electric sales threshold. During the permitting process, the owner or operator will be able to determine if the unit is subject to the final standards in this rule.

New EGUs with only limited useful thermal output will be subject to the final standards, but the vast majority of new CHP units will be classified as industrial CHP and will not be subject to the final standards. The EPA has concluded that this approach is similar to exempting CHP facilities that sell less than half of their total output (electricity plus thermal), but has the benefit of accounting for overall design efficiency.

[115] The EPA has concluded that it is appropriate to maintain the 219,000 MWh total electric sales criterion for combustion turbine based CHP units to avoid potentially covering smaller industrial CHP units.

This approach both limits applicability to the industrial CHP units and encourages the installation of the most efficient CHP systems because more efficient designs will be able to have higher permitted electric sales while not being subject to the CO_2 standards included in this rulemaking.

3. Municipal Waste Combustors and Commercial and Industrial Solid Waste Incinerators

The purpose of this rulemaking is to establish CO_2 standards for fossil fuel-fired EGUs. Municipal waste combustors and commercial and industrial solid waste incinerators typically have not been included in this source category. Therefore, even if one of these types of units meets the general heat input and electric sales criteria, we are not finalizing CO_2 emission standards for municipal waste combustors subject to subpart Eb of this part and commercial and industrial solid waste incinerators subject to subpart CCCC of this part.

4. Certain Projects Under Development

The EPA proposed that a limited class of projects under development should not be subject to the proposed standards. These were planned sources that may be capable of commencing construction (within the meaning of section 111(a)) shortly after the standard's proposal date, and so would be classified as new sources, but which have a design which would be incapable of meeting the proposed standard of performance. See 79 FR 1461 and CAA section 111(a)(2). The EPA proposed that these sources would not be subject to the generally-applicable standard of performance, but rather would be subject to a unit-specific permitting determination if and when construction actually commences. The EPA indicated that there could be three sources to which this approach could apply, and further indicated that the EPA could ultimately adopt the generally-applicable standard of performance for these sources (if actually constructed). 79 FR 1461.

As explained at Section III.J below, the EPA is finalizing this approach in this final rule. We again note that these sources, if and when constructed, could be ultimately subject to the 1,400 lb CO_2/MWh-g standard, especially if there is no engineering basis, or demonstrated action in reliance, showing that the new source could not meet that standard.

E. Coal Refuse

In the April 2012 proposal, we solicited comment on subcategorizing and exempting EGUs that burn over 75 percent coal refuse on an annual basis. Multiple commenters supported the exemption, citing numerous environmental benefits of remediating coal refuse piles. Observing that coal refuse-fired EGUs typically use fluidized bed technologies, other commenters disagreed with any exemption, specifically citing the N_2O emissions from fluidized bed boilers. In light of the environmental benefits of remediating coal refuse piles cited by commenters, the limited amount of coal refuse, and the fact that a new coal refuse-fired EGU would be located in close proximity to the coal refuse pile, we sought additional comments regarding a subcategory for coal refuse-fired EGUs in the January 2014 proposal. Specifically, we requested additional information on the net environmental benefits of coal refuse-fired EGUs and information to support an appropriate emissions standard for coal refuse-fired EGUs. One commenter on the April 2012 proposal stated that existing coal refuse piles are naturally combusting at a rate of 0.3 percent annually, and we requested comment on this rate and the proper approach to account for naturally occurring emissions from coal refuse piles in the January 2014 proposal.

Commenters said that a performance standard is not feasible for coal refuse CFBs since there is no economically feasible way to capture CO_2 through a conveyance designed and constructed to capture CO_2. Commenters suggested that the EPA establish BSER for GHGs at modified coal refuse CFBs as a boiler tune-up that must be performed at least every 24 months. Commenters stated that the EPA should exempt coal refuse CFB units relative to their CO_2 emissions to the extent that these units offset the uncontrolled ground level emissions from spontaneous combustion of legacy coal refuse stockpiles and noted that the mining of coal waste not only produces less emissions in the long term, but also helps to reclaim land that is currently used to store coal waste. In contrast, one commenter saw no legitimate basis for coal refuse to be subcategorized and stated that it should be treated in the same manner as all other coal-fired EGUs.

The EPA has concluded that an explicit exemption or subcategory specifically for coal refuse-fired EGUs is not appropriate. The costs faced by coal refuse facilities to install CCS are similar to coal-fired EGUs burning any of the primary coals, and the final applicable requirements and standards in the rule do not preclude the development of new coal refuse-fired units without CCS. Specifically, we are not finalizing CO_2 standards for industrial CHP units. Many existing coal refuse-fired units are relatively small and designed as CHP units. Due to the expense of transporting coal refuse long distances, we anticipate that any new coal refuse-fired EGU would be relatively small in size. Moreover, sites with sufficient thermal demand exist such that the unit could be designed as an industrial CHP facility and the requirements of this rule would not apply.

F. Format of the Output-Based Standard

1. Net and Gross Output-Based Standards

For all newly constructed units, the EPA proposed standards as gross output emission rates consistent with current monitoring and reporting requirements under 40 CFR part 75.[116] For a non-CHP EGU, gross output is the electricity generation measured at the generator terminals. However, we solicited comment on finalizing equivalent net-output-based standards either as a compliance alternative or in lieu of the proposed gross-output-based standards. Net output is the gross electrical output less the unit's total parasitic (*i.e.,* auxiliary) power requirements. A parasitic load for an EGU is a load or device powered by electricity, steam, hot water, or directly by the gross output of the EGU that does not contribute electrical, mechanical, or useful thermal output. In general, parasitic energy demands include less than 7.5 percent of non-IGCC and non-CCS coal-fired station power output, approximately 15 percent of non-CCS IGCC-based coal-fired station power output, and about 2.5 percent of non-CCS NGCC power output. The use of CCS increases both the electric and steam parasitic loads used internal to the unit, and these outputs are not considered when determining the emission rate. Net output is used to recognize the environmental benefits of: (1) EGU designs and control equipment that use less auxiliary power; (2) fuels that require less emissions control equipment; and (3) higher efficiency motors, pumps, and fans. For modified and reconstructed combustion turbines, the EPA also proposed standards as gross output emission rates, but solicited comment on finalizing net output standards. The rationale was that due to the low auxiliary loads in non-CCS NGCC designs, the difference between a gross-output standard and a net-output standard has a limited

[116] 79 FR 1447–48.

impact on environmental performance. Auxiliary loads are more significant for modified and reconstructed boilers and IGCC units, and the EPA proposed standards on a net output basis for these units. The rationale included that this would enable owners/operators of these types of units to pursue projects that reduce auxiliary loads for compliance purposes. However, the EPA solicited comment on finalizing the standards on a gross-output basis. We also proposed to use either gross-output or net-output bases for each respective subcategory of EGUs (*i.e.,* utility boilers, IGCC units, and combustion turbines) consistently across all CAA section 111(b) standards for new, modified, and reconstructed EGUs.

Many commenters supported gross-output-based standards, maintaining that a net-output standard penalizes the operation of air pollution control equipment. Several commenters disagreed with the agency's proposed rationale that a net-output standard would provide incentive to minimize auxiliary loads. The commenters believe utility commissions and existing economic forces already provide utilities with appropriate incentives to properly manage all of these factors. Some commenters supported a gross-output-based standard because variations in site conditions (*e.g.,* available natural gas pressure, available cooling water sources, and elevation) will likely penalize some owners and benefit others simply through variations in their particular plant-site conditions if a net basis is used. Several commenters stated that if the final rule includes a net-output-based standard, it should be included as an option in conjunction with a gross-output-based option.

Several commenters opposed net-output-based standards because they believe it is difficult to accurately determine the net output of an EGU. They pointed out that many facilities have transformers that support multiple units at the facility, making unit-level reporting difficult. These commenters also stated that station electric services may come from outside sources to supply certain ancillary loads. One commenter stated that the benefit of switching to net-output-based standards would be small and would not justify the substantial complexities in both defining and implementing such a standard. Conversely, other commenters stated that net-metering is a well-established technology that should be required, particularly for newly constructed units.

Other commenters, however, maintained that the final rule should strictly require compliance on a net output-basis. They believe that this is the only way for the standards to minimize the carbon footprint of the electricity delivered to consumers. These commenters believe that, at a minimum, net-output-based standards should be included as an option in the final rule.

We are only finalizing gross-output-based standards for utility boilers and IGCC units. Providing an alternate net-output-based standard that is based on gross-output-based emissions data and an assumed auxiliary load is most appropriate when the auxiliary load can be reasonably estimated and the choice between the net- and gross-output-based standard will not impact the identified BSER. For example, the auxiliary load for combustion turbines is relatively fixed and small, approximately 2.5 percent, so the choice between a gross and net-output-based standard will not substantially impact technology choices. However, in the case of utility boilers, we have concluded that we do not have sufficient information to establish an appropriate net-output-based standard that would not impact the identified BSER for these types of units. The BSER for newly constructed steam generating units is based on the use of partial CCS. However, unlike the case for combustion turbines, owners/operators of utility boilers have multiple technology pathways available to comply with the actual emission standard. The choice of both control technologies and fuel impact the overall auxiliary load. For example, a coal-fired hybrid EGU (*e.g.,* one that includes integrated solar thermal equipment for feedwater heating or steam augmentation) or a coal-fired EGU co-firing natural gas would have lower non-CCS related auxiliary loads and, because the amount of CCS needed to comply with the standard would also be smaller, the CCS auxiliary loads would also be reduced. Therefore, we cannot identify an appropriate assumed auxiliary load to establish an equivalent net-output-based standard. In addition, many IGCC facilities (which could be used as an alternative technology for complying with the standard of performance; see Sections IV.B and V.P below) have been proposed or are envisioned as co-production facilities (*i.e.,* to produce useful by-products and chemicals along with electricity). As noted in the proposal, we have concluded that predicting the net electricity at these co-production facilities would be more challenging to implement under these circumstances.

In contrast, based on further evaluation and review of issues raised by commenters, the EPA is finalizing the CO_2 standard for combustion turbine EGUs in a format that is similar to the current NSPS format for criteria pollutants. The default final standards establish a gross-output-based standard. This allows owners/operators of new combustion turbines to comply with the CO_2 emissions standard under part 60 using the same data currently collected under part 75.[117] However, many permitting authorities commented persuasively that the environmental benefits of using net-output-based standards can outweigh any additional complexities for particular units, and have indeed adopted net-output standards in recent GHG operating permits for combustion turbines. We expect this trend to continue and have concluded that it is appropriate to support the expanded use of net-output-based standards, and therefore are allowing certain sources to elect between gross output-based and net-output-based standards. Only combustion turbines are eligible to make this election.

The rule specifies an alternative net-output-based standard of 1,030 lb CO_2/MWh-n for combustion turbines. This standard is equivalent to the otherwise-applicable gross-output-based standard of 1,000 lb CO_2/MWh-g.[118]

The procedures for requesting this alternative net-output-based standard require the owner or operator to petition the Administrator in writing to comply with the alternate applicable net-output-based standard. If the Administrator grants the petition, this election would be binding and would be the unit's sole means of demonstrating compliance. Owners or operators complying with the net-output-based standard must similarly petition the Administrator to switch back to complying with the gross-output-based standard.

2. Useful Thermal Output

For CHP units, useful thermal output is also used when determining the emission rate. Previous rulemakings issued by the EPA have prescribed various ''discount factors'' of the measured useful thermal output to be used when determining the emission rate. We proposed that 75 percent credit is the appropriate discount factor for useful thermal output, and we solicited

[117] Additionally, having an NSPS standard that is measured using the same monitoring equipment as required under the operating permit minimizes compliance burden. If a combustion turbine were subject to both a gross and net emission limit, more expensive higher accuracy monitoring could be required for both measurements.

[118] Assuming a 3 percent auxiliary load for the NGCC system.

comment on a range from two-thirds to three-fourths credit for useful thermal output in the proposal for newly constructed units and two-thirds to one hundred percent credit in the proposal for modified and reconstructed units. The 75 percent credit was based on matching the emission rate, but not the overall emissions, of a hypothetical CHP unit to the proposed emission rate.

Many commenters said that in order to fully account for the environmental benefits of CHP and to reflect the environmental benefits of CHP, the EPA should allow 100 percent of the useful thermal output from CHP units. Commenters noted that providing 100 percent credit for useful thermal output is consistent with the past practice of the EPA in the stationary combustion turbine criteria pollutant NSPS and state approaches for determining emission rates for CHP units.

Based on further consideration and review of the comments submitted, we are finalizing 100 percent credit for useful thermal output for all newly constructed, modified, and reconstructed CHP sources. We have concluded that this is appropriate because, at the same reported emission rate, a hypothetical CHP unit would have the same overall GHG emissions as the combined emission rate of separate heat and power facilities. Any discounting of useful thermal output could distort the market and discourage the development of new CHP units. Full credit for useful thermal output appropriately recognizes the environmental benefit of CHP.

G. CO_2 Emissions Only

The air pollutant regulated in this final action is greenhouse gases. However, the standards in this rule are expressed in the form of limits on only emissions of CO_2, and not the other constituent gases of the air pollutant GHGs.[119] We are not establishing a limit on aggregate GHGs or separate emission limits for other GHGs (such as methane (CH_4) or nitrous oxide (N_2O)) as other GHGs represent less than 1 percent of total estimated GHG emissions (as CO_2e) from fossil fuel-fired electric power generating units.[120] Notwithstanding this form of the standard, consistent with other EPA regulations addressing GHGs, the air pollutant regulated in this rule is GHGs.[121]

H. Legal Requirements for Establishing Emission Standards

1. Introduction

In the January 2014 proposal, we described the principal legal requirement for standards of performance under CAA section 111(b), which is that the standards of performance must consist of standards for emissions that reflect the degree of emission limitation achievable though the application of the ''best system of emission reduction . . . adequately demonstrated,'' taking into account cost and any non-air quality health and environment impact and energy requirements. We noted that the D.C. Circuit has handed down numerous decisions that interpret this CAA provision, including its component elements, and we reviewed that case law in detail.[122]

We received comments on our proposed interpretation, and in light of those comments, in this rule, we are clarifying our interpretation in certain respects. We discuss our interpretation below.[123]

2. CAA Requirements and Court Interpretation

As noted above, the CAA section 111 requirements that govern this rule are as follows: As the first step towards establishing standards of performance, the EPA ''shall publish . . . a list of categories of stationary sources . . . [that] cause[ ], or contribute[ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' CAA section 111(b)(1)(A). Following that listing, the EPA ''shall publish proposed regulations, establishing federal standards of performance for new sources within such category'' and then ''promulgate . . . such standards'' within a year after proposal. CAA section 111(b)(1)(B). The EPA ''may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.'' CAA section 111(b)(2). The term ''standard of performance'' is defined to ''mean[ ] a standard for emissions . . . achievable through the application of the best system of emission reduction which [considering cost, non-air quality health and environmental impact, and energy requirements] the Administrator determines has been adequately demonstrated.'' CAA section 111(a)(1).

As noted in the January 2014 proposal, Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. It is in the legislative history for the 1970 and 1977 CAAAs that Congress primarily addressed the definition as it read at those times, and that legislative history provides guidance in interpreting this provision.[124] In addition, the D.C. Circuit has reviewed rulemakings under CAA section 111 on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,[125] through which the

[119] As noted above, in the Endangerment Finding, the EPA defined the relevant ''air pollution'' as the atmospheric mix of six long-lived and directly-emitted greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). 74 FR 66497.

[120] EPA Greenhouse Gas Reporting Program; *www.epa.gov/ghgreporting/*.

[121] See 77 FR 31257–30 (June 3, 2010).

[122] 79 FR 1430, 1462 (January 8, 2014).

[123] We also discuss our interpretation of the requirements for standards of performance and the BSER under section 111(d), for existing sources, in the section 111(d) rulemaking that the EPA is finalizing with this rule. Our interpretations and applications of these requirements in the two rulemakings are generally consistent with each other except to the extent that they reflect distinctions between new and existing sources. For example, the BSER for new industrial facilities, which are expected to have lengthy useful lives, should include, at a minimum, the most advanced pollution controls available, but for existing sources, the additional costs of retrofit may render those controls too expensive.

[124] In the 1970 CAAA, Congress defined ''standard of performance,'' under section 111(a)(1), as—a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard: (i) Be based on, in lieu of the ''best system of emission reduction . . . adequately demonstrated,'' the ''best technological system of continuous emission reduction . . . adequately demonstrated;'' and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider ''any nonair quality health and environment impact and energy requirements.''

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

[125] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, (D.C. Cir. 1973);

Continued

Court has developed a body of case law that interprets the term ''standard of performance.''

3. Key Elements of Interpretation

By its terms, the definition of ''standard of performance'' under CAA section 111(a)(1) provides that the emission limits that the EPA promulgates must be ''achievable'' by application of a ''system of emission reduction'' that the EPA determines to be the ''best'' that is ''adequately demonstrated,'' ''taking into account . . . cost . . . nonair quality health and environmental impact and energy requirements.'' The D.C. Circuit has stated that, in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution''[126] reduced and the role of ''technological innovation.''[127] The Court has emphasized that the EPA has discretion in weighing those various factors.[128] [129]

Our overall approach to determining the BSER, which incorporates the various elements, is as follows: First, the EPA identifies the ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category. Second, the EPA determines the ''best'' of these systems after evaluating extent of emission reductions, costs, any non-air health and environmental impacts, and energy requirements. And third, the EPA selects an achievable standard for emissions—here, the emission rate—based on the performance of the BSER. The remainder of this subsection discusses the various elements in that analytical approach.

a. ''System[s] of Emission Reduction . . . Adequately Demonstrated''

The EPA's first step is to identify ''system[s] of emission reduction . . . adequately demonstrated.'' For the reasons discussed below, for the various types of newly constructed, modified, and reconstructed sources in this rulemaking, the EPA focused on efficient generation, add-on controls, efficiency improvements, and clean fuels as the systems of emission reduction.

An ''adequately demonstrated'' system, according to the D.C. Circuit, 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.''[130] It does not mean that the system ''must be in actual routine use somewhere.''[131] Rather, the Court has said, ''[t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.''[132] Similarly, the EPA may ''hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.''[133] Ultimately, the analysis ''is partially dependent on 'lead time,' '' that is, ''the time in which the technology will have to be available.''[134] Per CAA section 111(e), standards of performance under CAA section 111(b) are applicable immediately after the effective date of their promulgation.

(1) Technical Feasibility of the Best System of Emission Reduction

As the January 2014 proposal indicates, the requirement that the standard for emissions be ''achievable'' based on the ''best system of emission reduction . . . adequately demonstrated'' indicates that one of the requirements for the technology or other measures that the EPA identifies as the BSER is that the measure must be technically feasible. See 79 FR 1430, 1463 (January 8, 2014).

b. ''Best''

In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA considers the following factors:

(1) Costs

Under CAA section 111(a)(1), the EPA is required to take into account ''the cost of achieving'' the required emission reductions. As described in the January 2014 proposal,[135] in several cases the D.C. Circuit has elaborated on this cost factor and formulated the cost standard in various ways, stating that the EPA may not adopt a standard the cost of which would be ''exorbitant,''[136] ''greater than the industry could bear and survive,''[137] ''excessive,''[138] or ''unreasonable.''[139] For convenience, in this rulemaking, we use 'reasonableness' to describe costs well within the bounds established by this jurisprudence.[140]

The D.C. Circuit has indicated that the EPA has substantial discretion in its consideration of cost under section 111(a). In several cases, the Court upheld standards that entailed significant costs, consistent with Congress's view that ''the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.''[141] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973);[142] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir.

Portland Cement Ass'n v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

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

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

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

[129] Although section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination, the D.C. Circuit's case law appears to treat them as part of the ''best'' determination. See *Sierra Club* v. *Costle,* 657 F.2d at 325–26. It does not appear that those two approaches would lead to different outcomes. In this rule, the EPA is following the D.C. Circuit case law and treating the factors as part of the ''best'' determination.

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

[131] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted) (discussing the Senate and House bills and reports from which the language in CAA section 111 grew).

[132] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[133] *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (1981).

[134] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[135] 79 FR 1464 (January 8, 2014).

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

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

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

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

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

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

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

The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91–1196 at 16. Some commenters asserted that we do not have authority to revise the cost standard as established in the case law, *e.g.,* ''exorbitant,'' ''excessive,'' etc., to a ''reasonableness'' standard that may be considered less protective of the environment. We agree that we do not have authority to revise the cost standard as established in the case law, and we are not attempting to do so here. Rather, our description of the cost standard as ''reasonableness'' is intended to be a convenient term for referring to the cost standard as established in the case law.

[141] 1977 House Committee Report at 184.

[142] The costs for these standards were described in the rulemakings. *See* 36 FR 24876 (December 23, 1971), 37 FR 5767, 5769 (March 21, 1972).

1981) (upholding standard imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial'').[143] Moreover, section 111(a) does not provide specific direction regarding what metric or metrics to use in considering costs, again affording the EPA considerable discretion in choosing a means of cost consideration.[144]

As discussed below, the EPA may consider costs on both a source-specific basis and a sector-wide, regional, or nationwide basis. The EPA is finding here that whether costs are considered on a source-specific basis, an industry/national basis, or both, they are reasonable. See Sections V.H and I below.

(2) Non-Air Quality Health and Environmental Impacts

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact'' in determining the BSER. As the D.C. Circuit has explained, this requirement makes explicit that a system cannot be ''best'' if it does more harm than good due to cross-media environmental impacts.[145] The EPA has carefully considered such cross-media impacts here, in particular potential impacts to underground sources of drinking water posed by CO_2 sequestration, and water use necessary to operate carbon capture systems. See Sections V.N and O below.

(3) Energy Considerations

Under CAA section 111(a)(1), the EPA is required to take into account ''energy requirements.'' As discussed below, the EPA may consider energy requirements on both a source-specific basis and a sector-wide, region-wide, or nationwide basis. Considered on a source-specific basis, ''energy requirements'' entail, for example, the impact, if any, of the system of emission reduction on the source's own energy needs. In this rulemaking, as discussed below in Section V.O.3, the EPA considered the parasitic load requirements of partial CCS. The EPA is finding here that whether energy requirements are considered on a source-specific basis, an industry/national basis, or both, they are reasonable. See Sections V.O.3 and XIII.C.

(4) Amount of Emissions Reductions

At proposal, we noted that although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must in fact do so. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[146] The fact that the purpose of a ''system of emission reduction'' is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the Court's view that in determining whether a ''system of emission reduction'' is the ''best,'' the EPA must consider the amount of emission reductions that the system would yield.[147] Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term ''system of emission reduction'' or the term ''best'' may reasonably be read to allow that discretion.

(5) Sector or Nationwide Component of the BSER Factors

As discussed in the January 2014 proposal, another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[148] The D.C. Circuit based this conclusion on a review of the legislative history, stating,

> The Conferees defined the best technology in terms of ''long-term growth,'' ''long-term cost savings,'' effects on the ''coal market,'' including prices and utilization of coal reserves, and ''incentives for improved technology.'' Indeed, the Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[149]

The Court has upheld rules that the EPA ''justified . . . in terms of the policies of the Act,'' including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . . By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.
>
> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[150]

Some commenters objected that this case law did not allow the EPA to ignore source-specific impacts (particularly cost impacts) by basing determinations solely on impacts at a regional or national level. In fact, the EPA's consideration of cost, non-air quality impacts, and energy requirements reflect source-specific impacts, as well as (for some considerations) impacts that are sector-wide, regional, or national. See Section V.H.6 below.

c. Achievability of the Standard for Emissions

In the January 2014 proposal, the EPA recognized that the first element of the definition of ''standard of performance'' is that ''the emission limit [*i.e.,* the 'standard for emissions'] that the EPA promulgates must be 'achievable' ''

[143] Indeed, in upholding the EPA's consideration of costs under the provisions of the Clean Water Act authorizing technology-based standards based on performance of a best technology taking costs into account, courts have also noted the substantial discretion delegated to the EPA to weigh cost considerations with other factors. *Chemical Mfr's Ass'n* v. *EPA,* 870 F.2d 177, 251 (5th Cir. 1989); *Association of Iron and Steel Inst.* v. *EPA,* 526 F.2d 1027, 1054 (3d Cir. 1975); *Ass'n of Pacific Fisheries* v. *EPA,* 615 F.2d 794, 808 (9th Cir. 1980).

[144] See, *e.g., Husqvarna AB* v. *EPA,* 254 F.3d 195, 200 (D.C. Cir. 2001) (where CAA section 213 does not mandate a specific method of cost analysis, the EPA may make a reasoned choice as to how to analyze costs).

[145] *Portland Cement* v. *EPA,* 486 F.2d at 384; *Sierra Club* v. *Costle,* 657 F.2d at 331; see also *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 439 (remanding standard to consider solid waste disposal implications of the BSER determination).

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

[147] See also *NRDC* v. *EPA,* 479 F.3d 875, 880 (D.C. Cir. 2006) (''best performing'' source for purposes of CAA section 112 (d)(3) is source with the lowest emission levels).

[148] 79 FR 1430, 1465 January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

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

[150] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583/3–33584/1). In the January 2014 proposal, we explained that although the D.C. Circuit decided *Sierra Club* v. *Costle* before the *Chevron* case was decided in 1984, the D.C. Circuit's decision could be justified under either *Chevron* step 1 or 2. 79 FR 1430, 1466 (January 8, 2014).

based on performance of the BSER. 79 FR 1430, 1463 (January 8, 2014). According to the D.C. Circuit, a standard for emissions is ''achievable'' if a technology can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard.[151] Moreover, according to the Court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.'' [152] To be achievable, a standard ''must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'cost of compliance.' '' [153] To show that a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard.'' [154]

In Sections V.J and IX.D below, we show both that the BSER for new steam generating units and combustion turbines is technically feasible and adequately demonstrated, and that the standards of 1,400 lb CO_2/MWh-g and 1,000 lb CO_2/MWh-g are achievable considering the range of operating variables that affect achievability.

d. Expanded Use and Development of Technology

In the January 2014 proposal, we noted that the D.C. Circuit has made clear that Congress intended for CAA section 111 to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' [155]

The Court grounded its reading in the statutory text.[156] In addition, in the January 2014 proposal, we noted that the Court's interpretation finds additional support in the legislative history.[157] We also explained that the legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (i) The development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated'' under section 111(a)(1); (ii) the expanded use of the best demonstrated technology; and (iii) the development of emerging technology.[158] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it, either because technological innovation may be considered an element of the term ''best,'' or because the term ''best system of emission reduction'' is ambiguous as to whether technological innovation may be considered. The interpretation is likewise consistent with the evident purpose of section 111(b) to require new sources to maximize emission reductions using state-of-the-art means of control.

Commenters stated that the requirement to consider technological innovation does not authorize the EPA to identify as the BSER a technology that is not adequately demonstrated. The proposal did not, and we do not in this final rule, claim to the contrary. In any event, as discussed below, the EPA may justify the control technologies identified in this rule as the BSER even without considering the factor of incentivizing technological innovation or development.

e. Agency Discretion

As discussed in the January 2014 proposal, the D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the Court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,'' [159] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard.'' [160] In *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them. . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.[161]

f. Lack of Requirement That Standard Must Be Met by All Sources

In the January 2014 proposal, the EPA proposed that, under CAA section 111, an emissions standard may meet the requirements of a ''standard of performance'' even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard. As described in the January 2014 proposal, the EPA based this view on (i) the legislative history of CAA section 111, read in conjunction with the legislative history of the CAA as a whole; (ii) case law under analogous CAA provisions; and (iii) long-standing precedent in the EPA rulemakings under CAA section 111.[162]

[151] *Portland Cement,* 486 F.2d at 391–92. Some commenters stated that the EPA's analysis of the requirements for ''standard of performance,'' including the BSER, attempted to eliminate the requirement that the standard for emissions must be ''achievable.'' We disagree with this comment. As just quoted, the EPA's analysis recognizes that the standard for emissions must be achievable through the application of the BSER.

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

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

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

[155] See 79 FR 1430, 1465 (January 8, 2014), *Sierra Club* v. *Costle,* 657 F.2d at 346–47.

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

[157] *See* 79 FR 1430, 1465 (January 8, 2014) (citing S.Rep. 91–1196 at 16 (1970)) (''Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources''); S. Rep. 95–127 at 17 (1977) (cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n. 174) (''The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology'').

[158] 79 FR 1465 (citing case law and legislative history).

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

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

[161] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience). S*ee also NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (The EPA did not err in its final balancing because ''neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decision making.'').

[162] 79 FR 1430, 1466 (January 8, 2014).

Commenters contested this assertion, arguing that a 111(b) standard must be achievable by all new sources. We continue to take the same position as at proposal for the reasons described there. We note that as a practical matter, in this rulemaking, the issue of whether all new steam-generating sources can implement partial-capture CCS is largely dependent on the geographic scope of geologic sequestration sites. As discussed below in Section V.M, geologic sequestration sites are widely available, and a steam-generating plant with partial CCS that is sited near an area that is suitable for geologic sequestration can serve demand in a large area that may not have sequestration sites available. In any event, the standard of 1,400 lb CO_2/MW-g that we promulgate in this final rule can be achieved by new steam generating EGUs—including new utility boilers and IGCC units—through co-firing with natural gas in lieu of installing partial CCS, which moots the issue of the geographic availability of geologic sequestration.

g. EPAct05

The Energy Policy Act of 2005 (''EPAct05'') authorizes assistance in the form of grants, loan guarantees, as well as federal tax credits for investment in ''clean coal technology.'' Sections 402(i), 421(a), and 1307(b) (adding section 48A(g) to the Internal Revenue Code (''IRC'')) address the extent to which information from clean coal projects receiving assistance under the EPAct05 may be considered by the EPA in determining what is the best system of emission reduction adequately demonstrated. Section 402(i) of the EPAct05 limits the use of information from facilities that receive assistance under EPAct05 in CAA section 111 rulemakings:

''No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .'' [163]

IRC section 48A(g) contains a similar constraint concerning the use of technology or level of emission reduction from EGU facilities for which a tax credit is allowed:

> ''No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .''

The EPA specifically solicited comment on its interpretation of these provisions. 79 FR 10750 (Feb. 26, 2014) (Notice of Data Availability). With respect to EPAct05 sections 402(i) and 421(a), the EPA proposed that these provisions barred consideration where EPAct05-assisted facilities were the sole support for the BSER determination, but that these sources could support a BSER determination so long as there is additional evidence supporting the determination.[164] In addition, the EPA viewed the two prohibitions as relating only to the technology or emissions reduction for which assistance was given.[165] The EPA likewise interpreted IRC section 48A(g)—based on the plain language and the context provided by sections 402(i) and 421(a)—to mean that use of technology, or emission performance, from a facility for which the credit is allowed cannot, by itself, support a finding that the technology or performance level is adequately demonstrated, but the information can corroborate an otherwise supported determination or otherwise provide part of the basis for such a determination.[166] The EPA also proposed to interpret the phrase ''with respect to which a credit is allowed under this section'' as referring to the entire phrase ''use of technology (or level of emission reduction . . .) and [] achievement of any emission reduction . . . , by or at one or more facilities.'' Thus, if technology A received a tax credit, but technology B at the same facility did not, the constraint would not apply to technology B.[167]

Some commenters supported the EPA's proposed interpretation. Others contended that the EPA's interpretation would allow it to support a BSER determination even where EPAct05 facility information comprised 99 percent of the supporting information for a BSER determination because that determination would not be based ''solely'' on EPAct05 sources. These commenters urged the EPA to conclude that a determination ''solely'' on the basis of information from EPAct05-assisted facilities is any determination where ''but for'' that information, the EPA could not justify its chosen standard as the BSER.[168] Other commenters argued that the provisions bar the EPA from all consideration of EPAct05 facilities when determining that a technology or level of performance is adequately demonstrated.

In this final rule, the EPA is adopting the interpretations of all three provisions that it proposed, largely for the reasons previously advanced. The EPA thus interprets these provisions to preclude the EPA from relying solely on the experience of facilities that received DOE assistance, but not to preclude the EPA from relying on the experience of such facilities in conjunction with other information. This reading of sections 402(i) and 421(a) is consistent with the views of the only court to date to consider the matter.[169]

The EPA notes that the extreme hypothetical posed in the comments (where the EPA might avoid a limitation on its consideration of EPAct05-assisted facilities by including a mere scintilla of evidence from non-EPAct05 facilities) is not presented here, where the principal evidence that partial post-combustion CCS is a demonstrated and feasible technology comes from sources which received no assistance of any type under EPAct05. The EPA also concludes that the ''but for'' test urged by these commenters is an inappropriate reading of the term ''solely'' in sections 402(i) and 421(a), as any piece of evidence may be a necessary, or ''but for,'' cause without being a sufficient, or ''sole,'' cause.[170] Nonetheless, if the ''but for'' test were applicable here, the available evidence would satisfy it.

[163] Codified at 42 U.S.C. 15962(a). EPAct05 section 421(a) similarly states: ''No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [sic] of section 7411 of this title, . . . solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title''.

[164] Technical Support Document, *Effect of EPAct05 on Best System of Emission Reduction for New Power Plants,* p. 6 (Docket entry: EPA–HQ–OAR–2013–0495–1873).

[165] Id.

[166] Id. p. 13.

[167] Id. p. 14.

[168] Comments of AFPM/API p. 46 (Docket entry: EPA–HQ–OAR–2013–0495–10098).

[169] *State of Nebraska* v. *EPA,* 2014 U.S. Dist. LEXIS 141898 at n. 1 (D. Nebr. 2014). (''But the Court notes that § 402(i) only forbids the EPA from considering a given technology or level of emission reduction to be adequately demonstrated *solely* on the basis of federally-funded facilities. 42 U.S.C. 15962(i). In other words, such technology might be adequately demonstrated if that determination is based at least in part on non-federally-funded facilities'') (emphasis original).

[170] For example, any vote of a Justice on the Supreme Court may be a necessary but not sufficient cause. In a 5–4 decision, the decision of the Court would have been different ''but for'' the assent of Justice A or Justice B, who were in the majority. But it would be incorrect to say that the assent of Justice A was the ''sole'' reason for the outcome, when the decision also required the assent of Justice B.

Other commenters took the extreme position that the EPAct05 provisions bar all consideration of a facility's existence if the facility received EPAct05 assistance.[171] The EPA does not accept this argument because it is contrary to both the plain statutory language [172] (see Chapter 2 of the Response-to-Comment document) and to Congress's intent that the EPAct05 programs advance the commercialization of clean coal technology. For the same reason, the EPA does not accept some commenters' suggestion that sections 402(i), 421(a), and 48A(g) preclude the EPA from considering NETL's cost projections for CCS, which base cost estimates on up-to-date vendor quotes reflecting costs for the CCS technology being utilized at the Boundary Dam Unit #3 facility (a facility receiving no assistance under EPAct05), but also considers that to-be-built plants will no longer be first-of-a kind. See generally Section V.I.2 below. Commenters suggest that the EPAct05 requires that the EPA treat future plants as ''first of a kind'' when projecting costs, as if EPAct05 facilities simply did not exist. This reading is contrary to the text of the provisions, which as noted, relates specifically to a source's performance and operation (whether a technology is demonstrated, and the level of performance achieved by use of technology), not to sources' existence. NETL's cost projections, on the other hand, merely acknowledge the evident fact that CCS technologies exist, and reasonably project that they will continue to develop. See Section V.I.2. The NETL cost estimates, moreover, are based on vendor quotes for the CCS technology in use at the Boundary Dam facility, a Canadian plant which obviously is not a recipient of EPAct05 assistance. See sections V.D.2.a and V.I.2 below.

In any case, as shown in Section V below, the EPA finds that a new highly-efficient SCPC EGU implementing partial post-combustion CCS is the best system of emission reduction adequately demonstrated and is doing so based in greater part on performance of facilities receiving no assistance under EPAct05, and on other information likewise not having any connection to EPAct05 assistance. The corroborative information from EPAct05 facilities, though supportive, is not necessary to the EPA's findings.

I. Severability

This rule has numerous components, and the EPA intends that they be severable from each other to the extent that they function separately. For example, the EPA intends that each set of BSER determinations and standards of performance in this rulemaking be severable from each other set. That is, the BSER determination and standard of performance for newly constructed fossil fuel-fired electric utility steam generating units are severable from all the other BSER determinations and standards of performance, and the same is true for the BSER determination and standard of performance for modified fossil fuel-fired electric utility steam generating units, and so on. It is reasonable to consider each set of BSER determination and standard of performance to be severable from each other set of BSER determination and standard of performance because each set is independently justifiable and does not depend on any other set. Thus, in the event that a court should strike down any set of BSER determination and standard of performance, the remaining BSER determinations and standards of performance should not be affected.

J. Certain Projects Under Development

In the January 2014 proposal, the EPA indicated that the proposed Wolverine EGU project (Rogers City, Michigan) appeared to be the only fossil fuel-fired steam generating unit that was currently under development that may be capable of ''commencing construction'' for NSPS purposes at the time of the proposal. See 79 FR 1461. The EPA also acknowledged that the Wolverine EGU, as designed, would not meet the proposed standard of 1,100 lb CO_2/MWh for new utility steam generating EGUs. The EPA proposed that, at the time of finalization of the proposed standards, if the Wolverine project remains under development and has not either commenced construction or been canceled, we anticipated proposing a standard of performance specifically for that facility. Additional discussion of the approach can be found in the proposal or in the technical support document in the docket entitled ''Fossil Fuel-Fired Boiler and IGCC EGU Projects under Development: Status and Approach.''

In December 2013—after the proposed action was signed, but before it was published—Wolverine Power Cooperative announced that it was cancelling construction of the proposed coal-fired power plant in Rogers City, MI.[173] Therefore, we are not finalizing the proposed exclusion for that project.

In the January 2014 proposal, the EPA also identified two other fossil fuel-fired steam generating EGU projects that, as currently designed, would not meet the proposed 1,100 lb CO_2/MWh emissions standard—the Plant Washington project in Georgia and the Holcomb 2 project in Kansas. We indicated that, at the time of the proposal, those projects appeared to remain under development but that the project developers had represented that the projects have commenced construction for NSPS purposes and, thus, would not be new sources subject to the proposed or final NSPS. Based solely on the developers' representations, the EPA indicated that those projects, if ultimately fully constructed, would be existing sources, and would thus not be subject to the standards of performance in this final action.

To date, neither developer has sought a formal EPA determination of NSPS applicability. As we specified in the January 2014 proposal—and we reiterate here—if such an applicability determination concludes that either the Plant Washington (GA) project or the Holcomb 2 (KS) project did not commence construction prior to January 8, 2014 (the publication of the January 2014 proposal), then the project should be situated similarly to the disposition the EPA proposed for the Wolverine project. Accordingly, the EPA is finalizing in this action that if it is determined that either of these projects has not commenced construction as January 8, 2014, then that project will be addressed in the same manner as was proposed for the Wolverine project.

In public comments submitted in response to the January 2014, Power4Georgians (P4G), the Plant Washington developer, reiterated that they had executed binding contracts for the purchase and erection of the facility boiler prior to publication of the January 2014 proposal and believe that the binding contracts are sufficient to constitute commencement of construction for purposes of the NSPS program, so that they are existing rather than new sources for purposes of this

[171] Supplemental Comments of Murray Energy p. 11 (Docket entry: EPA–HQ–OAR–2013–0495–9498).

[172] With respect to sections 402(i) and 421(a), commenters fail to reconcile their reading of the statute with the Act's grammatical structure, as explained in detail in chapter 2 of the Response-to-Comment document. One commenter supported its reading by adding suggested text to the statutory language, a highly disfavored form of statutory construction. Comments of UARG, p.124 n.38 (Docket entry: EPA–HQ–OAR–2013–0495–9666). With respect to section 48A(g), commenters misread the phrase ''considered to indicate,'' and do not explain how their reading of all three provisions together is tenable.

[173] ''Wolverine ends plant speculation in Rogers City'', The Alpena News, December 17, 2013. *http://www.thealpenanews.com/page/content.detail/id/527862/Wolverine-ends-plant-speculation-in-Rogers-City.html?nav=5004.*

rule.[174] Public comments submitted by Tri-State Generation and Transmission Association and Sunflower Electric Power Corporation, the developers of the Holcomb 2 project, discussed the cost incurred in the development of the project. They also indicated they had awarded contracts for the turbine/generator purchase and had negotiated a rail-supply agreement that provides for the delivery of fuel to the proposed Holcomb 2 site. The developers did not, however, explicitly characterize the construction status of the project.[175] Other groups submitted comments contending that neither project has actually commenced construction.

In October 2013, the Kansas Supreme Court invalidated the 2010 air pollution permit granted to Sunflower Electric Power Corporation by the Kansas Department of Health and Environment (KDHE).[176] In May 2014, the KDHE issued an air quality permit addendum for the proposed Holcomb 2 coal plant. The addendum addressed federal regulations that the Kansas Supreme Court held had been overlooked in the initial permitting determination. In June 2014, the Sierra Club filed an appeal with the Kansas Appellate Court challenging the legality of the May 2014 permit. Since the publication of the January 2014 proposal, the EPA is unaware of any physical construction activity at the proposed Holcomb 2 site.

In October 2014, the Plant Washington project was given an 18-month air permit extension by the Georgia Environmental Protection Division (EPD). However, as with the Holcomb expansion project, the EPA is unaware of any physical construction that has taken place at the proposed Plant Washington site and a recent audit of the project described it as ''dormant''.[177]

Based on this information, it appears that these sources have not commenced construction for purposes of section 111(b) and therefore would likely be new sources should they actually be constructed. As noted above, the EPA proposed that, if these projects are determined to not have commenced construction for NSPS purposes prior to the publication of the proposed rule, they will be addressed in the same manner proposed for the Wolverine project. 79 FR 1461. We are finalizing that proposal here. However, because these units may never actually be fully built and operated, we are not promulgating a standard of performance at this time because such action may prove to be unnecessary.[178]

There is one possible additional new EGU, the Two Elk project in Wyoming. In a supporting TSD accompanying the January 2014 proposal, we discussed the Two Elk project and relied on developer statements and state acquiescence that the unit had commenced construction for NSPS purposes before January 8, 2014.[179] We did not, therefore, propose any special section 111(b) standard for the project. Some commenters maintained that a continuous program of construction at the facility has not been maintained and that if the plant is ultimately constructed, it should be classified as a new source under CAA section 111(b). These comments were not specific enough to change the EPA's view of the project for purposes of this rulemaking. We accordingly continue to rely on developer statements that this facility has commenced construction and would not be a new source for purposes of this proceeding.

IV. Summary of Final Standards for Newly Constructed, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units

This section sets forth the standards for newly constructed, modified, and reconstructed steam generating units (*i.e.,* utility boilers and IGCCs). We explain the rationale for the final standards in Sections V (newly constructed steam generating unit), VI (modified steam generating units), and VII (reconstructed steam generating units).

A. Applicability Requirements and Rationale

We generally refer to fossil fuel-fired electric utility 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 units meet both the definition of ''affected'' and ''covered'' EGUs subject to an emission standard as provided by this rule, and the criteria for being considered ''new,'' ''modified'' or ''reconstructed'' sources as defined under the provisions of CAA section 111 and the EPA's regulations. This section discusses applicability for newly constructed, modified, and reconstructed steam generating units.

1. General Applicability Criteria

The EPA is finalizing applicability criteria for new, modified, and reconstructed electric utility steam generating units (*i.e.,* utility boilers and IGCC units) in 40 CFR part 60, subpart TTTT that are similar to the applicability criteria for those units in 40 CFR part 60, subpart Da (utility boiler and IGCC performance standards for criteria pollutants), but with some differences. The proposed applicability criteria, relevant comments, and final applicability criteria specific to newly constructed, modified, and reconstructed steam generating units are discussed below.

The applicability requirements in the proposal for newly constructed EGUs included that a utility boiler or IGCC unit must: (1) Be capable of combusting more than 250 MMBtu/h heat input of fossil fuel; (2) be constructed for the purpose of supplying, and actually supply, more than one-third of its potential net-electric output capacity to any utility power distribution system (that is, to the grid) for sale on an annual basis; (3) be constructed for the purpose of supplying, and actually supply, more than 219,000 MWh net-electric output to the grid on an annual basis; and (4) combust over 10 percent fossil fuel on a heat input basis over a 3-year average. At proposal, applicability was determined based on a combination of design and actual operating conditions that could change annually depending on the proportion and the amount of electricity actually sold and on the proportion of fossil fuels combusted by the unit.

In the proposal for modified and reconstructed EGUs, we proposed a broader applicability approach such that applicability would be based solely on design criteria and would be identical to the applicability requirements in

[174] Docket entry: EPA–HQ–OAR–2013–0495–9403.

[175] Docket entry: EPA–HQ–OAR–2013–0495–9599.

[176] ''Kansas High Court Invalidates 895–MW Coal Project Air Permit'', Power Magazine, 10/10/2013, available at: *www.powermag.com/kansas-high-court-invalidates-2010-895-mw-coal-project-air-permit/.*

[177] *http://www.macon.com/2015/06/23/3811798/audit-sandersville-coal-plant.html.*

[178] In the proposed emission guidelines for existing EGUs, the EPA did not include estimates of emissions for either Plant Washington or the Holcomb 2 unit in baseline data used to calculate proposed state goals for Georgia and Kansas. It appears that the possibility of these plants actually being built and operating is too remote. If either unit eventually seeks an applicability determination and that unit is determined to be an existing source, and there is reliable evidence that the source will operate, then the source will be subject to the final 111(d) rule and the EPA will allow the state to adjust its state goal to reflect adjustment of the state's baseline data so as to include the unit. Guidance for adjustment of state goals is provided in the record for the EPA's final CAA section 111(d) rulemaking.

[179] ''Fossil Fuel-Fired Boiler and IGCC EGU Projects Under Development: Status and Approach'', Technical Support Document at pp. 10–1 (Docket Entry: EPA–HQ–OAR–2013–0495–0024).

subpart Da. First, we proposed electric sales criteria that the source be constructed for the purpose of selling more than one-third of their potential electric output and more than 219,000 MWh to the grid on an annual basis, regardless of the actual amount of electricity sold (*i.e.,* we did not include the applicability criterion that the unit actually sell the specified amount of electricity on an annual basis). In addition, we proposed a base load rating criterion that the source be capable of combusting more than 250 MMBtu/h of fossil fuel, regardless of the actual amount of fossil fuel burned (*i.e.,* we did not include the fossil fuel-use criterion that an EGU actually combust more than 10 percent fossil fuel on a heat input basis on a 3-year average). Under this approach, applicability would be known prior to the unit actually commencing operation and would not change on an annual basis. We also proposed that the final applicability criteria would be consistent for newly constructed, reconstructed, and modified units. The proposed broad applicability criteria would still not have included boilers and IGCC units that were constructed for the purpose of selling one-third or less of their potential output or 219,000 MWh or less to the grid on an annual basis. These units are not covered under subpart Da (the utility boiler and IGCC EGU criteria pollutant NSPS) but are instead covered as industrial boilers under subpart Db (industrial, institutional, and commercial boilers NSPS) or subpart KKKK (the combustion turbine criteria pollutant NSPS).

We solicited comment on whether, to avoid implementation issues related with different interpretations of ''constructed for the purpose,'' the total and percentage electric sales criteria should be recast to be based on permit conditions. The ''constructed for the purpose'' language was included in the original subpart Da rulemaking. At that time, the vast majority of new steam generating units were clearly base load units. The ''constructed for the purpose'' language was intended to exempt industrial CHP units. These units tend to be relatively small and were not the focus of the rulemaking. In addition, units not meeting the electric sales applicability criteria in subpart Da would be covered by other NSPS so there is limited regulatory incentive, or impact to the environment, for owners/operators to avoid applicability with the utility NSPS. However, for new units, there is no corresponding industrial unit CO_2 NSPS and existing units could debate their original intent (*i.e.,* the purpose for which they were constructed) in an attempt to avoid applicability under section 111(d) requirements. Consequently, there could be a regulatory incentive for owners/operators to circumvent the CO_2 NSPS applicability. For units that avoid coverage, there would also be a corresponding environmental impact. For example, an owner/operator of a new unit could initially request a permit restriction to limit electric sales to less than one-third of potential annual electric output, but amend the operating permit shortly after operation has commenced to circumvent the intended applicability. Many existing units were initially built with excess capacity to account for projected load growth and were intended to sell more than one-third of their potential electric output. However, due to various factors (lower than expected load growth, availability of other lower cost units, etc.), certain units might have sold less than one-third of their potential electric output, at least during their initial period of operation. Therefore, the EPA has concluded that determining applicability based on whether a unit is ''*constructed for the purpose of* supplying one-third or more of its potential electric output and more than 219,000 MWh as net-electric sales'' (emphasis added) could create applicability uncertainty for both the regulated community and regulators. In addition, we have concluded that applicability based on actual operating conditions (*i.e.,* actual electric sales) is not ideal because applicability would not be known prior to determining compliance and could change annually.

This action finalizes applicability criteria based on design characteristics and federally enforceable permit restrictions included in each individual permit. Based on restrictions, if any, on annual total electric sales in the operating permit, it will be clear from the time of construction whether or not a new unit is subject to this rule. The applicability includes all utility boilers and IGCC units unless the electric sales restriction was in the original and remains in the current operating permit without any lapses (this is to be consistent with the 'constructed for the purpose of' criteria in subpart Da). We have concluded that this approach is equivalent to, but clearer than, the existing language used in subpart Da. In addition, we have concluded that it is important for both the 111(b) and 111(d) requirements for electric-only steam generating units that the permit restriction limiting annual electric sales be included in both the original and current operating permit. Without this restriction, existing units could avoid obligations under state plans developed as part of the 111(d) program by amending their operating permit to limit total annual electric sales to one-third of potential electric output. These units would not be subject to any GHG NSPS requirements because they would not meet the 111(b) or 111(d) applicability criteria and, at this time, there is no NSPS that would cover these units. As described in Section III, industrial CHP and dedicated non-fossil units also are not affected EGUs under this final action.

In this rule, we are finalizing the definition of a steam generating EGU as a utility boiler or IGCC unit that: (1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel) and (2) serves a generator capable of supplying more than 25 MW-net to a utility distribution system (*i.e.,* for sale to the grid). However, we are not establishing final CO_2 standards for certain EGUs. These include: (1) Steam generating units and IGCC units that are currently subject to—and have been continuously subject to—a federally enforceable permit limiting annual electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (2) units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of the unit's heat input capacity on an annual basis; and (3) CHP units that are subject to a federally enforceable permit condition limiting annual total electric sales to no more than their design efficiency times their potential electric output, or to no more than 219,000 MWh, whichever is greater.

2. Applicability Specific to Newly Constructed Steam Generating Units

In CAA section 111(a)(2), a ''new source'' is defined as any stationary source, the construction or modification of which is commenced after the publication of regulations (or if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source. Accordingly, for purposes of this rule, a newly constructed steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and commences construction on or after January 8, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 1430).

3. Applicability Specific to Modified Steam Generating Units

In CAA section 111(a)(4), a ''modification'' is defined as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[180]

For purposes of this rule, a modified steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and that modifies on or after June 18, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 34960).

4. Applicability Specific to Reconstructed Steam Generating Units

The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered a new source if it undertakes a ''reconstruction,'' 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.[181]

For purposes of this rule, a reconstructed steam generating EGU is a unit that fits the definition and applicability criteria of a fossil fuel-fired steam generating EGU and that reconstructs on or after June 18, 2014, which is the date that the proposed standards were published for those sources (see 79 FR 34960).

B. Best System of Emission Reduction

1. BSER for Newly Constructed Steam Generating Units

In the January 2014 proposal, the EPA proposed that highly efficient new generation technology implementing partial CCS is the BSER for GHG emissions from new steam generating EGUs. (See generally 79 FR 1468–1469.) In this final action, the EPA has determined that the BSER for newly constructed steam generating units is a new highly efficient supercritical pulverized coal (SCPC) boiler implementing partial CCS technology to the extent of removal efficiency that meets a final emission limitation of 1,400 lb CO_2/MWh-g. The final standard of performance is less stringent than the proposed emission limitation of 1,100 lb CO_2/MWh-g. This change, as will be discussed in greater detail later in this preamble, is in response to public comments and reflects both a re-examination of the potential BSER technologies and the most recent, reliable information regarding technology costs. A newly constructed fossil fuel-fired supercritical utility boiler will be able to meet the final standard by implementing post-combustion carbon capture treating a slip-stream of the combustion flue gas. Alternative potential compliance paths are to build a new IGCC unit and co-fire with natural gas (or use pre-combustion carbon capture on a slip-stream), or for a supercritical utility boiler to co-fire with natural gas.

The EPA of course realizes that the final standard of performance (1,400 lb CO_2/MWh-g) differs from the proposed standard (1,100 lb CO_2/MWh-g). The EPA notes further, however, that the methodology for determining the final standard of performance is identical to that at proposal—determining that a new highly efficient generating technology implementing some degree of partial CCS is the BSER, with that degree of implementation being determined based on the reasonableness of costs. A key means of assessing the reasonableness of cost at proposal was comparison of the levelized cost of electricity (LCOE) with that of other dispatchable, base load non-NGCC generating options. We have maintained that approach in identifying BSER for the final standard. Applying this methodology to the most recent cost information has led the EPA to adopt the final standard of performance of 1,400 lb CO_2/MWh-g. See Section V.H at Table 8 below. This final standard reflects the level of emission reduction achievable by a highly efficient SCPC implementing the degree of partial CCS that remains cost comparable to the other non-NGCC dispatchable base load generating options.

The BSER for newly constructed steam generating EGUs in the final rule is very similar to that in the proposal. In this final action, the EPA finds that a highly efficient new SCPC EGU implementing partial CCS to the degree necessary to achieve an emission of 1,400 lb CO_2/MWh-g is the BSER. Contrary to the January 2014 proposal, the EPA finds that IGCC technology—either alone or implementing partial CCS—is not part of the BSER, but rather is a viable alternative compliance option. As noted at proposal, a BSER typically advances performance of a technology beyond current levels of performance. 79 FR 1465, 1471. Similarly, promotion of technology innovation can be a relevant factor in BSER determinations. Id. and Section III.H.3.d above. For these reasons, the EPA at proposal voiced concerns about adopting standards that would allow an IGCC to comply without utilizing CCS for slip-stream control. Id. at 1471. The final standard of 1,400 lb CO_2/MWh-g, adopted as a means of assuring reasonableness of costs, allows IGCC units to comply without using partial CCS. Thus, although the standard can be met by a highly efficient new IGCC unit using approximately 3 percent partial CCS (see Sections V.E and V.H.7 below), the EPA does not believe that implementation of partial CCS at such a low level, while technically feasible, is the option that utilities and project developers will choose. The EPA believes that IGCC project developers will either choose to meet the final standard by co-firing with natural gas—which would be a less costly and very straightforward process for a new IGCC unit—or they will choose to install CCS equipment that will allow the facility to achieve much deeper CO_2 reductions than required by this rule—likely to co-produce chemicals and/or to capture large volumes of CO_2 for use in EOR operations. Similarly, project developers may also—as an alternative to utilizing partial CCS technology—meet the final standard by co-firing approximately 40 percent natural gas in a new highly efficient SCPC EGU.

While the EPA does not find that IGCC technology—either alone or with implementation of partial CCS—is part of the BSER for new steam generating EGUs, we remain convinced that it is technically feasible (see Section V.E below) and believe that it represents a viable alternative compliance option that some project developers will consider to meet the final standard issued in this action. The EPA notes further that IGCC is available at reasonable cost (see Table 9 below), and involves use of an advanced technology. So, although the final standard reflects performance of a BSER which includes partial CCS, even in the instances that a compliance alternative might be utilized, that alternative would both result in emission reductions consistent with use of the BSER, and would reflect many of the underlying principles and attributes of the BSER (costs are both reasonable, not greatly dissimilar than BSER, no collateral adverse impacts on health or the environment, and reflects

[180] 40 CFR 60.2, 60.14(e).

[181] 40 CFR 60.15.

performance of an advanced technology).

In reaching the final standard of performance, the EPA is aware that at proposal, the agency stated that it was not ''currently considering'' a standard of performance as high as 1,400 lb CO_2/MWh-g. 79 FR 1471. However, in that same discussion, the EPA noted the reasons for its reservations (chiefly reservations about the extent of emission reductions, promotion of advanced CO_2 control technologies, and whether the standard could be met by either utility boilers or IGCC units co-firing with natural gas, or otherwise complying without utilizing partial CCS), and we specifically solicited comment on the issue: ''We request that commenters who suggest emission rates above 1,200 lb CO_2/MWh address potential concerns about providing adequate reductions and technology development to be considered BSER.'' Id. The proposal thus both solicited comment on higher emission standards (including 1,400 lb CO_2/MWh-g based on a less aggressive rate of partial CCS), and provided ample notice of the methodology the EPA would use to determine the final BSER and the corresponding final standard.[182] For these reasons, the EPA believes that it provided adequate notice of this potential outcome at proposal, that the final standard of performance was reasonably foreseeable, and that the final standard is a logical outgrowth of the proposed rule. *Allina Health Services* v. *Sebelius,* 746 F. 3d 1102, 1107 (D.C. Cir. 2014).

A more detailed discussion of the rationale for the final BSER determination and of other systems that were also considered is provided in Section V.P of this preamble.[183]

2. BSER for Modified Steam Generating Units

The EPA has determined that, as proposed, the BSER for steam generating units that trigger the modification provisions is the modified unit's own best potential performance. However, as explained below, the final BSER determination and the scope of modifications to which the final standards apply differ in some important respects from what the EPA proposed.

The EPA proposed that the modified unit's best potential performance would be determined depending upon when the unit implemented the modification (*i.e.,* before or after being subject to an approved CAA section 111(d) state plan). For units that commenced modification prior to becoming subject to an approved CAA section 111(d) state plan, the EPA proposed unit-specific standards consistent with each modified unit's best one-year historical performance (during the years from 2002 to the time of the modification) plus an additional two percent reduction. For sources that commenced modification after becoming subject to an approved CAA section 111(d) plan, the EPA proposed that the unit's best potential performance would be determined from the results of an efficiency audit.

The final standards in this action do not depend upon when the modification commences, as long as it commences after June 18, 2014. We are establishing emission standards for large modifications in this rule and deferring at this time the setting of standards for small modifications.

In this final action, the EPA is issuing final emission standards for affected steam generating units that implement larger modifications that are consistent with the proposed BSER determination for those units. The final standard for those sources that implement larger modifications is a unit-specific emission limitation consistent with each modified unit's best one-year historical performance (during the years from 2002 to the time of the modification), but does not include the additional two percent reduction that was proposed in the January 2014 proposal.

In this action, the EPA is not finalizing standards for those sources that conduct smaller modifications and is withdrawing the proposed standards for those sources. See Section XV below.

A more detailed discussion of the rationale for the BSER determination and final standards is provided in Section VI of this preamble.

3. BSER for Reconstructed Steam Generating Units

Consistent with our proposal, the EPA has determined that the BSER for reconstructed steam generating units is the most efficient demonstrated generating technology for these types of units (*i.e.,* meeting a standard of performance consistent with a reconstructed boiler using the most efficient steam conditions available, even if the boiler was not originally designed to do so). A more detailed discussion of the rationale for the BSER determination and the final standards is provided in Section VII of this preamble.

C. Final Standards of Performance

The EPA is issuing final standards of performance for newly constructed, modified, and reconstructed affected steam generating units based on the degree of emission reduction achievable by application of the best system of emission reduction for those categories, as described above. The final standards are presented below in Table 6.

TABLE 6—FINAL STANDARDS OF PERFORMANCE FOR NEW, MODIFIED, AND RECONSTRUCTED STEAM GENERATING UNITS

Source	Description	Final standard * lb CO_2/MWh-g
New Sources	All newly constructed steam generating EGUs	1,400.

[182] Although co-firing with natural gas is not part of BSER, as noted above, it could be part of a compliance pathway for either SCPC or IGCC units. In this regard, a number of commenters addressed the issue of natural gas co-firing, indicating that there were circumstances where it could be part of BSER. See *e.g.* Comments of Exelon Corp. p. 12 (Docket entry: EPA–HQ–OAR–2013–0495–9406); Comments of the Sierra Club p. 108 Docket entry: EPA–HQ–OAR–2013–0495–9514). See *Northeast Md. Waste Disposal Authority* v. *EPA,* 358 F.3d 936, 952 (D.C. Cir. 2004); *Appalachian Power* v. *EPA,* 135 F.3d 791, 816 (D.C. Cir. 1998) (commenters understood a matter was under consideration when they addressed it in comments).

[183] Certain commenters maintained that the BSER determination does not comply with (purportedly) binding legal requirements created by regulations implementing the Information Quality Act. These comments are mistaken as a matter of both law and fact. The Information Quality Act does not create legal rights in third parties (see, *e.g. Mississippi Comm'n on Environmental Quality* v. *EPA,* no. 12–1309 at 84 (D.C. Cir. June 2, 2015)), and the OMB Guidelines are not binding rules but rather, as their title indicates, guidance to assist agencies. See *State of Mississippi,* 744 F.3d at 1347 (the Guidelines provide ''policy and procedural guidance'', are meant to be ''flexible'' and are to be implemented differently by different agencies accounting for circumstances). There are also significant factual omissions and mischaracterizations in these comments regarding peer review of the proposed standard and underlying record information. The complete response to these comments is in chapter 2 of the RTC. See also Section V.I.2.a and N below describing findings of the SAB panel that materials of the National Energy Technology Laboratory had been fully and adequately peer reviewed, and that the EPA findings related to sequestration of captured CO_2 reflected the best available science.

TABLE 6—FINAL STANDARDS OF PERFORMANCE FOR NEW, MODIFIED, AND RECONSTRUCTED STEAM GENERATING UNITS—Continued

Source	Description	Final standard * lb CO_2/MWh-g
Modified Sources	Sources that implement larger modifications—those resulting in an increase in hourly CO_2 emissions (lb CO_2/hr) of more than 10 percent.	Best annual performance (lb CO_2/MWh-g) during the time period from 2002 to the time of the modification.
Reconstructed Sources	Large **	1,800.
Reconstructed Sources	Small **	2,000.

* Standards are to be met over a 12-operating-month compliance period.
** Large units are those with heat input capacity of >2,000 mmBtu/hr; small units are those with heat input capacity of ≤2,000 mmBtu/hr.

For newly constructed and reconstructed steam generating units and for modified steam generating sources that result in larger hourly increases of CO_2 emissions, the EPA is finalizing standards in the form of a gross energy output-based CO_2 emission limit expressed in units of mass per useful energy output, specifically, in pounds of CO_2 per megawatt-hour (lb CO_2/MWh-g).[184] The standard of performance will apply to affected EGUs upon the effective date of the final action.

Compliance with the final standard will be demonstrated by summing the emissions (in pounds of CO_2) for all operating hours in the 12-operating-month compliance period and then dividing that value by the sum of the useful energy output (on a gross basis, *i.e.,* gross megawatt-hours) over the rolling 12-operating-month compliance period. The final rule requires rounding of emission rates with numerical values greater than or equal to 1,000 to three significant figures and rounding of rates with numerical values less than 1,000 to two significant figures.

For newly constructed steam generating units, we proposed two options for the compliance period. We proposed that a newly constructed source could choose to comply with a 12-operating-month standard or with a more stringent standard over an 84-operating-month compliance period, and we solicited comment on including an interim 12-operating-month standard (based on use of supercritical boiler technology, see 79 FR at 1448). We are not finalizing the proposed 84-operating-month compliance period option because the final standard of performance for newly constructed sources is less stringent than the proposed standard and because, as discussed in Section V below, we are identifying alternative compliance pathways for new steam generating EGUs. Specifically, we have concluded that there are unlikely to be significant issues with short-term variability during initial operation, in view of both the reduced numerical stringency of the standard, and the availability of compliance alternatives. The EPA notes that co-firing of natural gas can also serve as an interim means to reduce emissions if a new source operator believes additional time is needed to phase-in the operation of a CCS system. Therefore, the applicable final standards of performance for all newly constructed, modified, and reconstructed steam generating units must be met over a rolling 12-operating-month compliance period.

In the Clean Power Plan, which is a separate rulemaking under CAA section 111(d) published at the same time as the present rulemaking under CAA section 111(b), the EPA is promulgating emission guidelines for states to develop state plans regulating CO_2 emissions from existing fossil fuel-fired EGUs. Existing sources that are subject to state plans under CAA section 111(d) may undertake modifications or reconstructions and thereby become subject to the requirements under section 111(b) in the present rulemaking. In the section 111(d) Clean Power Plan rulemaking, the EPA discusses how undertaking a modification or reconstruction affects an existing source's section 111(d) requirements.

V. Rationale for Final Standards for Newly Constructed Fossil Fuel-Fired Electric Utility Steam Generating Units

In the discussion below, the EPA describes the rationale and justification of the BSER determination and the resulting final standards of performance for newly constructed steam generating units. We also explain why this determination is consistent with the constraints imposed by the EPAct05.

A. Factors Considered in Determining the BSER

In evaluating the final determination of the BSER for newly constructed steam generating units, the EPA considered the factors for the BSER described above, looked widely at all relevant information and considered all the data, information, and comments that were submitted during the public comment period. We re-examined and updated the information that was available to us and concluded, as described below, that the final standard of 1,400 lb CO_2/MWh-g is consistent with the degree of emission reduction achievable through the implementation of the BSER. This final standard of performance for newly constructed fossil fuel-fired steam generating units provides a clear and achievable path forward for the construction of new coal-fired generating sources that addresses GHG emissions.

B. Highly Efficient SCPC EGU Implementing Partial CCS as the BSER for Newly Constructed Steam Generating Units

In the sections that follow, we explain the technical configurations that may be used to implement BSER to meet the final standard, describe the operational flexibilities that partial CCS offers, and then provide the rationale for the final standard of performance. After that, we discuss, in greater detail, consideration of the criteria for the determination of the BSER. We describe why a highly efficient new SCPC EGU implementing partial CCS in the amount that results in an emission limitation of 1,400 lb CO_2/MWh-g best meets those criteria, including, among others, that such a system is technically feasible, provides meaningful emission reductions, can be implemented at a reasonable cost, does not pose non-air quality health and environmental concerns or impair energy reliability, and consequently is adequately demonstrated. We also explain why the emission standard of 1,400 lb CO_2/MWh-g is achievable, including under all circumstances

[184] Note that the standards for sources that conduct larger modifications is a unit-specific numerical standard based on the unit's best one-year historical performance during the period from 2002 to the time of the modification. The unit-specific standard will also be in the form of a gross energy output-based CO_2 emission limit expressed in pounds of CO_2 per megawatt-hour (lb CO_2/MWh-g).

reasonably likely to occur when the system is properly designed and operated. We also discuss alternative compliance options that new source project developers can elect to use, instead of SCPC with partial CCS, to meet the final standard of performance.

C. Rationale for the Final Emission Standards

1. The Proposed Standards

In the January 2014 proposal, the EPA proposed an emission limitation of 1,100 lb CO_2/MWh-g, which a new highly efficient utility boiler burning bituminous coal could have met by capturing roughly 40 percent of its CO_2 emissions and a new highly efficient IGCC unit could have met by capturing and storing roughly 25 percent of its CO_2 emissions. The captured CO_2 would then be securely stored in sequestration repositories subject to either Class II or Class VI standards under the Underground Injection Control program. The EPA arrived at the proposed standard by examining the available CCS implementation configurations and concluding that the proposed standard at the corresponding levels of partial CCS best balanced the BSER criteria and resulted in an achievable emission level. The EPA also proposed to find that highly efficient new generation implementing ''full CCS'' (*i.e.,* more than 90 percent capture and storage) was not the BSER because the costs of that configuration—for both utility boilers and IGCC units—are projected to substantially exceed the projected costs of other non-NGCC dispatchable technologies that utilities and project developers are considering (*e.g.,* new nuclear and biomass). See generally 79 FR at 1477–78. Conversely, the EPA rejected highly efficient SCPC as the BSER because it would not result in meaningful emission reductions from any newly constructed PC unit. Id. at 1470. The EPA also declined to base the BSER on IGCC operating alone due to the same concern—lack of emission reductions from a new IGCC unit otherwise planned. Id.

2. Basis for the Final Standards

For this final action, the EPA reexamined the BSER options available at proposal. Those options are: (1) Highly efficient generation without CCS, (2) highly efficient generation implementing partial CCS, and (3) highly efficient generation implementing full CCS. Consistent with our determination in the January 2014 proposal, we remain convinced that highly efficient generation (*i.e.,* a new supercritical utility boiler or a new IGCC unit) without CCS does not represent the BSER because it does not achieve emission reductions beyond the sector's business as usual, when options that do achieve more emission reductions are available. 79 FR 1470; see also Section V.P below. We also do not find that a highly efficient new steam generating unit implementing full CCS is the BSER because, at this time, the costs are predicted to be significantly more than the costs for implementation of partial CCS and significantly more than the costs for competing non-NGCC base load, dispatchable technologies—primarily new nuclear generation—and are, therefore, potentially unreasonable. See Section V.P.

As with the proposal, the EPA has determined the final BSER and corresponding emission limitation by appropriately balancing the BSER criteria and determining that the emission limitation is achievable. The final standard of performance of 1,400 lb CO_2/MWh-g is less stringent than at proposal and reflects changes that are responsive to comments received on, and the EPA's further evaluation of, the costs to implement partial CCS. The EPA has determined that a newly constructed highly efficient supercritical utility boiler burning bituminous coal can meet this final emission limitation by capturing 16 percent of the CO_2 produced from the facility (or 23 percent if burning subbituminous or dried lignite), which would be either stored in on-site or off-site geologic sequestration repositories subject to control under either the Class VI (for geologic sequestration) or Class II (for Enhanced Oil Recovery) standards under the UIC program. This BSER is technically feasible, as shown by the fact that post-combustion CCS technology—both the capture and storage components—is demonstrated in full-scale operation within the electricity generating industry. There are also numerous operating results from smaller-scale projects that are reasonably predictive of operation at full-scale. It is available at reasonable cost, does not have collateral adverse non-air quality health or environmental impacts, and does not have adverse energy implications.

The proposed BSER was a highly efficient newly constructed steam generating EGU implementing partial CCS to an emission standard of 1,100 lb CO_2/MWh-g. The final BSER is a highly efficient SCPC EGU implementing partial CCS to achieve an emission standard of 1,400 lb CO_2/MWh-g. In both cases, the EPA specified that the BSER includes a ''highly efficient'' new EGU implementing partial CCS. This assumes that a new project developer will construct the most efficient generating technology available—*i.e.,* a supercritical or ultra-supercritical utility boiler—that will inherently generate lower volumes of uncontrolled CO_2 per MWh. See Section V.J below. A well performing and highly efficient new SCPC EGU will need to implement lower levels of partial CCS in order to meet the final standard of 1,400 lb CO_2/MWh-g than a less efficient new steam generating EGU. The construction of highly efficient steam generating EGUs—as opposed to less efficient units such as a subcritical utility boiler—will result in lower overall costs from decreased fuel consumption and the need for lower levels of required partial CCS to meet the final standard.

3. Consideration of Projects Receiving Funding Under the EPAct05

As noted in Section III.H.3.g above, the EPA's determination of the BSER here includes review of recently constructed facilities and those planned or under construction to evaluate the control technologies being used and considered. Some of the projects discussed in the January 2014 proposal, and discussed here in this preamble, received or are receiving financial assistance under the EPAct05 (P.L. 109–58). This assistance may include financial assistance from the Department of Energy (DOE), as well as receipt of the federal tax credit for investment in clean coal technology under IRC Section 48A.

As noted above, the EPA interprets these provisions as allowing consideration of EPAct05 facilities provided that such information is not the sole basis for the BSER determination, and particularly so in circumstances like those here, where the information is corroborative but the essential information justifying the determinations comes from facilities and other sources of information with no nexus with EPAct05 assistance. In the discussion below, the EPA explains its reliance on other information in making the BSER determination for new fossil fuel-fired steam generating units. The EPA notes that information from facilities that did not receive any DOE assistance, and did not receive the federal tax credit, is sufficient by itself to support its BSER determination.

D. Post-Combustion Carbon Capture

In this section, we describe a variety of facts that support our conclusion that the technical feasibility of post-combustion carbon capture is adequately demonstrated. First, we describe the technology of post-combustion capture. We then describe EGUs that have previously utilized or are currently utilizing post-combustion carbon capture technology. This discussion is complemented by later sections that explain and justify our conclusions that the technical feasibility of other aspects of partial CCS are adequately demonstrated—namely, the transportation and carbon storage (see Sections V.M. and N). Further, the conclusions of this section are reinforced by the discussion in Section V.F. below, in which we identify commercial vendors that offer carbon capture technology and offer performance guarantees, and discuss industry and technology developers' public pronouncements of their confidence in the feasibility and availability of CCS technologies.

1. Post-Combustion Carbon Capture—How it Works

Post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system—such as a utility boiler. It is referred to as ''post-combustion capture'' because the CO_2 is the product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. The exhaust gases from most combustion processes are at atmospheric pressure and are moved through the flue gas system by fans. The concentration of CO_2 in most combustion flue gas streams is somewhat dilute.[185] Most post-combustion capture systems utilize liquid solvents[186] that separate the CO_2 from the flue gas in CO_2 scrubber systems. Because the flue gas is at atmospheric pressure and is somewhat dilute, the solvents used for post-combustion capture are ones that separate the CO_2 using chemical absorption (or chemisorption). Amine-based solvents[187] are the most commonly used in post-combustion capture systems. In a chemisorption-based separation process, the flue gas is processed through the CO_2 scrubber and the CO_2 is absorbed by the liquid solvent and then released by heating to form a high purity CO_2 stream. This heating step is referred to as ''solvent regeneration'' and is responsible for much of the ''energy penalty'' of the capture system. Steam from the boiler (or potentially from another external source) that would otherwise be used to generate electricity is instead used in the solvent regeneration process. The development of advanced solvents—those that are chemically stable, have high CO_2 absorption capacities, and have low regeneration energy requirements—is an active area of research. Many post-combustion solvents will also selectively remove other acidic gases such as SO_2 and hydrochloric acid (HCl), which can result in degradation of the solvent. For that reason, the CO_2 scrubber systems are normally installed downstream of other pollutant control devices (*e.g.,* particulate matter and flue gas desulfurization controls) and in some cases, the acidic gases will need to be scrubbed to very low levels prior to the flue gas entering the CO_2 capture system. See also RIA chapter 5 (quantifying SO_2 reductions resulting from this scrubbing process).

Additional information on post-combustion carbon capture—including process diagrams—can be found in a summary technical support document.[188]

2. Post-Combustion Carbon Capture Projects That Have Not Received DOE Assistance Through the EPAct05 or Tax Credits Under IRC Section 48A

a. Boundary Dam Unit #3

SaskPower's Boundary Dam CCS Project in Estevan, a city in Saskatchewan, Canada, is the world's first commercial-scale fully integrated post-combustion CCS project at a coal-fired power plant. The project fully integrates the rebuilt 110 MW coal-fired Unit #3 with a CO_2 capture system using Shell Cansolv amine-based solvent to capture 90 percent of its CO_2 emissions. The facility, which utilizes local Saskatchewan lignite, began operations in October 2014 and accounts of the system's performance describe it as working even ''better than expected.''[189] [190] The plant started by capturing roughly 75 percent of CO_2 from the plant emissions and its operators plan to increase the capture percentage as they optimize the equipment to reach full capacity. Initial indications are that the facility is producing more power than predicted and that the energy penalty (parasitic load—the energy needed to regenerate the CO_2 capture solvent) is much lower than initially predicted.[191] Water use at the facility is consistent with levels that were predicted.[192] The total project costs—for the power plant and the carbon capture plant—was $1.467B (CAD).[193] The CO_2 from the capture system is more than 99.999 percent pure with only trace levels of N_2 in the product stream.[194] This purity is food-grade quality CO_2 and is a clear indication that the system is working well. The captured CO_2 is transported by pipeline to nearby oil fields in southern Saskatchewan where it is being used for EOR operations. Any captured CO_2 that is not used for EOR operations will be stored in nearby deep brine-filled sandstone formations. Thus, the Boundary Dam Unit #3 project is demonstrating CO_2 post-combustion capture, CO_2 compression and transport, and CO_2 injection for both EOR and geologic storage. The CCS system is fully integrated with the electricity production of the plant.

Some commenters noted that, at 110 MW, the Boundary Dam Unit #3 is a relatively small coal-fired utility boiler and thus, in the commenters' view, does not demonstrate that such a system could be utilized at a much larger utility coal-fired boiler. However, there is nothing to indicate that the post-combustion system used at Boundary Dam could not be scaled-up for use at a larger utility boiler. In fact, the carbon capture system at Boundary Dam #3 is designed and constructed to implement ''full CCS''—that is to capture more than 90 percent of the CO_2 produced from the subcritical unit. A similarly-sized capture system—with no need for further scale-up—could be used to treat a slip-stream of a much larger

[185] The typical concentration of CO_2 in the flue gas of a coal-fired utility boiler is roughly around 15 volume percent.

[186] A *solvent* is a substance (usually a liquid) that dissolves a *solute* (a chemically different liquid, solid or gas), resulting in a solution.

[187] Amines are derivatives of ammonia (NH_3) where one or more hydrogen atoms have been replaced by hydrocarbon groups.

[188] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

[189] ''[W]e are achieving better than expected'' operation out of the plant, SaskPower's Mike Marsh said April 8, 2015 in Washington, DC, summarizing the status of the first-of-a-kind plant in Saskatchewan, Canada, known as Boundary Dam Unit 3. Marsh spoke at a meeting of the National Coal Council, which advises the Energy Department on coal-related topics. From ''Bolstering EPA's NSPS, Canadian CCS Plant Working 'Better Than Expected' '', Climate Daily News, Inside EPA/climate (April 08, 2015); *www.insideepa.com* (subscription required).

[190] ''CCS performance data exceeding expectations at world-first Boundary Dam Power Station Unit #3'', *http://www.saskpowerccs.com/newsandmedia/latest-news/ccs-performance-data-exceeding-expectations/.*

[191] Correspondence between Mike Monea (SaskPower) and Nick Hutson (EPA), February 20, 2015.

[192] 30 percent of the water used for cooling comes from the recycled or reclaimed water from the process itself; namely, water in the coal is reclaimed.

[193] About $1.2B USD; roughly $700M (USD) for the carbon capture system, which was on budget.

[194] ''Boundary Dam—The Future is Here'', plenary presentation by Mike Monea at the 12th International Conference on Greenhouse Gas Technologies (GHGT–12), Austin, TX (October 2014).

supercritical utility boiler (a new unit of approximately 500 to 600 MW) in order to meet the final standard of performance of 1,400 lb CO_2/MWh-g, which would only require partial CCS on the order of approximately 16 to 23 percent (depending on the coal used).

A ''slip-stream'' is a portion of the flue gas stream that can be treated separately from the bulk exhaust gas. It is not an uncommon configuration for the flue gas from a coal-fired boiler to be separated into two or more streams and treated separately in different control equipment before being recombined to exit from a common stack.[195] A slip-stream configuration is often used to treat a smaller portion of the bulk flue gas stream as a way of testing or demonstrating a control device or measurement technology. For implementation of post-combustion partial carbon capture, a portion of the bulk flue gas stream would be treated separately to capture approximately 90 percent of the CO_2 from that smaller slip-stream of the flue gas. For example, in order to capture 20 percent of the CO_2 produced by a coal-fired utility boiler, an operator would treat approximately 25 percent of the bulk flue gas stream (rather than treating the entire stream). Approximately 90 percent of the CO_2 would be captured from the slip-stream gas, resulting in an overall capture of about 20 percent.

In its study on the cost and performance of a range of carbon capture rates, the DOE/NETL determined that the slip-stream approach was the most economical for carbon capture of less than 90 percent of the total CO_2.[196] The advantage of the slip-stream approach is that the capture system will be sized to treat a lower volume of flue gas flow, which reduces the size of the CO_2 absorption columns, induced draft fans, and other equipment, leading to lower capital and operating costs.

The carbon capture system at Boundary Dam does not utilize the slip-stream configuration because it was designed to achieve more than 90 percent capture rates from the 110 MW facility. However, the same carbon capture equipment could be used to treat approximately 50 percent of the flue gas from a 220 MW facility—or 20 percent of the flue gas from a 550 MW facility. Thus, the equipment that is currently working very well (in fact, ''better than expected'') at the Boundary Dam plant can be utilized for partial carbon capture at a much larger coal-fired unit without the need for further scale-up.

The experience at Boundary Dam is directly transferrable to other types of post-combustion sources, including those using different boiler types and those burning different coal types. There is nothing to suggest that the Shell CanSolv process would not work with other coal types and indeed, the latest NETL cost estimates assume that the capture technology would be used in a new unit using bituminous coal.[197] The EPA is unaware of any reasons why the Boundary Dam technology would not be transferrable to another utility boiler at a different location at a different elevation or climate because the control technology is not climate or elevation-dependent.

Commenters also noted that the Boundary Dam Unit #3 project received financial assistance from both the Canadian federal government and from the Saskatchewan provincial government. But the availability of—or the lack of—external financial assistance does not affect the technical feasibility of the technology. Commenters further characterized Boundary Dam as a ''demonstration project''. These descriptors are beside the point. Regardless of what the project is called or how it was financed, the project clearly shows the technical feasibility of full-scale, fully integrated implementation of available post-combustion CCS technology, which in this case also appears to be commercially viable.

The EPA notes that, although there is ample additional information corroborating that post-combustion CCS is technically feasible, which we describe below, the performance at Boundary Dam Unit #3 alone would be sufficient to support that conclusion. *Essex Chemical Corp.,* 486 F. 2d at 436 (test results from single facility demonstrates achievability of standard of performance). As mentioned above, the post-combustion capture technology used at Boundary Dam is transferrable to all other types of utility boilers.

b. AES Warrior Run and Shady Point

AES's coal-fired Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) plants are both circulating fluidized bed (CFB) coal-fired power plants with carbon capture amine scrubbers developed by ABB/Lummus. The scrubbers were designed to process a slip-stream of each plant's flue gas. At the 180 MW Warrior Run Plant, a plant that burns bituminous coal, approximately 10 percent of the plant's CO_2 emissions (about 110,000 metric tons of CO_2 per year) has been captured since 2000 and sold to the food and beverage industry. At the 320 MW Shady Point Plant, a plant that burns a blend of bituminous and subbituminous coals, CO_2 from an approximate 5 percent slip-stream (about 66,000 metric tons of CO_2 per year) has been captured since 2001. The captured CO_2 from the Shady Point Plant is also sold for use in the food processing industry.[198] While these projects do not demonstrate the CO_2 storage component of CCS, they clearly demonstrate the technical viability of partial CO_2 capture. The capture of CO_2 from a slip-stream of the bulk flue gas, as described earlier, is the most economical method for capturing less than 90 percent of the CO_2. The amounts of partial capture that these sources have demonstrated—up to 10 percent—is reasonably similar to the level, at 16 to 23 percent, that the EPA predicts would be needed by a new highly efficient steam utility boiler to meet the final standard of performance. These facilities, which have been operating for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

c. Searles Valley Minerals

Since 1978, the Searles Valley Minerals soda ash plant in Trona, CA has used post-combustion amine scrubbing to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of a coal-fired power plant that generates steam and power for on-site use. The captured CO_2 is used for the carbonation of brine in the process of producing soda ash.[199] Again, while the captured CO_2 is not

[195] See Figure 1A from *Atmospheric Environment,* 43, 3974 (2009), for an example of this type of configuration.

[196] ''Cost and Performance of PC and IGCC for a Range of Carbon Capture'', Rev 1 (2013), DOE/NETL–2011/1498 p. 2 (''A literature search was conducted to verify that <90 percent CO_2 capture is most economical using a 'slip-stream' (or bypass) approach. Indeed, the slip-stream approach is more cost-effective for <90 percent CO_2 capture than removing reduced CO_2 fractions from the entire flue gas stream, according to multiple peer-reviewed studies.'' See also id. at 19, 21, 77, and 478 (documenting further that treating a slip-stream is the most economical approach).

[197] In fact, in ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015), Exh.2–3 the Shell Cansolv process is used as the capture process for a new SCPC unit using bituminous coal rather than the subcritical PC unit at Boundary Dam that uses Canadian lignite. The study evidently assumes that the CanSolv process can be used effectively for bituminous coal since this type of coal is assumed for cost estimation purposes.

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

[199] IEA (2009), World Energy Outlook 2009, OECD/IEA, Paris.

sequestered, this project clearly demonstrates the technical feasibility of the amine scrubbing system for CO_2 capture from a coal-fired power plant.[200] The fact that this system is an industrial coal-fired power plant rather than a utility coal-fired power plant is irrelevant as they both serve a similar purpose—the production of electricity.

Each of these processes indicate a willingness of industry to utilize available post-combustion technology for capture of CO_2 for commercial purposes. Not one of the CO_2 capture systems at Warrior Run, Shady Point, or Searles Valley was installed for regulatory purposes or as government-funded demonstration projects. They were installed to capture CO_2 for commercial use. The fact that the captured CO_2 was utilized rather than being stored is of no consequence in the consideration of the technical feasibility of post-combustion CO_2 capture technology. These commercial operations have helped to improve the performance of scrubbing systems that are available today. For example, the heat duty (*i.e.,* the energy needed to remove the CO_2) has been reduced by about 5 times from the amine process originally used at the Searles Valley facility. The amine scrubbing process used at Boundary Dam is equally efficient, and the amine scrubbing system to be used at the Petra Nova WA Parish project (Thompsons, TX) is projected to be as well.[201]

3. Post-Combustion Carbon Capture Projects That Received DOE Assistance Through the EPAct05, but Did Not Receive Tax Credits Under IRC Section 48A

The EPA considers the experiences from the CCS projects described above, coupled with evidence that the design of CCS is well accepted (also described above) and the strong support that CCS has received from vendors and others (described below) to adequately demonstrate that post-combustion partial CCS is technically feasible. The EPA finds that additional projects, described next, provide more support for that conclusion. These projects received funding under EPAct05 from the Department of Energy, but that does not disqualify them from being considered. See Section III.H.3 above.

a. Petra Nova WA Parish Project

Petra Nova, a joint venture between NRG Energy Inc. and JX Nippon Oil & Gas Exploration, is constructing a commercial-scale post-combustion carbon capture project at Unit #8 of NRG's WA Parish generating station southwest of Houston, Texas. The project is designed to utilize partial CCS by capturing approximately 90 percent of the CO_2 from a 240 MW slip-stream of the 610 MW WA Parish facility. The project is expected to be operational in 2016 and thus does not yet directly demonstrate the technical feasibility or performance of the MHI amine scrubbing system. However, this project is a clear indication that the developers have confidence in the technical feasibility of the post-combustion carbon capture system.

The project was originally envisioned as a 60 MW slip-stream demonstration and received DOE Clean Coal Power Initiative (CCPI) funding (as provided in EPAct05) on that basis. The developers later expanded the project to the larger 240 MW slip-stream because of the need to capture greater volumes of CO_2 for EOR operations. No additional DOE or other federal funding was obtained for the expansion from a 60 MW slip-stream to a 240 MW slip-stream.[202]

At 240 MW, the Petra Nova project will be the largest post-combustion carbon capture system installed on an existing coal-fueled power plant. The project will use for EOR or will sequester 1.6 million tons of captured CO_2 each year. The project is expected to be operational in 2016.

In 2014 project materials,[203] the project developer NRG recognized the importance of CCS technology by noting:

> The technology has the potential to enhance the long-term viability and sustainability of coal-fueled power plants across the U.S. and around the world. . . . Post-combustion carbon capture is essential so that we can use coal to sustain our energy ecosystem while we begin reducing our carbon footprint.

According to NRG, the Petra Nova Carbon Capture Project will utilize ''a proven carbon capture process,'' jointly developed by Mitsubishi Heavy Industries, Ltd. (MHI) and the Kansai Electric Power Co., that uses a high-performance solvent for CO_2 absorption and desorption.[204] In using the MHI high-performance solvent, the Petra Nova project will benefit from pilot-scale testing of this solvent at Alabama Power's Plant Barry and at other installations. WA Parish Unit #8 came on-line in 1982 and is thus an existing source that will not be subject to final standards of performance issued in this action. However, because it will be capturing roughly 35 percent of the CO_2 generated by the facility, its emissions will be below the final new source emission limitation of 1,400 lb CO_2/MWh-g.[205]

The captured CO_2 from the WA Parish CO_2 Capture Project will be used in EOR operations at mature oil fields in the Gulf Coast region. Using EOR at Hilcorp's West Ranch Oil Field, the production is expected to be boosted from around 500 barrels per day to approximately 15,000 barrels per day. Thus the project will utilize all aspects of CCS by capturing CO_2 at the large coal-fired power plant, compressing the CO_2, transporting it by pipeline to the EOR operations, and injecting it for EOR and eventual geologic storage.

The carbon capture system at WA Parish will utilize a slip-stream configuration. However, as noted, the system is designed to capture roughly 35 percent of the CO_2 from WA Parish Unit #8 (90 percent of the CO_2 from the 240 MW slip-stream from the 610 MW unit). A carbon capture system of the same size as that used at WA Parish could be used to treat a 240 MW slip-stream from a 1,000 MW unit in order to meet the final standard of performance of 1,400 lb CO_2/MWh-g.

Again, the experience at the WA Parish Unit #8 project will be directly transferable to post-combustion capture at a new utility boiler, even though WA Parish Unit #8 is an existing source that has been in operation for over 30 years. In fact, retrofit of such technology at an existing unit can be more challenging than incorporating the technology into the design of a new facility. The

[200] Moreover, the final rule allows alternative means of storage of captured CO_2 based on a case-by-case demonstration of efficacy. See Section V.M.4 below.

[201] The heat duty for the amine scrubbing process used at Searles Valley in the mid-70's was about 12 MJ/mt CO_2 removed as compared to a heat duty of about 2.5 MJ/mt CO_2 removed for the amine processes used at Boundary Dam and to be used at WA Parish. ''From Lubbock, TX to Thompsons, TX—Amine Scrubbing for Commercial CO_2 Capture from Power Plants'', plenary address by Prof. Gary Rochelle at the 12th International Conference on Greenhouse Gas Technology (GHGT–12), Austin, TX (October 2014).

[202] Thus, even if the project received DOE assistance for the initial 60 MW design, the expansion of the project from 60 MW to 240 MW should not be considered a DOE-assisted project. In any case, as described above, even without consideration of this facility at all, other information adequately demonstrates the technical feasibility of post-combustion CCS.

[203] WA Parish CO_2 Capture Project Fact Sheet; available at *www.nrg.com/documents/business/pla-2014-petranova-waparish-factsheet.pdf* (2014).

[204] The WA Parish project (described earlier) will utilize the KM–CDR Process®, which was jointly developed by MHI and the Kansai Electric Power Co., Inc. and uses the proprietary KS–1™ high-performance solvent for the CO_2 absorption and desorption.

[205] Using emissions data reported to the Acid Rain Program, the EPA estimates that the CO_2 emissions from the WA Parish Unit #8 will be 1,250–1,300 lb CO_2/MWh-g during operations with the post-combustion capture system.

experience will be directly transferrable to other types of post-combustion sources including those using different boiler types and those burning different coals. The amine scrubbing and associated systems are not boiler type- or coal-specific. The EPA is unaware of any reasons that the technology utilized at the WA Parish plant would not be transferrable to another utility boiler at a different location at a different elevation or climate, given that the technology is not dependent on either climate or topography.

b. AEP/Alstom Mountaineer Project

In September 2009, AEP began a pilot-scale CCS demonstration at its Mountaineer Plant in New Haven, WV. The Mountaineer Plant is a very large (1,300 MW) coal-fired unit that was retrofitted with Alstom's patented chilled ammonia CO_2 capture technology on a 20 MWe slip-stream of the plant's exhaust flue gas. In May 2011, Alstom Power announced the successful operation of the chilled ammonia CCS validation project. The demonstration achieved capture rates from 75 percent (design value) to as high as 90 percent, and produced CO_2 at a purity of greater than 99 percent, with energy penalties within a few percent of predictions. The facility reported robust steady-state operation during all modes of power plant operation, including load changes, and saw an availability of the CCS system of greater than 90 percent.[206]

AEP, with assistance from the DOE, had planned to expand the slip-stream demonstration to a commercial scale, fully integrated demonstration at the Mountaineer facility. The commercial-scale system was designed to capture at least 90 percent of the CO_2 from 235 MW of the plant's 1,300 MW total capacity. Plans were for the project to be completed in four phases, with the system to begin commercial operation in 2015. However, in July 2011, AEP announced that it would terminate its cooperative agreement with the DOE and place its plans to advance CO_2 capture and storage technology to commercial scale on hold. AEP cited the uncertain status of U.S. climate policy as a contributor to its decision, but did not express doubts about the feasibility of the technology. See Section V.L below.

AEP also prepared a Front End Engineering & Design (FEED) Report,[207] explaining in detail how its pilot-scale work could be scaled up to successful full-scale operation, and to accommodate the operating needs of a full-scale EGU, including reliable generating capacity capable of cycling up and down to accommodate consumer demand. Recommended design changes to accomplish the desired scaling included detailed flue gas specifications, ranges for temperature, moisture and SO_2 content; careful scrutiny of makeup water composition and temperature; quality and quantity of available steam to accommodate heat cycle based on unit load changes; and detailed scrutiny of material and energy balances.[208] See Section V.G.3 below, addressing in more detail the record support for how CCS technology can be scaled up to commercial size in both pre- and post-combustion applications.

c. Southern Company/MHI Plant Barry

In June 2011, Southern Company and Mitsubishi Heavy Industries (MHI) launched operations at a 25 MW coal-fired carbon capture facility at Alabama Power's Plant Barry. The facility, which completed the initial demonstration phase, captured approximately 165,000 metric tons of CO_2 annually at a CO_2 capture rate of over 90 percent. The facility employed the KM CDR Process, which uses a proprietary high performing solvent[209] for CO_2 absorption and desorption that was jointly developed by MHI and Japanese utility Kansai Electric Power Co. The captured CO_2 has been transported via pipeline approximately 12 miles to the Citronelle oil field where it is injected into the Paluxy formation, a saline reservoir, for storage.[210]

Project participants have reported that ''[t]he plant performance was stable at the full load condition with CO_2 capture rate of 500 TPD at 90 percent CO_2 removal and lower steam consumption than conventional capture processes.''[211]

E. Pre-Combustion Carbon Capture

As described earlier, the EPA does not find that IGCC technology—either alone or implementing partial CCS—is part of the BSER for newly constructed steam generating EGUs. However, as noted, there may be specific circumstances and business plans—such as co-production of chemicals or fertilizers, or capture of CO_2 for use in EOR operations—that encourage greater CO_2 emission reductions than are required by this standard. In this section, we describe and justify our conclusion that the technical feasibility of pre-combustion carbon capture is adequately demonstrated, indicating that this could be a viable alternative compliance pathway. First, we explain the technology of pre-combustion capture. We then describe EGUs that have previously utilized or are currently utilizing pre-combustion carbon capture technology. This discussion is complemented by other sections that conclude the technical feasibility of other aspects of partial CCS are adequately demonstrated—namely, post-combustion carbon capture (Section V.D) and sequestration (Sections V.M and V.N). Further, this section's conclusions are reinforced by Section V.F, in which we identify commercial vendors that offer CCS performance guarantees as well as developers that have publicly stated their confidence in CCS technologies.

1. Pre-Combustion Carbon Capture—How It Works

Pre-combustion capture systems are typically used with IGCC processes. In a gasification system, the fuel (usually coal or petroleum coke) is heated with water and oxygen in an oxygen-lean environment. The coal (carbon), water and oxygen react to form primarily a mixture of hydrogen (H_2) and carbon monoxide (CO) known as synthesis gas or syngas according to the following high temperature reaction:

$$3C + H_2O + O_2 \rightarrow H_2 + 3CO$$

In an IGCC system, the resulting syngas, after removal of the impurities, can be combusted using a conventional combustion turbine in a combined cycle configuration (*i.e.,* a combustion turbine combined with a HRSG and steam turbine). The gasification process also typically produces some amount of CO_2[212] as a by-product along with other

[206] *http://www.alstom.com/press-centre/2011/5/alstom-announces-sucessful-results-of-mountaineer-carbon-capture-and-sequestration-ccs-project/.*

[207] ''CCS front end engineering & design report: American Electric Power Mountaineer CCS II Project. Phase 1'', pp 10–11; available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[208] Id. at 11. The EPA does not view this information as being affected by the constraints in EPAct05. The information does not relate to use of technology, level of emission reduction by reason of use of technology, achievement of emission reduction by demonstration of technology, or demonstration of a level of performance. The FEED study rather explains engineering challenges which would remain at full scale and how those challenges can be addressed.

[209] This is the same carbon capture system that is being utilized at the Petra Nova project at the NRG WA Parish plant.

[210] Ivie, M.A. et al.; ''Project Status and Research Plans of 500 TPD CO_2 Capture and Sequestration Demonstration at Alabama Power's Plant Barry'', *Energy Procedia* 37, 6335 (2013).

[211] Id.

[212] The amount of CO_2 in syngas depends upon the specific gasifier technology used, the operating conditions, and the fuel used; but is typically less

gases (*e.g.,* H_2S) and inorganic materials originating from the coal (*e.g.,* minerals, ash). The amount of CO_2 in the syngas can be increased by ''shifting'' the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam (''water'') with CO (''gas'') to form H_2 and CO_2 according to the following catalytic reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

An emission standard that requires partial capture of CO_2 from the syngas could be met by adjusting the level of CO_2 in the syngas stream by controlling the level of syngas ''shift'' prior to treatment in the pre-combustion acid gas treatment system. If a high level of CO_2 capture is required, then multi-stage WGS reactors will be needed and an advanced hydrogen turbine will likely be needed to combust the resulting hydrogen-rich syngas.

Most syngas streams are at higher pressure and can contain higher concentrations of CO_2 (especially if shifted to enrich the concentration). As such, the pre-combustion capture systems can utilize physical absorption (physisorption) solvents rather than the chemical absorptions solvents described earlier. Physical absorption has the benefit of relying on weak intermolecular interactions and, as a result, the absorbed CO_2 can often be released (desorbed) by reducing the pressure rather than by adding heat. Pre-combustion capture systems have been used widely in industrial processes such as natural gas processing.

Additional information on pre-combustion carbon capture can be found in a summary technical support document.[213]

2. Pre-Combustion Carbon Capture Projects That Have Not Received DOE Assistance Through EPAct05 or Tax Credits Under IRC Section 48A

a. Dakota Gasification Great Plains Synfuels Plant

Each day, the Dakota Gasification Great Plains Synfuels Plant uses approximately 18,000 tons of North Dakota lignite in a coal gasification process that produces syngas (a mixture of CO, CO_2, and H_2), which is then converted to methane gas (synthetic natural gas) using a methanation process. Each day, the process produces an average of 145 million cubic feet of synthetic natural gas that is ultimately transported for use in home heating and electricity generation.[214]

Capture of CO_2 from the facility began in 2000. The Synfuels Plant, using a pre-combustion Rectisol® process, captures about 3 million tons of CO_2 per year—more CO_2 from coal conversion than any facility in the world, and is a participant in the world's largest carbon sequestration project. On average about 8,000 metric tons per day of captured CO_2 from the facility is sent through a 205-mile pipeline to oil fields in Saskatchewan, Canada, where it is used for EOR operations that result in permanent CO_2 geologic storage. The geologic sequestration of CO_2 in the oil reservoir is monitored by the International Energy Agency (IEA) Weyburn CO_2 Monitoring and Storage Project.

Several commenters to the January 2014 proposal argued that the Great Plains Synfuels facility is not an EGU, that it operates as a chemical plant, and that its experience is not translatable to an IGCC using pre-combustion carbon capture technology. The commenters noted that the Dakota facility can be operated nearly continuously without the need to adjust operations to meet cyclic electricity generation demands. In the January 2014 proposal, the EPA had noted that, while the facility is not an EGU, it has significant similarities to an IGCC and the implementation of the pre-combustion capture technology would be similar enough for comparison. See 79 FR at 1435–36 and n. 11. We continue to hold this view.

As explained above, in an IGCC gasification system, coal (or petroleum coke) is gasified to produce a synthesis gas comprised of primarily CO, H_2, and some amount of CO_2 (depending on the gasifier and the specific operating conditions). A water-gas-shift reaction using water (H_2O, steam) is then used to shift the syngas to CO_2 and H_2. The more the syngas is ''shifted,'' the more enriched it becomes in H_2. In an IGCC, power can be generated by directly combusting the un-shifted syngas in a conventional combustion turbine. If the syngas is shifted such that the resulting syngas is highly enriched in H_2, then a special, advanced hydrogen turbine is needed. If CO_2 is to be captured, then the syngas would need to be shifted either fully or partially, depending upon the level of capture required.[215]

The Dakota Gasification process bears essential similarities to the just-described IGCC gasification system. As with the IGCC gasification system, the Dakota Gasification facility gasifies coal (lignite) to produce a syngas which is then shifted to increase the concentration of CO_2 and to produce the desired ratio of CO and H_2. As with the IGCC gasification system, the CO_2 is then removed in a pre-combustion capture system, and the syngas that results is made further use of. For present purposes, only the manner in which the syngas is used distinguishes the IGCC gasification system from the Dakota Gasification facility. In the IGCC process, the syngas is combusted. In the Dakota Gasification facility, the syngas is processed through a catalytic methanation process where the CO and H_2 react to produce CH_4 (methane, synthetic natural gas) and water. Importantly, the CO_2 capture system that is used in the Dakota Gasification facility can readily be used in an IGCC EGU. There is no indication that the RECTISOL® process (or other similar physical gas removal systems) is not feasible for an IGCC EGU. In confirmation, according to product literature, RECTISOL®, which was independently developed by Linde and Lurgi, is frequently used to purify shifted, partially shifted or un-shifted gas from the gasification of coal, lignite, and residual oil.[216]

b. International Projects

There are some international projects that are in various stages of development that indicate confidence by developers in the technical feasibility of pre-combustion carbon capture. Summit Carbon Capture, LLC is developing the Caledonia Clean Energy Project, a proposed 570-megawatt IGCC plant with 90 percent CO_2 capture that would be built in Scotland, U.K. Captured CO_2 from the plant will be transported via on-shore and sub-sea pipeline for sequestration in a saline formation in the North Sea. The U.K. Department of Energy & Climate Change (DECC) recently announced funding to allow for feasibility studies for this plant.[217] Commercial operation is expected in 2017.[218]

The China Huaneng Group—with multiple collaborators, including Peabody Energy, the world's largest private sector coal company—is building the 400 MW GreenGen IGCC

than 20 volume percent (*http://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/syngas-composition*).

[213] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

[214] *http://www.dakotagas.com/Gasification/.*

[215] ''Cost and Performance of PC and IGCC for a Range of Carbon Capture'', Rev 1 (2013), DOE/NETL–2011/1498.

[216] *www.linde-engineering.com/en/process_plants/hydrogen_and_synthesis_gas_plants/gas_processing/rectisol_wash/index.html.*

[217] *http://www.downstreambusiness.com/item/Summit-Power-Wins-Funding-Studies-Proposed-IGCC-CCS-Project_140878.*

[218] *http://www.summitpower.com/projects/carbon-capture/.*

facility in Tianjin City, China. The goal is to complete the power plant before 2020. Over 80 percent of the CO_2 will be separated using pre-combustion capture technology. The captured CO_2 will be used for EOR operations.[219]

Vattenfall and Nuon's pilot project in Bugennum, The Netherlands involves carbon capture from coal- and biomass-fired IGCC plants. It has operated since 2011.[220]

Approximately 100 tons of CO_2 per day are captured from a coal- and petcoke-fired IGCC plant in Puertollano, Spain. The facility began operating in 2010.[221]

Emirates Steel Industries is expected to capture approximately 0.8Mt of CO_2 per year from a steel-production facility in the United Arab Emirates. Full-scale operations are scheduled to begin by 2016.[222]

The Uthmaniyah CO_2 EOR Demonstration Project in Saudi Arabia will capture 0.8 Mt of CO_2 from a natural gas processing plant over three years. It is expected to begin operating in 2015.[223]

The experience of the Dakota Gasification facility, coupled with the descriptions of the technology in the literature, the statements from vendors, and the experience of facilities internationally, are sufficient to support our determination that the technical feasibility of CCS for an IGCC facility is adequately demonstrated. The experience of additional facilities, described next, provides additional support.

3. Pre-Combustion Carbon Capture Projects That Have Received DOE Assistance Through EPAct05, but Did Not Receive Tax Credits Under IRC Section 48A

a. Coffeyville Fertilizer

Coffeyville Resources Nitrogen Fertilizers, LLC, owns and operates a nitrogen fertilizer facility in Coffeyville, Kansas. The plant began operation in 2000 and is the only one in North America using a petroleum coke-based fertilizer production process. The petroleum coke is generated at an oil refinery adjacent to the plant. The petroleum coke is gasified to produce a hydrogen rich synthetic gas, from which ammonia and urea ammonium nitrate fertilizers are subsequently synthesized.

As a by-product of manufacturing fertilizers, the plant also produces significant amounts of CO_2. In March 2011, Chaparral Energy announced a long-term agreement for the purchase of captured CO_2 which is transported 68 miles via CO_2 pipeline for use in EOR operations in Osage County, OK. Injection at the site started in 2013.

At least one commenter suggested that the cost and complexity of carbon capture from these and other industrial projects was significantly decreased because the sources already separate CO_2 as part of their normal operations. The EPA finds this argument unconvincing. The Coffeyville process involves gasification of a solid fossil fuel (pet coke), shifting the resulting syngas stream, and separation of the resulting CO_2 using a pre-combustion carbon capture system. These are the same, or very similar, processes that are used in an IGCC EGU. The argument is even less convincing when considering that the Coffeyville Fertilizer process uses the Selexol™ pre-combustion capture process—the same process that Mississippi Power described as having been ''in commercial use in the chemical industry for decades'' and is expected by Mississippi Power to ''pose little technology risk'' when used at the Kemper IGCC EGU.

4. Pre-Combustion Carbon Capture Projects That Have Received DOE Assistance Through EPAct05 and Tax Credits Under IRC Section 48A

a. Kemper County Energy Facility

Southern Company's subsidiary Mississippi Power has constructed the Kemper County Energy Facility in Kemper County, MS. This is a 582 MW IGCC plant that will utilize local Mississippi lignite and includes a pre-combustion carbon capture system to reduce CO_2 emissions by approximately 65 percent. The pre-combustion solvent, Selexol™ has also been used extensively for acid gas removal (including for CO_2 removal) in various processes. In filings with the Mississippi Public Service Commission for the Kemper project, Mississippi described the carbon capture system:

> The Kemper County IGCC Project will capture and compress approximately 65% of the Plant's CO_2 [. . .] a process referred to as Selexol™ is applied to remove the CO_2 such that it is suitable for compression and delivery to the sequestration and EOR process. [. . .] *The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk.* (emphasis added) [224]

Thus, Mississippi Power believes that, because the Selexol™ process has been in commercial use in the chemical industry for decades, it is well proven, and will pose little technical risk when used in the Kemper IGCC EGU.

b. Texas Clean Energy Project and Hydrogen Energy California Project

The Texas Clean Energy Project (TCEP), a 400 MW IGCC facility located near Odessa, Texas will capture 90 percent of its CO_2, which is approximately 3 million metric tons annually. The captured CO_2 will be used for EOR in the West Texas Permian Basin. Additionally, the plant will produce urea and smaller quantities of commercial-grade sulfuric acid, argon, and inert slag, all of which will also be marketed. Summit has announced that they expect to commence construction on the project in 2015.[225] The facility will utilize the Linde Rectisol® gas cleanup process to capture carbon dioxide [226]—the same process that has been deployed for decades, including at the Dakota Gasification facility, a clear indication of the developer's confidence in that technology and further evidence that the Dakota Gasification carbon capture technology is transferable to EGUs.

F. Vendor Guarantees, Industry Statements, Academic Literature, and Commercial Availability

In this section, we describe additional information that supports our determination that CCS is adequately demonstrated to be technically feasible. This includes performance guarantees from vendors, public statements from industry officials, and review of the literature.

1. Performance Guarantees

The D.C. Circuit made clear in its first cases concerning CAA section 111 standards, and has affirmed since then,

[219] *http://sequestration.mit.edu/tools/projects/greengen.html.*

[220] Buggenum Fact Sheet: Carbon Dioxide Capture and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *http://sequestration.mit.edu/tools/projects/buggenum.html.*

[221] Puertollano Fact Sheet: Carbon Dioxide Capture and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *https://sequestration.mit.edu/tools/projects/puertollanto.html.*

[222] ESI CCS Project Fact Sheet: Carbon Dioxide and Storage Project, Carbon Capture & Sequestration Technologies @MIT, *https://sequestration.mit.edu/tools/projects/esi_ccs.html* and *https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.*

[223] Uthmaniyah CO_2 EOR Demonstration Project, Global CCS Institute, *https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.*

[224] Mississippi Power Company, Kemper County IGCC Certificate Filing, Updated Design, Description and Cost of Kemper IGCC Project, Mississippi Public Service Commission (MPSC) DOCKET NO. 2009–UA–0014, filed December 7, 2009.

[225] ''Odessa coal-to-gas power plant to break ground this year'', Houston Chronicle (April 1, 2015).

[226] *http://www.texascleanenergyproject.com/project/.*

that performance guarantees from vendors are an important basis for supporting a determination that pollution technology is adequately demonstrated to be technically feasible. In 1973, in *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973), the Court upheld standards of performance for coal-fired steam generators based on ''prototype testing data and full-scale control systems, considerations of available fuel supplies, literature sources, and *documentation of manufacturer guarantees and expectations*'' (emphasis supplied)).[227] Subsequently, in *Sierra Club* v. *Costle,* the Court noted, in upholding the standard: ''we find it informative that the vendors of FGD equipment corroborate the achievability of the standard.'' [228]

Linde and BASF offer performance guarantees for carbon capture technology. The two companies are jointly marketing new, advanced technology for capturing CO_2 from low pressure gas streams in power or chemical plants. In product literature,[229] they note that Linde will provide a turn-key carbon capture plant using a scrubbing process and solvents developed by BASF, one of the world's leading technical suppliers for gas treatment. They further note that:

> The captured carbon dioxide can be used commercially for example for EOR (enhanced oil recovery) or as a building block for the production of urea. Alternatively it can be stored underground as a carbon abatement measure. [. . .] The PCC (Post-Combustion Capture) technology *is now commercially available* for lignite and hard coal fired power plant [. . .] applications.
>
> The alliance between Linde, a world-leading gases and engineering company and BASF, the chemical company, offers great benefits [. . .] Complete capture plants including CO_2 compression and drying . . . Proven and tested processes *including guarantee . . .* Synergies between process, engineering, construction and operation . . . Optimized total and operational costs for the owner. (emphasis added)

In addition, other well-established companies that either offer technologies that are actively marketed for CO_2 capture from fossil fuel-fired power plants or that develop those power plants, have publicly expressed confidence in the technical feasibility of carbon capture. For example, Fluor has developed patented CO_2 recovery technologies to help its clients reduce GHG emissions. The Fluor product literature [230] specifically points to the Econamine FG Plus℠ (EFG+) process, which uses an amine solvent to capture and produce food grade CO_2 from post-combustion sources. The literature further notes that EFG+ is also used for carbon capture and sequestration projects, that the proprietary technology provides a proven, cost-effective process for the removal of CO_2 from power plant flue gas streams, and that the process can be customized to meet a power plant's unique site requirements, flue gas conditions, and operating parameters.

Fluor has also published an article titled ''Commercially Available CO_2 Capture Technology'' in which it describes the EFG+ technology.[231] The article notes, ''Technology for the removal of carbon dioxide (CO_2) from flue gas streams has been around for quite some time. The technology was developed not to address the GHG effect but to provide an economic source of CO_2 for use in enhanced oil recovery and industrial purposes, such as in the beverage industry.''

Mitsubishi Heavy Industries (MHI) offers a CO_2 capture system that uses a proprietary energy-efficient CO_2 absorbent called KS–1™. Compared with the conventional monoethanolamine (MEA)-based absorbent, KS–1™ solvent requires less solvent circulation to capture the CO_2 and less energy to recover the captured CO_2.

In addition, Shell has developed the CANSOLV CO_2 Capture System, which Shell describes in its product literature [232] as a world leading amine based CO_2 capture technology that is ideal for use in fossil fuel-fired power plants where enormous amounts of CO_2 are generated. The company also notes that the technology can help refiners, utilities, and other industries lower their carbon intensity and meet stringent GHG abatement regulations by removing CO_2 from their exhaust streams, with the added benefit of simultaneously lowering SO_2 and NO_2 emissions.

At least one commenter suggested that it is unlikely that any vendor is willing or able to provide guarantees of the performance of the system as a whole, arguing that this shows the system isn't adequately demonstrated.[233] However, this suggestion is inconsistent with the performance guarantees offered for other air pollution control equipment. Particulate matter (PM) is controlled in the flue gas stream of a coal-fired power plant using fabric filters or electrostatic precipitators (ESP). The captured PM is then moved using PM/ash handling systems and is then transported for storage or re-use. It is unlikely that a fabric filter or ESP vendor would provide a performance guarantee for ''the system as a whole.'' Similarly, a wet-FGD scrubber vendor would not be expected to provide a performance guarantee for handling, transportation, and re-use of scrubber solids for gypsum wallboard manufacturing. CO_2 capture, transportation, and storage should, similarly, not be viewed as a single technology. Rather, these should be viewed as components of an overall system of emission reduction. Different companies will have expertise in each of these components, but it is unlikely that a single technology vendor would provide a guarantee for ''the system as a whole.''

2. Academic and Other Literature

Climate change mitigation options—including CCS—are the subject of great academic interest, and there is a large body of academic literature on these options and their technical feasibility. In addition, other research organizations (*e.g.,* U.S. national laboratories and others) have also published studies on these subjects that demonstrate the availability of these technologies. A compendium of relevant literature is provided in a Technical Support Document available in the rulemaking docket.[234]

3. Additional Statements by Technology Developers

The discussion above of vendor guarantees, positive statements by industry officials, and the academic literature supports the EPA's determination that partial CCS is adequately demonstrated to be

[227] *See* also *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 401–02 (D.C. Cir. 1973) (''It would have been entirely appropriate if the Administrator had justified the standards . . . on testimony from experts and vendors made part of the record.'').

[228] *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (D.C. Cir. 1981). *See* also *National Petrochem & Refiners Assn* v. *EPA,* 287 F. 3d 1130, 1137 (D.C. Cir. 2002) (noting that vendor guarantees are an indicia of availability and achievability of a technology-based standard since, notwithstanding a desire to promote sales, ''a manufacturer would risk a considerable loss of reputation if its technology could not fulfill a mandate that it had persuaded EPA to adopt'').

[229] *www.intermediates.basf.com/chemicals/web/gas-treatment/en/function/conversions:/publish/content/products-and-industries/gas-treatment/images/Linde_and_BASF-Flue_Gas_Carbon_Capture_Plants.pdf.*

[230] *www.fluor.com/client-markets/energy-chemicals/Pages/carbon-capture.aspx.*

[231] *http://www.powermag.com/commercially-available-co2-capture-technology/.*

[232] *http://www.shell.com/global/products-services/solutions-for-businesses/globalsolutions/shell-cansolv/shell-cansolv-solutions/co2-capture.html.*

[233] Comments of Murray Energy, p. 73, (Docket entry: EPA–HQ–OAR–2013–0495–10046).

[234] Technical Support Document—''Literature Survey of Carbon Capture Technology'', available in the rulemaking docket (Docket ID: EPA–HQ–OAR–2013–0495).

technically feasible. Industry officials have made additional positive statements in conjunction with facilities that received DOE assistance under EPAct05 or the IRC Section 48A tax credit. These statements provide further, although not necessary, support.

For example, Southern Company's Mississippi Power has stated that, because the Selexol™ process has been used in industry for decades, the technical risk of its use at the Kemper IGCC facility is minimized. For example:

> The carbon capture process being utilized for the Kemper County IGCC is a commercial technology referred to as Selexol™. The Selexol™ process is a commercial technology that uses proprietary solvents, but is based on a technology and principles that have been in commercial use in the chemical industry for over 40 years. Thus, the risk associated with the design and operation of the carbon capture equipment incorporated into the Plant's design is manageable.[235]
>
> And . . .
>
> The carbon capture equipment and processes proposed in this project have been in commercial use in the chemical industry for decades and pose little technology risk.[236]

Similarly, in an AEP Second Quarter 2011 Earnings Conference Call, Chairman and CEO Mike Morris said of the Mountaineer CCS project:

> We are encouraged by what we saw, we're clearly impressed with what we learned, and we feel that we have demonstrated to a certainty that the carbon capture and storage is in fact viable technology for the United States and quite honestly for the rest of the world going forward.[237]

Some commenters have claimed that CCS technology is not technically feasible, and some further assert that vendors do not offer performance guarantees. For example, Alstom commented:

> The EPA referenced projects fail to meet the 'technically feasible' criteria. These technologies are not operating at significant scale at any site as of the rule publication. We do not support mandating technology based on proposed projects (many of which may never be built).[238]

As discussed above, vendors do in fact offer performance guarantees. We further note that, as noted above, Boundary Dam Unit #3 is a full-scale project that is successfully implementing full CCS with post-combustion capture, and Dakota Gasification is likewise a full-scale commercial operation that is successfully implementing pre-combustion CCS technology. Moreover, as we explain above, this technology and performance is transferable to the steam electric generating sector. In addition, as noted above, technology providers and technology end users have expressed confidence in the availability and performance of CCS technology.[239]

G. Response to Key Comments on the Adequacy of the Technical Feasibility Demonstration

1. Commercial Availability

Some commenters asserted that CCS cannot be considered the BSER because it is not commercially available. There is no requirement, as part of the BSER determination, that the EPA finds that the technology in question is ''commercially available.'' As we described in the January 2014 proposal, the D.C. Circuit has explained that a standard of performance is ''achievable'' if a technology or other system of emission reduction can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard, and that there is no requirement that the technology ''must be in routine use somewhere.'' See *Portland Cement* v. *Ruckelshaus,* 486 F. 2d at 391; 79 FR 1463. In any case, as discussed above, CCS technology is available through vendors who provide performance guarantees, which indicates that in fact, CCS is commercially available, which adds to the evidence that the technology is adequately demonstrated to be technically feasible. In sum, ''[t]he capture and CO_2 compression technologies have commercial operating experience with demonstrated ability for high reliability.''[240]

2. Must a technology or system of emission reduction be in full-scale use to be considered demonstrated?

Commenters maintained that the EPA can only show that a BSER is ''adequately demonstrated'' using operating data from the technology or system of emission reduction itself. This is mistaken. Since the very inception of the CAA section 111 program, courts have noted that ''[i]t would have been entirely appropriate if the Administrator had justified the standard, not on the basis of tests on existing sources or old test data in the literature, but on extrapolations from this data, on a reasoned basis responsive to comments, and on testimony from experts and vendors . . . .'' *Portland Cement* v. *Ruckelshaus,* 486 F. 2d at 401–02.[241]

In a related argument, other commenters stated that a system cannot be adequately demonstrated unless all of its component parts are operating together.[242] Courts have, in fact, accepted that the EPA can legitimately infer that a technology is demonstrated as a whole based on operation of component parts which have not, as yet, been fully integrated. *Sur Contra la Contaminacion* v. *EPA,* 202 F. 3d 443, 448 (1st Cir. 2000); *Native Village of Point Hope v Salazar* 680 F. 3d 1123, 1133 (9th Cir. 2012). Moreover, all components of CCS are fully integrated at Boundary Dam: Post-combustion full CCS is being utilized at a steam electric fossil fuel-fired plant, with captured carbon being transported via dedicated pipeline to both sequestration and EOR sites. All components are likewise demonstrated for pre-combustion CCS at the Dakota Gasification facility, except that the facility does not generate electricity, a distinction without a difference for this purpose (see Section V.E.2.a above).

The short of it is that the ''EPA does have authority to hold the industry to a standard of improved design and

[235] Testimony of Thomas O. Anderson, Vice President, Generation Development for Mississippi Power, MS Public Service Commission Docket 2009–UA–14 at 22 (Dec. 7, 2009).

[236] Mississippi Power Company, Kemper County IGCC Certificate Filing, Updated Design, Description and Cost of Kemper IGCC Project, Mississippi Public Service Commission (MPSC) DOCKET NO. 2009–UA–0014, filed December 7, 2009.

[237] American Electric Power Co Inc AEP Q2 2011 Earnings Call Transcript, Morningstar, *http://www.morningstar.com/earnings/28688913-american-electric-power-co-incaep-q2–2011-earnings-call-transcript.aspx.*

[238] Alstom Comments, p. 3 (Docket entry: EPA–HQ–OAR–2013–0495–9033).

[239] We note that before filing comments for this rule asserting that CCS is not technically feasible, Alstom issued public statements that, like the other industry officials quoted above, affirmed that CCS is technically feasible. According to an Alstom Power press release, Alstom President Phillipe Joubert, referencing results from an internal Alstom study, stated at an industry meeting: ''We can now be confident that carbon capture technology (CCS) works and that it is cost-effective''. *http://www.alstom.com/press-centre/2011/6/2011-06-16-CCS-cost-competiveness/.*

[240] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 36.

[241] More recently, the D.C. Circuit stated:

> Our prior decisions relating to technology-forcing standards are no bar to this conclusion. We recognize here, as we have recognized in the past, that an agency may base a standard or mandate on future technology when there exists a rational connection between the regulatory target and the presumed innovation.

API v. *EPA,* 706 F. 3d at 480 (D.C. Cir. 2013) (citing the section 111 case *Sierra Club* v. *Costle,* 657 F. 2d at 364). The Senate Report to the original section 111 likewise makes clear that it was not intended that the technology ''must be in actual routine use somewhere.'' Rather, the question was whether the technology would be available for installation in new plants. S. Rep. No. 91–1196, 91st Cong., 2d Sess. 16 (1970).

[242] See, *e.g.,* Comments of UARG p. 5 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard.'' *Sierra Club,* 657 F. 2d at 364. The EPA's task is to ''identify the major steps necessary for development of the device, and give plausible reasons for its belief that the industry will be able to solve those problems in the time remaining''. *API* v. *EPA,* 706 F. 3d at 480 (quoting *NRDC* v. *EPA,* 655 F. 2d 318, 333 (D.C. Cir. 1981), and citing *Sierra Club* for this proposition).

3. Scalability of Pilot and Demonstration Projects

Commenters maintained that the EPA had no basis for maintaining that pilot and demonstration plant operations showed that CCS was adequately demonstrated. This is mistaken. In a 1981 decision, *Sierra Club* v. *Costle,* the D.C. Circuit explained that data from pilot-scale, or less than full-scale operation, can be shown to reasonably demonstrate performance at full-scale operation, although it is incumbent on the EPA to explain the necessary steps involved in scaling up a technology and how any obstacles may reasonably be surmounted when doing so.[243] The EPA has done so here.

Most obviously, the final standard reflects experience of full-scale operation of post-combustion carbon capture. Pre-combustion carbon capture is likewise demonstrated at full-scale. Second, the record explains in detail how CCS can be implemented at full-scale. The NETL cost and performance reports, indeed, contain hundreds of pages of detailed, documented explanation of how CCS can be implemented at full-scale for both utility boiler and IGCC facilities. See, for example, the detailed description of the following systems projected to be needed for a new supercritical PC boiler to capture CO_2: Coal and sorbent receiving and storage, steam generator and ancillaries, NO_X control system, particulate control, flue gas desulfurization, flue gas system, CO_2 recovery facility, steam turbine generator system, balance of plant, and accessory electric plant, and instrumentation and control systems.[244]

It is important to note that, while some commenters challenged the EPA's use of costs in the DOE/NETL cost and performance reports, commenters did not challenge the technical methodology in the work.

In addition, the AEP FEED study indicates how the development scale post-combustion CCS could be successfully scaled up to full-scale operation. See Section V.D.3.b above.

Tenaska Trailblazer Partners, LLC also prepared a FEED study[245] for the carbon capture portion of the previously proposed Trailblazer Energy Center, a 760 MW SCPC EGU that was proposed to include 85 to 90 percent CO_2 post-combustion capture. Tenaska selected the Fluor Econamine FG Plus℠ technology and contracted Fluor to conduct the FEED study. One of the goals of the FEED study was to ''[c]onfirm that scale up to a large commercial size is achievable.'' Tenaska ultimately concluded that the study had achieved its objectives resulting in ''[c]onfirmation that the technology can be scaled up to constructable design at commercial size through (1) process and discipline engineering design and CFD (computational fluid dynamics) analysis, (2) 3D model development, and (3) receipt of firm price quotes for large equipment.''

Much has been written about the complexities of adding CCS systems to fossil fuel-fired power plants. Some of these statements come from high government officials. Some commenters argued that the EPA minimized—or even ignored—these publically voiced concerns in the discussion presented in the January 2014 proposal. On the contrary, the EPA has not minimized or ignored these complexities, but it is important to realize that most of these statements come in a different context: Namely, implementing full CCS, or retrofitting CCS onto existing power plants. For example, in the Final Report of the President's CCS Task Force, it was noted that ''integration of CCS technologies with the power cycle at generating plants can present significant cost and operating issues that will need to be addressed to facilitate widespread, cost-effective deployment of CO_2 capture.''[246] This statement—and most of the statements in this vein—are in reference to implementation of full CCS systems that capture more than 90 percent of the CO_2 and many reference widespread implementation of such technology. The EPA has addressed the concerns regarding ''significant cost'' by finalizing a standard that relies on partial CCS which we show, in this preamble and in the supporting record, can be implemented at a reasonable, non-exorbitant cost. The Boundary Dam facility, in particular, demonstrates that the complexities of implementing CCS—even full CCS—can be overcome.

Concerns regarding ''operating issues'' are also often associated with implementation of full CCS—and often with implementation of full CCS as a retrofit to an existing source. Implementation of CCS at some existing sources may be challenging because of space limitations. That should not be an issue for a new facility because the developer will need to ensure that adequate space is available during the design of the facility. Constructing CCS technology at an existing facility can be challenging even if there is adequate space because the positioning of the equipment may be awkward when it must be constructed to fit with the existing equipment at the plant. Some commenters noted the challenges of diverting steam from the plant's steam cycle. Again, that is primarily an issue with full CCS implementation as a retrofit to an existing source. Consideration of steam requirements for solvent regeneration can be factored into the design of a new facility. We also note that issues of integration with the plant's steam cycle are less challenging when implementing partial CCS.

Some commenters noted conclusions and statements from the CCS Task Force report as contradictory to the EPA's determination of that partial CCS is technically feasible and adequately demonstrated. However, the EPA mentioned in the January 2014

[243] *Sierra Club* v. *Costle,* 657 F. 2d 298, 341 n.157 and 380–84 (D.C. Cir. 1981). See also *Essex Chemical Corp.* v. EPA, 486 F. 2d at 440 (upholding achievability of standard of performance for coal-burning steam generating plants which hadn't been achieved in full-scale performance based in part on ''prototype testing data'' which, along with vendor guarantees, indicated that the promulgated standard was achievable); *Weyerhaeuser* v. *Costle,* 590 F. 2d 1054 n. 170 (D.C. Cir. 1978) (use of pilot plant information to justify technology-based standard for Best Available Technology Economically Achievable under section 304 of the Clean Water Act); *FMC Corp.* v. *Train,* 539 F. 2d 973, 983–84 (4th Cir. 1976)(same).

[244] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity; Revision 2a, pp. 57–74.

[245] Final front-end engineering design (FEED) study report'', available at: *www.globalccsinstitute.com/publications/tenaska-trailblazer-front-end-engineering-design-feed-study.*

[246] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 28. See also DOE Carbon Capture Web site: ''First generation CO_2 capture technologies are currently being used in various industrial applications. However, in their current state of development, these technologies are not ready for implementation on coal-based power plants because they have not been demonstrated at appropriate scale, requisite approximately one-third of the plant's steam power to operate, and are cost prohibitive.'' (Dec 2010); and Testimony of Dr. S. Julio Friedmann, Deputy Asst. Secretary of Energy for Clean Coal, U.S. Dept. of Energy, before the Subcommittee on Oversight and Investigations Committee on Energy and Commerce (Feb. 11, 2014): CCS technologies at new coal-fired plants would result in ''something like a 70 to 80 percent increase on the wholesale price of electricity.''

proposal, and we emphasize again here, that the Task Force was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS by 2020. Implicit in all of the conclusions, recommendations, and statements of that final report is a goal of widespread implementation of full CCS—including retrofits of existing sources. This final action does not require—nor does it envision—the near term widespread implementation of full CCS. On the contrary, as we have noted several times in this preamble, the EPA and others predict that very few, if any, new coal-fired steam generating EGUs will be built in the near term.

Thus, the EPA has provided an ample record supporting its finding that partial CCS is feasible at full-scale. As in *Sierra Club,* the EPA has presented evidence from full-scale operation, smaller scale installations, and reasonable, corroborated technical explanations of how the BSER can be successfully operated at full scale. See 657 F. 2d at 380, 382. Indeed, the EPA has more evidence here, as the baghouse standard in *Sierra Club* was justified based largely on less-than-full-scale operation. See 657 F.2d at 380 (there was only ''limited data from one full scale commercial sized operation''), 376 (''the baghouses surveyed were installed at small plants''), and 341 n.157; see also Section V.L, explaining why CCS is a more developed technology than FGD scrubbers were at the inception of the 1971 NSPS for this industry.

H. Consideration of Costs

CAA section 111(a) defines ''standard of performance'' as an emission standard that reflects the best system of emission reduction that is adequately demonstrated, ''taking into account [among other things] the cost of achieving such reduction.'' Based on consideration of relevant cost metrics in the context of current market conditions, the EPA concludes that the costs associated with the final standard are reasonable.

In reaching this determination, the EPA considered a host of different cost metrics, each of which illuminated a particular aspect of cost consideration, and each of which demonstrated that the costs of the final standard are reasonable. The EPA evaluated capital costs on a per-plant basis, responding to public comment that noted the particular significance of capital costs for coal-fired EGUs. As in the proposal, the EPA also considered how the standard would affect the LCOE for individual affected EGUs as well as national, overall cost impacts of the standard. The EPA found that the anticipated cost impacts are similar to those in other promulgated NSPS—including for this industry—that have been upheld by the D.C. Circuit. The costs are also comparable to those of other base load technologies that might be selected on comparable energy portfolio diversity grounds. Finally, the EPA does not anticipate any significant overall nationwide costs or cost impacts on consumers because projected new generating capacity is expected to meet the standards even in the baseline. Accordingly, after considering costs from a range of different perspectives, the EPA concludes that the costs of the final standard are reasonable.

1. Rationale at Proposal

At proposal, the EPA evaluated the costs of new coal-fired EGUs implementing full (90 percent) and partial CCS. The EPA compared the predicted LCOE of those units against the LCOE of other new dispatchable technologies often considered for new base load power with fuel diversity, primarily including a new nuclear plant, as well as a new biomass-fired EGU. See 79 FR at 1475–78. The levelized cost for a new steam EGU implementing full CCS was higher than that of the other non-NGCC dispatchable technologies, and we did not propose to identify a new steam EGU implementing full CCS as BSER on that basis. Id. at 1477. The EPA proposed that a standard of performance of 1,100 lb CO_2/MWh-g, reflecting a new steam EGU implementing partial CCS, could be achieved at reasonable cost based on a comparison of the projected LCOE associated with achieving this standard with the alternative dispatchable technologies just mentioned. In the January 2014 proposal, the EPA used LCOE projections for new fossil fuel-fired EGUs from a series of studies conducted by the DOE NETL. These studies—the ''cost and performance studies''—detail expected costs and performance for a range of technology options both with and without CCS.[247] The EPA used LCOE projections for non-fossil dispatchable generation—specifically nuclear and biomass—from the EIA AEO 2013. See 79 FR 1435.

In addition, the EPA proposed that the costs to implement partial CCS were reasonable because a segment of the industry was already accommodating them. *Id.* at 1478. The EPA also considered anticipated decreases in the cost of CCS technologies, the availability of government tax benefits, loan guarantees, and direct expenditures, and the opportunity to generate income from sale of captured CO_2 for EOR. *Id.* at 1478–80. The EPA noted that the proposed standard was not expected to lead to any significant overall costs or effects on electricity prices. *Id.* at 1480–81. The EPA also acknowledged the overall market context, noting that fossil steam EGUs, even without any type of CCS, are significantly more expensive than new natural gas-fired electricity generation, but that some electricity suppliers might include new coal-fired generating sources in their generation portfolio, and would pay a premium to do so. *Id.* at 1478.

2. Brief Summary of Cost Considerations Under CAA Section 111

As explained above, CAA section 111(a) directs the EPA to ''tak[e] into account the cost'' of achieving reductions in determining if a particular system of emission reduction is the best that is adequately demonstrated. The statute does not provide further guidance on how costs should be considered, thus affording the EPA considerable discretion in choosing a means of cost consideration. In addition, it should be noted that in evaluating the reasonableness of costs, the D.C. Circuit has upheld application of a variety of metrics, such as the amount of control costs or product price increases. See Section III.H.3.(b).(1) above.

Following the directive of CAA section 111(a) and applicable precedent, the EPA evaluated relevant metrics and context in considering the reasonableness of the regulation's costs. The EPA's findings demonstrate that the costs of the selected final standard are reasonable.

3. Current Context

The EIA projects that few new coal-fired EGUs will be constructed over the coming decade and that those that are built will apply CCS, reflecting the broad consensus of government, academic, and industry forecasters.[248]

[247] For the cost estimates in the January 2014 proposal, the EPA used costs for new SCPC and IGCC units utilizing bituminous coal from the reports ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010) and ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture'', DOE/NETL–2011/1498, May 27, 2011. Additional cost and performance information can be found in additional volumes that are available at *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[248] Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal beyond its

The primary reasons for this projected trend include low electricity demand growth, highly competitive natural gas prices, and increases in the supply of renewable energy. In particular, U.S. electricity demand growth has followed a downward sloping trend for decades with future growth expected to remain very low.[249] Furthermore, the EPA projects that, for any new fossil fuel-fired electricity generating capacity that is constructed through 2030, natural gas will be the overwhelming fuel of choice.[250] See RIA chapter 4.

The EIA's projection is confirmed by an examination of Integrated Resource Plans (IRPs) contained in a TSD in the docket for this rulemaking. IRPs are used by utilities to plan operations and investments in both owned generation and power purchase agreements over long time horizons. Though IRPs do not demonstrate a utility's intent to pursue a particular generation technology, they do indicate the types of new generating technologies that a utility would consider for new generating capacity. The EPA's survey of recent IRPs demonstrates that across the nation, utilities are not actively considering constructing new coal-fired generation without CCS in the near term.

Accordingly, construction of new uncontrolled coal-fired generating capacity is not anticipated in the near term, even in the absence of the standards of performance we are finalizing in this rule, except perhaps in certain limited circumstances.

In particular, commenters suggested that some developers might choose to build a new coal-fired EGU, despite its not being cost competitive, in order to achieve or maintain ''fuel diversity.'' Fuel diversity could provide important value by serving as a hedge against the possibility that future natural gas prices will far exceed projected levels.

Public announcements, including IRPs, confirm that utilities are interested in technologies that could provide or preserve fuel diversity within generating fleets. The Integrated Resource Plan TSD [251] notes examples where the goal of fuel diversity was considered in IRPs; in many cases, these plans considered new generation that would not rely on natural gas. In particular, several utilities that considered fuel diversity in developing their IRPs included new nuclear generation as a potential future generation strategy.

In addition, the EPA recognizes that there may be interest in constructing a new combined-purpose coal-fired facility that would generate power as well as produce chemicals or CO_2 for use in EOR projects. These facilities would similarly provide additional value due to the revenue streams from saleable chemical products or CO_2.[252]

As demonstrated below, the agency carefully considered the reasonableness of costs in identifying a standard that allows a path forward for such projects and rejects more stringent options that would impose potentially excessive costs. In fact, based on this careful consideration of costs, the EPA is finalizing a substantially lower cost standard than the one we proposed. At the same time, we note the unusual circumstances presented here, where the record, and indeed simple consideration of electricity market economics, demonstrates that non-economic factors such as fuel diversity are likely to drive any construction of new coal-fired generation. See also RIA chapter 4 (documenting that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions). Under these circumstances, the EPA's consideration of costs takes into account that higher costs can be viewed as reasonable when costs are not a paramount factor in new coal capacity decisions. At the same time, the EPA acknowledges and agrees with the public comments that such an argument, left unconstrained, could justify any standard and obviate all cost considerations.[253] The EPA has reasonably cabined its consideration of costs by examining costs for comparable non-NGCC base load dispatchable technologies, as well as by considering capital costs and other cost metrics.[254] This cost-reasonable standard will preserve the opportunity for such projects while driving new technology deployment.[255]

4. Consideration of Capital Costs

As noted above, CAA section 111 does not mandate any particular method for evaluating costs, leaving the EPA with significant discretion as to how to do so. One method is to consider the incremental capital costs required for a unit to achieve the standard of performance.

The EPA included information on capital cost at proposal and, as discussed further below, the LCOE metric relied upon at proposal and in this final rulemaking incorporates and fully reflects capital costs.[256] Nonetheless, extensive comment from industry representatives and others noted persuasively that fossil-steam units are very capital-intensive projects and recommended that a separate metric, solely of capital costs, be considered by the EPA in evaluating the final standard's costs. Accordingly, the EPA has considered the final standard's impact on the capital costs of new fossil-steam generation. The EPA has determined that the incremental capital costs of the final standard are reasonable because they are comparable to those in prior regulations and to industry experience, and because the fossil steam electric power industry has been shown to be able to successfully absorb capital costs of this magnitude in the past.

Prior new source performance standards for new fossil steam generation units have had significant—yet manageable—impacts on the capital costs of construction. The EPA estimated that the costs for the 1971 NSPS for coal-fired EGUs were $19M for a 600 MW plant, consisting of $3.6M for particulate matter controls, $14.4M for sulfur dioxide controls, and $1M for nitrogen oxides controls, representing a 15.8 percent increase in capital costs

reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations. EIA, ''Annual Energy Outlook 2015,'' DOE/EIA–0383(2015), April 2015, ''[v]ery little unplanned coal-fired capacity is added across all the AEO 2015 cases'', p. 26.

[249] EIA, ''Annual Energy Outlook 2015,'' DOE/EIA–0383(2015), April 2015, p. 8.

[250] Integrated Planning Model (IPM) run by the EPA (v. 5.15) Base Case, available at *www.epa.gov/airmarkets/powersectormodeling.html*.

[251] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

[252] The EPA may, of course, consider revenues generated as a result of application of pollution control measures in assessing the costs of a best system of emission reduction. See *New York* v. *Reilly,* 969 F.2d 1147, 1150–52 (D.C. Cir. 1992).

[253] See, *e.g.,* Comments of Murray Energy, pp. 79–80 (Docket entry: EPA–HQ–OAR–2013–0495–10046).

[254] Indeed, the EPA is not only adopting a standard predicated on a lower rate of carbon capture than proposed, but also rejecting full CCS for reasons of cost. See Section V.P below. Thus, although the EPA has reasonably taken into account the current economic posture of the industry whereby new capacity is not cost-competitive and so would be added for non-economic reasons, it is not using that fact to negate consideration of cost here. See also Section V.I.4 below responding to comments that the incremental cost of partial CCS could prove the difference between constructing and not constructing new coal capacity.

[255] In this rulemaking, our determination that the costs are reasonable means that the costs meet the cost standard in the case law no matter how that standard is articulated, that is, whether the cost standard is articulated through the terms that the case law uses, *e.g.,* ''exorbitant,'' ''excessive,'' etc., or through the term we use for convenience, ''reasonableness.''

[256] See RIA chapter 4.5.4 and Fig. 4–3; see also ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (July 2015) p. 17.

above the $120M cost of the plant. See 1972 Supplemental Statement, 37 FR 5767, 5769 (March 21, 1972). The D.C. Circuit upheld the EPA's determination that the costs associated with the final 1971 standard were reasonable, concluding that the EPA had properly taken costs into consideration. *Essex Cement* v. *EPA,* 486 F. 2d at 440.

In reviewing the 1978 NSPS for coal-fired EGUs, the D.C. Circuit recognized that ''EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS'' and that ''[c]onsumers will ultimately bear these costs.'' *Sierra Club,* 657 F.2d at 314. The court nonetheless upheld the EPA's determination that the standard was reasonable. *Id.* at 410.

The cost and investment impacts of the 1978 NSPS on electric utilities were subsequently evaluated in a 1982 Congressional Budget Office (CBO) retrospective study.[257] The CBO study highlighted that installation of scrubbers—capital intensive pollution control equipment that had ''in effect'' been mandated by the 1978 NSPS—increased capital costs for new EGUs by 10 to as much as 20 percent.[258] The study further noted that air pollution control requirements in general had led to an estimated 37.5 to 45 percent increase in capital costs for coal-fired power plant installation between 1971 and 1980.[259]

The study retrospectively confirmed the EPA's conclusion that imposition of these costs was reasonable, finding that ''utilities with commitments to pollution control tend to fare no better and no worse than all electric utilities in general.'' [260] In assessing the capital cost impacts of the suite of 1970s EPA air pollution standards, the report concluded that ''though controlling emissions is indeed costly, it has not played a major role in impairing the utilities' financial position, and is not likely to do so in the future.'' [261]

In NSPS standards for other sectors, the EPA's determination that capital cost increases were reasonable has similarly been upheld. In *Portland Cement Association,* the D.C. Circuit upheld the EPA's consideration of costs for a standard of performance that would increase capital costs by about 12 percent, although the rule was remanded due to an unrelated procedural issue. 486 F.2d at 387–88. Reviewing the EPA's final rule after remand, the court again upheld the standards and the EPA's consideration of costs, noting that ''[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed.'' *Portland Cement* v. *Ruckelshaus,* 513 F. 2d 506, 508 (D.C. Cir. 1975).

The capital cost impacts incurred under these prior standards are comparable in magnitude on an individual unit basis to those projected for the present standard. We predict that the incremental costs of control for a new highly efficient SCPC unit to meet the final emission limitation of 1,400 lb CO_2/MWh-g would be an increase of 21–22 percent for capital costs. See Table 7 below.[262] [263]

TABLE 7—COMPARISON OF ESTIMATED CAPITAL COSTS FOR A NEW SCPC AND A NEW SCPC MEETING THE FINAL STANDARD OF PERFORMANCE [264]

	Total overnight cost (2011$/kW)	Total as-spent capital (2011$/kW)
SCPC—no CCS	2,507	2,842
SCPC—partial CCS (1,400 lb CO_2/MWh-g)	3,042	3,458
Incremental cost increase	21.3%	21.7%

By comparison, a SCPC that co-fires with natural gas to meet the final standard of 1,400 lb CO_2/MWh-g would not result in an increase in capital cost over the uncontrolled SCPC. A compliant IGCC unit co-firing natural gas is predicted to have Total Overnight Cost of $3,036/kW—an approximately 21.1 percent increase in capital over the uncontrolled SCPC unit.

5. Consideration of Costs Based on Levelized Cost of Electricity

As in the proposal, the EPA also considered the reasonableness of costs by evaluating the LCOE associated with the final standard. The LCOE is a commonly used economic metric that takes into account all costs to construct and operate a new power plant over an assumed time period and an assumed capacity factor. The LCOE is a summary metric, which expresses the full cost of generating electricity on a per unit basis (*i.e.,* megawatt-hours). Levelized costs are often used to compare the cost of different potential generating sources. While capital cost is a useful and relevant metric for capital-intensive fossil-steam units, the LCOE can serve as a useful complement because it takes into account all specified costs (operation and maintenance, fuel—as well as capital costs), over the whole lifetime of the project.

As previously mentioned, at proposal the EPA relied on LCOE projections for fossil fuel-fired EGUs (with and without CCS) from DOE/NETL reports detailing the results of studies evaluating the costs and performance of such units. For non-fossil dispatchable generating sources, the EPA relied on LCOE projections from EIA AEO 2013. For this final action, the EPA is relying on updated costs from the same sources. The NETL has provided updated cost and performance information in recently published revisions of reports used in the January 2014 proposal.[265] The updated SCPC cases in the reports include up-to-date cost and performance information from recent vendor quotes

[257] Congressional Budget Office report, ''The Clean Air Act, the Electric Utilities, and the Coal Market'', April 1982, p. 10–11, 23.

[258] *Id.* at 10–11.

[259] *Id.* at 22.

[260] *Id.* at xvi.

[261] *Id.*

[262] We explain at Section V.I.2 and 3 below the reasonableness of the EPA's cost projections here.

[263] We estimate that a new SCPC EGU using low rank coal (subbituminous coal or dried lignite) would incur a capital cost increase of 23 percent to meet the final standard. See ''Achievability of the Standard for Newly Constructed Steam Generating EGUs'' technical support document available in the rulemaking docket.

[264] Exhibit A–3 (p. 18); ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015).

[265] ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1a'' Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, U.S. DOE NETL report (2015) and ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1b: Bituminous Coal (IGCC) to Electricity, Revision 2—Year Dollar Update, U.S. DOE NETL report (2015). Both reports are available at *www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

and implementation of the Shell Cansolv post-combustion capture process—the process that is currently being utilized at the Boundary Dam #3 facility. The IGCC cost and performance results in the updated reports utilize vendor quotes from the previous report; the costs are adjusted from $2007 to $2011. Important also to note is that DOE/NETL utilized conventional financing for cases without CCS and utilized high-risk financial assumptions for cases that include CCS.[266]

Using information from those reports, the DOE/NETL prepared a separate report summarizing a study that evaluated the cost and performance of various plants designed to meet a range of CO_2 emissions by varying the CO_2 capture rate (*i.e.,* the level of partial capture).[267] The EIA also updated LCOE projections from AEO 2013 to AEO 2014 and again in AEO 2015. Those are discussed in more detail in Section V.I.2.b and d. In evaluating costs for the final standards in this action, the EPA relied primarily on the updated NETL LCOE projections for new fossil fuel-fired EGUs provided in the reports described above and on the LCOE projections for non-fossil, dispatchable generating options from the EIA's AEO 2015.[268] Here, the EPA compared the LCOE of the final standard to the LCOE of analogous potential sources of intermediate and base load power. This comparison demonstrated that the LCOE for a fossil steam unit with partial CCS is within the range of the LCOE of comparable alternative non-NGCC generation sources. In particular, nuclear and biomass generation, which similarly provide both base load power and fuel diversity, have comparable LCOE. The EPA concludes that an evaluation of the LCOE also demonstrates that the costs of the final standard are reasonable.

a. Calculation of the LCOE

The LCOE of a power plant source is calculated with the expected lifetime and average capacity factor, and represents the average cost of producing a megawatt-hour (MWh) of electricity over the expected lifetime of the asset.

The LCOE incorporates all specified costs, and therefore is dependent on the project's capital costs, the fixed and variable operating and maintenance (O&M) costs, the fuel costs, the costs to finance the project, and finally on the assumed capacity factor.[269] The relative contribution of each of these inputs to LCOE will vary among the generating technologies. For example, the LCOE for a new supercritical PC plant or a new IGCC plant is influenced more by the capital costs (and thus the financing assumptions) and less on fuel costs than a comparably sized new NGCC facility which would require less capital investment but would be more influenced by assumed fuel costs.

b. Use of the LCOE

The utility industry and electricity sector regulators often use levelized costs as a summary measure for comparing the cost of different potential generating sources. Use of the LCOE as a comparison measure is appropriate where the facilities being compared would serve load in a similar manner.

The value of generation, as reflected in the wholesale electricity price, can vary seasonally and over the course of a day. In addition, electricity generation technologies differ on dimensions other than just cost, such as ramping efficiency, intermittency, or uncertainty in future fuel costs. These other factors are also important in determining the value of a particular generation technology to a firm, and accordingly cost comparisons between two different technologies are most appropriate and insightful when the technologies align along these other dimensions. Isolating a comparison of technologies based on their LCOE is appropriate when they can be assumed to provide similar services and similar values of electricity generated.

As we indicated in the proposal, we evaluated publicly available IRPs and other available information (such as public announcements) to determine the types of technologies that utilities are considering as options for new generating capacity.[270] In the near future, the largest sources of new fossil fuel-fired power generation are expected to be new NGCC units. But the IRPs also suggested that utilities are interested in a range of technologies that can be used to provide or preserve fuel diversity within the utilities' respective generating fleets.[271] [272] The options for

[266] Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) p. 18.

[267] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015). Available at *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[268] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[269] See, *e.g.* ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 17.

[270] See also discussion at V.C.3 above. The IRPs do not provide an indication of the utility's intention to pursue a particular generation technology. However, the IRPs do provide an indication of the types of new generating technologies that the utility would consider for new generating capacity.

[271] See, *e.g.* the 2014 IRP of Dominion Virginia Power:

With those factors in mind, the 2014 Plan presents two paths forward for resource expansion: a Base Plan, designed using least-cost planning methods and consistent with the requirements of Rule R8–60 for utility plans to provide ''reliable electric utility service at least cost over the planning period;'' and a Fuel Diversity Plan, which includes a broader array of low or zero-emissions options. While the Fuel 2 Diversity Plan currently represents a higher cost option at today's current and projected commodity prices, its resource mix provides the important benefits of greater fuel diversity and lower carbon intensity. Therefore, the Company will continue reasonable development of the more diverse and lower carbon intensive options in the Fuel Diversity Plan and will be ready to implement them as conditions warrant. . . . The Fuel Diversity Plan places a greater reliance on generation sources with little or no carbon emissions and is less reliant on natural gas. While following the resource expansion scenario in the least-cost Base Plan, the Company will continue evaluation and reasonable development efforts for the following projects identified in the Fuel Diversity Plan. These include:

Continued development of a third nuclear reactor at North Anna Power Station, using reactor technology supplied by GE-Hitachi Nuclear Energy Americas LLC. While the Company has made no final commitment to building this unit, it recognizes the many operational and environmental benefits of nuclear power and continues to actively develop the project. Our customers have benefitted from the existing nuclear fleet for many years now, and they will continue to benefit from the existing fleet for many years in the future. A final decision on construction of North Anna Unit 3 will not be made until after the Company receives a Combined Operating License or COL from the U.S. Nuclear Regulatory Commission, now expected in 2016. The Fuel Diversity Plan includes the addition of North Anna Unit 3's 1,453 megawatts of zero-emissions generation by 2028. If constructed, the project would provide a dramatic boost to the regional economy.

Additional reliance on renewable energy, including 247 megawatts of onshore wind capacity at sites in western Virginia and a 12 megawatt offshore wind demonstration project by 2018.

An additional 559 megawatts of nameplate solar capacity, including several new Company-owned photovoltaic CPV) installations. Solar PV costs have declined significantly in recent years, making utility-scale solar much more cost-effective than distributed solar, and continuing technological development, in which the Company is participating, may allow it to become a more cost-effective source of intermittent generation in the future.cover letter for 2014 IRP—*https://www.dom.com/library/domcom/pdfs/corporate/integrated-resource-planning/va-irp-2014.pdf.*

[272] Another example are the recent statements of officials of Tri-State Generation and Transmission, available at *http://www.wyofile.com/coal-power/*, including:

''We are considering nuclear, coal and natural gas,'' said Ken Anderson, general manager of Tri-State at a conference in October [2010], a position that Tri-State representatives say remains. ''We will pick our technology once policy certainty comes about,'' he added. . . . Longer-term forecasts are based on assumptions that may or may not prove well-founded. Because of this uncertainty, Tri-State believes it must retain options for all fuels and technologies.

''We will not take anything off the table,'' [Tri-State spokesman Lee] Boughey said. That includes coal. ''Coal is an affordable and plentiful resource, but it does come with challenges—and we are

Continued

dispatchable generation that can provide intermediate or base-load power and fuel diversity would include new fossil steam units, new nuclear power, and biomass-fired generation.

Thus, in both the proposal and in this final rule, the EPA is comparing the LCOE of technologies that would be reasonably anticipated to be designed, constructed, and operated for a similar purpose—that is, to provide dispatchable base load power that provides fuel diversity by relying on a fuel source other than natural gas. In contrast, it may not be appropriate to compare the LCOE for a base load coal-fired plant with that of a peaking natural gas-fired simple cycle turbine. Similarly, it may not be appropriate to compare LCOE for dispatchable technologies (*i.e.,* generating sources that can be ramped up or down as needed, *e.g.,* coal-fired units, NGCC units, nuclear) with that of non-dispatchable technologies (*i.e.,* generating sources that cannot be reliably ramped up or down to meet demand, *e.g.,* wind, solar.)

c. Reasonableness of Costs Based on LCOE

An examination of the LCOE of analogous sources of base load, dispatchable power shows that the final standard's LCOE is comparable to that of other sources, as shown in Table 8 below. As mentioned earlier and discussed in further detail below, these estimates rely most heavily on DOE/NETL cost projections for fossil fuel generating technologies and on the updated EIA AEO 2015 for non-fossil generation technologies. Recent estimates from Lazard [273] [274] are also provided for nuclear and biomass generation options.

TABLE 8—PREDICTED COST AND CO_2 EMISSION LEVELS FOR A RANGE OF POTENTIAL NEW GENERATION TECHNOLOGIES [275]

New generation technology	Emission lb CO_2/MWh-g	LCOE* $/MWh
SCPC—no CCS (bit)	1,620	76–95
SCPC—no CCS (low rank)	1,740	75–94
SCPC + ~16% partial CCS (bit)	1,400	92–117
SCPC + ~23% partial CCS (low rank)	1,400	95–121
Nuclear (EIA)	0	87–115
Nuclear (Lazard)	0	92–132
Biomass (EIA) [276]	—	94–113
Biomass (Lazard)	—	87–116
IGCC	1,430	94–120
NGCC	1,000	** 52–86

* The LCOE ranges presented in Table 8 include an uncertainty of −15%/+30% on capital costs for SCPC and IGCC cases and an uncertainty of −10%/+30% on capital costs for nuclear and biomass cases from EIA. This reflects information provided by EIA. Nuclear staff experts expect that nuclear plants currently under construction would not have capital costs under estimates and that one could expect to see a 30% "upside" variation in capital cost. There is also insufficient market data to get a good statistical range of potential capital cost variation (*i.e.* only 2 plants under construction, neither complete). The nuclear cost estimates from Lazard likewise reflect the range of expected nuclear costs. LCOE estimates displayed in this table for SCPC units with partial CCS as well as for IGCC units use a higher financing cost rate in comparison to the SCPC unit without capture.[277]

** This range represents a natural gas price from $5/MMBtu to $10/MMBtu.

As shown in Table 8, we project that the LCOE for new fossil steam capacity meeting the final 1,400 lb CO_2/MWh-g standard to be substantially similar to that for a new nuclear unit, the principal other alternative to natural gas to provide new base load power. This is the case for new units firing bituminous and subbituminous coals and dried lignite. This is another demonstration that the costs of the final standard are reasonable because nuclear and fossil steam generation each would serve an analogous role in adding dispatchable base load generation diversity—or at least non-NGCC alternatives—to a power provider's portfolio; hence, they are reasonably viewed as comparable alternatives.[278]

As previously mentioned, the DOE/NETL assumed conventional financing

looking to different technology that can address some of those challenges while continuing to provide a reliable and affordable power supply,'' Boughey said. ''Some critics believe we shouldn't be looking at resource options that include coal, and even nuclear technology,'' Boughey added. ''We believe it would be irresponsible not to consider these fuels or technologies as part of an affordable, reliable and responsible resource portfolio.''

[273] Lazard's Levelized Cost of Energy Analysis—Version 8.0; September 2014; available at: *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf* and in the rulemaking docket.

[274] Lazard is one of the world's preeminent financial advisory and asset management firms. Lazard's Global Power, Energy & Infrastructure Group serves private and public sector clients with advisory services regarding M&A, financing, and other strategic matters. The group is active in all areas of the traditional and alternative energy industries, including regulated utilities, independent power producers, advanced transportation technologies, renewable energy technologies, meters, smart grid and energy efficiency technologies, and infrastructure. *http://www.marketwatch.com/story/lazard-releases-new-levelized-cost-of-energy-analysis-2014-09-18.*

[275] LCOE cost estimates for SCPC and IGCC cases come from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'' DOE/NETL–2015/1720 (June 22, 2015). Cost and performance for low rank SCPC is adapted from ''Cost and Performance Baseline for Fossil Energy Plants Volume 3 Executive Summary: Low Rank Coal and Natural Gas to Electricity'', DOE/NETL–2010/1399 (September 2011). LCOE cost estimates for nuclear and biomass are derived from ''Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015'', June 2015, *www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.* LCOE cost estimates for NGCC technology are EPA estimates based on a range of potential natural gas prices.

[276] Table 8 includes LCOE figures for biomass-fired generation, a potential sources of dispatchable base load power that is not fueled by natural gas. The EPA includes this information for completeness, while noting that biomass-fired units in operation in the U.S. are smaller scale and thus are not as robust analogues as nuclear power. CO_2 emissions are not provided for biomass units because different biomass feedstocks have different net CO_2 emissions; therefore a single emission rate is not appropriate to show in Table 8.

[277] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 18.

[278] LCOE comparisons of reasonably available compliance alternatives—IGCC with natural gas co-firing, and SCPC with natural gas co-firing—are found below in Table 9. As shown there, these alternatives are either lower cost than SCPC with partial CCS, or of comparable cost.

for cases without CCS and assumed high-risk financing for cases with some level of CCS. Specifically a high-risk financial structure resulting in a capital charge factor (CCF) of 0.124 is used in the study to evaluate the costs of all cases with CO_2 capture (non-capture case uses a conventional financial structure with a CCF of 0.116).[279] As a comparison of how this affects the resulting DOE/NETL costs, a new SCPC utilizing 16 percent partial CCS is projected to have an LCOE of $99/MWh (including transportation and storage costs; does not include the range for uncertainty). That projected LCOE includes the ''high risk financial assumptions''. If the LCOE for that unit were to be calculated using the ''conventional financing assumptions'', the resulting LCOE would be $94/MWh.

This approach is in contrast to that taken by the EIA which applies a 3-percentage-point cost of capital premium (the 'climate uncertainty adder') to non-capture coal plants to reflect the market reaction to potential future GHG regulation.

Under current and anticipated market conditions, power providers that are considering costs alone in choosing a fuel source for new intermediate or base load generation will choose natural gas because of its competitive current and projected price. However, as noted in Section V.H.3, public IRPs indicate that utilities are considering and selecting technologies that could provide or preserve fuel diversity within generating fleets. For example, utilities have been willing to pay a premium for nuclear power in certain circumstances, as indicated by the recent new constructions of nuclear facilities and by IRPs that include new nuclear generation in their plans. In general, fossil steam and nuclear generation each can provide dispatchable, base load power while also maintaining or increasing fuel diversity.[280] Utilities may be willing to pay a premium for these generation sources because they could serve as a hedge against the possibility that future natural gas prices will far exceed projected levels. Accordingly, the LCOE analysis demonstrates that the final standard's costs are in line with power sources that provide analogous services—dispatchable base load power and fuel diversity.

We further note a number of conservative elements of the costs we used in making this comparison. In particular, these estimates include the highest value in the projected range of potential costs for partial CCS. They do not reflect revenues which can be generated by selling captured CO_2 for enhanced oil recovery, and reflect the costs of partial CCS rather than potentially less expensive alternative compliance paths such as a utility boiler co-firing with natural gas. See also V.H.7 and 8 below.

6. Overall Costs and Economic Impacts

As noted above, an assessment of national costs is also an appropriate means of evaluating the reasonableness of costs under CAA section 111. See *Sierra Club,* 657 F.2d at 330.

The EPA considered the regulation's overall costs and economic impacts as part of its RIA. The RIA demonstrates that these costs would be negligible and that the effects on electricity rates and other market indicators would similarly be minimal.

These results are driven by the existing market context for fossil-steam generation. Even in the absence of the standards of performance for newly constructed EGUs, substantial new construction of uncontrolled fossil steam units is not anticipated under existing prevailing and anticipated future economic conditions. Modeling projections from government, industry, and academia anticipate that few new fossil steam EGUs will be constructed over the coming decade and that those that are built would have CCS.[281] Instead, EIA data shows that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity in the near future.[282] Of the coal-fired units moving forward at various advanced stages of construction and development—Southern Company's Kemper County Energy Facility and Summit Power's Texas Clean Energy Project (TCEP)—each will deploy IGCC with some level of CCS. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand, and increases in the supply of renewable energy.

In its RIA, the EPA considered the overall costs of this regulation in the context of these prevailing market trends. Because of the expectation of no new fossil steam generation, the RIA projects that this final rule will result in negligible costs overall on owners and operators of newly constructed EGUs by 2022.[283] More broadly, this regulation is not expected to have significant effects on fuel markets, electricity prices, or the economy as a whole, as described in detail in Chapter 4 of the RIA.

In comparison, courts have upheld past regulations that imposed substantial overall costs in order to protect against uncontrolled emissions. As noted above, in *Sierra Club* v. *Costle,* the D.C. Circuit upheld a standard of performance that imposed costly controls on SO_2 emissions from new coal-fired power plants. 657 F.2d at 410. These standards had implications for the economy ''at the local and national levels,'' as ''EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.'' *Id.* at 314. Further, the court acknowledged that ''[c]onsumers will ultimately bear these costs, both directly in the form of residential utility bills, and indirectly in the form of higher consumer prices due to increased energy costs,'' before concluding that the costs were reasonable. *Id.*

The projected total incremental capital costs associated with the standard we are finalizing in this rule are dramatically lower than was the case for this prior standard, as well as other prior standards summarized previously. For example, when the standard at issue in *Sierra Club* was upheld, the industry was expected to build, and did build, dozens of plants ultimately meeting the standards—at a projected incremental cost of tens of billions of dollars.[284] Here, by contrast, few if any fossil steam EGUs are projected to be built in the foreseeable future, indicating that the total incremental costs are likely to be considerably more modest.

Commenters stated that the cost provision in CAA section 111(a)(1) does not authorize the EPA to consider the nationwide costs of a system of emission reduction in lieu of considering the cost impacts for individual new plants. In this rule, we

[279] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015) at p. 7.

[280] As another example, San Antonio customers will benefit from low-carbon power from the Texas Clean Energy Project. CPS Energy CEO Doyle Deneby said in a news release: ''*Adding clean coal to our portfolio dovetails with our strategy to diversify and reduce the carbon intensity of the power we supply to our customers.*'' *www.bizjournals.com/sanantonio/news/2014/10/06/cps-energy-strikes-new-deal-to-buy-power-from.html*.

[281] RIA chapter 4. For example, even in the EIA's sensitivity analysis that assumes higher natural gas prices and electricity demand, the EIA does not project any additional coal beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations. AEO 2015.

[282] Annual Energy Outlook 2010, 2011, 2012, 2013, 2014 and 2015.

[283] Conditions in the analysis year of 2022 are represented by a model year of 2020.

[284] *Sierra Club,* 657 F.2d at 314.

are considering both sets of costs and, in fact, we are not identifying full CCS as the BSER primarily for reasons of its cost to individual sources. At the same time, total projected costs are relevant in assessing the overall reasonableness of costs associated with a standard. Our analysis demonstrates that the impacts on the industry as a whole are negligible, and are certainly not greater than ''what the industry could bear and survive.'' [285] These facts support the EPA's overall conclusion that the costs of the standard are reasonable.

However, as noted earlier, for a variety of reasons, some companies may consider coal-fired steam generating units that the modeling does not anticipate. Thus, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a newly constructed coal-fired steam generating unit with partial CCS that meets the requirements of this final rule alongside the project-level costs of a newly constructed coal-fired unit without CCS. This analysis in RIA chapter 5 indicates that the quantified benefits of the standards of performance would exceed their costs under a range of assumptions.

As required under Executive Order 12866, the EPA conducts benefit-cost analyses for major Clean Air Act rules, and has done so here. While such analysis can help to inform policy decisions, as permissible and appropriate under governing statutory provisions, the EPA does not use a benefit-cost test (*i.e.,* a determination of whether monetized benefits exceed costs) as the sole or primary decision tool when required to consider costs or to determine whether to issue regulations under the Clean Air Act, and is not doing so here.[286] Nonetheless, as just noted, the RIA analysis shows that the standard of performance has net quantified benefits under a range of assumptions.

7. Opportunities to Further Reduce Compliance Costs

While the EPA believes, as detailed above, that there is sufficient evidence to show that the final standards of performance for new steam generating units can be met at a reasonable cost, we also note that there are potential opportunities to further reduce compliance costs. We believe that, in most cases, the actual costs will be less than those presented earlier.

As explained in more detail in the following subsection, a new utility boiler can meet the final standard of performance by co-firing with natural gas. Some project developers may choose to utilize natural gas co-firing as a means of delaying, rather than avoiding, implementation of partial CCS. Developers can also choose to install IGCC with a small amount of natural gas co-firing at costs within the range of SCPC with partial CCS, although slightly higher.

The EPA also notes that new units that capture CO_2 will likely be built in areas where there are opportunities to sell the captured CO_2 for some useful purpose prior to (or concomitant with) permanent storage. The DOE refers to this as ''carbon capture, utilization and storage'' or CCUS. In particular, the ability to sell captured CO_2 for use in enhanced oil recovery operations offers the most opportunity to reduce costs. In this regard, the newly-operating Boundary Dam facility is selling captured CO_2 for EOR. The Kemper facility likewise plans to do so.[287]

In some instances, the costs of CCS may be defrayed by grants or other benefits provided by federal or state governments. The need for subsidies to support emerging energy systems and new control technologies is not unusual. Each of the major types of energy used to generate electricity has been or is currently being supported by some type of government subsidy such as tax benefits, loan guarantees, low-cost leases, or direct expenditures for some aspect of development and utilization, ranging from exploration to control installation. This is true for fossil fuel-fired, as well as nuclear-, geothermal-, wind-, and solar-generated electricity. As stated earlier, the EPA considers the costs of partial CCS at a level to meet the final standard of performance to be reasonable even without considering these opportunities to further reduce implementation and compliance costs. We did not in the proposal—and we do not here in this final action—rely on any cost reduction opportunities to justify the costs of meeting the standard as reasonable, but again note the conservative assumptions embodied in our assessment of compliance costs.

a. Cost and Feasibility of Natural Gas Co-firing as an Alternative Compliance Pathway

Although the EPA has determined that implementation of partial CCS at an emission limitation of 1,400 lb CO_2/MWh-g is the BSER for newly constructed fossil fuel-fired steam generating EGUs, we also note that operators can consider the use of natural gas co-firing to achieve the final emission limitation, likely at a lower cost.

At the final emissions limitation of 1,400 lb CO_2/MWh-g a new supercritical PC or supercritical CFB can meet the standard by co-firing with natural gas at levels up to approximately 40 percent (heat input basis) and could potentially avoid (or delay) installation and use of partial CCS altogether.

Natural gas co-firing has long been recognized as an option for coal-fired boilers to reduce emissions of criteria and hazardous air pollutants. EPRI sponsored a study to assess both technical and economic issues associated with natural gas co-firing in coal-fired boilers.[288] They determined that the largest number of applications and the longest experience time is with natural gas reburning and with supplemental gas firing. Natural gas reburning has been used primarily as a NO_X control technology. It is implemented by introducing natural gas (up to 20 percent total fuel heat input) in a secondary combustion zone (called the ''reburn zone'') downstream of the primary combustion zone in the boiler. Injecting the natural gas creates a fuel-rich zone where NO_X formed in the main combustion zone is reduced to nitrogen and water vapor.

Higher levels of natural gas co-firing can be met by utilizing supplemental gas co-firing (either alone or along with natural gas reburning). This involves the simultaneous firing of natural gas and pulverized coal in a boiler's primary combustion zone. Others have also evaluated configurations that would allow coal-fired units to utilize natural gas.[289] [290]

[285] *Portland Cement Ass'n,* 513 F.2d at 508.

[286] See Memorandum ''Consideration of Costs and Benefits under the Clean Air Act'' available in the rulemaking dockets, EPA–HQ–OAR–2013–0495 (new sources) and EPA–OAR–HQ–2013–0603 (modified and reconstructed sources).

[287] The EPA is referring to the Kemper facility here as an example of how costs can be defrayed, not for use of technology or level of emission reduction achieved. The EPA therefore does not believe that the EPAct05 prevents reference to the fact that Kemper plans to sell captured carbon.

[288] Gas Cofiring Assessment for Coal Fired Utility Boilers; Final Report, August 2000; EPRI Technical Report available at *www.epri.com.*

[289] Many of the studies evaluated opportunities to use natural gas reburn, natural gas co-firing and other configurations in existing coal-fired boilers. Those conclusions would also be applicable for new coal-fired boilers.

[290] ''Dual Fuel Firing—The New Future for the Aging U.S. Based Coal-Fired Boilers'', presented by Riley Power, Inc. at 37th International Technical Conference on Clean Coal and Fuel Systems June 2012 Clearwater, FL, available at *http://www.babcockpower.com/pdf/RPI-TP-0228.pdf.*

A 2013 article entitled ''Utility Options for Leveraging Natural Gas'' [291] noted that:

Utility owners of coal-fired power stations that wish to balance their exposure to coal-fired generation with additional natural gas-fired generation have several options to consider. The four most practical options are co-firing coal and gas in the same boiler, converting the coal-fired boiler to gas-only operation, repowering the coal plant with natural gas-fired combustion turbines, or replacing the coal plant with a combined cycle plant. [. . .] Co-firing is the lowest-risk option for substituting gas use for coal.

The EPA examined compliance costs for a new steam generating unit to meet the final standard of performance using natural gas co-firing and compared those costs to the estimated costs of meeting the final standards using partial CCS. Those costs are provided below in Table 9.

TABLE 9—PREDICTED COSTS TO MEET THE FINAL STANDARD USING NATURAL GAS CO-FIRING [292]

New generation technology	Emission lb CO_2/MWh-g	LCOE $/ MWh
SCPC—no CCS	1,620	82
SCPC + ~16% partial CCS	1,400	99
SCPC + ~34% NG co-fire	1,400	92
IGCC—no CCS	1,434	103
IGCC + ~6% NG co-fire	1,400	105
NGCC*	1,000	60

* The generation cost using NG co-fire and NGCC assume a natural gas price of $6.19/mmBtu.

The EPA thus again notes that the cost assumptions it is making in its BSER determination are conservative. That is, by costing partial CCS as BSER, the EPA may be overestimating actual compliance costs since there exist other less expensive means of meeting the promulgated standard.[293]

Notwithstanding that costs for a SCPC to meet the standard would be lower if it co-fired with natural gas, we have not identified that compliance alternative as BSER because we believe that new coal-fired steam electric generating capacity would be built to provide fuel diversity, and burning substantial amounts of natural gas would be contrary to that objective. In addition, this choice would not promote use of advanced pollution control technology. New IGCC has costs which are comparable to SCPC, as does IGCC with natural gas co-firing,[294] but we are choosing not to identify it as BSER for reasons stated at Sections V.C.2 and V.P: use of IGCC does not advance emission control beyond current levels of performance for sources which may choose to utilize IGCC technology. Nonetheless, use of IGCC remains a viable, demonstrated compliance option to meet the 1,400 lb CO_2/MWh-g standard of performance, and is available at reasonable cost and (as shown at Section V.P below) without significant adverse non-air quality impacts or energy implications.

Costs are Reasonably Expected To Decrease Over Time

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

We expect the costs of CCS technologies to decrease for several reasons. We expect that significant additional knowledge will be gained from deployment and operation of the new coal-fired generation facilities that are either operating or are nearing completion. These would include the Boundary Dam Unit #3 facility, the Petra Nova WA Parish project, and the Kemper County IGCC facility. The operators of the Boundary Dam Unit #3 are considering construction of additional CCS units and have projected that the next units could be constructed at a cost of at least 30 percent less than that at Unit #3.[295] These savings primarily come from application of lessons learned from the Unit #3 design and construction.

To facilitate the transfer of the technology and to accelerate development of carbon capture technology, SaskPower has created the CCS Global Consortium.[296] This consortium provides SaskPower the opportunity to share the knowledge and experience from the Boundary Dam Unit #3 facility with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology development through the creation of the Shand Carbon Capture Test Facility (CCTF).[297] The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

The DOE also sponsors testing at the National Carbon Capture Center (NCCC). The NCCC—located at Southern Company's Plant Gaston in Wilsonville, AL—provides first-class facilities to test new capture technologies for extended periods under commercially representative conditions with coal-derived flue gas and syngas.[298]

[291] Utility Options for Leveraging Natural Gas, 10/01/2013 article in *Power.* Available at *http://www.powermag.com/utility-options-for-leveraging-natural-gas/.*

[292] Costs and emissions for cases that do not utilize natural gas co-firing are from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015). Costs and emissions for natural gas co-fired cases are EPA estimates.

[293] Certain commenters argued that the proposed standard essentially mandated a sole method of compliance, and hence constituted a work practice for purposes of section 111(h) of the Act. These commenters argued further that the EPA had failed to justify the proposal under the section 111(h) criteria. The EPA disagrees with the premise of these comments, but, in any case, there are clearly multiple compliance paths available for achieving the final standard.

[294] IGCC units already have combined cycle capacity, and so can be readily operated in whole or in part using natural gas as a fuel. Indeed, both the Edwardsport and Kemper IGCC facilities have operated at times by firing exclusively natural gas.

[295] ''Boundary Dam—The Future is Here'', plenary presentation by Mike Monea at the 12th International Conference on Greenhouse Gas Technologies (GHGT–12), Austin, TX (October 2014).

[296] *http://www.saskpowerccs.com/consortium/.*

[297] *www.saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/.*

[298] *www.nationalcarboncapturecenter.com/index.html.*

We expect continued additional cost reductions to come from knowledge gained from continued operation of non-power sector industrial projects which, as we have discussed, are informative in transferring the technology to power sector applications. We expect the on-going research and development efforts—such as those sponsored by the DOE/NETL.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, reductions in financial premiums related to risk, research and development investments, and other factors have been observed over the decades.

c. Opportunities To Reduce Cost Through Sales of Captured CO_2

Geologic storage options include use of CO_2 in EOR operations, which is the injection of fluids into a reservoir after production yields have decreased from primary production in order to increase oil production efficiency. CO_2-EOR has been successfully used for decades at many production fields throughout the U.S. to increase oil recovery. The use of CO_2 for EOR can significantly lower the net cost of implementing CCS. The opportunity to sell the captured CO_2 for EOR, rather than paying directly for its long-term storage, improves the overall economics of the new generating unit. According to the International Energy Agency (IEA), of the CCS projects under construction or at an advanced stage of planning, 70 percent intend to use captured CO_2 to improve recovery of oil in mature fields.[299] See also Section V.M.3 below.

I. Key Comments Regarding the EPA's Consideration of Costs

In its consideration of the costs associated with the final standard, the EPA considered a range of different cost metrics, each with its individual strengths and weaknesses. As discussed above, each metric supports the EPA's conclusion that the costs of the final standard are reasonable.

In this section, we review the comments received on assessing cost reasonableness and specific cost metrics. We explain how these comments informed our consideration of different metrics and cost reasonableness in general.

1. Use of LCOE as a Cost Metric

As noted, CAA section 111(a) directs the EPA to consider ''cost'' in determining if the BSER is adequately demonstrated. It does not provide further guidance as to how costs are to be considered, thus affording the EPA considerable discretion to choose a reasonable means of cost consideration. See, *e.g. Lignite Energy Council* v. *EPA,* 198 F. 3d at 933. Certain commenters nonetheless argued that LCOE was an impermissible metric because it does not measure the cost of achieving the emission reduction, but rather measures the impact on the product produced by the entity subject to the standard.[300] The EPA does not agree that its authority is so limited. Indeed, in the first decided case under section 111, the D.C. Circuit, in holding that the EPA's consideration of costs was reasonable, specifically noted the EPA's examination of the impact of the standards on the regulated source category's product in comparison to competitive products. *Portland Cement Ass'n* v. *EPA,* 486 F. 2d at 388 (''costs of control equipment could be passed on without substantially affecting competition with construction substitutes such as steel, asphalt, and aluminum'').

Commenters also argued that the choice of LCOE as a cost metric masked consideration of the considerable capital costs associated with CCS. The EPA disagrees with this contention. The LCOE does not mask consideration of capital costs. Rather, as explained at V.H.5 above, LCOE is a summary metric that expresses the full cost (*e.g.,* capital, O&M, fuel) of generating electricity and therefore provides a useful summary metric of costs per unit of production (*i.e.,* megawatt-hours). Provided that those megawatt-hours provide similar electricity services and align on dimensions other than just cost, then the LCOE provides a useful comparison of which technologies are least cost.

The EPA certainly does not minimize that project developers must take capital costs into consideration, and as discussed in Section V.H.4 above, the EPA accordingly has considered direct capital costs here as part of its assessment and found those costs to be reasonable. In addition, the EPA notes that its comparison of the marginal impacts from an individual illustrative facility's compliance with the standard, discussed in detail above and in the RIA Chapter 5, took into account the marginal capital costs that would be incurred by an individual facility.

According to EIA,[301] capital costs represent approximately 63 percent of the LCOE for a new coal-fired SCPC plant; approximately 66 percent of the LCOE for a new IGCC plant; approximately 74 percent of the LCOE for a new nuclear plant; and only about 22 percent of the LCOE for a new NGCC unit. The LCOE of a new NGCC unit is much more strongly affected by fuel costs (natural gas). As we have discussed in detail in this preamble, in the preamble for the January 2014 proposal, and in associated technical support documents, the power sector has moved toward increased use of natural gas for a variety of reasons. If capital was the only cost that utilities and project developers considered, then they would almost certainly always choose to build a new NGCC unit. However, a variety of factors can be involved in selecting a generation source beyond capital costs. Accordingly, in considering cost reasonableness the EPA considered metrics that encompassed other costs as well as the value of fuel and fleet diversity.

Some commenters maintained that even if LCOE was a proper cost metric, the comparison with the costs of a new nuclear power plant is improper because nuclear itself is a highly expensive technology. The EPA disagrees. The comparison is appropriate and valid because, as discussed at V.H.3 above, under current and foreseeable economic conditions affecting the cost of new fossil steam generation and new nuclear generation relative to the cost of new natural gas generation, neither new nuclear power nor fossil steam generation are competitive with new natural gas if evaluated on the basis of LCOE alone. Nonetheless, both are important potential alternatives to natural gas power for those interested in dispatchable base load power that maintains or increases fuel diversity. As shown in a survey of recent IRP filings in the docket[302] and Section II.C.5 above, several utilities are considering new nuclear power as a potential generation option. Because both fossil steam and nuclear generation serve a comparable role of offering a diverse source of base load power generation, the EPA concludes that the comparison of their LCOE is a valid approach to evaluating cost reasonableness.

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

[300] Comments of EEI, pp 94–5 (Docket entry: EPA–HQ–OAR–2013–0495–9780).

[301] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[302] Technical Support Document—''Review of Electric Utility Integrated Resource Plans'' (May 2015), available in the rulemaking docket EPA–HQ–OAR–2013–0495.

2. Use of Cost Estimates From DOE/NETL and DOE/EIA

In the January 2014 proposal, the EPA relied mostly on the cost projections for new fossil fuel-fired generating sources that were informed by cost studies conducted by DOE/NETL. The EPA relied on the EIA's AEO 2013 projections for non-fossil based generating sources (*i.e.,* nuclear, renewables, etc.). For this final rule, the EPA continues to rely most heavily on DOE/NETL cost projections for fossil fuel generating technologies and on the updated DOE/EIA AEO 2014 for nuclear and other base load non-fossil generation technologies.

a. DOE/NETL Cost and Performance Studies

The DOE/NETL ''Cost and Performance Baselines for Fossil Energy Plants'' are a series of studies conducted by NETL to establish estimates for the cost and performance of combustion and gasification based power plants with and without CO_2 capture and storage.[303] The studies evaluate numerous technology configurations utilizing different coal ranks and natural gas.

The EPA relied on those sources because the NETL studies are the most comprehensive and transparent of the available cost studies and NETL has a reputation in the power sector industry for producing high quality, reliable work.[304] The NETL studies were extensively peer reviewed.[305] The EPA Science Advisory Board Work Group considering the adequacy of the peer review noted the EPA staff's statement that ''the NETL studies were all peer reviewed under DOE peer review protocols'', further noted the EPA staff's statement that ''the different levels of review of these DOE documents met the requirements to support the analyses as defined by the EPA Peer Review Handbook,'' and concluded that ''peer review on the DOE documents'' was conducted ''at a level required by agency guidance.'' [306]

The cost estimates were indicated by DOE/NETL to carry an accuracy of −15 percent to +30 percent on the capital costs, consistent with a AACE Class 4 cost estimate—*i.e.,* a ''feasibility study'' level of design engineering.[307] The DOE/NETL further notes that ''The value of the study lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.'' [308]

For the final standard, the EPA made particular use of the most recent NETL cost estimates for post-combustion CCS, which reflect up-to-date vendor quotes and incorporate the post-combustion capture technology—the Shell Cansolv amine-based process—that is being utilized at the Boundary Dam Unit #3 facility.[309] The EPA used this latest version of the NETL studies not only to assure that it considers the most up-to-date information but also to address public comments criticizing the proposal for relying on out-of-date cost information.

b. Other Studies That Corroborate NETL Cost Estimates

A variety of government, industry and academic groups routinely conduct studies to estimate costs of new generating technologies. These studies use techno-economic models to predict the cost to build a new generating facility at some point in the future. These studies often use levelized cost of electricity (LCOE) to summarize costs and to compare the competiveness of the different generating technologies.

A variety of groups have recently published LCOE estimates for new dispatchable generating technologies. Those are shown below in Table 10. The table shows LCOE projections from the EPA's January 2014 proposal, from studies conducted by the Electric Power Research Institute (EPRI),[310] by the DOE's Energy Information Administration (EIA) in their 2015 Annual Energy Outlook (AEO 2015), by the DOE's National Energy Technology Laboratory (NETL), and by researchers from the Department of Engineering and Public Policy at the Carnegie Mellon University (CMU) in Pittsburgh, PA.

The Global CCS Institute [311] has recently published a report that examines costs of major low and zero emissions technologies currently available for power generation and compares the predicted LCOEs of those technologies. Importantly, the analysis presented in the report uses cost and performance data from several recent studies, and applies a common methodology and economic parameters to derive comparable lifetime costs. Analysis and findings in the paper reflect costs specific to the U.S.

The fact that these various groups have conducted independent studies and that the results of those independent studies are reasonably consistent with the estimates of DOE/NETL are further indications that the DOE/NETL cost estimates are reasonable.

[303] *http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.*

[304] The NETL costs and studies are often cited in academic and other publications.

[305] The initial NETL study ''Cost and Performance Baseline for Fossil Energy Plants, Vol. 1: Bituminous Coal and Natural Gas to Electricity'' (2006) was subject to peer review by industry experts, academia, and government research and regulatory agencies. Subsequent iterations of the study were not further peer reviewed because the modeling procedures used in the cost estimation were not revised.

[306] Letter from James Mihelcic, Chair, SAB Work Group on EPA Planned Actions for SAB Consideration of the Underlying Science to Members of the Chartered SAB and SAB Liaisons (page 3, Jan. 24, 2014). *http://yosemite.epa.gov/sab/sabproduct.nsf/F43D89070E89893485257C5A007AF573/$File/SAB+work+grp+memo+w+attach+20140107.pdf.* The SAB's statement that these guidance documents ''require'' any specific peer review is an overstatement, since guidance documents, by definition, do not mandate any specific course of action.

[307] Recommended Practice 18R–97 of the Association for the Advancement of Cost Engineering International (AACE) describes a Cost Estimate Classification System as applied in Engineering, Procurement and Construction for the process industries.

[308] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'' Rev 2a (Sept 2013); DOE/NETL–2010/1397, page 9.

[309] Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, July 6, 2015, DOE/NETL–2015/1723.

[310] EPRI is a non-profit organization, headquartered in Palo Alto, CA, that conducts research on issues related to the U.S. electric power industry (*www.epri.com*).

[311] *www.globalccsinstitute.com.*

TABLE 10—SELECTION OF LEVELIZED COST OF ELECTRICITY (LCOE) PROJECTIONS

New generation technology	Lazard[312] $2014/MWh	EPRI[313] $2011/MWh	AEO2015[314] $2013/MWh*	DOE/NETL[315] $2011/MWh*	CMU[316] $2010/MWh	GCCSI[317]** $2014/MWh
SCPC—no CCS	66	62–77	95	76–95	59	78
SCPC—full CCS	151	102–137	—	140–176	—	115–160
SCPC—16% CCS	—	—	—	92–117	—	—
Nuclear***	92–132	85–97	87–115	—	—	86–102
Biomass	87–116	90–155	94–113	—	—	123–137
IGCC	102	82–96	116	94–120	—	—
IGCC—full CCS	171	105–136	144	142–178	—	—
NGCC	61—87	33—65	73	58	63	60

* EIA, in cost projections for SCPC and IGCC with no CCS, includes a climate uncertainty adder (CUA), which is a 3-percentage point increase in the cost of capital. In contrast, DOE/NETL utilized conventional financing for cases without CCS and utilized high-risk financial assumptions for cases that include CCS.

** The Global CCS Institute provided range for coal with full CCS (shown as ''CCS(coal)'' in Figure 5.2 of the referenced report) reflects a combination of costs for both PC and IGCC coal plants.

*** EIA AEO assumes use of Westinghouse AP1000 technology. Other groups assume a wider range of technology options.

The LCOE values from the Lazard, EPRI, and NETL studies are presented as a range. The EPRI costs incorporate uncertainty reflecting the range of inputs (*i.e.,* capital costs, fuel costs, fixed and variable O&M, etc.). The NETL costs are indicated to carry an accuracy of −15 percent to + 30 percent, consistent with a ''feasibility study'' level of design. The range in Table 10 is the NETL projected costs with the −15 percent to +30 percent uncertainty on the capital costs. Overall, as can be seen from the results in Table 10, the range of LCOE estimates from the different groups are in reasonable agreement with the DOE/NETL estimates most often representing the most conservative of the estimates shown.

The EIA cost estimates include a climate uncertainty adder (CUA)—represented by a three percent increase to the weighted average cost of capital—to certain coal-fired capacity types. The EIA developed the CUA to address inconsistencies between power sector modeling absent GHG regulation and the widespread use of a cost of CO_2 emissions in power sector resource planning. The CUA reflects the additional planning cost typically assigned by project developers and utilities to GHG-intensive projects in a context of climate uncertainty. The EPA believes the CUA is consistent with the industry's planning and evaluation framework (demonstrable through IRPs and PUC orders) and is therefore pertinent when evaluating the cost competitiveness of alternative generating technologies. The EPA believes the CUA is relevant in considering the range of costs that power companies are willing to pay for generation alternatives to natural gas.

c. Industry Information That Corroborates NETL Cost Estimates

Information from vendors of CCS technology also supports the reliability of the cost estimates the EPA is using here.[318] Specifically, the EPA had conversations with representatives from Summit Carbon Capture, LLC regarding available cost information. Cost estimates provided by another leading provider of CCS technology likewise are consistent (indeed, somewhat less than) the estimates the EPA is using for purposes of cost analysis in the rule.

Summit Carbon Capture's primary business is large-scale carbon capture from power and other industrial projects and use of the captured CO_2 for EOR.[319] Summit is actively working with several different technology companies offering CO_2 capture systems, including the leading equipment manufacturers for fossil fuel power production equipment. Their current projects include the 400 MW IGCC Texas Clean Energy Project and the Caledonia Clean Energy Project—a new project underway in the United Kingdom—and a variety of other projects under development which are not yet public.

Summit is also interested in potentially retrofitting CCS onto existing coal-fired plants for the purpose of capturing CO_2 for sale to EOR markets. Summit provided the EPA with copies of slides from a presentation that it has used in different public forums.[320] The presentation focused on costs to retrofit available carbon capture equipment at an existing PC power plant that is ideally located to take advantage of opportunities to sell captured CO_2 for use in EOR operations. Summit received proprietary costing information from numerous technology providers and that information, along with other publically available information, was used to develop their cost predictions.[321] Though the primary focus of their effort was to examine costs associated with retrofitting CCS to an existing coal fired power plant, Summit Power also calculated costs for several new generation scenarios—including the cost of a new NGCC, a new SCPC, a new SCPC with full CCS, and a new SCPC with partial CCS at 50 percent. The costs are reasonably consistent with costs predicted by NETL, EIA, EPRI and others. The company ultimately concluded that ''in a world of uncertain gas prices, falling CO_2 capture

[312] Lazard's Levelized Cost of Energy Analysis—Version 8.0 (Sept 2014); available at *http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf* and in the rulemaking docket.

[313] ''Program on Technology Innovation: Integrated Generation Technology Options 2012; Report 1026656; Available at: *www.epri.com*.

[314] ''Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015'', Available at: *www.eia.gov/forecasts/aeo/electricity_generation.cfm*; the LCOE values displayed incorporate −10%/+30% for uncertainty for biomass and nuclear.

[315] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'' DOE/NETL–2015/1720 (June 22, 2015).

[316] CMU is Carnegie Mellon University; Zhai, H., Rubin, E.; ''Comparative Performance and Cost Assessments of Coal- and Natural Gas-Fired Power Plants under a CO_2 Emission Performance Standard Regulation'', *Energy & Fuels,* 2013, 27, 4290, Table 1.

[317] ''The Costs of CCS and other Low-Carbon Technologies—2015 update'' July 2015, Global CCS Institute, Available at: *http://hub.globalccsinstitute.com/sites/default/files/publications/195008/costs-ccs-other-low-carbon-technologies-2015-update.pdf.*

[318] See Section V.F above, explaining that the D.C. Circuit has repeatedly stated that vendor statements are probative in demonstrating that a technology is adequately demonstrated under section 111.

[319] *http://www.summitpower.com/projects/carbon-capture/*.

[320] ''Coal's Role in a Low Carbon Energy Environment'', presented at 2015 Euromoney Power & Renewables Conference, remarks by Jeffrey Brown (amended to address EPA questions on the original). Available in the rulemaking docket.

[321] No proprietary or business confidential information was shared with the EPA. No specific vendors were mentioned by name during discussions with Summit Power. Summit also used available DOE/NETL and EIA cost information.

equipment prices, improving CCS process efficiency, and possible compliance costs . . . existing coal plants retrofitted with available CCS equipment can be cost competitive with development of new NGCC generation.'' [322]

In June 2012, Alstom Power released a report entitled ''Cost assessment of fossil power plants equipped with CCS under typical scenarios''.[323] The study examined costs for a new coal-fired power plant implementing post-combustion CCS (full CCS) in Europe, in North America, and in Asia. The results for the North American case—along with similar cost estimates from Summit—are shown in Table 11 below. The DOE/NETL estimated costs are also included for comparison. The results show predicted costs for a new SCPC ranging from $53/MWh to $82/MWh and costs to implement full CCS ranging from $97/MWh to $143/MWh. Costs to implement varying levels of partial CCS are also provided for comparison. The industry cost estimates are on the lower end of the range of costs predicted from other techno-economic studies (see Table 11 below) and, like those economic studies, are affected by the specific assumptions. As with the techo-economic studies presented earlier in Table 10, there is relatively good agreement among these projected costs and the DOE/NETL costs. There is relatively good agreement in the incremental levelized cost to implement full CCS on the new SCPC units (ranging from 74 to 85 percent) and to implement 50 percent CCS on the new SCPC unit (from 41 to 45 percent increase). These industry estimates are also lower than the DOE/NETL estimates for both full and 50 percent partial CCS (with the incremental cost percentage for full CCS being almost identical), providing further support for the reasonableness of the EPA using the NETL cost estimates here.

TABLE 11—INDUSTRY LCOE ESTIMATES FOR IMPLEMENTATION OF POST-COMBUSTION CCS [324]

	Summit $/MWh	Alstom $/MWh*	DOE/NETL $/MWh
SCPC	64.5	52.6	82.3
SCPC + full CCS	117.6	97.4	152.4
Full CCS incremental cost, %	82.3%	85.0%	85.2%
SCPC + 50% CCS	91.1	—	123.6
50% CCS incremental cost, %	41.2%	—	50.1%
SCPC + 35% CCS	—	—	114.7
SCPC + 16% CCS	—	—	100.5
NGCC**	47.7	35.0	**52.0

* Costs are from Figure 2 in the referenced Alstom report (North American case); costs are presented as €/MWh in the report. The costs were converted to $/MWh assuming a conversion rate of 1 USD = 0.76 € (in 2012).

** NGCC cost is estimated by the EPA using NETL information. Assumed natural gas prices = Summit ($4/mmBtu); Astom ($3.9/mmBtu); EPA ($5.00/mmBtu).

The EPA notes that in its public comments, Alstom maintained that ''no CCS projects that would [sic] be considered cost competitive in today's energy economy.'' [325] As explained above, no steam electric EGU would be cost competitive even without CCS—and that is substantiated in the projected costs presented above in Table 11 where NGCC is consistently the most economic new generation option when compared to the other listed technologies. Alstom does not explain (or address) why the cost premium for partial CCS would be a decisive deterrent for capacity that would otherwise be constructed. More important, Alstom does not challenge the specific cost estimates used by the EPA at proposal, nor disavow its own estimates of CCS costs (which are even less) which it is publically disseminating in the marketplace. See also Section V.F.3 above, quoting Alstom's press release stating unequivocally that ''CCS works and is cost-effective''. The EPA reasonably is relying on the specific Alstom estimates which it is using for its own commercial purposes, and not on the generalized concerns presented in its public comments.

d. Use of Cost Information From EIA Annual Energy Outlook (AEO)

For the January 2014 proposal the EPA chose to rely on the EIA AEO 2013 cost projections for non-fossil based generation. The AEO presents long-term annual projections of energy supply, demand, and prices focused on U.S. energy markets. The predictions are based on results from EIA's National Energy Modeling System (NEMS). The AEO costs are updated annually, they are highly scrutinized, and they are widely used by those involved in the energy sector.

In the January 2014 proposal, the EPA presented LCOE costs for new non-fossil dispatchable generation (see 77 FR 1477, Table 7) from the AEO 2013. Those costs were updated as part of the AEO 2015 release. The estimated cost for all of these technologies decreased from AEO 2013 to AEO 2014 and AEO 2015. This was due to changes in the interest rates that resulted in lower financing costs relative to those used the AEO 2013.[326] The EIA commissioned a comprehensive update of its capital cost assumptions for all generation technologies in 2013. Fuel cost and

[322] Others have come to similar conclusions—that retrofit of CCS technology at existing coal-fired power plants can be feasible—*e.g.,* ''The results indicate that for about 60 gigawatts of the existing coal-fired capacity, the implementation of partial CO_2 capture appears feasible, though its cost is highly dependent on the unit characteristics and fuel prices.'' (Zhai, H.; Ou, Y.; Rubin, E.S.; ''Opportunities for Decarbonizing Existing U.S. Coal-fired Plants via CO_2 Capture, Utilization, and Storage'', accepted for publication in *Env. Sci & Tech.* (2015).

[323] Leandri, J., Skea, A., Bohtz, C., Heinz, G.; ''Cost assessment of fossil power plants equipped with CCS under typical scenarios'', Alstom Power, June 2012. Available in the rulemaking docket: EPA–HQ–OAR–2013–0495.

[324] Note that in other tables in this preamble, the EPA has presented LCOE values from the DOE/NETL work as a range in order to incorporate the uncertainty on the capital costs. The range is not present here for easy comparison with the industry costs which were not provided as a range. The full range of DOE/NETL costs for each of the cases presented can be found in Exhibit A–3 in ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015), p. 18.

[325] Alstom Comment p. 3 (Docket entry: EPA–HQ–OAR–2013–0495–9033). The comment also urged the EPA to evaluate costs without considering EOR opportunities (which in fact is our methodology, albeit a conservative one), and without considering possible subsidies. Id. The LCOE and capital cost estimates above are direct cost comparisons, again consistent with the commenter's position.

[326] *www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.*

financial assumptions are updated for each edition of the Annual Energy Outlook.

e. Accounting for Uncertainty of Projected Costs

As previously mentioned, the projected costs are dependent upon a range of assumptions including the projected capital costs, the cost of financing the project, the fixed and variable O&M costs, the projected fuel costs, and incorporation of any incentives such as tax credits or favorable financing that may be available to the project developer. There are also regional or geographic differences that affect the final cost of a project. The LCOE projections in this final action are not intended to provide an absolute cost for a new project using any of these respective technologies. Large construction projects—as these would be—would be subjected to detailed cost analyses that would take into consideration site-specific information and specific design details in order to determine the project costs.

The DOE/NETL noted that the cost estimates from their studies carry an accuracy in the range of −15 percent to +30 percent, which is consistent with a ''feasibility study'' level of design. They also noted that the value of the studies lies ''not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.''

The EIA AEO 2015 presented LCOE costs as a single point estimate representing average nationwide costs and separately as a range to represent the regional variation in costs. In order to compare the fossil fuel generation technologies from the NETL studies with the cost projections for non-fossil dispatchable technologies from EIA AEO 2015, we assume that the EIA studies would carry a similar level of uncertainty (*i.e.,* +30 percent) and we present the AEO 2015 projected costs as the average nationwide LCOE with a range of −10 percent to +30 percent to account for uncertainty.[327] The EIA does not provide uncertainty estimates in the AEO cost projections. However, nuclear experts from EIA staff have indicated to the EPA that a range of uncertainty of −10 percent to +30 percent on the capital component of the LCOE can be expected based on market uncertainties. Specifically, these staff experts expect that nuclear plants currently under construction would not have capital costs under estimates and that one could expect to see a 30 percent ''upside'' variation in capital cost. There is also insufficient market data to get a good statistical range of potential capital cost variation (*i.e.,* only two plants under construction, neither complete). This is reasonably consistent with estimates for nuclear costs estimated by Lazard (see Table 8 above) which likewise reflect a similar level of cost uncertainty. The Lazard nuclear costs show a range of projected levelized capital cost from $73/MWh to $110/MWh—a range of 50 percent, very similar to the 40 percent range (*i.e.,* −10 percent to +30 percent) suggested by EIA nuclear experts. The Global CCS Institute, in its most recent cost update, also provides nuclear costs as a range from $86/MWh to $102/MWh.[328]

3. Use of Costs From Current Projects

Although we are relying on cost estimates drawn from techno-economic models, we recognize that there are a few steam electric plants that include CCS that have been built, or are being constructed. Some information about the costs (or cost-to-date) for these projects is known. We discuss in this section the costs at facilities which have installed or are installing CCS, why the EPA does not consider those costs to be reasonably predictive of the costs of the next new plants to be built, and why the EPA considers that the next new plants will have lower costs along the lines predicted by NETL.[329]

The Boundary Dam Unit #3 facility utilizing post-combustion capture from Shell Cansolv is now operational. Petra Nova, a joint venture between NRG Energy Inc. and JX Nippon Oil & Gas Exploration, is currently constructing a post-combustion capture system at NRG's WA Parish generating station near Houston, TX. The post-combustion capture system will utilize MHI amine-based solvents and is currently being constructed with plans to initiate operation in 2016.[330]

Construction on Mississippi Power's Kemper County Energy Center IGCC facility is now nearly complete. The combined cycle portion of the facility has been generating power using natural gas. The gasification portion of the facility and the carbon capture system are undergoing system checks and training to enable commercial operations using a UOP Selexol™ pre-combustion capture system in early 2016.[331]

Another full-scale project, the Summit Power Texas Clean Energy Project has not commenced construction but remains a viable project. Several other full-scale projects have been proposed and have progressed through the early stages of design, but have been cancelled or postponed for a variety of reasons.

Some cost information is also available for small demonstration projects—including those that have been supported by USDOE research programs. These projects would include Alabama Power's demonstration project at Plant Barry and the AEP/Alstom demonstration at Plant Mountaineer.

Many commenters felt that the EPA should rely on those high costs when considering whether the costs are reasonable. The costs from these large-scale projects appear to be consistently higher than those projected by techno-economic models. However, the costs from these full-scale projects represent first-of-a-kind (FOAK) costs and, it is reasonable to expect these costs to come down to the level projected in the NETL and other techno-economic studies for the next new projects that are built—which are the sources that would be subject to this standard.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. A significant body of literature suggests

[327] EIA does not provided uncertainty estimates in the AEO cost projections. However, EIA staff have indicated to the EPA that a range of uncertainty of −10%/+30% on the capital component of the LCOE can be expected based on market uncertainties. See memorandum ''Range of uncertainty for AEO nuclear costs'' available in the rulemaking docket, EPA–HQ–OAR–2013–0495.

[328] ''The Costs of CCS and other Low-Carbon Technologies—2015 update'' July 2015, Global CCS Institute, Available at: *http://hub.globalccsinstitute.com/sites/default/files/publications/195008/costs-ccs-other-low-carbon-technologies-2015-update.pdf.*

[329] The EPA notes that two of these facilities, Kemper and TCEP, received both assistance from DOE under EPAct05 and the IRC section 48A tax credit; and that the AEP Mountaineer pilot project received assistance from DOE under EPAct05. Under the most extreme interpretations of those provisions offered by commenters, the EPA would be precluded from any consideration of any information from those sources, including cost information, in showing whether a system of emission reduction is adequately demonstrated. We note, however, that many of these same commenters urged consideration of the cost information from these sources. In fact, the EPA is not relying on information about the costs of these sources to determine the BSER or the standards of performance in this rulemaking, and the EPA is discussing the cost information here to explain why not. Accordingly, this discussion of cost information from these sources is not precluded by the EPAct05 and IRC section 48A provisions and, even if it is precluded, that would have no impact on the EPA's determination of the BSER and the standards of performance in this rule.

[330] *http://www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.*

[331] *http://www.mississippipower.com/about-energy/plants/kemper-county-energy-facility/facts.*

that the per-unit cost of producing or using a given technology declines as experience with that technology increases over time, and this has certainly been the case with air pollution control technologies. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, research and development investments, and other factors have been observed over the decades. We expect that the costs of capture technology will follow this pattern.

The NETL cost estimates reasonably account for this documented phenomenon. Specifically, ''[I]n all cases, the report intends to represent the next commercial offering, and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs (a challenge for emerging technologies).'' [332]

Commenters argued that the next plants to be built would still reflect first-of-a-kind costs, pointing to the newness of the technology and the lack of operating experience, *i.e.* the alleged absence of learning by doing. The EPA disagrees. In addition to operating experience from operating and partially constructed CCS projects, substantial research efforts are underway providing a further knowledge base to reduce CO_2 capture costs and to improve performance.

The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO_2 from fossil fuel energy plants compared to currently available capture technologies. The large-scale CO_2 capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will generate operational knowledge and enable continued commercialization and deployment of these technologies. Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2. The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO_2 capture. Most single component amine systems are not practical in a flue gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FG process, the process modeled in the NETL cost study for the SCPC cases, uses a monoethanolamine (MEA) formulation specially designed to recover CO_2 and contains a corrosion inhibitor that allows the use of less expensive, conventional materials of construction. Other commercially available processes use sterically hindered amine formulations (for example, the Mitsubishi Heavy Industries KS–1 solvent) which are less susceptible to degradation and corrosion issues.

The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO_2 capture performance and reduce costs.

As noted in Section V.H.7.d above, SaskPower has created the CCS Global Consortium to facilitate further knowledge regarding, and use of, carbon capture technology.[333] This consortium provides SaskPower the opportunity to share its knowledge and experience with global energy leaders, technology developers, and project developers. SaskPower, in partnership with Mitsubishi and Hitachi, is also helping to advance CCS knowledge and technology through the creation of the Shand Carbon Capture Test Facility (CCTF).[334] The test facility will provide technology developers with an opportunity to test new and emerging carbon capture systems for controlling carbon emissions from coal-fired power plants.

We also note certain features of the commercial plants already built that suggest that their costs are uniquely high, and otherwise not fairly comparable to the costs of plants meeting the NSPS using the BSER. Most obviously, many of these projects involve deeper capture than the partial CCS that the EPA assumes in this final action. In addition, cost overruns at the Kemper facility, mentioned repeatedly in the public comments, resulted in major part from highly idiosyncratic circumstances, and are related to the cost of the IGCC system, not to the cost of CCS.[335] The EPA does not believe that these unusual circumstances are a reasonable basis for assessing costs of either CCS or IGCC here.

4. Cost Competitiveness of New Coal Units

As the EPA noted, all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future. Although a small number of new coal-fired power plants have been built recently, the industry generally is not building these kinds of power plants at present and is not expected to do so for the foreseeable future. The reasons include the current economic environment and improved energy efficiency, which has led to lower electricity demand, and competitive current and projected natural gas prices. On average, the cost of generation from a new NGCC power plant is expected to be lower than the cost of generation from a new coal-fired power plant, and the EPA has concluded that, even in the absence of the requirements of this final rule, very few new coal-fired power plants will be built in the near term.

Some commenters, however, disagreed with this conclusion. They contended instead that it is the CCS-based NSPS that would preclude such new generation. However, as the EPA has discussed, there is considerable evidence that utilities and project developers are moving away—or have already moved away—from a long term dependence on coal-fired generating sources. A review of publicly available integrated resource plans show that many utilities are not considering construction of new coal-fired sources without CCS. See Section V. H.3 above. Few new coal-fired generating sources have commenced construction in the past 5 years and, of the projects that are currently in the development phase, the EPA is only aware of projects that will include CCS in the design. As we have noted in this preamble, the bulk of new

[332] ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 38.

[333] *http://www.saskpowerccs.com/consortium/*.

[334] *http://www.saskpowerccs.com/ccs-projects/shand-carbon-capture-test-facility/*.

[335] See Independent Monitor's Prudency Evaluation Report for the Kemper County IGCC Project (prepared for Mississippi Public Utilities Staff), available at *www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=328417* (''Report''). As documented in this Report, costs escalated significantly because the developers adopted a ''compressed schedule'' in an attempt to obtain the IRC 48A tax credit, resulting in ''engineering and design changes which are a normal result of detailed engineering and design . . . occurring at the same time as, rather than ahead of, construction activities'', which did not allow for proper sequencing during construction. This '' 'just-in-time' approach to engineering and procurement (meaning that the engineering was often completed shortly before material procurement and construction activities) resulted in a greater number of construction work-arounds, congestion of construction craft labor in the field, inefficiencies and additional steps that became necessary during construction to cope with this just-in-time engineering, procurement and construction approach.'' Report, p. 6. Ironically, work was still completed too late to obtain the tax credit. Id. p. 15.

generation that has been added recently has been either natural gas-fired or renewable sources. Overall, the EPA remains convinced that the energy sector modeling is reflecting the realities of the market in predicting very few new coal-fired power plants in the near future—even in the absence of these final standards.

In addition, we note that the Administration's CCS Task Force report recognized that CCS would not become more widely available without the advent of a regulatory framework that promoted CCS or provided a strong price signal for CO_2. In this regard, we note American Electric Power's statements regarding the need for federal requirement for GHG control to aid in cost recovery for CCS projects, to attract other investment partners, and thereby promote advancement and deployment of CCS technology: ''as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share''.[336] Indeed, AEP has stated that CCS is important for the very future of the industry: ''AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.'' [337] This final rule's action is an important component in developing that needed regulatory framework.

5. Accuracy of Cost Estimates for Transportation and Geologic Sequestration

The EPA's estimates of costs take into account the transport of CO_2 and sequestration of captured CO_2. Estimates of transport and sequestration costs—approximately $5–$15 per ton of CO_2—are based on DOE NETL studies and are also consistent with other published studies.[338] For transport, costs reflect pipeline capital costs, related capital expenditures, and O&M costs. Sequestration cost estimates reflect the cost of site screening and evaluation, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long term liability protection. These sequestration costs reflect the regulatory requirements of the Underground Injection Control Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations, which are discussed further in Sections V. M. and N below.[339]

Based on DOE/NETL studies, the EPA estimated that the total CO_2 transportation, storage, and monitoring (TSM) cost associated with EGU CCS would comprise less than 5.5 percent of the total cost of electricity in all capture cases modeled—approximately $5–$15 per ton of CO_2.[340] The range of TSM costs the EPA relied on are broadly consistent with estimates provided by the Global Carbon Capture and Storage Institute as well.[341] Some commenters suggested that the EPA underestimated the costs associated with transporting captured CO_2 from an EGU to a sequestration site.[342] Specifically, commenters suggested that the EPA's estimated costs for constructing pipelines were lower than costs based on actual industry experience. Commenters also opined that the EPA's assumed length of pipeline needed between the EGU and the sequestration site is not reasonable and that the DOE/NETL study upon which the EPA relied does not account for CO_2 transport costs when EOR is not available.

The EPA believes its estimates of transportation and sequestration costs are reasonable. First, the EPA in fact includes cost estimates for CO_2 transport when EOR opportunities are not available—consistent with its overall conservative cost methodology of assuming no revenues from sale of captured CO_2. Specifically, the EPA estimates transport, storage and monitoring (TSM) costs of $5–$15 per ton of CO_2 for non-EOR applications.[343] This estimate is reflected in the LCOE comparative costs.[344]

The EPA also carefully reviewed the assumptions on which the transport cost estimates are based and continues to find them reasonable. The NETL studies referenced in Section V.I.2 above based transport costs on a generic 100 km (62 mi) pipeline and a generic 80 kilometer pipeline.[345] At least one study estimated that of the 500 largest point sources of CO_2 in the United States, 95 percent are within 50 miles of a potential storage reservoir.[346] As a point of reference, the longest CO_2 pipeline in the United States is 502 miles.[347] For new sources, pipeline distance and costs can be factored into siting and, as discussed in Section V.M, there is widespread availability of geologic formations for geologic sequestration (GS). Moreover, data from the Pipeline and Hazardous Materials Safety Administration show that in 2013 there were 5,195 miles of CO_2 pipelines operating in the United States. This represents a seven percent increase in CO_2 pipeline miles over the previous year and a 38 percent increase in CO_2 pipeline miles since 2004. For the reasons outlined above, the EPA believes its estimates have a reasoned basis. See also Section V.M below further discussing the current availability of CO_2 pipelines.

With respect to sequestration, certain commenters argued that the EPA's cost analysis failed to account for many contingencies and uncertainties (surface and sub-surface property rights in particular), ignored the costs of GHGRP subpart RR, and also was not representative of the costs associated with specific GS site characterization, development, and operation/injection of monitoring wells. Commenter American Electric Power (AEP) referred to its own

336 *www.aep.com/newsroom/newsreleases/?id=1704.*

337 ''CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase 1'', prepared for The Global CCS Institute Project # PRO 004, January 23, 2012, page 2. Available at: *www.globalccsinstitute.com/publications/ccs-lessons-learned-report-american-electric-power-mountaineer-ccs-ii-project-phase-1*; See also AEP FEED Study at pp. 4, 63, Available at: *www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

338 *Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases* (DOE/NETL–341/082312); *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture* (DOE/NETL–2011/1498); *Cost and Performance Baseline for Fossil Energy Plants* (DOE/NETL–2010/1397); *Economic Evaluation of* CO_2 *Storage and Sink Enhancement Options, Tennessee Valley Authority, NETL and EPRI, December 2002; Carbon Dioxide and Transport and Storage Costs in NETL Studies* (DOE/NETL–2013/1614), March 2013; *Carbon Dioxide and Transport and Storage Costs in NETL Studies* (DOE/NETL–2014/1653), May 2014; *Cost and Performance Baseline for Fossil Energy Power Plants, Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity* (DOE–NETL–2015/1723), July 2015.

339 Carbon Dioxide and Transport and Storage Costs in NETL Studies. DOE/NETL–2013/1614. March 2013. P. 13.

340 RIA at section 5.5; proposed rule RIA at 5–30.

341 *http://hub.globalccsinstitute.com/sites/default/files/publications/12786/economic-assessment-carbon-capture-and-storage-technologies-2011-update.pdf.*

342 See, for example, comments from American Electric Power, pp 97–8 (Docket entry: EPA–HQ–OAR–2013–0495–10618), Southern Company, pp. 47–48 (Docket entry: EPA–HQ–OAR–2013–0495–10095), and Duke Energy p. 28 (Docket entry: EPA–HQ–OAR–2013–0495–9426).

343 See RIA at section 5.5 and proposed RIA at 5–30.

344 See RIA at section 5.5.

345 The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

346 JJ Dooley, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone (2006), Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change. Joint Global Change Research Institute, Battelle Pacific Northwest Division. PNWD–3602. College Park, MD.

347 A Review of the CO_2 Pipeline Infrastructure in the U.S., April 21, 2015, DOE/NETL–2014/1681, Office of Fossil Energy, National Energy Technology Laboratory.

experience with the Mountaineer demonstration project. AEP noted that although this project was not full scale, finding a suitable repository, notwithstanding a generally favorable geologic area, proved difficult. The company referred to its estimated cost of expanding the existing Mountaineer plant to a larger scale project, particularly the cost of site characterization and well construction.[348]

The EPA's cost estimates account for the requirements of the Underground Injection Control Class VI program, and GHGRP subpart RR, among them site screening and evaluation costs, costs for injection wells and equipment, O&M costs, and monitoring costs. The estimated sequestration costs include operational and post-injection site care monitoring, which are components of the UIC Class VI requirements, and also reflect costs for sub-surface pore volume property rights acquisition.[349] These estimates are consistent with the costs presented in the study *CO_2 Storage and Sink Enhancements: Developing Comparable Economics,* which incorporates the costs associated with site evaluation, well drilling, and the capital equipment required for transporting and injecting CO_2.[350 351] Monitoring costs were evaluated based on the methodology set forth in the International Energy Agency Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report.[352]

The EPA's cost estimates for sequestration thus cover all aspects commenters claimed the EPA disregarded. The EPA believes that the use of costs and scenarios presented in the studies referenced are representative for purposes of the cost analysis. The NETL cost estimates upon which the EPA's costs draw directly from the UIC Class VI economic impact analysis.[353] That analysis is based on estimated characteristics for a representative group of projects over a 50-year period of analysis, as well as industry averages for several cost components and sub-components. The EPA also made reasonable assumptions regarding the assumed injection site: A deep saline formation with typical characteristics (*e.g.,* representative depth and pressure).[354]

With respect to AEP's experience with the Mountaineer demonstration project, sequestration siting issues are of course site-specific, and raise individual issues. For this reason, it is inappropriate to generalize from a particular individual experience. In this regard, as explained in Section V.N below, the construction permits issued by the EPA to-date under the Underground Injection Control Class VI regulations required far fewer wells for site characterization and monitoring than AEP found to be necessary at its Mountaineer site. Moreover, notwithstanding difficulties, the company was able to successfully drill and complete wells, and safely inject captured CO_2. The company also indicated it fully expected to be able to do so at full scale and explained how.[355] For discussion of 40 CFR part 98, subpart RR (the GHGRP requirements for geologic sequestration), including costs associated with compliance with those requirements, see Section V.N below.

J. Achievability of the Final Standards

The EPA finds the final standard of 1,400 lb CO_2/MWh-g to be achievable over a wide range of variable conditions that are reasonably likely to occur when the system is properly designed and operated. As discussed elsewhere, the final standard reflects the degree of emission limitation achievable through the application of the BSER which we have determined to be a highly efficient SCPC implementing partial CCS at a level sufficient to achieve the final standard—for such a unit utilizing bituminous coal that would be approximately 16 percent. In determining the predicted cost and performance of such a system, the EPA utilized information contained in updated DOE/NETL studies that assumed use of bituminous coal and an 85 percent capacity factor. Here we examine the effects of deviating from those assumed operational parameters on the achievability of the final standard of performance.[356] This is in keeping with the requirement that a standard of performance must be achievable accounting for all normal operating variability when a control system is properly designed, maintained, and operated. See Section III.H.1.c above.

1. Operational Fluctuations, Start-Ups, Shutdowns, and Malfunctions

Importantly, compliance with the standard must be demonstrated over a 12-operating-month average. The total CO_2 emissions (pounds of CO_2) over 12 operational months are summed and divided by the total gross output (in megawatt-hours) over the same 12 operational months. Such a compliance averaging period is very forgiving of short-term excursions that can be associated with non-routine events such as start-ups, shutdowns, and malfunctions. A new fossil fuel-fired steam generating EGU—if constructed—would, most likely, be built to serve base load power demand and would not be expected to routinely start-up or shutdown or ramp its capacity factor in order to follow load demand. Thus, planned start-up and shutdown events would only be expected to occur a few times during the course of a 12-operating-month compliance period. Malfunctions are unplanned and unpredictable events and emission excursions can happen at or around the time of the equipment malfunction. But a malfunctioning EGU that cannot be operated properly should be shut down until the malfunctioning equipment can be addressed and the EGU can be restarted to operate properly.

The post-combustion capture systems that have been utilized have proven to be reliable. The Boundary Dam facility has been operating full CCS successfully at commercial scale since October 2014. As described earlier, in evaluating results from the Mountaineer slip-

[348] AEP Comments at pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[349] "Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.'' DOE/NETL–2011/1498 (September 2013) p. 49. Specifically, the report estimates the costs associated with acquiring rights to use the pore space in the geologic formation. Costs are estimated based on studies of subsurface rights acquisition for natural gas storage. The report also estimates costs for land acquisition for surface property rights. Id. p. 48.

[350] Bock, B., R. Rhudy, H. Herzog, M. Klett, J. Davidson, D.G. De La Torre Ugarte, and D. Simbeck. (2003). Economic Evaluation of CO_2 Storage and Sink Enhancement Options, Final Technical Report Prepared by Tennessee Valley Authority for DOE.

[351] As noted above, other sequestration-related costs are also estimated, including injection wells and equipment, pore volume acquisition, and long-term-liability. "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 2a, September 2013 DOE/NETL–2010/1397, p. 55.

[352] "Overview of Monitoring Requirements for Geologic Storage Projects'', IEA Greenhouse Gas R&D Programme, Report Number PH4/29, November 2004.

[353] Cost Analysis for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells, U.S. Environmental Protection Agency Office of Water, EPA 816–R10–013, November 2010, pages 3–1, 5–42.

[354] Economic Evaluation of CO_2 Storage and Sink Enhancement Options, Tennessee Valley Authority, NETL and EPRI, December 2002.

[355] See "CCS front end engineering & design report: American Electric Power Mountaineer CCS II Project. Phase 1'' at pp. 36–43. The company likewise explained the monitoring regime it would utilize to verify containment, and the well construction it would utilize to guarantee secure sequestration. Id. at pp. 44–54. Available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report.*

[356] Additional information can be found in a Technical Support Document (TSD)—"Achievability of the Standard for Newly Constructed Steam Generating EGUs'' available in the rulemaking docket.

stream demonstration, AEP and Alstom reported robust steady-state operation during all modes of power plant operation including load changes, and saw an availability of the CCS system of greater than 90 percent.[357]

2. Variations in Coal Type

The use of specific coal types can affect the amount of CO_2 that is emitted from a new coal-fired power plant. As previously discussed, the EPA utilized studies by the DOE/NETL to predict the cost and performance of new steam generating units. Based on those reports, the EPA predicts that a new SCPC burning low rank coal (subbituminous coal or dried lignite) would have an uncontrolled emission rate about 7 percent higher than a similar unit firing typical bituminous coal.[358] The EPA predicts that such a highly efficient new SCPC utilizing subbituminous coal or dried lignite would need to capture approximately 23 percent of the CO_2. The EPA also believes that it is technically feasible to do so, although additional cost would be entailed. The EPA has evaluated those costs and finds them to remain reasonable.[359] As shown in Table 8 above, the predicted cost remains within the estimated range for the other principal base load, dispatchable non-NGCC alternative technologies. Estimated capital cost using these coal types would also be somewhat higher, an estimated 23 percent increase.[360] The EPA finds these increases to be reasonable because, as discussed earlier, the costs are reasonably consistent with capital cost increases in previous NSPS. See Section V.H.4 above.

K. Emission Reductions Utilizing Partial CCS

Although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources and the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must do so. See *Sierra Club* v. *Costle,* 657 F.2d at 326 (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[361] This is consistent with the Court's statements in *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 437 that it is necessary to ''[k]eep[] in mind Congress' intent that new plants be controlled to the 'maximum practicable degree' ''.

The final standard of performance will result in meaningful and significant emission reductions of GHG emissions from a new coal-fired steam generating unit. The EPA estimates that a new highly efficient 500 MW coal-fired SCPC meeting the final standard of 1,400 lb CO_2/MWh-g will emit about 354,000 fewer metric tons of CO_2 each year than that new highly efficient unit would have emitted otherwise. That is equivalent to taking about 75,000 vehicles off the road each year[362] and will result in over 14,000,000 fewer metric tons of CO_2 in a 40-year operating life. To emphasize the importance of constructing a highly efficient SCPC unit that includes partial CCS—the highly efficient 500 MW coal-fired SCPC with partial CCS would emit about 675,000 fewer metric tons of CO_2 each year than that from a new, less efficient coal-fired utility boiler with an assumed emission of 1,800 lb CO_2/MWh-g.

For comparison, see Table 12 below which provides the amount of CO_2 emissions captured each year by other CCS projects. These result show that, even though the emission reductions are significant, they are reasonably within the range of emission reductions that are currently being achieved now in existing facilities. For comparison, approximately 60,000,000 metric tons of CO_2 were supplied to U.S. EOR operations in 2013.[363]

TABLE 12—ANNUAL METRIC TONS OF CO_2 CAPTURED (OR PREDICTED TO CAPTURE) FROM CCS PROJECTS AND FROM A MODEL 500 MW PLANT MEETING THE FINAL STANDARD.

Project	CO_2 captured tonnes/year
AES Shady Point	66,000
AES Warrior Run	110,000
Southern Company Plant Barry	165,000
Searles Valley Minerals	270,000
New 500 MW SCPC EGU (1,400 lb CO_2/MWh-g)	354,000
Coffeyville Fertilizer	700,000
Boundary Dam #3	1,000,000
Petra Nova/NRG WA Parish	1,400,000
Dakota Gasification	3,000,000

[357] *http://www.alstom.com/press-centre/2011/5/alstom-announces-sucessful-results-of-mountaineer-carbon-capture-and-sequestration-ccs-project/*. The Boundary Dam facility likewise is operating reliably (see Section V.D.3.a above). See also ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3'', DOE/NETL–2015/1723 (July 2015) at p. 36 (''[t]he capture and CO_2 compression technologies have commercial operating experience with demonstrated ability for high reliability'').

[358] For additional detail, see the Technical Support Document (TSD)—''Achievability of the Standard for Newly Constructed Steam Generating EGUs''—available in the rulemaking docket.

[359] The cost of the lignite drying equipment is assumed to be low compared to the cost of the carbon capture equipment. Further, pre-drying of the lignite reduces fuel, auxiliary power consumption and other O&M costs. *www.iea-coal.org.uk/documents/83436/9095/Techno-economics-of-modern-pre-drying-technologies-for-lignite-fired-power-plants,-CCC/241*.

[360] Note that the 23 percent increase in expected capital costs and the 23 percent CO_2 capture needed to meet the final standard are coincidental and are not correlated.

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

[362] Using U.S. EPA Office of Transportation and Air Quality (OTAQ) estimate of average vehicle emissions of 4.7 tonnes/year.

[363] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

L. Further Development and Deployment of CCS Technology

Researchers at Carnegie Mellon University (CMU) have studied the history and the technological response to environmental regulations.[364] By examining U.S. research funding and patenting activity over the past century, the CMU researchers found that promulgation of national policy requiring large reductions in power-plant emissions resulted in a significant upswing in inventive activity to develop technologies to reduce those emissions. The researchers found that, following the 1970 Clean Air Act, there was a 10-fold increase in patenting activity directed at improving the SO_2 scrubbers that were needed to comply with stringent federal and state-level standards.

Much like carbon capture scrubbers today, the technology to capture and remove SO_2 from power plant flue gases was new to the industry and was not yet widely deployed at large coal-burning plants when the EPA first promulgated the 1971 standards.

Many of the early Flue Gas Desulfurization (FGD) units did not perform well, as the technology at that time was poorly understood and there was little or no prior experience on coal-fired power plants. In contrast, amine-based capture systems have a much longer history of reliable use at coal-fired plants and other industrial sources. There is also a better understanding of the amine process chemistry and overall process design—and project developers have much sophisticated analytical tools available today than in the 1970s during the development of FGD scrubber technologies.

While R&D efforts were essential to achieving improvements in FGD scrubber technology—and are also very important to improving carbon capture technologies, the influence of regulatory actions that establish commercial markets for advanced technologies cannot be minimized. The existence of national government regulation for SO_2 emissions control stimulated innovation, as shown by the patent analysis following initial SO_2 regulatory requirements for EGU emissions. The study author further found that regulatory stringency appears to be particularly important as a driver of innovation, both in terms of inventive activity and in terms of the communication processes involved in knowledge transfer and diffusion. Further, as electric power generation doubled, the operating and maintenance costs of FGD systems decline to 83 percent of their original level. This finding, which is very much in line with progress ratios determined in other industries, shows that quantifiable technological improvements can be shown to occur solely on the basis of the experience of operating an environmental control technology forced into being by government actions.

M. Technical and Geographic Aspects of Disposition of Captured CO_2

In the following sections of the preamble, we discuss issues associated with the disposition of captured CO_2: the ‘‘S’’—sequestration—in CCS. In this section, we review the existing processes, technologies, and geologic conditions that enable successful geologic sequestration (GS). In Section V.N., we discuss in detail the comprehensive, in-place regulatory structure that is currently available to oversee GS projects and assure their safety and effectiveness. Together, these discussions demonstrate that the technical feasibility of GS, another key component of a partial CCS unit, is adequately demonstrated. Sequestration is already well proven. CO_2 has been retained underground for eons in geologic (natural) repositories and the mechanisms by which CO_2 is trapped underground are well understood. The physical and chemical trapping mechanisms, along with the regulatory requirements and safeguards of the Underground Injection Control Program and complementary monitoring and reporting requirements of the GHGRP, together ensure that sequestered CO_2 will remain secure and provide the monitoring to identify and address potential leakage using Safe Drinking Water Act (SDWA) and CAA authorities (see Section V.N of this preamble).[365]

1. Geologic and Geographic Considerations for GS

Geologic sequestration (*i.e.,* long-term containment of a CO_2 stream in subsurface geologic formations) is technically feasible and available throughout most of the United States. GS is based on a demonstrated understanding of the processes that affect CO_2 fate in the subsurface; these processes can vary regionally as the subsurface geology changes. GS occurs through a combination of mechanisms including: (1) Structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).[366] These mechanisms are functions of the physical and chemical properties of CO_2 and the geologic formations into which the CO_2 stream is injected. Subsurface formations suitable for GS of CO_2 captured from affected EGUs are geographically widespread throughout most parts of the United States.

Storage security is expected to increase over time through post-closure, resulting in a decrease in potential risks.[367] This expectation is based in part on a technical understanding of the variety of trapping mechanisms that work to reduce CO_2 mobility over time.[368] In addition, site characterization, site operations, and monitoring strategies can work in combination to promote storage security.

[364] See Technical Support Document/Memorandum ‘‘History Of Flue Gas Desulfurization in the United States’’ (July 11, 2015) summarizing the doctoral dissertation of Margaret R. Taylor, ‘‘The Influence of Government Actions on Innovative Activities in the Development of Environmental Technologies to Control Sulfur Dioxide Emissions from Stationary Sources,’’ MA dissertation submitted to the Carnegie Institute of Technology, Carnegie Mellon University in partial fulfillment of the requirements for the degree of Doctor of Philosophy in Engineering and Public Policy, Pittsburgh, PA, January 2001.

[365] See also *Carbon Sequestration Council and Southern Company Services* v. *EPA,* No. 14–1406 (D.C. Cir. June 2, 2015) at *10 (‘‘[c]arbon capture and storage is an emerging climate change mitigation program that involves capturing carbon dioxide from industrial sources, compressing it into a ‘supercritical fluid,’ and injecting that fluid underground for the purposes of geologic sequestration, with the goal of preventing the carbon from reentering the atmosphere. Because the last of these steps—geologic sequestration of the supercritical carbon dioxide—involves that injection of fluid into underground wells, it is subject to regulation under the Safe Drinking Water Act’’).

[366] See, *e.g.,* USEPA. 2008. Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide.

[367] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 47.

[368] See, *e.g.,* Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

The effectiveness of long-term trapping of CO_2 has been demonstrated by natural analogs in a range of geologic settings where CO_2 has remained trapped for millions of years.[369] For example, CO_2 has been trapped for more than 65 million years in the Jackson Dome, located near Jackson, Mississippi.[370] Other examples of natural CO_2 sources include Bravo Dome and McElmo Dome in Colorado and New Mexico, respectively. These natural storage sites are themselves capable of holding volumes of CO_2 that are larger than the volume of CO_2 expected to be captured from a fossil fuel-fired EGU. In 2010, the Department of Energy (DOE) estimated current CO_2 reserves of 594 million metric tons at Jackson Dome, 424 million metric tons at Bravo Dome, and 530 million metric tons at McElmo Dome.[371]

GS is feasible in different types of geologic formations including deep saline formations (formations with high salinity formation fluids) or in oil and gas formations, such as where injected CO_2 increases oil production efficiency through a process referred to as enhanced oil recovery (EOR). Both deep saline and oil and gas formation types are widely available in the United States. The geographic availability of deep saline formations and EOR is shown in Figure 1 below.[372] As shown in the figure, there are 39 states for which onshore and offshore deep saline formation storage capacity has been identified.[373] EOR operations are currently being conducted in 12 states. An additional 17 states have geology that is amenable to EOR operations. Figure 1 also shows areas that are within 100 kilometers (62 miles) of where storage capacity has been identified.[374] There are 10 states with operating CO_2 pipelines and 18 states that are within 100 kilometers (62 miles) of an active EOR location.

CO_2 may also be used for other types of enhanced recovery, such as for natural gas production. Reservoirs such as unmineable coal seams also offer the potential for geologic storage.[375] Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively ''locks'' the CO_2 to the coal, where it remains stored. DOE has identified over 54 billion metric tons of potential CO_2 storage capacity in unmineable coal across 21 states.[376] The availability of unmineable coal seams is shown in Figure 1 below.

As discussed below in Section M.7, a few states do not have geologic conditions suitable for GS, or may not be located in proximity to these areas. However, in some cases, demand in those states can be served by coal-fired power plants located in areas suitable for GS, and in other cases, coal-fired power plants are unlikely to be built in those areas for other reasons, such as the lack of available coal or state law prohibitions and restrictions against coal-fired power plants.[377]

[369] Holloway, S., J. Pearce, V. Hards, T. Ohsumi, and J. Gale. 2007. Natural Emissions of CO_2 from the Geosphere and their Bearing on the Geological Storage of Carbon Dioxide. Energy 32: 1194–1201.

[370] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[371] DiPietro, P., Balash, P. & M. Wallace. A Note on Sources of CO_2 Supply for Enhanced-Oil Recovery Operations. SPE Economics & Management. April 2012.

[372] A color version of the figure, which readers may find easier to view, can be found in the technical support document on geographic availability in the rulemaking docket.

[373] Alaska is not shown in Figure 1; it has deep saline formation storage capacity, geology amenable to EOR operations, and potential GS capacity in unmineable coal seams.

[374] The distance of 100 kilometers reflects assumptions in DOE–NETL cost estimates which the EPA used for cost estimation purposes. See ''Carbon Dioxide and Transport and Storage Costs in NETL Studies'', DOE/NETL–2014/1653 (May 2014).

[375] Other types of opportunities include organic shales and basalt.

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

[377] Similarly, as discussed below, the U.S. territories lack available coal, do not currently have coal-fired power plants, and, as a result, are not expected to see new coal-fired power plants. Hawaii is not expected to constructed new coal plants as it intends to utilize 100 percent renewable energy sources by 2050.

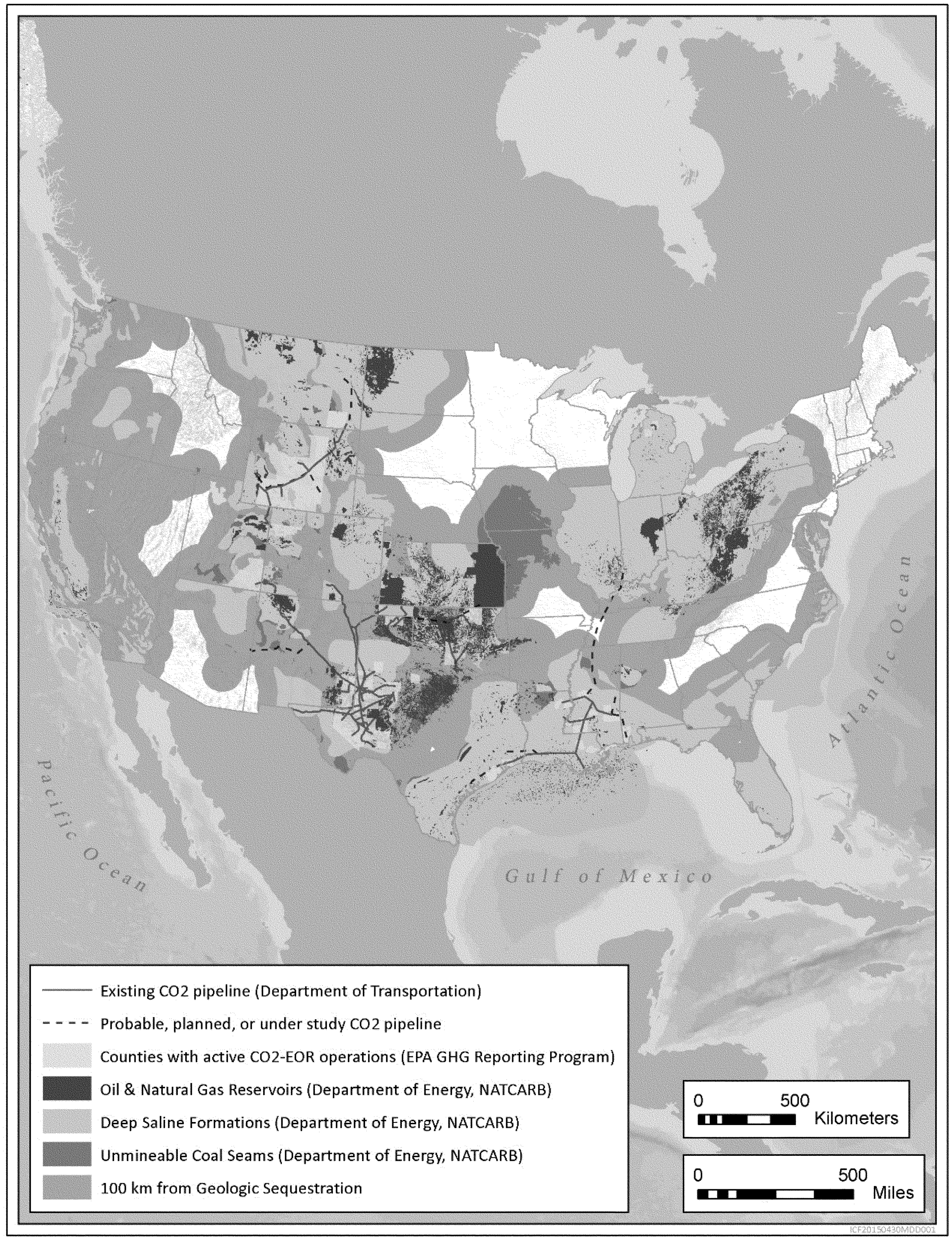

Figure 1: Geologic Sequestration in the Continental United States

Figure 2 – Electrical Transmission Lines across the Continental United States[378]

2. Availability of Geologic Sequestration in Deep Saline Formations

The DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration capacity of deep saline formations in the United States. DOE estimates are compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) using volumetric models and published in a Carbon Utilization and Storage Atlas.[379] DOE estimates that areas of the United States

[378] Ventyx Velocity Suite Online. April 2015.

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

with appropriate geology have a sequestration potential of at least 2,035 billion metric tons of CO_2 in deep saline formations. According to DOE and as noted above, at least 39 states have geologic characteristics that are amenable to deep saline GS in either onshore or offshore locations. In 2013, the USGS completed its evaluation of the technically accessible GS resources for CO_2 in U.S. onshore areas and state waters using probabilistic assessment.[380] The USGS estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential, including saline and oil and gas reservoirs, across the basins studied in the United States.

The DOE has created a network of seven Regional Carbon Sequestration Partnerships (RCSPs) to deploy large-scale field projects in different geologic settings across the country to demonstrate that GS can be achieved safely, permanently, and economically at large scales. Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-fired CO_2 emissions, 97 percent of industrial CO_2 emissions, 96 percent of the total land mass, and essentially all the geologic sequestration sites in the United States potentially available for GS.[381] The seven partnerships include more than 400 organizations spanning 43 states (and four Canadian provinces).[382] RCSP project objectives are to inject at least one million metric tons of CO_2. In April 2015, DOE announced that CCS projects supported by the department have safely and permanently stored 10 million metric tons of CO_2.[383]

Eight RCSP ''Development Phase'' projects have been initiated and five of the eight projects are injecting or have completed CO_2 injection into deep saline formations. Three of these projects have already injected more than one million metric tons each, and one, the Cranfield Site, injected over eight million metric tons of CO_2 between 2009 and 2013.[384] Various types of technologies for monitoring CO_2 in the subsurface and air have been employed at these projects, such as seismic methods (crosswell seismic, 3–D and 4–D seismic, and vertical seismic profiling), atmospheric CO_2 monitoring, soil gas sampling, well and formation pressure monitoring, and surface and ground water monitoring.[385] No CO_2 leakage has been reported from these sites, which further supports the availability of effective GS.

3. Availability of CO_2 Storage via EOR

Although the determination that the BSER is adequately demonstrated and the regulatory impact analysis for this rule relies on GS in deep saline formations, the EPA also recognizes the potential for securely sequestering CO_2 via EOR.

EOR is a technique that is used to increase the production of oil. Approaches used for EOR include steam injection, injection of specific fluids such as surfactants and polymers, and gas injection including nitrogen and CO_2. EOR using CO_2, sometimes referred to as ''CO_2 flooding'' or CO_2-EOR, involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil to make it more amenable for recovery. The crude oil and CO_2 mixture is then recovered and sent to a separator where the crude oil is separated from the gaseous hydrocarbons, native formation fluids, and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, purified to remove hydrocarbons, re-compressed, and re-injected into the reservoir to further enhance oil recovery. Not all of the CO_2 injected into the oil reservoir is recovered and re-injected. As the CO_2 moves from the injection point to the production well, some of the CO_2 becomes trapped in the small pores of the rock, or is dissolved in the oil and water that is not recovered. The CO_2 that remains in the reservoir is not mobile and becomes sequestered.

The amount of CO_2 used in an EOR project depends on the volume and injectivity of the reservoir that is being flooded and the length of time the EOR project has been in operation. Initially, all of the injected CO_2 is newly received. As discussed above, as the project matures, some CO_2 is recovered with the oil and the recovered CO_2 is separated from the oil and recycled so that it can be re-injected into the reservoir in addition to new CO_2 that is received. If an EOR operator will not require the full volume of CO_2 available from an EGU, the EGU has other options such as sending the CO_2 to other EOR operators, or sending it to deep saline formation GS facilities.

CO_2 used for EOR may come from anthropogenic or natural sources. The source of the CO_2 does not impact the effectiveness of the EOR operation. CO_2 capture, treatment and processing steps provide a concentrated stream of CO_2 in order to meet the needs of the intended end use. CO_2 pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO_2 and take into account CO_2 composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications related to the composition of the CO_2 stream. The regulatory requirements and company specifications ensure EOR operators receive a known and consistent CO_2 stream.

EOR has been successfully used at numerous production fields throughout the United States to increase oil recovery. The oil industry in the United States has over 40 years of experience with EOR. An oil industry study in 2014 identified more than 125 EOR projects in 98 fields in the United States.[386] More than half of the projects evaluated in the study have been in operation for more than 10 years, and many have been in operation for more than 30 years. This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure GS (see Section N below) that can be used for deployment of CCS across geographically diverse areas.

Currently, 12 states have active EOR operations and most have developed an extensive CO_2 infrastructure, including pipelines, to support the continued operation and growth of EOR. An additional 18 states are within 100 kilometers (62 miles) of current EOR operations. See Figure 1 above. The vast majority of EOR is conducted in oil reservoirs in the Permian Basin, which extends through southwest Texas and southeast New Mexico. States where EOR is utilized include Alabama, Colorado, Louisiana, Michigan,

[380] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, p. 41, *http://pubs.usgs.gov/circ/1386/*.

[381] *http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/regional-partnerships*.

[382] *http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/regional-partnerships*.

[383] *http://energy.gov/articles/milestone-energy-department-projects-safely-and-permanently-store-10-million-metric-tons*.

[384] U.S. Department of Energy, National Energy Technology Laboratory, Project Facts, Southeast Regional Carbon Sequestration Partnership—Development Phase, Cranfield Site and Citronelle Site Projects, NT42590, October 2013. Available at: *http://www.netl.doe.gov/publications/factsheets/project/NT42590.pdf*.

[385] A description of the types of monitoring technologies employed at RCSP projects can be found here: *http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/regional-partnership-development-phase-iii*.

[386] Koottungal, Leena, 2014, 2014 Worldwide EOR Survey, Oil & Gas Journal, Volume 112, Issue 4, April 7, 2014 (corrected tables appear in Volume 112, Issue 5, May 5, 2014).

Mississippi, New Mexico, Oklahoma, Texas, Utah, and Wyoming. Several commenters raised concerns about the volume of CO_2 used in EOR projects relative to the scale of EGU emissions and the demand for CO_2 for EOR projects. At the project level, the volume of CO_2 already injected for EOR and the duration of operations are of similar magnitude to the duration and volume of CO_2 expected to be captured from fossil fuel-fired EGUs. The volume of CO_2 used in EOR operations can be large (*e.g.,* 55 million tons of CO_2 were stored in the SACROC unit in the Permian Basin over 35 years), and operations at a single oil field may last for decades, injecting into multiple parts of the field.[387] According to data reported to the EPA's GHGRP, approximately 60 million metric tons of CO_2 were supplied to EOR in the United States in 2013.[388] Approximately 70 percent of this total CO_2 supplied was produced from natural (geologic) CO_2 sources and approximately 30 percent was captured from anthropogenic sources.[389]

A DOE-sponsored study has analyzed the geographic availability of applying EOR in 11 major oil producing regions of the United States and found that there is an opportunity to significantly increase the application of EOR to areas outside of current operations.[390] DOE-sponsored geologic and engineering analyses show that expanding EOR operations into areas additional to the capacity already identified and applying new methods and techniques over the next 20 years could utilize 18 billion metric tons of anthropogenic CO_2 and increase total oil production by 67 billion barrels. The study found that one of the limitations to expanding CO_2 use in EOR is the lack of availability of CO_2 in areas where reservoirs are most amenable to CO_2 flooding.[391] DOE's Carbon Utilization and Storage Atlas identifies 29 states with oil reservoirs amenable to EOR, 12 of which currently have active EOR operations. A comparison of the current states with EOR operations and the states with potential for EOR shows that an opportunity exists to expand the use of EOR to regions outside of current areas. The availability of anthropogenic CO_2 in areas outside of current sources could drive new EOR projects by making more CO_2 locally available.

Some commenters raised concerns that data are extremely limited on the extent to which EOR operations permanently sequester CO_2, and the efficacy of long term storage, or that the EOR industry does not have the requisite experience with and technical knowledge of long-term CO_2 sequestration. The EPA disagrees with these commenters. Several EOR sites, which have been operated for years to decades, have been studied to evaluate the viability of safe and secure long-term sequestration of injected CO_2. Examples are identified below.

CO_2 has been injected in the SACROC Unit in the Permian basin since 1972 for EOR purposes. One study evaluated a portion of this project, and estimated that the injection operations resulted in final sequestration of about 55 million tons of CO_2.[392] This study used modeling and simulations, along with collection and analysis of seismic surveys, and well logging data, to evaluate the ongoing and potential CO_2 trapping occurring through various mechanisms. The monitoring at this site demonstrated that CO_2 can become trapped in geologic formations. In a separate study in the SACROC Unit, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO_2 leakage in the shallow freshwater aquifers. No evidence of leakage was detected.[393]

The International Energy Agency Greenhouse Gas Programme conducted an extensive monitoring program at the Weyburn oil field in Saskatchewan between 2000 and 2010 (the site receiving CO_2 captured by the Dakota Gasification synfuel plant discussed in Section V.E.2.a above). During that time over 16 million metric tons of CO_2 were safely sequestered as evidenced by soil gas surveys, shallow groundwater monitoring, seismic surveys and wellbore integrity testing. An extensive shallow groundwater monitoring program revealed no significant changes in water chemistry that could be attributed to CO_2 storage operations.[394] The International Energy Agency Greenhouse Gas Programme developed a best practices manual for CO_2 monitoring at EOR sites based on the comprehensive analysis of surface and subsurface monitoring methods applied over the 10 years.[395]

The Texas Bureau of Economic Geology also has been testing a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi (see Section L.1 above).[396] As part of a DOE Southeast Regional Carbon Sequestration Partnership study, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year. Texas Bureau of Economic Geology is currently evaluating the results of several monitoring techniques employed at the Cranfield project and preliminary findings indicate no impact to groundwater.[397] The project also demonstrates the availability and effectiveness of many different monitoring techniques for tracking CO_2 underground and detecting CO_2 leakage to ensure CO_2 remains safely sequestered.

As discussed in Section M.1 above and as shown in Figure 1, the United States has widespread potential for storage, including in deep saline formations and oil and gas formations. However, some commenters maintained that the EPA's information regarding availability of GS sites is overly general and ignores important individual considerations. A number of commenters, for example, maintained that site conditions often make monitoring difficult or impossible, so

[387] Han, Weon S., McPherson, B J., Lichtner, P C., and Wang, F P. ''Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection.'' American Journal of Science 310. (2010): 282–324.

[388] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[389] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[390] ''Improving Domestic Energy Security and Lowering CO_2 Emissions with ''Next Generation'' CO_2-Enhanced Oil Recovery'', Advanced Resources International, Inc. (ARI), 2011. Available at: *http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=df02ffba-6b4b-4721-a7b4-04a505a19185.*

[391] ''Improving Domestic Energy Security and Lowering CO_2 Emissions with ''Next Generation'' CO_2-Enhanced Oil Recovery'', Advanced Resources International, Inc. (ARI), 2011. Available at: *http://www.netl.doe.gov/research/energy-analysis/publications/details?pub=df02ffba-6b4b-4721-a7b4-04a505a19185.*

[392] Han, Weon S., McPherson, B J., Lichtner, P C., and Wang, F P. ''Evaluation of CO_2 trapping mechanisms at the SACROC northern platform, Permian basin, Texas, site of 35 years of CO_2 injection.'' American Journal of Science 310. (2010): 282–324.

[393] Romanak, K.D., Smyth, R.C., Yang, C., and Hovorka, S., Detection of anthropogenic CO_2 in dilute groundwater: field observations and geochemical modeling of the Dockum aquifer at the SACROC oilfield, West Texas, USA: presented at the 9th Annual Conference on Carbon Capture & Sequestration, Pittsburgh, PA, May 10–13, 2010. GCCC Digital Publication Series #10–06.

[394] Roston, B., and S. Whittaker (2010), 10+ years of the IEA–GHG Weyburn-Midale CO_2 monitoring and storage project; success and lessons learned from multiple hydrogeological investigations, to be published in Energy Procedia, Elsevier, Proceedings of 10th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Amsterdam, The Netherlands.

[395] Hitchon, B. (Editor), 2012, Best Practices for Validating CO_2 Geological Storage: Geoscience Publishing, p. 353.

[396] *http://www.beg.utexas.edu/gccc/cranfield.php.*

[397] *http://www.beg.utexas.edu/gccc/cranfield.php.*

that sites are not available as a practical matter.[398] Commenter American Electric Power pointed to its own experience in siting monitoring wells for its pilot plant Mountaineer CCS project, which involved protracted time and expense to eventually site monitoring wells.[399] Other commenters noted significant geographic disparity in GS site availability, claiming absence of sites in southeastern areas of the country.[400]

Project- and site-specific factors do influence where CO_2 can be safely sequestered. However, as outlined above, there is widespread potential for GS in the United States. If an area does not have a suitable GS site, EGUs can either transport CO_2 to GS sites via CO_2 pipelines (see Section M.5 below), or they may choose to locate their units closer to GS sites and provide electric power to customers through transmission lines (see Figure 2 and Section M.7). In addition, there are alternative means of complying with the final standards of performance that do not necessitate use of partial CCS, so any siting difficulties based on lack of a CO_2 repository would be obviated. See *Portland Cement Ass'n* v. *EPA,* 665 F. 3d 177, 191 (D.C. Cir. 2011), holding that the EPA could adopt section 111 standards of performance based on the performance of a kiln type that kilns of older design would have great difficulty satisfying, since, among other things, there were alternative methods of compliance available should a new kiln of this older design be built.

4. Alternatives to Geologic Sequestration

Potential alternatives to sequestering CO_2 in geologic formations are emerging. These relatively new potential alternatives may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. PCC is produced through a chemical reaction process that utilizes calcium oxide (quicklime), water, and CO_2. Likewise, the combination of magnesium oxide and CO_2 results in a precipitation reaction where the CO_2 becomes mineralized. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. These carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products, including sodium carbonate, sodium bicarbonate, hydrochloric acid and bleach.[401]

A few commenters suggested that CO_2 utilization technologies alternative to GS are being commercialized, and that these should be included as compliance options for this rule. The rule generally requires that captured CO_2 be either injected on-site for geologic sequestration or transferred offsite to a facility reporting under 40 CFR subpart RR. The EPA does not believe that the emerging technologies just discussed are sufficiently advanced to unqualifiedly structure this final rule to allow for their use. Nor are there plenary systems of regulatory control and GHG reporting for these approaches, as there are for geologic sequestration. Nonetheless, as stated above, these technologies not only show promise, but could potentially be demonstrated to show permanent storage of CO_2.

In the January 2014 proposal, the EPA noted that it would need to adopt a mechanism to evaluate these alternative technologies before any could be used in lieu of geologic sequestration. 79 FR at 1484. The EPA is establishing such a mechanism in this final rule. See § 60.5555(g). The rule provides for a case-by-case adjudication by the EPA of applications seeking to demonstrate to the EPA that a non-geologic sequestration technology would result in permanent confinement of captured CO_2 from an affected EGU. The criteria to be addressed in the application, and evaluated by the EPA, are drawn from CAA section 111(j), which provides an analogous mechanism for case-by-case approval of innovative technological systems of continuous emission reduction which have not been adequately demonstrated. Applicants would need to demonstrate that the proposed technology would operate effectively, and that captured CO_2 would be permanently stored. Applicants must also demonstrate that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare or safety. In evaluating applications, the EPA may conduct tests itself or require the applicant to conduct testing in support of its application. Any application would be publicly noticed, and the EPA would solicit comment on the application and on intended action the EPA might take. The EPA could also provide a conditional approval of an application on operating results from a proscribed period. The EPA could also terminate an approval, including a termination based on operating results calling into question a technology's effectiveness.

As noted at proposal, given the unlikelihood of new coal-fired EGUs being constructed, the EPA does not expect there to be many (if any) applications for use of non-geologic sequestration technology. 79 FR at 1484.

5. Availability of Existing or Planned CO_2 Pipelines

CO_2 pipelines are the most economical and efficient method of transporting large quantities of CO_2.[402] CO_2 has been transported via pipelines in the United States for nearly 40 years. Over this time, the design, construction, operation, and safety requirements for CO_2 pipelines have been proven, and the U.S. CO_2 pipeline network has been safely used and expanded. The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported that in 2013 there were 5,195 miles of CO_2 pipelines operating in the United States. This represents a seven percent increase in CO_2 pipeline miles over the previous year and a 38 percent increase in CO_2 pipeline miles since 2004.[403]

Some commenters argued that the existing CO_2 pipeline capacity is not adequate and that CO_2 pipelines are not available in a majority of the United States.

The EPA does not agree. The CO_2 pipeline network in the United States has almost doubled in the past ten years in order to meet growing demands for CO_2 for EOR. CO_2 transport companies have recently proposed initiatives to expand the CO_2 pipeline network. Several hundred miles of dedicated CO_2 pipeline are under construction, planned, or proposed, including

[398] Comments of Southern Co., p. 38 (Docket entry: EPA–HQ–OAR–2013–0495–10095).

[399] Comments of AEP pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[400] Comments of Duke Energy, pp. 24–5 Docket entry: EPA–HQ–OAR–2013–0495–9426); UARG, pp. 53, 57 (Docket entry: EPA–HQ–OAR–2013–0495–9666) citing Cichanowicz (2012).

[401] *http://skyonic.com/technologies/skymine.*

[402] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 36.

[403] ''Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems'', U.S. Pipeline and Hazardous Materials Safety Administration, March 2, 2015. Available at: *http://www.phmsa.dot.gov/pipeline/library/data-stats.*

projects in Colorado, Louisiana, Montana, New Mexico, Texas, and Wyoming.

Examples are identified below.

Kinder Morgan has reported several proposed pipeline projects including the proposed expansion of the existing Cortez CO_2 pipeline, crossing Colorado, New Mexico, and Texas, to increase the CO_2 transport capacity from 1.35 billion cubic feet per day (Bcf/d) to 1.7 Bcf/d, to support the expansion of CO_2 production capacity at the McElmo Dome production facility in Colorado. The Cortez pipeline expansion is expected to be placed into service in 2015.[404]

Denbury reported that the company utilized approximately 70 million cubic feet per day of anthropogenic CO_2 in 2013 and that an additional approximately 115 million cubic feet per day of anthropogenic CO_2 may be utilized in the future from currently planned or future construction of facilities and associated pipelines in the Gulf Coast region.[405] Denbury also initiated transport of CO_2 from a Wyoming natural gas processing plant in 2013 and reported transporting approximately 22 million cubic feet per day of CO_2 in 2013 from that plant alone.[406]

Denbury completed the final section of the 325-mile Green Pipeline for transporting CO_2 from Donaldsonville, Louisiana, to EOR oil fields in Texas.[407] Denbury completed construction and commenced operation of the 232-mile Greencore Pipeline in 2013; the Greencore pipeline transports CO_2 to EOR fields in Wyoming and Montana.[408]

A project being constructed by NRG and JX Nippon Oil & Gas Exploration (Petra Nova) would capture CO_2 from a power plant in Fort Bend County, Texas for transport to EOR sites in Jackson County, Texas through an 82-mile CO_2 pipeline.[409] The project is anticipated to commence operation in 2016.[410]

Some commenters suggested that there may be challenges associated with the safety of transporting supercritical CO_2 over long distances, or that the EPA did not adequately consider the potential non-air environmental impacts of the construction of CO_2 pipelines.

The EPA has carefully evaluated the safety of pipelines used to transport captured CO_2 and determined that pipelines can indeed convey captured CO_2 to sequestration sites with certainty and provide full protection of human health and the environment. 76 FR at 48082–83 (Aug. 8, 2011); 79 FR 352, 354 (Jan. 3, 2014). Existing and new CO_2 pipelines are comprehensively regulated by the Department of Transportation's Pipeline Hazardous Material Safety Administration. The regulations govern pipeline design, construction, operation and maintenance, and emergency response planning. See generally 49 CFR 195.2. Additional regulations address pipeline integrity management by requiring heightened scrutiny to assure the quality of pipeline integrity in areas with a higher potential for adverse consequences. See 49 CFR 195.450 and 195.452. On-site pipelines are not subject to the Department of Transportation standards, but rather adhere to the Pressure Piping standards of the American Society of Mechanical Engineers (ASME B31), which the EPA has found would ensure that piping and associated equipment meet certain quality and safety criteria sufficient to prevent releases of CO_2, such that certain additional requirements were not necessary (See 79 FR 358–59 (Jan. 3, 2014)).[411] These existing controls over CO_2 pipelines assure protective management, guard against releases, and assure that captured CO_2 will be securely conveyed to a sequestration site.

6. States With Emission Standards That Would Require CCS

Several states have established emission performance standards or other measures to limit emissions of GHGs from new EGUs that are comparable to or more stringent than the final standard in this rulemaking. For example, in September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in base load generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing base load generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO_2/MWh.

In May 2007, Washington Governor Gregoire signed Substitute Senate Bill 6001, which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any base load electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Base load generation facilities must initially comply with an emission limit of 1,100 lb CO_2/MWh.

In July 2009, Oregon Governor Kulongoski signed Senate Bill 101, which mandated that facilities generating base load electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO_2/MWh, and prohibited utilities from entering into long-term purchase agreements for base load electricity with out-of-state facilities that do not meet that standard.

In 2012 New York established emission standards of CO_2 at 925 lb CO_2/MWh for new and expanded base load fossil fuel-fired plants.

In May 2007, Montana Governor Schweitzer signed House Bill 25, adopting a CO_2 emissions performance standard for EGUs in the state. House Bill 25 prohibits the state Public Utility Commission from approving new EGUs primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and sequestered.

On January 12, 2009, Illinois Governor Blagojevich signed Senate Bill 1987, the Clean Coal Portfolio Standard Law. The legislation establishes emission standards for new power plants that use coal as their primary feedstock. From 2009–2015, new coal-fueled power plants must capture and store 50 percent of the carbon emissions that the facility would otherwise emit; from 2016–2017, 70 percent must be captured and stored; and after 2017, 90 percent must be captured and stored.

7. Coal-by-Wire

In addition, as discussed in the proposal, electricity demand in states

[404] ''Form 10–K: Annual Report Pursuant to Section 13 or 15(d) of the Security and Exchange Act of 1934, For the Fiscal Year Ended December 31, 2014'', Kinder Morgan, February 2015. Available at: *http://ir.kindermorgan.com/sites/kindermorgan.investorhq.businesswire.com/files/report/additional/KMI–2014–10K_Final.pdf.*

[405] ''2013 Annual Report'', Denbury, April 2014. Available at *http://www.denbury.com/files/doc_financials/2013/Denbury_Final_040814.pdf.*

[406] ''CO_2 Sources'', Denbury, 2015. Available at: *http://www.denbury.com/operations/rocky-mountain-region/co2-sources-and-pipelines/default.aspx.*

[407] *http://www.denbury.com/operations/gulf-coast-region/Pipelines/default.aspx.*

[408] ''CO_2 Pipelines'', Denbury, 2014. Available at: *http://www.denbury.com/operations/rocky-mountain-region/COsub2-sub-Pipelines/default.aspx.*

[409] ''The West Ranch CO_2-EOR Project, NRG Fact Sheet'', NRG, 2014. Available at: *www.nrg.com/documents/business/pla-2014-west-ranch-fact-sheet.pdf.*

[410] ''WA Parish Carbon Capture Project'', NRG, 2015. Available at: *www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.*

[411] See the B31 Code for pressure piping, developed by the American Society of Mechanical Engineers, Pipeline Transportation Systems for liquid hydrocarbons and other liquids.

that may not have geologic sequestration sites may be served by coal-fired electricity generation built in nearby areas with geologic sequestration, and this electricity can be delivered through transmission lines. This method, known as ''coal-by-wire,'' has long been used in the electricity sector because siting a coal-fired power plant near the coal mine and transmitting the generation long distances to the load area is generally less expensive than siting the plant near the load area and shipping the coal long distances.

For example, we noted in the proposal that there are many examples where coal-fired power generated in one state is used to supply electricity in other states. In the proposal we specifically noted that historically nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah and Idaho Power, which serves customers in Idaho and Eastern Oregon, meets its demand in part from coal-fired power plants located in Wyoming and Nevada. 79 FR at 1478.

In the Technical Support Document on Geographic Availability (Geographic Availability TSD), we explore in greater detail the issue of coal-by-wire and the ability of demand in areas without geologic sequestration to be served by coal generation located in areas that have access to geologic sequestration. Figure 1 of this preamble (a color version of which is provided as Figure 1 of the Geographic Availability TSD) depicts areas of the country with: (1) existing CO_2 pipeline; (2) probable, planned, or under study CO_2 pipeline; (3) counties with active CO_2-EOR operations; (4) oil and natural gas reservoirs; (5) deep saline formations; (6) unmineable coal seams; and (7) areas 100 kilometers from geologic sequestration. As demonstrated by Figure 1, the vast majority of the country has existing or planned CO_2 pipeline, active CO_2-EOR operations, the necessary geology for CO_2 storage, or is within 100 kilometers of areas with geologic sequestration.[412] A review of Figure 1 indicates limited areas that do not fall into these categories.

As an initial matter, we note that the data included in Figure 1 is a conservative outlook of potential areas available for the development of CO_2 storage in that we include only areas that have been assessed to date. Portions of the United States—such as the State of Minnesota—have not yet been assessed and thus are depicted as not having geological formations suitable for CO_2 storage, even though assessment could in fact reveal additional formations.[413]

As one considers the areas on the map depicted in Figure 1 that fall outside of the above enumerated categories, in many instances, we find areas with low population density, areas that are already served by transmission lines that could deliver coal-by-wire, and/or areas that have made policy or other decisions not to pursue a resource mix that includes coal. In many of these areas, utilities, electric cooperatives, and municipalities have a history of joint ownership of coal-fired generation outside the region or contracting with coal and other generation in outside areas to meet their demand. Some of the relevant areas are in RTOs[414] which engage in planning across the RTO, balancing supply and demand in real time throughout the RTO. Accordingly, generating resources in one part of the RTO such as a coal generator can serve load in other parts of the RTO, as well as load outside of the RTO. As we consider each of these geographic areas in the Geographic Availability TSD, we make key points as to why this final rule does not negatively impact the ability of these regions to access new coal generation to the extent that coal is needed to supply demand and/or those regions want to include new coal-fired generation in their resource mix.

N. Final Requirements for Disposition of Captured CO_2

This section discusses the different regulatory components, already in place, that assure the safety and effectiveness of GS. This section, by demonstrating that GS is already covered by an effective regulatory structure, complements the analysis of the technical feasibility of GS contained in Sec. V.M. Together, these sections affirm that the technical feasibility of GS is adequately demonstrated.

In 2010, the EPA finalized an effective and coherent regulatory framework to ensure the long-term, secure and safe storage of large volumes of CO_2. The EPA developed these Underground Injection Control (UIC) Class VI well regulations under authority of the Safe Drinking Water Act (SDWA) to facilitate injection of CO_2 for GS, while protecting human health and the environment by ensuring the protection of underground sources of drinking water (USDWs). The Class VI regulations are built upon 35 years of federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The EPA and states have decades of UIC experience with the Class II program, which provides a regulatory framework for the protection of USDWs for CO_2 injected for purposes of EOR.

In addition, to complement both the Class VI and Class II rules, the EPA used CAA authority to develop air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration through the GHGRP. Information collected under the GHGRP provides a transparent means for the EPA and the public to continue to evaluate the effectiveness of GS.

As explained below, these requirements help ensure that sequestered CO_2 will remain in place, and, using SDWA and CAA authorities, provide the monitoring mechanisms to identify and address potential leakage. We note the near consensus in the public responses to the Class VI rulemaking that saline and oil and gas reservoirs provide ready means for secure GS of CO_2.[415]

1. Requirements for UIC Class VI and Class II Wells

Under SDWA, the EPA developed the UIC Program to regulate the underground injection of fluids in a manner that ensures protection of USDWs. UIC regulations establish six different well classes that manage a range of injectates (*e.g.,* industrial and municipal wastes; fluids associated with oil and gas activities; solution mining fluids; and CO_2 for geologic sequestration) and which accommodate varying geologic, hydrogeological, and other conditions. The standards apply to injection into any type of formation that meets the rule's rigorous criteria, and so apply not only to injection into deep

[412] The NETL cost estimates for CO_2 transport assume a pipeline of 100 kilometers. NETL (2015) at p. 44.

[413] The data in Figure 1 is based on estimates compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) and published in the United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition. As discussed in the TSD, deep saline formation potential was not assessed for Alaska, Connecticut, Hawaii, Massachusetts, Nevada, Rhode Island, and Vermont. Oil and gas storage potential was not assessed for Alaska, Washington, Nevada, and Oregon. Unmineable coal seams were not assessed for Nevada, Oregon, California, Idaho, and New York. We are assuming for purposes of our analysis here that they do not have storage potential in those formations.

[414] In this discussion, we use the term RTO to indicate both ISOs and RTOs.

[415] In that rulemaking, we stated that ''most commenters encouraged the EPA not to automatically exclude any potential injection formations for GS at this stage of deployment.'' We added that commenters suggested, in particular, ''that there is sufficient technical basis and scientific evidence to allow GS in depleted oil and gas reservoirs and in saline formations, noting that there is consensus on how to inject into these formation types.'' 75 FR at 77252 (Dec. 10, 2010).

saline formations, but also can apply to injection into unmineable coal seams and other formations. See 75 FR 77256 (Dec. 10, 2010).

The EPA's UIC regulations define the term USDWs to include current and future sources of drinking water and aquifers that contain a sufficient quantity of ground water to supply a public water system, where formation fluids either are currently being used for human consumption or that contain less than 10,000 ppm total dissolved solids.[416] UIC requirements have been in place for over three decades and have been used by the EPA and states to manage hundreds of thousands of injection wells nationwide.

a. Class VI Requirements

In 2010, the EPA established a new class of well, Class VI. Class VI wells are used to inject CO_2 into the subsurface for the purpose of long-term sequestration. See 75 FR 77230 (Dec. 10, 2010). This rule accounts for the unique nature of CO_2 injection for large-scale GS. Specifically, the EPA addressed the unique characteristics of CO_2 injection for GS including the large CO_2 injection volumes anticipated at GS projects, relative buoyancy of CO_2, its mobility within subsurface geologic formations, and its corrosivity in the presence of water. The UIC Class VI rule was developed to facilitate GS and ensure protection of USDWs from the particular risks that may be posed by large scale CO_2 injection for purposes of long-term GS. The Class VI rule establishes technical requirements for the permitting, geologic site characterization, area of review (*i.e.,* the project area) and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, site closure, and financial responsibility for the purpose of protecting USDWs.[417] Notably:

Site characterization includes assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of a proposed GS site to ensure that Class VI wells are sited in appropriate locations and CO_2 streams are injected into suitable formations with a confining zone or zones free of transmissive faults or fractures to ensure USDW protection.[418] [419] Site characterization is designed to eliminate unacceptable sites that may pose risks to USDWs. Generally, injection of CO_2 for GS should occur beneath the lowermost formation containing a USDW.[420] To increase the availability of Class VI sites in geographic areas with very deep USDWs, waivers from the injection depth requirements may be sought where owners or operators can demonstrate USDW protection.[421]

Owners or operators of Class VI wells must delineate the project area of review using computational modeling that accounts for the physical and chemical properties of the injected CO_2 and displaced fluids and is based on an iterative process of available site characterization, monitoring, and operational data.[422] Within the area of review, owners or operators must identify and evaluate all artificial penetrations to identify those that need corrective action to prevent the movement of CO_2 or other fluids into or between USDWs.[423] [424] Due to the potentially large size of the area of review for Class VI wells, corrective actions may be conducted on a phased basis during the lifetime of the project.[425] Periodic reevaluation of the area of review is required and enables owners or operators to incorporate previously collected monitoring and operational data to verify that the CO_2 plume and the associated area of elevated pressure are moving as predicted within the subsurface.[426]

Well construction must use materials that can withstand contact with CO_2 over the operational and post-injection life of the project.[427] These requirements address the unique physical characteristics of CO_2, including its buoyancy relative to other fluids in the subsurface and its potential corrosivity in the presence of water.

Requirements for operation of Class VI injection wells account for the unique conditions that will occur during large-scale GS including buoyancy, corrosivity, and high sustained pressures over long periods of operation.[428] [429]

Owners or operators of Class VI wells must develop and implement a comprehensive testing and monitoring plan for their projects that includes injectate analysis, mechanical integrity testing, corrosion monitoring, ground water and geochemical monitoring, pressure fall-off testing, CO_2 plume and pressure front monitoring and tracking, and, at the discretion of the Class VI director, surface air and/or soil gas monitoring.[430] Owners and operators must periodically review the testing and monitoring plan to incorporate operational and monitoring data and the most recent area of review reevaluation.[431] Robust monitoring of the CO_2 stream, injection pressures, integrity of the injection well, ground water quality and geochemistry, and monitoring of the CO_2 plume and position of the pressure front throughout injection will ensure protection of USDWs from endangerment, preserve water quality, and allow for timely detection of any leakage of CO_2 or displaced formation fluids.

Although subsurface monitoring is the primary and effective means of determining if there are any risks to a USDW, the Class VI rule also authorizes the UIC Program Director to require surface air and/or soil gas monitoring on a site-specific basis. For example, the Class VI Director may require surface air/soil gas monitoring of the flux of CO_2 out of the subsurface, with elevation of CO_2 levels above background serving as

[416] 40 CFR 144.3.

[417] The Class VI rule rests on a robust technical and scientific foundation, reflecting scientific oversight and peer review. In developing these Class VI rules, the EPA engaged with the SAB, providing detailed information on key issues relating to geologic sequestration—including monitoring schemes; methods to predict and verify capacity, injectivity, and effectiveness of subsurface CO_2 storage; and characterization and management of risks associated with plume migration and pressure increases in the subsurface. See: *http://yosemite.epa.gov/sab/sabproduct.nsf/0/AD09B42B75D9E36D85257704004882CF?OpenDocument.* In addition, the EPA developed a peer reviewed Vulnerability Evaluation Framework, which served as a technical support document for both the Class VI and Subpart RR rules. See: *http://www.epa.gov/climatechange/Downloads/ghgemissions/VEF-Technical_Document_072408.pdf.* In the section 111(b) rulemaking here, the SAB Work Group, in a letter endorsed by the full SAB Committee, found that ''while the scientific and technical basis for carbon storage provisions is new and emerging science, the agency is using the best available science and has conducted peer review at a level required by agency guidance.'' Memorandum of Jan. 7, 2014, from SAB Work Group Chair to Members of the Chartered SAB and SAB Liaisons, p. 3. The letter was subsequently endorsed by the full SAB. Work Group Letter of Jan. 24, 2014, as edited by the full Committee.

[418] 75 FR 77240 and 75 FR 77247 (December 10, 2010).

[419] 40 CFR 146.82 and 146.83. Comments indicating that EPA rules have not considered issues of exposure pathways such as abandoned wells or formation fissures are mistaken. (See, *e.g.,* Comments of UARG, p. 52 (Docket entry: EPA–HQ–OAR–2013–0495–9666).)

[420] 40 CFR 146.81(d).

[421] 40 CFR 146.95.

[422] 40 CFR 146.84(a).

[423] 40 CFR 146.84(c)(1)(3) and 146.90(d)(1).

[424] 40 CFR 146.81(d) and 146.84.

[425] 40 CFR 146.84(b)(2)(iv).

[426] 40 CFR 146.84(e)(1).

[427] 40 CFR 146.86(b).

[428] 75 FR 77250–52 (December 10, 2010); see also id. at 77234–35. Commenters were mistaken in asserting (without reference to Class VI provisions) that the EPA had ignored issues relating to CO_2 properties when injected in large volumes in supercritical state into geologic formations.

[429] 40 CFR 146.88.

[430] 40 CFR 146.90.

[431] 40 CFR 146.90(j).

an indicator of potential leakage and USDW endangerment.[432]

Class VI well owners or operators must develop and update a site-specific, comprehensive emergency and remedial response plan that describes actions to be taken (*e.g.,* cease injection) to address potential events that may cause endangerment to a USDW during the construction, operation, and post-injection site care periods of the project.[433]

Financial responsibility demonstrations are required to ensure that funds will be available for all area of review corrective action, injection well plugging, post-injection site care, site closure, and emergency and remedial response.[434]

Following cessation of injection, the operator must conduct comprehensive post-injection site care activities to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither poses an endangerment to USDWs.[435] The injection well also must be plugged, and following a demonstration of non-endangerment of USDWs by the Class VI owner or operator, the site must be closed.[436 437] The default duration for the post-injection site care period is 50 years, with flexibility for demonstrating that an alternative period is appropriate if it ensures non-endangerment of USDWs.[438] Following successful closure, the facility property deed must record that the underlying land is used for GS.[439]

The EPA has completed technical guidance documents on Class VI well site characterization, area of review and corrective action, well testing and monitoring, project plan development, well construction, and financial responsibility.[440 441 442 443 444 445] The EPA has also issued guidance documents on transitioning Class II wells to Class VI wells; well plugging, post-injection site care, and site closure; and recordkeeping, reporting, and data management.[446 447 448 449]

To inform the development of the UIC Class VI rule, the EPA solicited stakeholder input and reviewed ongoing domestic and international GS research, demonstration, and deployment projects. The EPA also leveraged injection experience of the UIC Program, such as injection via Class II wells for EOR. A description of the work conducted by the EPA in support of the UIC Class VI rule can be found in the preamble for the final rule (see 75 FR 77230 and 77237–240(December 10, 2010)).

The EPA has issued Class VI permits for six wells under two projects. In September 2014, a UIC Class VI injection well permit (to construct) was issued by the EPA to Archer Daniels Midland for an ethanol facility in Decatur, Illinois. The goal of the project is to demonstrate the ability of the Mount Simon geologic formation, a deep saline formation, to accept and retain industrial scale volumes of CO_2 for permanent GS. The permitted well has a projected operational period of five years, during which time 5.5 million metric tons of CO_2 will be injected into an area of review with a radius of approximately 2 miles.[450] Following the operational period, Archer Daniels Midland plans a post-injection site care period of ten years.[451] In September 2014, the EPA also issued four Class VI injection well permits (to construct) to the FutureGen Industrial Alliance project in Jacksonville, Illinois, which proposed to capture CO_2 emissions from a coal-fired power plant in Meredosia, Illinois and transport the CO_2 by pipeline approximately 30 miles to the deep saline GS site.[452] The Alliance proposed to inject a total of 22 million metric tons of CO_2 into an area of review with a radius of approximately 24 miles over the 20-year life of the project, with a post-injection site care period of fifty years.[453]

Both permit applicants addressed siting and operational aspects of GS (including issues relating to volumes of the CO_2 and nature of the CO_2 injectate), and included monitoring that helps provide assurance that CO_2 will not migrate to shallower formations. The permits were based on findings that regional and local features at the site allow the site to receive injected CO_2 in specified amounts without buildup of pressure which would create faults or fractures, and further, that monitoring provides early warning of any changes to groundwater or CO_2 leakage.[454]

The permitting of these projects illustrates that permit applicants were able to address perceived challenges to issuance of Class VI permits. These permits demonstrate that these projects are capable of safely and securely sequestering large volumes of CO_2—including from steam generating units—for long-term storage since the EPA would not otherwise have issued the permits.

b. Class II Requirements

As explained in Section M.3 above, CO_2 has been injected into the subsurface via injection wells for EOR, boosting production efficiency by re-pressurizing oil and gas reservoirs and increasing the mobility of oil. There are decades of industry experience in operating EOR projects. The CO_2 injection wells used for EOR are regulated through the UIC Class II program.[455] CO_2 storage associated with Class II wells is a common occurrence and CO_2 can be safely stored where injected through Class II-permitted wells for the purpose of enhanced oil or gas-related recovery.

UIC Class II regulations issued under section 1421 of SDWA provide minimum federal requirements for site characterization, area of review, well construction (*e.g.,* casing and cementing), well operation (*e.g.,* injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational

[432] 40 CFR 146.90(h)(1) and 75 FR at 77259 (Dec. 10, 2010).

[433] 40 CFR 146.94.

[434] 40 CFR 146.85.

[435] 40 CFR 146.93.

[436] 40 CFR 146.92.

[437] 40 CFR 146.93.

[438] 40 CFR 146.93(b).

[439] 40 CFR 146.93(c).

[440] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13004.pdf.*

[441] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13005.pdf.*

[442] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r13001.pdf.*

[443] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r11017.pdf.*

[444] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816r11020.pdf.*

[445] *http://water.epa.gov/type/groundwater/uic/class6/upload/uicfinancialresponsibilityguidancefinal072011v.pdf.*

[446] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13004.pdf.* See also 40 CFR 144.19 and ''Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil Recovery or Gas Recovery Wells to Class VI'', April 23, 2015, Available at: *http://water.epa.gov/type/groundwater/uic/class6/upload/class2eorclass6memo.pdf.*

[447] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13005.pdf.*

[448] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13001.pdf.*

[449] *http://water.epa.gov/type/groundwater/uic/class6/upload/epa816p13002.pdf.*

[450] *http://www.epa.gov/region5/water/uic/adm/.* In addition, Archer Daniels Midland received a UIC Class VI injection well permit for a second well in December 2014. Archer Daniels Midland had been injecting CO_2 at this well since 2011 under a UIC Class I permit issued by the Illinois EPA.

[451] *http://www.epa.gov/region5/water/uic/adm/.*

[452] After permit issuance, and for reasons unrelated to the permitting proceeding, DOE initiated a structured closeout of federal support for the FutureGen project in February 2015. However, these are still active Class VI permits.

[453] *http://www.epa.gov/r5water/uic/futuregen/.*

[454] *http://www.epa.gov/r5water/uic/futuregen/; http://www.epa.gov/region5/water/uic/adm/.*

[455] 40 CFR 144.6(b).

conditions that could lead to loss of injectate and migration into USDWs.

Section 1425 of SDWA allows states to demonstrate that their program is effective in preventing endangerment of USDWs. These programs must include permitting, inspection, monitoring, record-keeping, and reporting components.

2. Relevant Requirements of the GHGRP

The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the United States. The final rules under 40 CFR part 60 specifically require that if an affected EGU captures CO_2 to meet the applicable emissions limit, the EGU must report in accordance with 40 CFR part 98, subpart PP (Suppliers of Carbon Dioxide) and the captured CO_2 must be injected at a facility or facilities that reports in accordance with 40 CFR part 98, subpart RR (Geologic Sequestration of Carbon Dioxide). See § 60.5555(f). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting.

Specifically, subpart PP provides requirements to account for CO_2 supplied to the economy. This subpart requires affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied to the economy.[456] CO_2 suppliers are required to report the annual quantity of CO_2 transferred offsite and its end use, including GS.[457]

This rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) the electronic GHG Reporting Tool identification (e–GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e–GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR.[458]

As noted, this final rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emissions limit must transfer the captured CO_2 to a facility that reports under GHGRP subpart RR. In order to provide clarity on this requirement, the EPA reworded the proposed language under § 60.5555(f) to use the phrase ''If your affected unit captures CO_2'' in place of the phrase ''If your affected unit employs geologic sequestration''. This revision is not a change from the EPA's initial intent.

Reporting under subpart RR is required for all facilities that have received a Class VI UIC permit for injection of CO_2.[459] Subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the mass of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities.[460] [461] [462] [463] Although deep subsurface monitoring is the primary and effective means of determining if there are any leaks to a USDW, the monitoring employed under a subpart RR MRV Plan can be utilized, if required by the UIC Program Director, to further ensure protection of USDWs.[464] The subpart RR MRV plan includes five major components:

A delineation of monitoring areas based on the CO_2 plume location. Monitoring may be phased in over time.[465]

An identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways. The monitoring program will be designed to address the risks identified.[466]

A strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs. Multiple monitoring methods and accounting techniques can be used to address changes in plume size and risks over time.[467]

An approach for establishing the expected baselines for monitoring CO_2 surface leakage. Baseline data represent pre-injection site conditions and are used to identify potential anomalies in monitoring data.[468]

A summary of considerations made to calculate site-specific variables for the mass balance equation. Site-specific variables may include calculating CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment, and considerations for calculating CO_2 from produced fluids.[469]

Subpart RR provides a nationally consistent mass balance framework for reporting the mass of CO_2 that is sequestered. Certain monitoring and operational data for a GS site is required to be reported to the EPA annually. More information on the MRV plan and annual reporting is available in the subpart RR final rule (75 FR 75065; December 1, 2010) and its associated technical support document.[470]

Under this final rule, any well receiving CO_2 captured from an affected EGU, be it a Class VI or Class II well, must report under subpart RR.[471] As explained below in Section V.N.5.a, a Class II well's UIC regulatory status does not change because it receives such CO_2. Nor does it change by virtue of reporting under subpart RR.

3. UIC and GHGRP Rules Provide Assurance To Prevent, Monitor, and Address Releases of Sequestered CO_2 to Air

Together the requirements of the UIC and GHGRP programs help ensure that sequestered CO_2 will remain secure, and provide the monitoring mechanisms to identify and address potential leakage using SDWA and CAA authorities. The EPA designed the GHGRP subpart RR requirements for GS with consideration of UIC requirements. The monitoring required by GHGRP subpart RR is complementary to and builds on UIC monitoring and testing requirements. 75 FR 77263. Although the regulations for Class VI and Class II injection wells are designed to ensure protection of USDWs from endangerment the practical effect of these complementary technical requirements, as explained below, is that they also prevent releases of CO_2 to the atmosphere.

The UIC and GHGRP programs are built upon an understanding of the mechanisms by which CO_2 is retained in geologic formations, which are well understood and proven.

Structural and stratigraphic trapping is a physical trapping mechanism that occurs when the CO_2 reaches a stratigraphic zone with low permeability (*i.e.,* geologic confining

[456] 40 CFR 98.420(a)(1).

[457] 40 CFR 98.426.

[458] 40 CFR 98.426(h).

[459] 40 CFR 98.440.

[460] 40 CFR 98.446.

[461] 40 CFR 98.448.

[462] 40 CFR 98.446(f)(9) and (10).

[463] 40 CFR 98.446(f)(12).

[464] See 75 FR at 77263 (Dec. 10, 2010).

[465] 40 CFR 98.448(a)(1).

[466] 40 CFR 98.448(a)(2).

[467] 40 CFR 98.448(a)(3).

[468] 40 CFR 98.448(a)(4).

[469] 40 CFR 98.448(a)(5).

[470] Technical Support Document: ''General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU'' (Docket EPA–HQ–OAR–2009–0926), November 2010.

[471] See § 60.5555(f).

system) that prevents further upward migration.

Residual trapping is a physical trapping mechanism that occurs as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces.

Adsorption trapping is another physical trapping mechanism that occurs when CO_2 molecules attach to the surfaces of coal and certain organic rich shales, displacing other molecules such as methane.

Solubility trapping is a geochemical trapping mechanism where a portion of the CO_2 from the pure fluid phase dissolves into native ground water and hydrocarbons.

Mineral trapping is a geochemical trapping mechanism that occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals.

a. Class VI Wells

As just discussed in Section V.N.1, the UIC Class VI rule provides a framework to ensure the safety of underground injection of CO_2 such that USDWs are not endangered. As explained below, protection against releases to USDWs likewise assures against releases to ambient air. Through the injection well permit application process, the Class VI permit applicant (*i.e.,* a prospective Class VI well owner or operator) must demonstrate that the injected CO_2 will be trapped and retained in the geologic formation, and not migrate out of the injection zone or the approved project area (*i.e.,* the area of review). To assure that CO_2 is confined within the injection zone, major components to be considered and included in Class VI permits are site characterization, area of review delineation and corrective action, well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure as described in Section V.N.1.

Site characterization provides the foundation for successful GS projects. It includes evaluation of the chemical and physical mechanisms that will occur in the subsurface to immobilize and securely store the CO_2 within the injection zone over the long-term (see above). Site characterization requires a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that wells are sited in suitable locations.[472] Data and information collected during site characterization are used in the development of injection well construction and operating plans; provide inputs for modeling the extent of the injected CO_2 plume and related pressure front; and establish baseline information to which geochemical, geophysical, and hydrogeologic site monitoring data collected over the life of the injection project can be compared.

The Class VI rules contain rigorous subsurface monitoring requirements to assure that the chosen site is functioning as characterized. This subsurface monitoring should detect leakage of CO_2 before CO_2 would reach the atmosphere. For example, when USDWs are present, they are generally located above the injection zone. If CO_2 were to reach a USDW prior to being released to the atmosphere, the presence of CO_2 or geochemical changes that would be caused by CO_2 migration into unauthorized zones would be detected by a UIC Class VI monitoring program that is approved and periodically evaluated/adjusted based on permit conditions.

Likewise, UIC Class VI mechanical integrity testing requirements are designed to confirm that a well maintains internal and external mechanical integrity. Continuous monitoring of the internal mechanical integrity of Class VI wells ensures that injection wells maintain integrity and serves as a way to detect problems with the well system. Mechanical integrity testing provides an early indication of potential issues that could lead to CO_2 leakage from the confining zone, providing assurance and verification that CO_2 will not reach the atmosphere.

Further assurance is provided by the regulatory requirement that injection must cease if there is evidence that the injected CO_2 and/or associated pressure front may cause endangerment to a USDW.[473] Once the anomalous operating conditions are verified, the cessation of injection, as required by UIC permits, will minimize any risk of release to air.

Following cessation of injection, the operator must conduct comprehensive post-injection site care to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither poses an endangerment to USDWs—also having the practical effect of preventing releases of CO_2 to the atmosphere. Post-injection site care includes appropriate monitoring and other needed actions (including corrective action). The default duration for the post-injection site care period is 50 years, with flexibility for demonstrating that an alternative period is appropriate if it ensures non-endangerment of USDWs.

As the EPA has found, the UIC Class VI injection well requirements protect against releases from all exposure pathways. Specifically, the EPA stated that the Class VI rules ''[are] specifically designed to ensure that the CO_2 (and any incidental associated substances derived from the source materials and the capture process) will be isolated within the injection zone.'' The EPA further stated that ''[t]he EPA concluded that the elimination of exposure routes through these requirements, which are implemented through a SDWA UIC permit, will ensure protection of human health and the environment. . .''.[474]

GHGRP subpart RR complements these UIC Class VI requirements. Requirements under the UIC program are focused on demonstrating that USDWs are not endangered as a result of CO_2 injection into the subsurface, while requirements under the GHGRP through subpart RR enable accounting for CO_2 that is geologically sequestered. A methodology to account for potential leakage is developed as part of the subpart RR MRV plan (see Section V.N.2). The MRV plan submitted for subpart RR may describe (or provide by reference to the UIC permit) the relevant elements of the UIC permit (*e.g.* assessment of leakage pathways in the monitoring area) and how those elements satisfy the subpart RR requirements. The MRV plan required under subpart RR may rely upon the knowledge of the subsurface location of CO_2 and site characteristics that are developed in the permit application process, and operational monitoring results for UIC Class VI permitted wells.

In summary, there are well-recognized physical mechanisms for storing CO_2 securely. The comprehensive and rigorous site characterization requirements of the Class VI rules assure that sites with these properties are selected. Subsurface monitoring serves to assure that the sequestration site operates as intended, and this monitoring continues through a post-closure period. Although release of CO_2 to air is unlikely and should be detected prior to release by subsurface monitoring, the subpart RR air-side monitoring and reporting regime

[472] 40 CFR 146.82(a) and (c).

[473] 40 CFR 146.94(b).

[474] 79 FR at 353 (January 3, 2014) (Final Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO_2) Streams in Geologic Sequestration Activities under subtitle C of RCRA). See Section N.5.c below.

provides back up assurance that sequestered CO_2 has not been released to the atmosphere.

b. Class II Wells

The Class II rules likewise are designed to protect USDWs during EOR operation, including the injection of CO_2 for EOR. For example, UIC Class II minimum federal requirements promulgated under SDWA address site characterization, area of review, well construction (*e.g.,* casing and cementing), well operation (*e.g.,* injection pressure), injectate sampling, mechanical integrity testing, plugging and abandonment, financial responsibility, and reporting. Class II wells must undergo periodic mechanical integrity testing which will detect well construction and operational conditions that could lead to loss of injectate and migration into USDWs. The establishment of maximum injection pressures, designed to ensure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the confining zone, prevents injection from causing the movement of fluids into an underground source of drinking water. The safeguards that protect USDWs also serve as an early warning mechanism for releases of CO_2 to the atmosphere.

CO_2 injected via Class II wells becomes sequestered by the trapping mechanisms described above in this Section V.N.3. As with Class VI wells, for Class II wells that report under subpart RR, there is monitoring to evaluate whether CO_2 used for EOR will remain safely in place both during and after the injection period. Subpart RR provides a CO_2 accounting framework that will enable the EPA to assess both the project-level and national efficacy of geologic sequestration to determine whether additional requirements are necessary and, if so, inform the design of such regulations.

c. Response to Comments

Commenters maintained that GS was not demonstrated for CO_2 captured from EGUs. In addition, commenters noted that the volumes of captured CO_2 would be considerably larger than from existing GS sites, and could quadruple amounts injected into Class II EOR wells. In addition to volumes of CO_2 to be injected, commenters opined on the possibility of sporadic CO_2 supply due to the nature of EGU operation.[475]

The EPA does not agree. CO_2 capture from EGUs is demonstrated as discussed in Sections V.D and V.E. As discussed below, the volumes of CO_2 are comparable to the amounts that have been injected at large scale commercial operations. The EPA also disagrees that the volume of CO_2 would quadruple amounts injected into Class II EOR wells because CO_2 may be sequestered in deep saline formations, which have widespread geographic availability (see Section M.1). The BSER determination and regulatory impact analysis for this rule relies on GS in deep saline formations.[476] However, the EPA also recognizes the potential for sequestering CO_2 via EOR and allows the use of EOR as a compliance option. According to data reported to the GHGRP, approximately 60 million metric tons of CO_2 were supplied to EOR in the United States in 2013.[477] Approximately 70 percent of total CO_2 supplied in the United States was produced from geologic (natural) CO_2 sources and approximately 30 percent was captured from anthropogenic sources. CO_2 pipeline systems, such as those serving the Permian Basin, have multiple sources of CO_2 that serve to levelize the pipeline supply, thus minimizing the effect of supply on the EOR operator.

GS of anthropogenic CO_2 in deep saline formations is demonstrated. First, as explained above, the EPA has issued construction permits under the Class VI program. It would not have done so, and under the regulations cannot have done so, without demonstrations that CO_2 would be securely confined. One of these projects was for a steam generating EGU.

Second, international experience with large scale commercial GS projects has demonstrated through extensive monitoring programs that large volumes of CO_2 can be safely injected and securely sequestered for long periods of time at volumes and rates consistent with those expected under this rule. This experience has also demonstrated the value and efficacy of monitoring programs to determine the location of CO_2 in the subsurface and detect potential leakage through the presence of CO_2 in the shallow subsurface, near surface and air.

The Sleipner CO_2 Storage Project is located at an offshore gas field in the North Sea where CO_2 must be removed from the natural gas in order to meet customer requirements and reduce costs. The project began injecting CO_2 into the deep subsurface in 1996. The single offshore injection well injects approximately 1 million metric tons per year into a thick, permeable sandstone above the gas producing zone. Approximately 15 million metric tons of CO_2 have been injected since inception. Many US and international organizations have conducted monitoring at Sleipner. The location and dimensions of the CO_2 plume have been measured numerous times using 3-dimensional seismic monitoring since the 1994 pre-injection survey. The monitoring data have demonstrated that although the plume is behaving differently than initially modeled due to thin layers of impermeable shale that were not initially identified in the reservoir model, the CO_2 remains trapped in the injection zone. Numerous other techniques have been successfully used to monitor CO_2 storage at Sleipner. The research and monitoring at Sleipner demonstrates the value of a comprehensive approach to site characterization, computational modeling and monitoring, as is required under UIC Class VI rules. The experience at Sleipner demonstrates that large volumes of CO_2, of the same order of magnitude expected for an EGU, can be safely injected and stored in saline reservoirs over an extended period.

Snøhvit is another large offshore CO_2 storage project, located at a gas field in the Barents Sea. Like Sleipner the natural gas must be treated to reduce high levels of CO_2 to meet processing standards and reduce costs. Gas is transported via pipeline 95 miles to a gas processing and liquefied natural gas plant and the CO_2 is piped back offshore for injection. Approximately 0.7 million metric tons per year CO_2 are injected into permeable sandstone below the gas reservoir. Between 2008 and 2011, the operator observed pressure increases in the injection formation (Tubaen Formation) greater than expected and conducted time lapse seismic surveys and studies of the injection zone and concluded that the pressure increase was mainly caused by a limited storage capacity in the formation.[478] In 2011,

[475] See, *e.g.* Comments of Southern Company, p. 41 (Docket entry: EPA–HQ–OAR–2013–0495–10095).

[476] The EPA anticipates EOR projects may be early GS projects because these formations have been previously well characterized for hydrocarbon recovery, likely already have suitable infrastructure (*e.g.,* wells, pipelines, etc.), and have an associated economic benefit of oil production.

[477] Greenhouse Gas Reporting Program, data reported as of August 18, 2014.

[478] Grude, S. M. Landrøa, and J. Dvorkinb, 2014, Pressure effects caused by CO_2 injection in the Tubåen Fm., the Snøhvit field. International Journal of Greenhouse Gas Control 27 (2014) 178–187. Commenters argued that the project had failed to sequester CO_2, referring to the initial cessation of injection. See, *e.g.* Comments of UARG p. 56 (Docket entry: EPA–HQ–OAR–2013–0495–9666). In fact, injection resumed successfully, as described in the text above.

the injection well was modified and injection was initiated in a second interval (Stø Formation) in the field to increase the storage capacity. Approximately 3 million metric tons of CO_2 have been injected since 2008. Monitoring demonstrates that no leakage has occurred, again demonstrating that large volumes of CO_2, of the same order of magnitude expected for an EGU, can be safely injected and stored in deep saline formations over an extended period.

As discussed above in Sections V.E.2.a and M, CO_2 from the Great Plains Synfuels plant in North Dakota has been injected into the Weyburn oil field in Saskatchewan Canada since 2000. Over that time period the project has injected more than 16 million metric tons of CO_2. It is anticipated that approximately 40 million metric tons of CO_2 will be permanently sequestered over the lifespan of the project. Extensive monitoring by U.S. and international partners has demonstrated that no leakage has occurred. The sources of CO_2 for EOR may vary (*e.g.,* industrial processes, power generation); however, this does not impact the effectiveness of EOR operations (see Section V.M.3).

CO_2 used for EOR may come from anthropogenic or natural sources. The source of the CO_2 does not impact the effectiveness of the EOR operation. CO_2 capture, treatment and processing steps provide a concentrated stream of CO_2 in order to meet the needs of the intended end use. CO_2 pipeline specifications of the U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration found at 49 CFR part 195 (Transportation of Hazardous Liquids by Pipeline) apply regardless of the source of the CO_2 and take into account CO_2 composition, impurities, and phase behavior. Additionally, EOR operators and transport companies have specifications to ensure related to the composition of CO_2. These requirements and specifications ensure EOR operators receive a known and consistent CO_2 stream.

At the In Salah CO_2 storage project in Algeria, CO_2 is removed from natural gas produced at three nearby gas fields in order to meet export quality specification. The CO_2 is transported by pipeline approximately 3 miles to the injection site. Three horizontal wells are used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir approximately 6,200 feet deep. Between 2004 and 2011 over 3.8 million metric tons of CO_2 were stored. Injection rates in 2010 and 2011 were approximately 1 million metric tons per year. Storage integrity has been monitored by several U.S. and international organizations and the monitoring program has employed a wide range of geophysical and geochemical methods, including time lapse seismic, microseismic, wellhead sampling, tracers, down-hole logging, core analysis, surface gas monitoring, groundwater aquifer monitoring and satellite data. The data have been used to support periodic risk assessments during the operational phase of the project. In 2010 new data from seismic, satellite and geomechanical models were used to inform the risk assessment and led to the decision to reduce CO_2 injection pressures due to risk of vertical leakage into the lower caprock, and risk of loss of well integrity. The caprock at the site consisted of main caprock units, providing the primary seal, and lower caprock units, providing additional buffers. There was no leakage from the well or through the caprock, but the risk analysis identified an increased risk of leakage, therefore, the aforementioned precautions were taken. Additional analysis of the reservoir, seismic and geomechanical data led to the decision to suspend CO_2 injection in June 2011. No leakage has occurred and the injected CO_2 remains safely stored in the subsurface. The decision to proceed with safe shutdown of injection resulted from the analysis of seismic and geomechanical data to identify and respond to storage site risk. The In Salah project demonstrates the value of developing an integrated and comprehensive set of baseline site data prior to the start of injection, and the importance of regular review of monitoring data. Commenters also noted that the data collection and analysis had proven effective at preventing any release of sequestered CO_2 to either underground drinking water sources or to the atmosphere.[479]

These projects demonstrate that sequestration of CO_2 captured from industrial operations has been successfully conducted on a large scale and over relatively long periods of time. The volumes of captured CO_2 are within the same order of magnitude as that expected from EGUs. Even though potentially adverse conditions were identified at some projects (In Salah and Snøhvit), there were no releases to air and the monitoring systems were effective in identifying the issues in a timely manner, and these issues were addressed effectively. In each case, the site-specific characteristics were evaluated on a case-by-case basis to select a site where the geologic conditions are suitable to ensure long-term, safe storage of CO_2. Each project was designed to address the site-specific characteristics and operated to successfully inject CO_2 for safe storage.

4. Must the standard of performance for CO_2 include CAA requirements on the sequestration site?

One commenter maintained as a matter of law that a standard predicated on use of CCS is not a ''system of emission reduction'', and therefore is not a ''standard of performance'' within the meaning of section 111 (a)(1) of the Act. The commenter argued that the standard does not require sequestration of captured CO_2 but only capture, so that no emission reductions are associated with the standard. A gloss on this argument is that there are no enforceable requirements for the captured CO_2 (''[t]he fate of that [captured] CO_2 is something that the proposed standard does not proscribe with enforceable requirements''). The commenter further argues that a ''system of emission reduction'' under section 111 must be ''designed into the new source *itself''* so that off-site underground sequestration of captured CO_2 emissions ''could never satisfy the statutory requirements governing a 'standard of performance''' (emphasis original).[480]

The EPA disagrees with both the legal and factual assertions in this comment. As to the legal point, the commenter fails to distinguish capture and sequestration of carbon from every other section 111 standard which is predicated on capture of a pollutant. Indeed, all emission standards not predicated on outright pollutant destruction involve capture of the pollutant and its subsequent disposition in the capturing medium. Thus, metals are captured in devices like baghouses or scrubbers, leaving a solid waste or wastewater to be managed. Gases can be captured with activated carbon or under pressure, again requiring further management of the captured pollutant(s). The EPA is required to consider these potential implications in promulgating an NSPS. See section 111(a)(1) (in promulgating a standard of performance under section 111, the EPA must ''tak[e] into account . . . any nonair quality health and environmental

[479] ''It is important to note that although the In Salah project is no longer injecting CO_2, the CCS community still views this early saline project as a success because the monitoring program served its intended purpose. That is, the monitoring methods deployed at this site informed the operator of a potential problem, leading to a shutdown of CO_2 injection before the Caprock was breached.'' Comment of EPRI, p. 14 Docket entry: EPA–HQ–OAR–2013–0495–8925).

[480] Comments of UARG, pp. 37–38 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

impact''). The EPA thus considers such issues as solid waste and wastewater generation as part of determining if a system of emission reduction is ''best'' and ''adequately demonstrated'' under section 111. See Section V.O below (discussion of this rule's potential cross-media impacts).

The further comment that the standard is arbitrary because it fails to impose any requirements on the captured CO_2 is misplaced. The commenter mischaracterizes the standard as requiring capture only. The BSER is not just capturing a certain amount of CO_2, but sequestering it. Sequestration can occur either on-site or off-site. Sequestration sites receiving and injecting the captured CO_2 are required to obtain UIC permits and report under subpart RR of the GHGRP. They must conduct comprehensive monitoring as part of these obligations. Although the NSPS does not impose regulatory requirements on the transportation pipeline or the sequestration site, such requirements already exist under other regulatory programs of the Department of Transportation and the EPA. In particular, the EPA is reasonably relying on the already-adopted, and very rigorous, Class VI well requirements in combination with the subpart RR requirements to provide secure sequestration of captured CO_2. The EPA has also considered carefully the requirements and operating history of the Class II requirements for EOR wells, which, in combination with the subpart RR requirements, ensure protection of USDWs from endangerment, provide the monitoring mechanisms to identify and address potential leakage using SDWA and CAA authorities, and have the practical effect of preventing releases of CO_2 to the atmosphere. This is analogous to the many section 111 standards of performance for metals which result in a captured air pollution control residue to be disposed of pursuant to waste management requirements of the rules implementing the Resource Conservation and Recovery Act. It is also analogous to the many section 111 standards of performance for metals or organics captured in wet air pollution control systems resulting in wastewater discharged to a navigable water where pollutant loadings are controlled under rules implementing the Clean Water Act. Again, these are non-air environmental impacts for which the EPA must account in establishing a section 111(a) standard. The EPA has reasonably done so here based on the regulatory regimes of the Class VI and Class II UIC requirements in combination with the monitoring regime of the subpart RR reporting rules, as well as the CO_2 pipeline standards of the Department of Transportation.

In this regard, the EPA notes that at proposal it acknowledged the possibility ''that there can be downstream losses of CO_2 after capture, for example during transportation, injection or storage.'' 79 FR at 1484. Given the rigorous substantive requirements and the monitoring required by the Class VI rules, the complementary monitoring regime of the subpart RR MRV plan and reporting rules, as well as the regulatory requirements for Class II wells, any such losses would be de minimis. Indeed, the same commenter maintained that the monitoring requirements of the Class VI rule are overly stringent and that a 50-year post-injection site care period is unnecessarily long.[481] As it happens, as noted above, the Class VI rules allow for an alternative post-injection site care period based on a site-specific demonstration. See 40 CFR 146.93(b).

The EPA addresses this comment in more detail in Chapter 2 of the Response-to-Comment Document.

5. Other Perceived Obstacles to Geologic Sequestration

a. Class II to Class VI transition

A number of commenters maintained that the Class VI rules could effectively force all Class II wells to transition to Class VI wells if they inject anthropogenic CO_2, and further maintained that, as a practical matter, this would render EOR unavailable for such CO_2. The EPA disagrees with these comments. Injection of anthropogenic CO_2 into Class II wells does not force transition of these wells to Class VI wells—not during the well's active operation and not when EOR operations cease. We recognize the widespread use of EOR and the expectation that injected CO_2 can remain underground. The EPA issued a memorandum to its regional offices on April 23, 2015 reflecting these principles: [482]

Geologic storage of CO_2 can continue to be permitted under the UIC Class II program.

Use of anthropogenic CO_2 in EOR operations does not necessitate a Class VI permit.

Class VI site closure requirements are not required for Class II CO_2 injection operations.

EOR operations that are focused on oil or gas production will be managed under the Class II program. If oil or gas recovery is no longer a significant aspect of a Class II permitted EOR operation, the key factor in determining the potential need to transition an EOR operation from Class II to Class VI is increased risk to USDWs related to significant storage of CO_2 in the reservoir, where the regulatory tools of the Class II program cannot successfully manage the risk.[483]

b. GHGRP Subpart RR

A number of commenters maintained that no EOR operator would accept captured carbon from an EGU due to the reporting and other regulatory burdens imposed by the monitoring requirements of GHGRP subpart RR.[484] They noted that preparing a subpart RR MRV plan could cost upwards of $100,000 which would be cost prohibitive given other available sources of CO_2.

The EPA disagrees with this comment in several respects. First, the BSER determination and regulatory impact analysis for this rule relies on GS in deep saline formations, not on EOR. However, the EPA also recognizes the potential for sequestering CO_2 via EOR, but disagrees that subpart RR requirements effectively preclude or substantially inhibit the use of EOR.

The cost of compliance with subpart RR is not significant enough to offset the potential revenue for the EOR operator from the sale of produced oil for CCS projects that are reliant on EOR. First, the costs associated with subpart RR are relatively modest, especially in comparison with revenues from an EOR field. In the economic impact analysis for subpart RR, the EPA estimated that an EOR project with a Class II permit would incur a first year cost of up to $147,030 to develop an MRV plan, and an annual cost of $27,787 to maintain the plan; the EPA estimated annual reporting and recordkeeping costs at $13,262 per year.[485] Monitoring costs

[481] Comments of UARG, p. 63 (Docket entry: EPA–HQ–OAR–2013–0495–9666).

[482] ''Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil Recovery or Gas Recovery Wells to Class VI'', April 23, 2015. Available at: *http://water.epa.gov/type/groundwater/uic/class6/upload/class2eorclass6memo.pdf*.

[483] In this regard, the Class VI rules provide that, owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations. 40 CFR 144.19.

[484] See *e.g.,* comments of UARG, p, 63 (Docket entry: EPA–HQ–OAR–2013–0495–9666); Southern Co., p. 37 (Docket entry: EPA–HQ–OAR–2013–0495–10095); American Petroleum Institute pp. 40–50 Docket entry: EPA–HQ–OAR–2013–0495–10098).

[485] Subpart RR costs are presented in 2008 US dollars.

are estimated to range from $0.02 per metric ton (base case scenario) to approximately $2 per metric ton of CO_2 (high scenario). Using a range of scenarios (that included high end estimates), these subpart RR costs are approximately three to four percent of estimated revenues for an average EOR field, indicating that the costs can readily be absorbed. 75 FR 75073.

Furthermore, there is a demand for new CO_2 by EOR operators, even beyond current natural sources of CO_2. For example, in an April 2014 study, DOE concluded that future development of EOR will need to rely on captured CO_2.[486] Thus, the argument that EOR operators will obtain CO_2 from other sources without triggering subpart RR responsibilities, which assumes adequate supplies of CO_2 from other sources, lacks foundation. In addition, the Internal Revenue Code section 45Q provides a tax credit for CO_2 sequestration which is far greater than subpart RR costs.[487] In sum, the cost of complying with subpart RR requirements, including the cost of MRV, is not significant enough to deter EOR operators from purchasing EGU captured CO_2.

The EPA addresses these comments in more detail in the Response to Comment Document.

c. Conditional exclusion for geologic sequestration of CO2 streams under the Resource Conservation and Recovery Act (RCRA)

Certain commenters voiced concerns that regulatory requirements for hazardous wastes might apply to captured CO_2 and these requirements might be inconsistent with, or otherwise impede, GS of captured CO_2 from EGUs. The EPA has acted to remove any such (highly conjectural) uncertainty. The Resource Conservation and Recovery Act (RCRA) authorizes the EPA to regulate the management of hazardous wastes. In particular, RCRA Subtitle C authorizes a cradle to grave regulatory program for wastes identified as hazardous, whether specifically listed as hazardous or whether the waste fails certain tests of hazardous characteristics. The EPA currently has little information to conclude that CO_2 streams (defined in the RCRA exclusion rule as including incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process) might be identified as ''hazardous wastes'' subject to RCRA Subtitle C regulation.[488] Nevertheless, to reduce potential uncertainty regarding the regulatory status of CO_2 streams under RCRA Subtitle C, and in order to facilitate the deployment of geologic sequestration, the EPA recently concluded a rulemaking to exclude certain CO_2 streams from the RCRA definition of hazardous waste.[489] In that rulemaking, the EPA determined that if any such CO_2 streams would be hazardous wastes, further RCRA regulation is unnecessary to protect human health and the environment provided certain conditions are met. Specifically, the rule conditionally excludes from Subtitle C regulations CO_2 streams if they are (1) transported in compliance with U.S. Department of Transportation or state requirements; (2) injected in compliance with UIC Class VI requirements (summarized above); (3) no other hazardous wastes are mixed with or co-injected with the CO_2 stream; and (4) generators (*e.g.,* emission sources) and Class VI well owners or operators sign certification statements. See 40 CFR 261.4(h)).[490] The D.C. Circuit recently dismissed all challenges to this rule in *Carbon Sequestration Council and Southern Company Services* v. *EPA,* No. 787 F. 3d 1129 (D.C. Cir. 2015).

d. Other perceived uncertainties

Other commenters claimed that various legal uncertainties preclude a finding that geologic sequestration of CO_2 from EGUs can be considered to be adequately demonstrated. Many of the issues referred to in comments relate to property rights: issues of ownership of pore space, relationship of sequestration to ownership of mineral rights, issues of dealing with multiple landowners, lack of state law frameworks, or competing, inconsistent state laws.[491] Other commenters noted the lack of long-term liability insurance, and noted uncertainties regarding long-term liability generally.[492]

An IPCC special report on CCS found that with an appropriate site selection, a monitoring program, a regulatory system, and the appropriate use of remediation methods, the risks of GS would be comparable to risks of current activities, such as EOR, acid gas injection and underground natural gas storage.[493] Furthermore, an interagency CCS task force examined GS-related legal issues thoroughly and concluded that early CCS projects can proceed under the existing legal framework with respect to issues such as property rights and liability.[494] As noted earlier, both the Archer Daniels Midland (ADM) and FutureGen projects addressed siting and operational aspects of GS (including issues relating to volumes of the CO_2 and the nature of the CO_2 injectate) in their permit applications. The fact that these applicants pursued permits indicates that they regarded any potential property rights issues as resolvable.

Commenter American Electric Power (AEP) referred to its own experience with the Mountaineer demonstration project. AEP noted that although this project was not full scale, finding a suitable repository, notwithstanding a generally favorable geologic area, proved difficult. The company referred to years spent in site characterization and digging multiple wells.[495] Other commenters noted more generally that site characterization issues can be time-consuming and difficult, and quoted

[486] ''Near Term Projections of CO_2 Utilization for Enhanced Oil Recovery''. DOE/NETL–2014/1648. April 2014.

[487] *http://www.irs.gov/irb/2009-44_IRB/ar11.html.* The section 45Q tax credit for calendar year 2015 is $10.92 per metric ton of qualified CO_2 that is captured and used in a qualified EOR project and $21.85 per metric ton of qualified CO_2 that is captured and used in a qualified non-EOR GS project. *http://www.irs.gov/irb/2015-26_IRB/ar14.html.*

[488] No hazardous waste listings apply to CO_2 streams. Therefore, a CO_2 stream could be identified (*i.e.* defined) as a hazardous waste only if it exhibits one or more of the hazardous characteristics. 79 FR 355 (Jan 3. 2014).

[489] 79 FR 350 (Jan. 3, 2014).

[490] The EPA made clear in the final conditional exclusion that that rule does not address, and is not intended to affect the RCRA regulatory status of CO_2 streams that are injected into wells other than Class VI. However, the EPA noted in the preamble to the final rule that (based on the limited information provided in public comments) should CO_2 be used for its intended purpose as it is injected into UIC Class II wells for the purpose of EOR/EGR (enhanced oil recovery/enhanced gas recovery), it is the EPA's expectation that such an injection process would not generally be a waste management activity. 79 FR 355. The EPA encouraged persons to consult with the appropriate regulatory authority to address any fact-specific questions that they may have regarding the status of CO_2 in situations that are beyond the scope of that rule. *Id.* Moreover, use of anthropogenic CO_2 for EOR is long-standing and has flourished in all of the years that EPA's subtitle C regulations (which among other things, define what a solid waste is for purposes of those regulations) have been in place. The RCRA subtitle C regulatory program consequently has not been an impediment to use of anthropogenic CO_2 for EOR.

[491] See *e.g.* Comments of Duke Energy, p. 28 Docket entry: EPA–HQ–OAR–2013–0495–9426); UARG, p. 62 (Docket entry: EPA–HQ–OAR–2013–0495–9666); AEP, p. 91 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

[492] See *e.g.* Comments of UARG, pp. 26 (Docket entry: EPA–HQ–OAR–2013–0495–9666), 62; EEI, p. 92 Docket entry: EPA–HQ–OAR–2013–0495–9780); Duke Energy, pp. 27, 28 Docket entry: EPA–HQ–OAR–2013–0495–9426).

[493] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

[494] *http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf.*

[495] AEP Comments at pp. 93, 96 (Docket entry: EPA–HQ–OAR–2013–0495–10618).

studies suggesting that it could take 5 years to obtain a Class VI permit.[496]

The EPA agrees that robust site characterization and selection is important to ensuring capacity needs are met and that the sequestered CO_2 is safely stored. Efforts to characterize geologic formations suitable for GS have been underway at DOE through the RCSPs since 2003 (see Section V.M). Additionally, since 2007, the USGS has been assessing U.S. geologic storage resources for CO_2. As noted earlier, DOE, in partnership with researchers, universities, and organizations across the country, is demonstrating that GS can be achieved safely, permanently, and economically at large scales, and projects supported by the department have safely and permanently stored 10 million metric tons of CO_2.

In the time since the commenter submitted comments several Class VI permits have been issued by the EPA. These projects demonstrate that a GS site permit applicant could potentially prepare and obtain a UIC permit concurrent with permits required for an EGU. With respect to AEP's experience with the Mountaineer demonstration project, notwithstanding difficulties, the company was able to successfully dig wells, and safely inject captured CO_2. Moreover, the company indicated it fully expected to be able to do so at full scale and explained how.[497] The EPA notes further that a monitoring program and its associated infrastructure (*e.g.*, monitoring wells) and costs will be dependent on site-specific characteristics, such as CO_2 injection rate and volume, geology, the presence of artificial penetrations, among other factors. It is thus not appropriate to generalize from AEP's experience, and assume that other sites will require the same number of wells for site characterization or injection. In this regard, we note that the ADM and FutureGen construction permits for Class VI wells involved far fewer injection wells than AEP references.[498] See also discussion of this issue in Section V.I.5 above.

O. Non-air Quality Impacts and Energy Requirements

As part of the determination that SCPC with partial CCS is the best system of emission reduction adequately demonstrated, the EPA has given careful consideration to non-air quality health and environmental impacts and energy requirements, as required by CAA section 111 (a). We have also considered those factors for alternative potential compliance paths to assure that the standard does not have unintended adverse health, environmental or energy-related consequences. The EPA finds that neither the BSER, nor the possible alternative compliance pathways, would have adverse consequences from either a non-air quality impact or energy requirement perspective.

1. Transport and Sequestration of Captured CO_2

As just discussed in detail, the EPA finds that the Class VI and II rules, as complemented by the subpart RR GHGRP reporting and monitoring requirements, amply safeguard against potential of injected CO_2 to degrade underground sources of drinking water and amply protect against any releases of sequestered CO_2 to the atmosphere. The EPA likewise finds that the plenary regulatory controls on CO_2 pipelines assure that CO_2 can be safely conveyed without environmental release, and that these rules, plus the complementary tracking and reporting rules in subpart RR, assure that captured CO_2 will be properly tracked and conveyed to a sequestration site.

2. Water Use Impacts

Commenters claimed that the EPA ignored the negative environmental impacts of the use of CCS for the mitigation of CO_2 emissions from fossil fuel-fired steam generating EGUs. In particular, commenters noted that the use of CCS will increase the water usage at units that implement CCS to meet the proposed standard of performance. At least one commenter claimed that addition of an amine-based CCS system would double the consumptive water use of a power plant, which would be unacceptable, especially in drought-ridden states and in the arid west and referenced a study in the scientific literature as support.[499] The commenter also references a DOE/NETL report that likewise notes significant increases in the amount of cooling and process water required with the use of carbon capture technology.[500] However, those studies discuss increased water use for cases where full CCS (90 percent or greater capture) is implemented. As we discussed in both the proposal and in this preamble, the EPA does not find that highly efficient new generation technology implementing full CCS is the BSER for new steam generating EGUs.

The EPA examined water use predicted from the updated DOE/NETL studies in order to determine the magnitude of increased water usage for a new SCPC implementing partial CCS to meet the final standard of 1,400 lb CO_2/MWh-g. The predicted water consumption for varying levels of partial and full CCS are provided in Table 13. The results show that a new SCPC unit that implements 16 percent partial CCS to meet the final standard would see an increase in water consumption (the difference between the predicted water withdraw and discharge) of about 6.4 percent compared to an SCPC with no CCS and the same net power output. By comparison, a unit implementing 35 percent CCS to meet the proposed emission limitation of 1,100 lb CO_2/MWh-g would see an increase in water consumption of 16.0 percent and a new unit implementing full (90 percent) CCS would see an increase of almost 50 percent.

TABLE 13—PREDICTED WATER CONSUMPTION WITH IMPLEMENTATION OF VARIOUS LEVELS OF PARTIAL CCS [501]

Technology	Raw water consumption, gpm	Increase compared to SCPC, %
SCPC	4,095	—

[496] See *e.g.* Comments of UARG, p. 55 (Docket entry: EPA–HQ–OAR–2013–0495–9666), citing to Cichanowitz CCS Report (2012).

[497] See AEP FEED Study at pp. 36–43. The company likewise explained the monitoring regime it would utilize to verify containment, and the well construction it would utilize to guarantee secure sequestration. Id. at pp. 44–54. Available at: *www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report*.

[498] The FutureGen UIC Class VI injection well permits (four in total) require nine monitoring wells. *http://www.epa.gov/r5water/uic/futuregen/*. The Archer Daniels Midland UIC Class VI injection well permit issued in September 2014 (CCS2) requires five monitoring wells and the Archer Daniels Midland UIC Class VI injection well permit issued in December 2014 (CCS1) was permitted with two monitoring wells. *http://www.epa.gov/region5/water/uic/adm/*.

[499] See comments of UARG at p. 84 (Docket entry: EPA–HQ–OAR–2013–0495–9666) referencing Haibo Zhai, *et al.*, Water Use at Pulverized Coal Power Plants with Post-combustion Carbon Capture and Storage, 45 *Environ. Sci. Technol.*, 2479–85 (2011).

[500] Id at p. 84 referencing DOE/NETL–402/080108, ''Water Requirements for Existing and Emerging Thermoelectric Plant Technologies'' at 13 (Aug. 2008, Apr. 2009 revision).

TABLE 13—PREDICTED WATER CONSUMPTION WITH IMPLEMENTATION OF VARIOUS LEVELS OF PARTIAL CCS [501]—Continued

Technology	Raw water consumption, gpm	Increase compared to SCPC, %
SCPC + 16% CCS	4,359	6.4
SCPC + 35% CCS	4,751	16.0
SCPC + 90% CCS	6,069	48.2
IGCC*	3,334	−18.6
IGCC + 90% CCS*	4,815	17.6

*The IGCC results presented in the DOE/NETL report are for an IGCC with net output of 622 MWe and an IGCC with full CCS with net output of 543 MWe. The water consumption for each was normalized to 550 MWe to be consistent with the SPCP cases.

Similar to other air pollution controls—such as a wet flue gas desulfurization scrubber—utilization of post-combustion amine-based capture systems results in increased consumption of water. However, by finalizing a standard that is less stringent than the proposed limitation and by rejecting full CCS as the BSER, the EPA has reduced the increased amount of water needed as compared to a similar unit without CCS. Further, the EPA notes that there are additional opportunities to minimize the water usage at such a facility. For example, the SaskPower Boundary Dam Unit #3 post-combustion capture project captures water from the coal and from the combustion process and recycles the captured water in the process, resulting in decreased need for withdrawal of fresh water.

The EPA also examined the predicted water usage for a new IGCC and for a new IGCC implementing 90 percent CCS. The predicted water consumption for the new IGCC unit is nearly 20 percent less than that predicted for the new SCPC unit without CCS (and almost 25 percent less than the SCPC unit meeting the final standard). The EPA rejected new IGCC implementing full CCS as BSER because the predicted costs were significantly more than alternative technologies. The EPA also does not find that a new IGCC EGU is part of the final BSER (for reasons discussed in Section V.P). However, the EPA does note that IGCC is a viable alternative compliance option and, as shown here, would result in less water consumption than a compliant SCPC EGU. The EPA also notes that predicted water consumption at a new NGCC unit would be less than half that for a new SCPC EGU with the same net output.[502]

3. Energy Requirements

The EPA also examined the expected impacts on energy requirements for a new unit meeting the final promulgated standard and finds impacts to be minimal. Specifically, the EPA examined the increased auxiliary load or parasitic energy requirements of a system implementing CCS. The EPA examined the predicted auxiliary power demand from the updated DOE/NETL studies in order to determine the increased energy requirement for a new SCPC implementing partial CCS to meet the final standard of 1,400 lb CO_2/MWh-g. The predicted gross power output, the auxiliary power demand, and the parasitic power demand (percent of gross output) are provided in Table 14 for varying levels of partial and full CCS.

TABLE 14—PREDICTED PARASITIC POWER DEMAND WITH IMPLEMENTATION OF VARIOUS LEVELS OF PARTIAL CCS [503]

Generation technology	Gross power output, MWe	Auxiliary power, MWe	Parasitic demand (%)
SCPC	580	30	5.2
SCPC + 16% CCS	599	38	6.3
SCPC + 35% CCS	603	53	8.8
SCPC + 90% CCS	642	91	14.2
IGCC	748	126	16.8
IGCC + 90% CCS	734	191	26.0
CCS	734	191	26.0

The auxiliary power demand is the amount of the gross power output that is utilized within the facility rather than used to produce electricity for sale to the grid. The parasitic power demand (or parasitic load) is the percentage of the gross power output that is needed to meet the auxiliary power demand.[504] In an SCPC EGU without CCS, the auxiliary power is used to primarily to operate fans, motors, pumps, etc. associated with operation of the facility and the associated pollution control equipment. When carbon capture equipment is incorporated, additional power is needed to operate associated equipment, and steam is need to regenerate the capture solvents (*i.e.,* the solvents are heated to release the captured CO_2).

The results in Table 14 show that a new SCPC unit without CCS can expect a parasitic power demand of about 5.2 percent. A new SCPC unit meeting the

[501] Exhibits A–1 and A–2 at p. 16–17 from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 22, 2015).

[502] The EPA also finds that the standards would not result in any significant impact on solid waste generation or management. See Section XIII.D below.

[503] Exhibits A–1 and A–2 at p. 16–17 from ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015).

[504] Note that this auxiliary power demand is not necessarily met from power or steam generated from the EGU. External sources can also be utilized for this purpose.

final standard of performance by implementing 16 percent partial CCS will see a parasitic power demand of about 6.3 percent, which is not a significant increase in energy requirement. Of course, new SCPC EGUs that implement higher levels of CCS will expect higher amounts of parasitic power demand. As shown in Table 14, a new SCPC EGU implementing full CCS would expect to utilize over 14 percent of its gross power output to operate the facility and the carbon capture system. But, the EPA does not find that a new SCPC implementing full CCS is the BSER for new fossil-fired steam generating units. See Section V.P.2 below.

The EPA also notes that there is on-going research sponsored by DOE/NETL and others to further reduce the energy requirements of the carbon capture systems. Progress is being made. As was mentioned previously, the heat duty (the energy required to regenerate the capture solvent) for the amine scrubbing process used at the Searles Valley facility in the mid-70's was about 12 MJ/mt CO_2 removed as compared to a heat duty of about 2.5 MJ/mt CO_2 removed for the amine processes used at Boundary Dam and for the amine system that will be used at the WA Parish facility.[505]

The EPA also examined the predicted parasitic power demand for a new IGCC and for a new IGCC implementing 90 percent CCS. As we have noted elsewhere, the auxiliary power demand for a new IGCC unit is more than that for that of a new SCPC. As one can see in Table 14, a new IGCC unit can expect to see a nearly 17 percent parasitic power demand; and a new IGCC unit implementing full CCS would expect a parasitic power demand of nearly 30 percent. Of course, the EPA rejected new IGCC implementing full CCS as BSER because of the potentially unreasonable costs. The EPA also does not find that a new IGCC EGU is part of the final BSER (for reasons discussed elsewhere in Section V.P.1 below). However, as we have noted, the EPA does find IGCC to be a viable alternative compliance option. Utilities and project developers should consider the increased auxiliary power demand for an IGCC when considering their options for new power generation. The EPA also notes that the predicted parasitic load for a new NGCC unit would be about 2 percent—less than half that for a new SCPC EGU with the same net output.[506]

With respect to potential nationwide impacts on energy requirements, as described above in Section V.H.3 and more extensively in the RIA chapter 4, the EPA reasonably projects that no new non-compliant fossil-fuel fired steam electric capacity will be constructed through 2022 (the end of the 8 year review cycle for NSPS). It is possible, as described earlier, that some new sources could be built to preserve fuel diversity, but even so, the number of such sources would be small and therefore would not significantly impact national energy requirements (assuming that such sources would not already be reflected in the baseline conditions just noted).

P. Options That Were Considered by the EPA but Were Ultimately Not Determined To Be the BSER

In light of the comments received, the EPA re-examined several alternative systems of emission reduction and reaffirms in this rulemaking our proposed determination that those alternatives do not represent the ''best'' system of emission reduction when compared against the other available emission reduction options. These are described below. See also Section IV.B.1 above.

1. Highly Efficient Generation Technology (*e.g.,* Supercritical or Ultra-supercritical Boilers)

In the January 2014 proposal, we considered whether 'Highly Efficient New Generation without CCS Technology' should constitute the BSER for new steam generating units. 79 FR at 1468–69. The discussion focused on the performance of highly efficient generation technology (that does not include any implementation of CCS), such as a supercritical[507] pulverized coal (SCPC) or a supercritical CFB boiler, or a modern, well-performing IGCC unit.

All these options are technically feasible—there are numerous examples of each operating in the U.S. and worldwide. However, we do not find them to qualify as the best system for reduction of CO_2 emissions for the following reasons:

a. Lack of Significant CO_2 Reductions When Compared to Business as Usual

At the outset, we reviewed the emission rates of efficient PC and CFB units. According to the DOE/NETL estimates, a newly constructed subcritical PC unit firing bituminous coal would emit approximately 1,800 lb CO_2/MWh-g,[508] a new highly efficient SCPC unit using bituminous coal would emit nearly 1,720 lb CO_2/MWh-g, and a new IGCC unit would emit about 1,430 lb CO_2/MWh-g.[509] [510] Emissions from comparable sources utilizing sub-bituminous coal or lignite will have somewhat higher CO_2 emissions.[511]

Some commenters noted that new coal-fired plants utilizing supercritical boiler design or IGCC would provide substantial emission reductions compared to the emissions from the existing subcritical coal plants that are currently in wide use in the power sector. However, most of the recent new power sector projects using solid fossil fuel (coal or petroleum coke) as the primary fuel—both those that have been constructed and those that have been proposed—are supercritical boilers and IGCC units. About 60 percent of new coal-fired utility boiler capacity that has come on-line since 2005 was supercritical and of the new capacity that came on-line since 2010, about 70 percent was supercritical. No new coal-fired utility boilers began operation in either 2013 or 2014. Coal-fired power plants that have come on-line most recently include AEP's John W. Turk, Jr. Power Plant, which is a 600 MW ultra-supercritical[512] PC (USCPC) facility located in the southwest corner of Arkansas, and Duke Energy's Edwardsport plant, which is a 618 MW

[505] ''From Lubbock, TX to Thompsons, TX—Amine Scrubbing for Commercial CO_2 Capture from Power Plants'', plenary address by Prof. Gary Rochelle at the 12th International Conference on Greenhouse Gas Technology (GHGT–12), Austin, TX (October 2014).

[506] The EPA also finds that the standards would not result in any significant impact on solid waste generation or management. See Section XII.D below.

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

[508] Exhibit ES–2 from ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010).

[509] ''Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO_2 Capture Rate in Coal-Fired Power Plants'', DOE/NETL–2015/1720 (June 2015); SCPC rates come from Exhibit A–2 and IGCC rates come from Exhibit A–4.

[510] The comparable emissions on a net basis are: subcritical PC—1,890 lb CO_2/MWh-n; SCPC–1,705 lb CO_2/MWh-n; and IGCC—1,724 lb CO_2/MWh-n. (See same references as for gross emissions provided in the text).

[511] Exhibit ES–2 from ''Cost and Performance Baseline for Fossil Energy Plants Volume 3b: Low Rank Coal to Electricity: Combustion Cases'', Report DOE/NETL–2010/1463 (March 2011).

[512] Ultra-supercritical (U.S.C.) and advanced ultra-supercritical (A–U.S.C.) are terms often used to designate a coal-fired power plant design with steam conditions well above the critical point.

''CCS ready'' [513] IGCC unit located in Knox County, Indiana. Both of those facilities came on-line in 2012. It is likely that the units that initiated operation in 2010 or later were conceived of, planned, designed, and permitted well before 2010—likely in the early 2000s. Thus, it seems clear that the power sector had already, at that point, transitioned to the selection of supercritical boiler technology as ''business as usual'' for new coal-fired power plants. Since that time, there have been other coal-fired power plants that have been proposed and almost all of them have been either supercritical boiler designs or IGCC units. In Table 1 of the Technical Support Document *Fossil Fuel-Fired Boiler and IGCC EGU Projects Under Development: Status and Approach* [514] for the January 2014 proposal, the EPA listed the development status of ''potential transitional sources'' (*i.e.,* projects that had been proposed and had received Prevention of Significant Deterioration (PSD) preconstruction permits as of April 13, 2012). Of the 16 proposed EGU projects in Table 1—most of which have been cancelled or converted to or replaced with NGCC projects—the majority (nine) are either supercritical PC or IGCC designs. Five of the proposed projects were CFB designs with only one being a subcritical PC design.

The EPA is aware of only one new coal-fired power plant that is actively in the construction phase. That plant is Mississippi Power's Kemper County Energy Facility in Kemper County, MS—an IGCC unit that plans to begin operations in 2016 and will implement partial CCS to capture approximately 65 percent of the available CO_2, which will be sold for use in EOR operations.

Considering the direction that the power sector has been taking and the changes that it is undergoing, identifying a new supercritical unit as the BSER and requiring an emission limitation based on the performance of such units thus would provide few, if any, additional CO_2 emission reductions beyond the sector's ''business as usual''. As noted, for the most part, new sources are already designed to achieve at least that emission limitation. This criterion does not itself eliminate supercritical technology from consideration as BSER. However, existing technologies must be considered in the context of the range of technically feasible technologies and, as we discuss elsewhere in this final preamble, partial CCS can achieve emission limitations beyond business as usual and do so at a reasonable cost.

The EPA also considered IGCC technology and whether it represents the BSER for new power plants utilizing coal or other solid fossil fuels. IGCC units, on a gross-output basis, have inherently lower CO_2 emission rates when compared to similarly-sized SCPC units. However, the net emission rates and overall emissions to the atmosphere (*i.e.,* tons of CO_2 per year) tend to be more similar (though still somewhat lower) for new IGCC units when compared to new SCPC units with the same electrical output. Therefore an emission limitation based on the expected performance of a new IGCC unit would result in some CO_2 emission reductions from the segment of the industry that would otherwise construct new PC units, but not from the segment of the industry that would already construct new IGCC units. A gross-output-based emission limitation consistent with the expected performance of a new IGCC unit would still require some additional control, such as partial CCS, on a new supercritical boiler.

As is shown in Section V.J and H, additional emission reductions beyond those that would result from an emission standard based on a new SCPC boiler or even a new IGCC unit as the BSER can be achieved at a reasonable cost. Because practicable emission controls are available that are of reasonable cost at the source level and that will have little cost and energy impact at the national level, the EPA is according significant weight to the factor of amount of emissions reductions in determining the BSER. As discussed above, the D.C. Circuit has emphasized this factor in describing the purpose of CAA section 111 as to achieve ''as much [emission reduction] as practicable.'' [515]

b. Lack of Incentive for Technological Innovation

As discussed above, the EPA is justifying its identification of the BSER based on its weighing of the factors explicitly identified in CAA section 111(a)(1), including the amount of the emission reduction. Under the D.C. Circuit case law, encouraging the development and implementation of advanced control technology must also be considered (and, in any case, may reasonably be considered; see Section V.H.3.d above). Consideration of this factor confirms the EPA's decision not to identify highly efficient generation technology (without CCS) as the BSER. At present, CCS technologies are the most promising options to achieve significant reductions in CO_2 emissions from newly constructed fossil fuel-fired steam generating units. CCS technology is also now a viable retrofit option for some modified, reconstructed and existing sources—depending upon the configuration, location and age of those sources. As CCS technologies are deployed and used more there is an expectation that, based on previous experience with advanced technologies, the performance will improve and the implementation costs will decline. The improved performance and lower costs will provide additional incentive for further implementation in the future.

The Intergovernmental Panel on Climate Change (IPCC) recently released its Fifth Assessment report, [516] which recognizes that widespread deployment of CCS is crucial to reach the long term climate goals. The authors of the report used models to predict the likelihood of stabilizing the atmospheric concentration of CO_2 at 450 ppm by 2050 with or without carbon capture and storage (CCS). They found that several of the models were not able to reach this goal without CCS, which underlines the importance of deploying and further developing CCS on a large scale.

American Electric Power (AEP), in an evaluation of lessons learned from the Phase 1 of its Mountaineer CCS project, wrote: ''AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation.'' [517]

Some commenters felt that the proposed standard of performance for new steam generating units, based on implementation of partial CCS at an emission rate of 1,100 lb/MWh-g, would not serve to promote the increased deployment and implementation of CCS. The commenters argued that such a standard could instead have the unintended result of discouraging the further development of advanced coal generating technologies such as ultra-supercritical boilers and improved IGCC designs.

Commenters further argued that such a standard will stifle further

[513] A ''CCS ready'' facility is one that is designed such that the CCS equipment can be more easily added at a later time.

[514] Available in the rulemaking docket (entry: EPA–HQ–OAR–2013–0495–0024).

[515] *Sierra Club,* 657 F.2d at 327 & n. 83.

[516] IPCC, Working Group III, Climate Change 2014: Mitigation of Climate Change, *http://mitigation2014.org/report/publication/*.

[517] CCS LESSONS LEARNED REPORT American Electric Power Mountaineer CCS II Project Phase 1, Prepared for The Global CCS Institute Project # PRO 004, January 23, 2012, page 2. See also AEP FEED Study at pp. 4, 63 (same). Available at: *http://www.globalccsinstitute.com/publications/aep-mountaineer-ii-project-front-end-engineering-and-design-feed-report*.

development of CCS technologies. Commenters felt that the standard would effectively deter the construction of new coal-fired generation—and, if there is no new coal-fired generation, then there will be no implementation of CCS technology and, therefore, no need for continued research and development of CCS technologies. They argued, in fact, that the best way to promote the development of CCS was to set a standard that did not rely on it.

The EPA does not agree with these arguments and, in particular, does not see how a standard that is not predicated on performance of an advanced control technology would serve to promote development and deployment of that advanced control technology. On the contrary, the history of regulatory actions has shown that emission standards that are based on performance of advanced control equipment lead to increased use of that control equipment, and that the absence of a requirement stifles technology development.

There is a dramatic instance of this paradigm presented in the present record. In 2011, AEP deferred construction of a large-scale CCS retrofit demonstration project on one of its coal-fired power plants because the state's utility regulators would not approve cost recovery for CCS investments without a regulatory requirement to reduce CO_2 emissions. AEP's chairman was explicit on this point, stating in a July 17, 2011 press release announcing the deferral:

We are placing the project on hold until economic and policy conditions create a viable path forward . . . We are clearly in a classic 'which comes first?' situation. The commercialization of this technology is vital if owners of coal-fueled generation are to comply with potential future climate regulations without prematurely retiring efficient, cost-effective generating capacity. But as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share.[518]

Some commenters also argued that the incremental cost associated with including CCS at the proposed level would prevent new coal-fired units from being built. Instead, they advocated for a standard based on most efficient technology (supercritical) coupled with government subsidies to advance and promote CCS technology. The final standard is less stringent than that proposed, and can be met at a lower cost than the proposed standard, and as explained above in Section V.H, the EPA has carefully evaluated those costs and finds them to be reasonable. Further, the record and current economic conditions (fuel costs, renewables, demand growth, etc.) show that non-economic factors such as a desire for fuel diversity will likely drive future development of any new coal-fired EGUs. For this reason, the EPA does not find the commenters' bare assertions that the incremental cost of CCS (particularly as reasonably modulated for this final standard) would make the difference between constructing and not constructing new coal capacity to be persuasive. Rather, a cost-reasonable standard reflecting use of the new technology is what will drive new technology deployment.

The EPA expects that it is unlikely that a new IGCC unit would install partial CCS to meet the final standard unless the facility is built to take advantage of EOR opportunities or to operate as a poly-generation facility (*i.e.,* to co-produce power along with chemicals or other products). For new IGCC units, the final standard of performance can be met by co-firing a small amount of natural gas. Some commenters argued that IGCC is an advanced technology that, like CCS, should be promoted. The EPA agrees. IGCC is a low-emitting, versatile technology that can be used for purposes beyond just power production (as mentioned just above). Commenters further argued that a requirement to include partial CCS (at a level to meet the proposed standard of performance) would serve to deter—rather than promote—more installation of IGCC technology. We disagree with a similar argument that commenters make with respect to partial CCS for post-combustion facilities, but our final standard moots that argument for IGCC facilities because the final emission limitation of 1,400 lb CO_2/MWh-g will not itself deter installation of IGCC technology, by the terms of the commenters' own argument.

2. ''Full'' Carbon Capture and Storage (*i.e.,* 90 Percent Capture)

We also reconsidered whether the emission limitation for new coal-fired EGUs should be based on the performance of full implementation of CCS technology. For a newly constructed utility boiler, this would mean that a post-combustion capture system would be used to treat the entire flue gas stream to achieve an approximately 90 percent reduction in CO_2 emissions. For a newly constructed IGCC unit, a pre-combustion capture system would be used to capture CO_2 from a fully shifted gasification syngas stream to achieve an approximately 90 percent reduction in CO_2 emissions.

In the proposal for newly constructed sources, we found that ''full CCS'' would certainly result in significant CO_2 reductions from any new source implementing the technology. However, we also found that the costs associated with implementation, on either a new utility boiler system or a new IGCC unit, are predicted to substantially exceed the costs for other dispatchable non-NGCC generating options that are being considered by utilities and project developers (*e.g.,* new nuclear plants and new biomass-fired units). See 79 FR at 1477. This remains the case, and indeed, the difference between cost of full capture and new nuclear technology is estimated to be even greater than at proposal. The EPA thus is not selecting full capture CCS as BSER.

Q. Summary

The EPA finds that the best system of emission reduction adequately demonstrated is a highly efficient supercritical pulverized coal boiler using post-combustion partial CCS so that CO_2 is captured, compressed and safely stored over the long-term. Properly designed, operated, and maintained, this best system can achieve a standard of performance of 1,400 lb CO_2/MWh-g, an emission limitation that is achievable over the 12-operating-month compliance period considering usual operating variability (including use of different coal types, periods of startup and shutdown, and malfunction conditions). This standard of performance is technically feasible, given that the BSER technology is already operating reliably in full-scale commercial application. The technology adds cost to a new facility which the EPA has evaluated and finds to be reasonable because the costs are in the same range as those for new nuclear generating capacity—a competing non-NGCC, dispatchable technology that utilities and project developers are also considering for base load application. The EPA has also considered capital cost increases associated with use of post-combustion partial CCS at the level needed to meet the final standard and found them to be reasonable, and within the range of capital cost increases for this industry in prior NSPS which have been adjudicated as reasonable. The EPA's consideration of costs is also informed by its judgment that new coal-

[518] *http://www.aep.com/newsroom/newsreleases/?id=1704.*

fired capacity would be constructed not as the most economic option, but for such purposes as preserving fuel diversity in an energy portfolio, and so would not be cost competitive with natural gas-fired capacity, so that some additional cost premium may therefore be reasonable. The EPA has carefully evaluated the non-air quality health and environmental impacts of the final standard and found them to be reasonable: CO_2 pipelines and CO_2 sequestration via deep well injection are subject already to rigorous control under established regulatory programs which assure prevention of environmental release during transport and storage. In addition, water use associated with use of partial CCS at the level to meet the final standard is acceptable, and use of the technology does not impose significant burdens on energy requirements at either the plant or national level. The 1,400 lb CO_2/MWh-g standard reflecting performance of the BSER may be achieved without geographic constraint, both because geologic sequestration and EOR capacity are widely available and accessible, and also because alternative compliance pathways are available in the unusual circumstance where a new coal-fired plant is sited in an area without such access, that area has not already limited construction of new coal-fired capacity in some way, and the area cannot be serviced by coal-by-wire. Accordingly, the EPA finds that the promulgated standard of performance for new fossil fuel-fired steam electric generating units satisfies the requirements of CAA section 111(a).

VI. Rationale for Final Standards for Modified Fossil Fuel-Fired Electric Utility Steam Generating Units

The EPA has determined that, as proposed, the BSER for steam generating units that trigger the modification provisions is each affected unit's own best potential performance as determined by that unit's historical performance. The final standards of performance are similar to those proposed in the June 2014 proposal. Differences between the proposed standards and the final standards issued in this action reflect responses to comments received on the proposal. Those changes are described below.

As noted previously, the EPA is issuing final emission standards only for affected modified steam generating units that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of more than 10 percent (''large'' modifications). The EPA is continuing to review the appropriate standards for modified sources that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of less than or equal to 10 percent (''small'' modifications), is not issuing final standards for those sources in this action, and is withdrawing the proposed standards for those sources. See Section XV below.

A. Rationale for Final Applicability Criteria for Modified Steam Generating Units

Final applicability criteria for modified steam generating EGUs include those discussed earlier in Section III.A.1 (General Applicability) and Section III.A.3 (Applicability Specific to Modified Sources).

CAA section 111(a)(4) defines a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' Certain types of physical or operational changes are exempt from consideration as a modification. Those are described in 40 CFR 60.2, 60.14(e). To be clear, our action in this final rule, and the discussion below, does not change anything concerning what constitutes or does not constitute a modification under the CAA or the EPA's regulations.[519]

A modified steam generating unit is a source that fits the definition and applicability criteria of a fossil fuel-fired steam generating unit and that commences a qualifying modification on or after June 18, 2014 (the publication date of the proposed modification standards). 79 FR 34960.

For the reasons discussed below, the EPA in this final action is finalizing requirements only for steam generating units that conduct modifications resulting in an increase in hourly CO_2 emissions (mass per hour) of more than 10 percent as compared to the source's highest hourly emission during the previous five years. With respect to modifications with smaller increases in CO_2 emissions (specifically, steam generating units that conduct modifications resulting in an increase in hourly CO_2 emissions (mass per hour) of 10 percent or less compared to the source's highest hourly emission during the previous 5 years), the EPA is not finalizing any standard or other requirements, and is withdrawing the June 2014 proposal with respect to these sources (see Section XV below).

The effect of the EPA's deferral on setting standards for sources undertaking modifications resulting in smaller increases in CO_2 emissions and the withdrawal of the June 2014 proposal with respect to such sources is that such sources will continue to be existing sources and subject to requirements under section 111(d). This is because an existing source does not always become a new source when it modifies. Under the definition of ''new source'' in section 111(a)(2), an existing source only becomes a new source if it modifies after the publication of proposed or final regulations that will be applicable to it. Thus, if an existing source modifies at a time that there is no promulgated final standard or pending proposed standard that will be applicable to it as a modified ''new'' source, that source is not a new source and continues to be an existing source. Here, because the EPA is not finalizing standards for sources undertaking modifications resulting in smaller increases in CO_2 emissions and is withdrawing the proposal with respect to such sources, these sources do not fall within the definition of ''new source'' in section 111(a)(2) and continue to be an ''existing source'' as defined in section 111(a)(6). See Section XV below.

As we discussed in the June 2014 proposal, the EPA has historically been notified of only a limited number of NSPS modifications[520] involving fossil steam generating units and therefore predicted that very few of these units would trigger the modification provisions and be subject to the proposed standards. Given the limited information that we have about past modifications, the agency has concluded that it lacks sufficient information to establish standards of performance for all types of modifications at steam generating units at this time. Instead, the EPA has determined that it is appropriate to establish standards of performance at this time for larger modifications, such as major facility upgrades involving, for example, the refurbishing or replacement of steam turbines and other equipment upgrades that result in substantial increases in a unit's hourly CO_2 emissions rate. The agency has determined, based on its review of public comments and other publicly available information, that it has adequate information regarding the types of modifications that could result in large increases in hourly CO_2 emissions, as well as on the types of

[519] CAA section 111(a)(4); See also 40 CFR 60.14 concerning what constitutes a modification, how to determine the emission rate, how to determine an emission increase, and specific actions that are not, by themselves, considered modifications.

[520] NSPS modifications resulting in increases in hourly emissions of criteria pollutants.

measures available to control emissions from sources that undergo such modifications, and on the costs and effectiveness of such control measures, upon which to establish standards of performance for modifications with large emissions increases at this time.

In establishing standards of performance at this time for modifications with large emissions increases, but not for those with small increases, the EPA is exercising its policy discretion to promulgate regulatory requirements in a sequential fashion for classes of modifications within a source category, accounting for the information available to the agency, while also focusing initially on those modifications with the greatest potential environmental impact. This approach is consistent with the case law that authorizes agencies to establish a regulatory framework in an incremental fashion, that is, a step at a time.[521]

To be clear, the EPA is not reaching a final decision as to whether it will regulate modifications with smaller increases, or even that such modifications should be subject to different requirements than we are finalizing in this rule for the modifications with larger increases. We have made no decisions and this matter is not concluded. We plan to continue to gather information, consider the options for modifications with smaller increases, and, in the future, develop a proposal for these modifications or otherwise take appropriate steps.

As a means of determining the proper threshold between the larger and smaller increases in CO_2 emissions, the EPA examined changes in CO_2 emissions that may result from large, capital-intensive projects, such as major facility upgrades involving the refurbishing or replacement of steam turbines and other equipment upgrades that would significantly increase a unit's capacity to burn more fossil fuel, thereby resulting in large emissions increases. Major upgrades such as these could increase a steam generating unit's hourly CO_2 emissions by well over 10 percent.[522]

An example of such major upgrade would be work performed at AmerenUE's Labadie Plant, a facility with four 600–MW (nominal) coal-fired units located 35 miles west of St. Louis. In the early 2000s, plant staff conducted process improvements that raised maximum unit capacity by nearly 10 percent (from 580 MW to 630 MW).[523] Those changes included boiler improvements necessitated by its switch from bituminous to subbituminous coal,[524] installation of low-NO_X burners, an overfire air system, and advanced computer controls. One of the performance gains came from upgrading all four steam turbines, which AmerenUE chose to replace as modules allowing engineers more freedom to maximize performance unconstrained by the units' existing outer casing.

Another example is the refurbishment of the 2,100 MW Eskom Arnot coal-fired power plant in South Africa with a resulting increase in its power output by 300 MW to 2,400 MW—an increase in capacity of 14 percent.[525] For each of the plant's six steam generating units, the company conducted a complete retrofit of the high pressure and intermediate pressure steam turbines, a capacity upgrade of the low pressure steam turbine, and the replacement and upgrade of associated turbine side pumps and auxiliaries. In addition, major upgrades to the boiler plant were conducted, including supply of new pressure part components, new burners, and modification to other equipment such as the coal mills and classifiers, fans, and heaters. Other examples are provided in a technical memo available in the rulemaking docket.[526]

The EPA does not intend to imply that these specific projects would have resulted in an increase in hourly CO_2 emissions of greater than 10 percent. Capacity increases are often the result of efficient improvements or are accompanied by other facility improvements that can offset emissions increases due to increased fuel input capacity. However, these examples are intended to show the types of large, more capital intensive projects that can potentially result in increases in hourly emissions of CO_2 of at least 10 percent.

The EPA believes that it is reasonable to set the threshold between ''large'' modifications and ''small'' modifications at 10 percent, a level commensurate with the magnitude of the emissions increases that could result from the types of projects described above, and we are issuing a final standard of performance for those sources that conduct modifications resulting in hourly CO_2 emission increases that exceed that threshold. We are not issuing standards of performance for those sources that conduct modifications resulting in an hourly increase of CO_2 emissions of less than or equal to 10 percent.

Therefore, the EPA is withdrawing the proposed standards for those sources that conduct modifications resulting in a hourly increase in CO_2 emissions (mass per hour) of less than or equal to ten percent and is not issuing final standards for those sources at this time. See Section XV below. Utilities, states and others should be aware that the differentiation between modifications with larger and smaller increases in CO_2 emissions only applies to sources covered under 40 CFR part 60, subpart TTTT, *i.e.,* it is only applicable to CO_2 emissions from fossil fuel-fired steam generating units. There is no similar provision for criteria pollutants or for other source categories. Utilities, states and others should also be aware that the distinction between large and small modifications only applies to NSPS modifications. Sources undertaking modifications may still be subject to requirements of New Source Review under CAA Title I part C or D (which have different standards for modifications than the NSPS and require a case-by-case analysis) or other CAA requirements.

The EPA notes that some commenters expressed concern that a number of existing fossil steam generating units, in order to fulfill requirements of an approved CAA section 111(d) plan, may pursue actions that involve physical or operational changes that result in some increase in their CO_2 emissions on an hourly basis, and thus constitute

[521] As the U.S. Supreme Court recently stated in *Massachusetts* v. *EPA,* 549 U.S. 497, 524 (2007): '' 'Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;' '' and instead they may permissibly implement such regulatory programs over time, '' 'refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed.' '' *See Grand Canyon Air Tour Coalition* v. *F.A.A.,* 154 F.3d 455 (D.C. Cir. 1998), *City of Las Vegas* v. *Lujan,* 891 F.2d 927, 935 (D.C. Cir. 1989), *National Association of Broadcasters* v. *FCC,* 740 F.2d 1190, 1209–14 (D.C. Cir. 1984). See also, *Hazardous Waste Treatment Council* v. *U.S. E.P.A.*, 861 F.2d 277, 287 (D.C. Cir. 1988) (''[A]n agency's failure to regulate more comprehensively is not ordinarily a basis for concluding that the regulations already promulgated are invalid. 'The agency might properly take one step at a time.' *United States Brewers Assoc.* v. *EPA,* 600 F.2d 974,982 (D.C. Cir. 1979). Unless the agency's first step takes it down a path that forecloses more comprehensive regulation, the first step is not assailable merely because the agency failed to take a second. The steps may be too plodding, but that raises an entirely different issue . . . .'').

[522] See *e.g.,* Power Engineering, Steam Turbine Upgrades Boost Plant Reliability, Efficiency, available at *www.power-eng.com/articles/print/volume-116/issue-11/features/steam-turbine-upgrades-boost-plant-reliability-efficiency.html.*

[523] ''Steam turbine upgrading: Low-hanging fruit'', Power (04/15/2006), *www.powermag.com/steam-turbine-upgrading-low-hanging-fruit.*

[524] Note that a change in coal-type or change in the use of other raw material does not necessarily constitute an ''operational change''. See 40 CFR 60.14(e)(4).

[525] *www.alstom.com/press-centre/2006/10/alstom-signs-power-plant-upgrade-and-retrofit-contract-with-eskom-in-south-africa/.*

[526] See ''U.S. DOE Information Relevant to Technical Basis for ''Large Modification'' Threshold'' available in the rulemaking docket EPA–HQ–OAR–2013–0495.

modifications. Some commenters suggested that the EPA should exempt projects undertaken specifically for the purpose of complying with CAA section 111(d).

The EPA does not have sufficient information at this time to predict the full array of actions that existing steam generating units may undertake in response to applicable requirements under an approved CAA section 111(d) plan, or which, if any, of these actions may result in increases in CO_2 hourly emissions. Nevertheless, the EPA expects that, to the extent actions undertaken by existing steam generating units in response to 111(d) requirements trigger modifications, the magnitude of the increases in hourly CO_2 emissions associated with such modifications would generally be smaller and would therefore generally not subject such modifications to the standards of performance that the EPA is finalizing in this rule for modified steam generating units with larger increases in hourly CO_2 emissions.

B. Identification of the Best System of Emission Reduction

The EPA has determined that, as was proposed, the BSER for steam generating units that trigger the modification provisions is the affected EGU's own best potential performance as determined by that source's historical performance.

The EPA proposed that the BSER for modified steam generating EGUs is each unit's own best potential performance based on a combination of best operating practices and equipment upgrades. Specifically, the EPA co-proposed two alternative standards for modified utility steam generating units. In the first co-proposed alternative, modified steam generating EGUs would be subject to a single emission standard determined by the affected EGU'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 proposed that the standard could 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 specified that modified facilities would not have to meet an emission standard more stringent than the corresponding standard for reconstructed EGUs.

The EPA also co-proposed that the specific standard for modified sources would be dependent on the timing of the modification. We proposed 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-proposal—that is, the modified source would be required to meet a unit-specific emission limit determined by the affected EGU'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). We also proposed that 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 final standards in this action do not depend upon when the modification commences (as long as it commences after June 8, 2014). The EPA received comments on the June 2014 proposal that called into question the need to differentiate the standard based on when the modification was undertaken. Further, commenters noted that the proposed requirements for sources modifying after becoming subject to a CAA section 111(d) plan, which were based on energy efficiency improvement opportunities were vague and that standard setting under CAA section 111(b) is a federal duty and would require notice-and-comment rulemaking. The EPA considered those comments and has determined that we agree that there is no need for subcategories based on the timing of the modification.

C. BSER Criteria

1. Technical Feasibility

The EPA based technical feasibility of the unit-specific efficiency improvement on analyses done to support heat rate improvement for the proposed CAA section 111(d) emission guidelines (Clean Power Plan). That work was summarized in Chapter 2 of the TSD, ''GHG Abatement Measures''.[527] In response to comments on the proposed Clean Power Plan, the approach was adjusted, as described in the final CAA section 111(d) emission guidelines. As with proposed actions, the EPA is basing technical feasibility for final standards for modified source efficiency improvements on the analyses for heat rate improvements for the CAA 111(d) final rule.

2. Cost

Any efficiency improvement made by EGUs for the purpose of reducing CO_2 emissions will also reduce the amount of fuel that EGUs consume to produce the same electricity output. The cost attributable to CO_2 emission reductions, therefore, is the net cost of achieving heat rate improvements after any savings from reduced fuel expenses. As summarized below, we estimate that, on average, the savings in fuel cost associated with a 4 percent heat rate improvement would be sufficient to cover much of the associated costs, and thus that the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low.

We recognize that our cost analysis just described will represent the costs for some EGUs better than others because of differences in EGUs' individual circumstances. We further recognize that reduced generation from coal-fired EGUs will tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that the majority of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of implementing heat rate improvements as an approach to reducing CO_2 emissions from modified fossil fuel-fired EGUs are reasonable. The EPA further notes that the types of large, more capital intensive projects that may trigger the ''larger modifications'' threshold (*i.e.,* result in an hourly increase in CO_2 emissions of more than 10 percent) often are undertaken in order to increase the capacity of the source but also to improve the heat rate or efficiency of the unit.

3. Emission 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.

4. Promotion of Technology and Other Systems of Emission Reduction

As noted previously, the case law makes clear that the EPA is to consider

[527] Technical Support Documents ''GHG Abatement Measures'' (proposal) and ''GHG Mitigation Measures'' (final) available in the rulemaking docket EPA–HQ–OAR–2013–0495.

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 standards promote technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

VII. Rationale for Final Standards for Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units

A. Rationale for Final Applicability Criteria for Reconstructed Sources

The applicability rationale for reconstructed utility steam generating units is the same as for newly constructed utility steam generating units. We are finalizing the same general criteria and not amending the reconstruction provisions included in the general provisions.

B. Identification of the Best System of Emission Reduction

In the proposal, the EPA evaluated seven different control technology configurations to determine 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 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.

Although the EPA concluded that the first 4 technologies met most of the evaluation criteria, namely they are adequately demonstrated, have reasonable costs and provide GHG emissions reductions, they were inappropriate for BSER due to site specific constraints for existing EGUs on a nationwide basis. We rejected best operating practices and equipment upgrades because we concluded the GHG reductions are not sufficient to qualify as BSER. The majority of commenters agree with the EPA's decision that these technologies are not BSER. In contrast, as described in more detail later in this section a few commenters did support partial CCS as BSER.

The fifth option, reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency, is comparable to application of measures identified in building blocks two, three and four in the emissions guidelines that we proposed under CAA section 111(d). We solicited 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. Most commenters stated that building blocks two, three and four should not be considered for reconstructed sources.

The proposed BSER was based on the performance of the most efficient generation technology available, which we concluded was the use of the best available subcritical steam conditions for small units and the use of supercritical steam conditions for large units. We concluded this technology to be technically feasible, to have sufficient emission reductions, to have reasonable costs, and some opportunity for technological innovation. The proposed emission standard for these sources was 1,900 lb CO_2/MWh-n for units with a heat input rating of greater than 2,000 MMBtu/h and 2,100 lb CO_2/MWh-n for units with a heat input rating of 2,000 MMBtu/h or less. The difference in the proposed standards for larger and smaller units was based on greater availability of higher pressure/temperature steam turbines (*e.g.* supercritical steam turbines) for larger units. As explained in Section III of this preamble, we are finalizing the standard on a gross output basis for utility steam generating units. The equivalent gross-output-based standards are 1,800 lb CO_2/MWh and 2,000 lb CO_2/MWh respectively.

We solicited comment on multiple aspects of the proposed standards. First, we solicited comment on a range of 1,600 to 2,000 lb CO_2/MWh-g for large units and 1,800 to 2,200 lb CO_2/MWh-g for small units. We also solicited comment on whether the standards for utility boilers and IGCC units should be subcategorized by primary fuel type. In addition, we solicited comment on if there are sufficient alternate compliance technologies (*e.g.,* co-firing natural gas) that the small unit subcategory is unnecessary and should be eliminated. Those small sources would be required to meet the same emission standard as large utility boilers and IGCC units.

Many commenters supported the upper limits of the suggested ranges, saying the standard will be consistently met. Some commenters raised concerns about the achievability of these limits for the many boiler and fuel types. A few commenters suggested that there should be separate subcategories for coal-fired utility boilers and IGCC units, since IGCC units have demonstrated limits closer to 1,500 lb CO_2/MWh-n and the units' designs are so fundamentally different. Some commenters said that CFB (due to lower maximum steam temperatures), IGCC, and traditional boilers each need their own subcategory. Some commenters suggested that due to high moisture content and high relative CO_2 emissions of lignite, lignite-fired units should have its own subcategory. Other commenters opposed the proposed standards for reconstructed units because they thought the BSER determination for reconstructed subpart Da units was inconsistent with the BSER determination for newly constructed units. These commenters stated that the EPA did not provide sufficient justification for eliminating partial carbon capture and sequestration (CCS). These commenters also stated that the reason the EPA gave for dismissing CCS in the proposal was a lack of ''sufficient information about costs.'' These commenters hold that the cost rationale does not apply for reconstructed coal-fired power plants. The fact that reconstructed units may face greater costs to comply with a CAA section 111(b) standard than new sources does not relieve them of their compliance obligation.

Based on a review of the comments, we have concluded that both the proposed BSER and emission standards are appropriate, and we are finalizing the standards as proposed. Nothing in the comments changed our view that the BSER for reconstructed steam generating units should be based on the performance of a well operated and maintained EGU using the most efficient generation technology available, which we have concluded is a supercritical pulverized coal (SCPC) or supercritical circulating fluidized bed (CFB) boiler for large units, and subcritical for small units. As described at proposal, we have concluded that these standards are achievable by all the primary coal types. The final standards for reconstructed utility boilers and IGCC units is 1,800 lb CO_2/MWh-g for sources with a heat input rating of greater than 2,000 MMBtu/h and 2,000 lb CO_2/MWh-g for sources with a heat input rating of 2,000 MMBtu/h or less.

While the final emission standards are based on the identified BSER, a reconstructed EGU would not necessarily have to rebuild the boiler to use steam temperatures and pressures that are higher than the original design. As commenters noted, a reconstructed unit is not required to meet the standards if doing so is deemed to be ''technologically and economically'' infeasible. 40 CFR 60.15(b). This provision inherently requires case-by-case reconstruction determinations in the light of considerations of economic and technological feasibility. However, this case-by-case determination would consider the identified BSER (the use of the best available steam conditions), as well as—at a minimum—the first four technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and reasonable cost, depending on site specific considerations and, if so, would likely result in sufficient GHG reductions to comply with the applicable reconstructed standards. Finally, in some cases, equipment upgrades and best operating practices would result in sufficient reductions to achieve the reconstructed standards.

VIII. Summary of Final Standards for Newly Constructed and Reconstructed Stationary Combustion Turbines

This section summarizes the final applicability requirements, BSER determinations, and emission standards for newly constructed and reconstructed stationary combustion turbines. In addition, it also summarizes significant differences between the proposed and final provisions.

A. Applicability Requirements

We are finalizing BSER determinations and emission standards for newly constructed and reconstructed stationary combustion turbines that (1) have a base load rating for fossil fuels greater than 260 GJ/h (250 MMBtu/h) and (2) serve a generator capable of selling more than 25 MW-net of electricity to the grid. We also are finalizing applicability requirements that will exempt from the final standards (1) all stationary combustion turbines that are dedicated non-fossil fuel-fired units (*i.e.,* combustion turbines capable of combusting 50 percent or more non-fossil fuel) and subject to a federally enforceable permit condition restricting annual fossil fuel use to 10 percent or less of a unit's annual heat input capacity; (2) the large majority of industrial CHP units (*i.e.,* CHP combustion turbines that are subject to a federally enforceable permit condition limiting annual net-electric sales to the product of the unit's net design efficiency multiplied by the unit's potential output, or 219,000 MWh, whichever is greater); (3) combustion turbines that are physically incapable of burning natural gas (*i.e.,* not connected to a natural gas pipeline); and (4) municipal waste combustors and commercial or industrial solid waste incinerators (units subject to subparts Eb or CCCC of this part).

For combustion turbines subject to an emission standard, we are finalizing three subcategories: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. We use the term base load natural gas-fired units to refer to stationary combustion turbines that (1) burn over 90 percent natural gas and (2) sell electricity in excess of their design efficiency (not to exceed 50 percent) multiplied by their potential electric output. To be in this subcategory, a stationary combustion turbine must exceed the ''natural gas-use criterion'' on a 12-operating-month rolling average and the ''percentage electric sales'' criterion on both a 12-operating-month and 3-year rolling average basis. We use the term non-base load natural gas-fired units to refer to stationary combustion turbines that (1) burn over 90 percent natural gas and (2) have net-electric sales equal to or below their design efficiency (not to exceed 50 percent) multiplied by their potential electric output. These criteria are calculated on the same rolling average bases as for the base load subcategory. Finally, we use the term multi-fuel-fired units to refer to stationary combustion turbines that burn 10 percent or more non-natural gas on a 12-operating-month rolling average basis. We are not finalizing the proposed emission standards for modified sources and are withdrawing those standards. We explain our rationale for these final decisions in Sections IX and XV of this preamble.

B. Best System of Emission Reduction

We are finalizing BSER determinations for the three subcategories of stationary combustion turbines referred to above: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the BSER is the use of efficient NGCC technology. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines, the BSER is the use of clean fuels (*i.e.,* natural gas with an allowance for a small amount of distillate oil). For multi-fuel-fired stationary combustion turbines, the BSER is also the use of clean fuels (*e.g.,* natural gas, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, biodiesel, and landfill gas).

C. Final Emission Standards

For all newly constructed and reconstructed base load natural gas-fired combustion turbines, we are finalizing an emission standard of 1,000 lb CO_2/MWh-g, calculated on a 12-operating-month rolling average basis. We are also finalizing an optional emission standard of 1,030 lb CO_2/MWh-n, calculated on a 12-operating-month rolling average basis, for stationary combustion turbines in this subcategory. For newly constructed and reconstructed non-base load natural gas-fired combustion turbines, we are finalizing a standard of 120 lb CO_2/MMBtu, calculated on a 12-operating-month rolling average basis. For newly constructed and reconstructed multi-fuel-fired combustion turbines, we are finalizing a standard of 120 to 160 lb CO_2/MMBtu, calculated on a 12-operating-month rolling average basis. The emission standard for multi-fuel-fired combustion turbines co-firing natural gas with other fuels shall be determined at the end of each operating month based on the percentage of co-fired natural gas. Table 15 summarizes the subcategories, BSER determinations, and emission standards for combustion turbines.

TABLE 15—COMBUSTION TURBINE SUBCATEGORIES AND BSER

Subcategory	BSER	Emission standard
Base load natural gas-fired combusiton turbines	Efficient NGCC	1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n
Non-base load natural gas-fired combustion turbines	Clean fuels	120 lb CO_2/MMBtu
Multi-fuel-fired combustion turbines	Clean fuels	120 to 160 lb CO_2/MMBtu [528]

D. Significant Differences Between Proposed and Final Combustion Turbine Provisions

As shown in Tables 16 and 17 below, the proposed rule included several general applicability criteria and two subcategorization criteria for combustion turbines. In addition to the proposed applicability and subcategorization framework, we solicited comment on a ''broad applicability approach'' that included most combustion turbines irrespective of the actual amount of electricity sold to the grid or the actual amount of natural gas burned (*i.e.,* non-base load units and multi-fuel-fired units, respectively). The broad applicability approach changed the proposed ''percentage electric sales'' and ''natural gas-use'' criteria to distinguish among subcategory-specific emissions standards. Specifically, in the broad applicability approach, we solicited comment on subjecting non-base load units and multi-fuel-fired units to ''no emissions standard,'' while still including them in the general applicability. We also solicited comment on establishing a separate numerical standard for non-base load units. The final rule retains all of the proposed applicability criteria in some form, but most closely tracks the broad applicability approach by finalizing the percentage electric sales and natural gas-use criteria as thresholds that distinguish among three subcategories of combustion turbines with separate emissions standards.

The final rule also includes exceptions to the broad applicability approach that we solicited comment on, with some changes that are responsive to public comments. Categorical exceptions to the broad applicability criteria are the exclusions for CHP units, non-fossil fuel units, and combustion turbines not able to combust natural gas. First, the proposed applicability criteria did not include CHP units that were constructed for the purpose of or that actually sell one-third or less of their potential electric output or 219,000 MWh, whichever is greater, to the grid. The final rule eliminates the ''constructed for the purpose of'' and actual sales aspects of the proposal and replaces them with an exemption for CHP units that take federally enforceable permit conditions restricting net-electric sales to a percentage of potential electric sales based on the unit's design efficiency or 219,000 MWh, whichever is greater. Second, the proposed applicability criteria did not include non-fossil fuel units that burn 10 percent or less fossil fuel on a 3-year rolling average. The final rule similarly replaces the actual fuel-use aspect of the proposal with an exemption for non-fossil fuel units that take federally enforceable permit conditions limiting fossil-fuel use to 10 percent or less of annual heat input capacity. Finally, the proposed applicability criteria did not include combustion turbines that burn 90 percent or less natural gas on a 3-year rolling average basis. In contrast, the final rule includes most fossil fuel-fired combustion turbines regardless of the amount of natural gas burned, with an exception for combustion turbines that are not connected to natural gas pipelines. Finally, in response to public comments, we are not finalizing the subcategories for large and small combustion turbines that were contained in the proposal. Instead, all base load natural gas-fired combustion turbines must meet an emission standard of 1,000 lb CO_2/MWh-g.

TABLE 16—PROPOSED APPLICABILITY CRITERIA VERSUS FINAL APPLICABILITY CRITERIA

Applicability Criteria	Proposed Applicability	Final Applicability
Base load rating criterion	Base load rating > 73 MW (250 MMBtu/h)	Base load rating > 260 GJ/h [529] (250 MMBtu/h)
Total electric sales criterion	Constructed for purpose of and actually selling > 219,000 MWh-n to the grid.	Ability to sell > 25 MW-n to the grid
Percentage electric sales criterion	Constructed for purpose of and having actual net-sales to the grid > one-third of potential electric output.	Changed to subcategorization criterion per broad applicability approach
Natural gas-use criterion	Actually burns > 90 percent natural gas	• Changed to subcategorization criterion per broad applicability approach • Exemption for combustion turbines that are not connected to a natural gas supply
Fossil fuel-use criterion	Actually burns > 10 percent fossil fuel	Exemption based on permit condition limiting amount of fossil fuel burned to ≤ 10 percent of annual heat input capacity
Combined Heat and Power (CHP) exemption	NA	Exemption based on permit condition limiting net-electric sales to ≤ design efficiency multiplied by potential electric output, or 219,000 MWh-n, whichever is greater
Non-EGU exemption	Exemption for municipal solid waste combustors and commercial or industrial solid waste incinerators.	Same as proposal

[528] The emission standard for combustion turbines co-firing natural gas with other fuels shall be determined based on the amount of co-fired natural gas at the end of each operating month.

TABLE 17—PROPOSED SUBCATEGORIES VERSUS FINAL SUBCATEGORIES

Subcategory	Proposed Criteria	Final Criteria
Small combustion turbine subcategory	Base load rating ≤ 850 MMBtu/h	NA
Large combustion turbine subcategory	Base load rating > 850 MMBtu/h	NA
Base load natural gas-fired base load combustion turbine subcategory.	NA	• Actually burns > 90 percent natural gas • Net-electric sales > design efficiency (not to exceed 50 percent) multiplied by potential electric output
Non-base load natural gas-fired combustion turbine subcategory.	NA	• Actually burns > 90 percent natural gas • Net-electric sales ≤ design efficiency (not to exceed 50 percent) multiplied by potential electric output
Multi-fuel-fired combustion turbine subcategory	NA	Actually burns ≤ 90 percent natural gas

IX. Rationale for Final Standards for Newly Constructed and Reconstructed Stationary Combustion Turbines

This section discusses the EPA's rationale for the final applicability criteria, BSER determinations, and standards of performance for newly constructed and reconstructed stationary combustion turbines. In this section, we present a summary of what we proposed, a selection of the significant comments we received, and our rationale for the final determinations, including how the comments influenced our decision-making.

A. Applicability

This section describes the proposed applicability criteria, applicability issues we specifically solicited comment on, the relevant significant comments, and the final applicability criteria. We also provide our rationale for finalizing applicability criteria based strictly on design and permit restrictions rather than actual operating characteristics. Finally, we explain why the proposed percentage electric sales and natural gas-use applicability criteria are being finalized instead as criteria to distinguish between separate subcategories of stationary combustion turbines.

1. Proposed Applicability Criteria

In the January 2014 proposal, we proposed several applicability criteria for stationary combustion turbines. Specifically, to be subject to the proposed emission standards, we proposed that a unit must (1) be capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel; (2) be constructed for the purpose of supplying and actually supply more than one-third of its potential electric output capacity to a utility power distribution system for sale (that is, to the grid) on a 3-year rolling average; (3) be constructed for the purpose of supplying and actually supply more than 219,000 MWh net-electric output to the grid on a 3-year rolling average; (4) combust over 10 percent fossil fuel on a 3-year rolling average; and (5) combust over 90 percent natural gas on a 3-year rolling average. We proposed exempting municipal solid waste combustors and commercial and industrial solid waste incinerators.

Under these proposed applicability criteria, two types of stationary combustion turbines that are currently subject to criteria pollutant standards under subpart KKKK would not have been subject to CO_2 standards. The first type was stationary combustion turbines that are constructed for the purpose of selling and that actually sell one-third or less of their potential output or 219,000 MWh or less to the grid on a 3-year rolling average basis (*i.e.,* non-base load units). The second type was combustion turbines that actually combust 90 percent or less natural gas on a 3-year rolling average basis (*i.e.,* multi-fuel-fired units).

We proposed the electric sales criteria in part because they already exist in other regulatory contexts (*e.g.,* the coal-fired EGU criteria pollutant NSPS) and would promote consistency between regulations. Our understanding at proposal was that the percentage electric sales criterion would distinguish between non-base load units (*e.g.,* low capital cost, flexible, but relatively inefficient simple cycle units) and base load units (*i.e.,* higher capital cost, less flexible, but relatively efficient combined cycle units).

While the proposed applicability criteria did not explicitly exempt simple cycle combustion turbines from the emission standards, we concluded that, as a practical matter, the vast majority of simple cycle turbines would be excluded because they historically have operated as peaking units and, on average, have sold less than five percent of their potential electric output on an annual basis, well below the proposed one-third electric sales threshold.

a. Solicitation of comment on applicability, generally

We solicited comment on a range of issues related to applicability. In conjunction with the proposed one-third (*i.e.,* 33.3 percent) electric sales threshold, we solicited comment on a threshold between 20 to 40 percent of potential electric output. We also solicited comment on a variable percentage electric sales criterion, which would allow more efficient, lower emitting turbines to run for longer periods of operation before becoming subject to the standards of performance. Under this ''sliding scale'' approach, the percentage electric sales criterion would be based on the net design efficiency of the combustion turbine being installed. In this way, more efficient combustion turbines would be able to sell a greater portion of their potential electric output compared with less efficient combustion turbines before becoming subject to an emission standard. This approach had the benefit of incentivizing the development and installation of more efficient simple cycle combustion turbines to serve peak load.

We also solicited comment on whether the percentage electric sales criterion for stationary combustion turbines should be defined on a single calendar year basis. In addition, we solicited comment on eliminating the 219,000 MWh aspect of the total electric sales criterion to eliminate any incentive for generators to install multiple, small, less-efficient stationary combustion turbines that would be exempt due to their lower output. We further solicited comment on whether to provide an explicit exemption for all simple cycle combustion turbines regardless of the amount of electricity sold. We additionally solicited comment on how to implement the proposed electric sales, fossil fuel-use, and natural

[529] 73 MW is equivalent to 260 GJ/h. We changed units to avoid potential confusion of MW referring to electric output rather than heat input.

gas-use criteria given that they were to be evaluated as 3-year rolling averages during the first three years of operation, and we requested comment on appropriate monitoring, recordkeeping, and reporting requirements. We specifically solicited comment on whether these proposed requirements raised implementation issues because they were based on source operation after construction has occurred.

We also solicited comment on excluding electricity sold during system emergencies from the calculation of percentage electric sales. The rationale for this exclusion was that simple cycle combustion turbines intended only for peaking applications might be required to operate above the proposed percentage electric sales threshold if a major power plant or transmission line became unexpectedly unavailable for an extended period of time. The EPA proposed that this flexibility would be appropriate if the unit were called upon to run after all other available generating assets were already running at full load.

b. Solicitation of comment on broad applicability approach

In both the January 2014 proposal for newly constructed EGUs and the June 2014 proposal for modified and reconstructed EGUs, the EPA solicited comment on finalizing a broad applicability approach instead of the proposed approach. Under the proposed approach, a stationary combustion turbine could be an affected EGU one year, but not the next, depending on the unit's actual electric sales and the composition of fuel burned. The broad applicability approach is consistent with historical NSPS applicability approaches that are based on design criteria and include different emission standards for subcategories that are distinguished by operating characteristics. Specifically, we solicited comment on whether we should completely remove the electric sales and natural gas-use criteria from the general applicability framework. Instead, the percentage electric sales and natural gas-use thresholds would serve as subcategorization criteria for distinguishing among classes of EGUs and subcategory-specific emissions standards. Under this broad applicability approach, the ''constructed for the purpose of'' component of the percentage electric sales criterion would be completely eliminated so that applicability for combustion turbines would be determined only by a unit's base load rating (*i.e.,* greater than 260 GJ/h (250 MMBtu/h)) and its capability to sell power to a utility distribution system (*i.e.,* serving a generator capable of selling more than 25 MW). In contrast to the proposed applicability criteria, under the broad applicability approach, non-base load (*e.g.,* simple cycle) and multi-fuel-fired (*e.g.,* oil-fired) combustion turbines would remain subject to the rule regardless of their electric sales or fuel use. We solicited comment on all aspects of this ''broad applicability approach,'' including the extent to which it would achieve our policy objective of assuring that owners and operators install NGCC combustion turbines if they plan to sell more than the specified electric sales threshold to the grid.

2. Comments on Applicability

This section summarizes the comments we received specific to each of the proposed applicability criteria. We also received more general comments on the scope of the proposed framework as compared to the scope of the broad applicability approach. Comments on applicability for dedicated non-fossil and CHP units are discussed in Section III.

a. Base load rating criterion

Many commenters supported a base load rating of 260 GJ/h (250 MMBtu/h) because it is generally consistent with the threshold used in states participating in the Regional Greenhouse Gas Initiative (RGGI) and under Title IV programs. Other commenters opposed the proposed applicability thresholds and stated that all new, modified, and reconstructed units that sell electricity to the grid, including small EGUs and simple cycle combustion turbines, should be affected EGUs because they would otherwise have a competitive advantage in energy markets as they would not be required to internalize the costs of compliance.

b. Total electric sales criterion

Commenters noted that the 219,000 MWh total electric sales threshold put larger combustion turbines at a competitive disadvantage by distorting the market and could have the perverse impact of increasing CO_2 emissions. These commenters noted that the 219,000 MWh total electric sales threshold would allow combustion turbines smaller than approximately 80 MW to sell more than one-third of their potential electric output, but larger, more efficient combustion turbines would still be restricted to selling one-third of their potential electric output to avoid triggering the NSPS. They argued that this would result in a regulatory incentive for generators to install multiple, less-efficient combustion turbines instead of fewer, more-efficient combustion turbines and could have the unintended consequence of increasing CO_2 emissions.

c. Percentage electric sales criterion

Commenters from the power sector generally supported a complete exemption for simple cycle turbines. These commenters stated that simple cycle turbines are uniquely capable of achieving the ramp rates (the rate at which a power plant can increase or decrease output) necessary to respond to emergency conditions and hourly variations in output from intermittent renewables. Commenters noted that simple cycle combustion turbines serve a different purpose than NGCC power blocks. In addition, commenters noted that electricity generation dispatch is based on the incremental cost to generate electricity and that because NGCC units have a lower incremental generation cost than simple cycle units, economics will drive the use of NGCC technologies over simple cycle units. However, commenters also stated that historic simple cycle operating data may not be representative of future system requirements as coal units retire, generation from intermittent renewable generation increases, and numerous market and regulatory drivers impact plant operations. In the absence of a complete exemption, these commenters supported a percentage electric sales threshold between 40 to 60 percent of a unit's potential electric output.

Some commenters said that because the proposed percentage electric sales criterion applied over a three-year period, it would adversely affect grid reliability because operators conservatively would hedge short-term operating decisions to ensure that they have sufficient capacity to respond to unexpected scenarios during future compliance periods when the demand for electricity is higher. These commenters were concerned that such compliance decisions would drive up the cost of electricity as the most efficient new units are taken out of service to avoid triggering the NSPS and older, less efficient units with no capacity factor limitations are ramped up instead.

Some commenters supported the sliding-scale approach (*i.e.,* a percentage electric sales threshold based on the design efficiency of the combustion turbine) and stated that incentives for manufacturers to develop (and end users to purchase) higher efficiency combustion turbines could help mitigate concerns about a monolithic national constraint on simple cycle capacity factors.

In contrast, others commented that fast-start NGCC units intended for peaking and intermediate load applications can achieve comparable ramp rates to simple cycle combustion turbines, but with lower CO_2 emission rates. These commenters said that simple cycle turbines should be restricted to their historical role as true peaking units and that the proposed one-third electric sales threshold provided sufficient flexibility. Some commenters suggested that the one-third electric sales threshold could be reduced to 20 percent or lower without adverse impacts on grid reliability.

Commenters noted that a complete exclusion for simple cycle turbines would create a regulatory incentive for generators to install and operate less efficient unaffected units instead of more efficient affected units, thereby increasing CO_2 emissions. According to these commenters, any applicability distinctions should be based on utilization and function rather than purpose or technology.

Commenters in general supported the use of 3-year rolling averages instead of a single-year average for the percentage and total electric sales criteria because, in their view, the 3-year rolling averages would provide a better overall picture of normal operations. Some commenters stated that a rolling 12-month or calendar-year average could be severely skewed in a given year because of unforeseen or unpredicted events. They said that using a 3-year averaging methodology would provide system operators with needed flexibility to dispatch simple cycle units at higher than normal capacity factors. In contrast, some commenters stated that, because capacity is forward-looking (*e.g.,* payments for capacity are often made several years in advance), the 3-year averaging period provides limited benefit because owner/operators need to reserve the ability to respond to unforeseen events.

Commenters noted that potential compliance issues could result from the inconsistent time frame between the 3-calendar-year applicability period and the 12-operating-month compliance period. For example, a facility could sell more than one-third of its potential electric output over a 3-year period, but sell less than one-third of its potential electric output during any given 12-operating-month compliance period within that 3-year period. During a 12-operating-month period with electric sales of less than one-third of potential electric output, a unit could be operating for long periods at part load and have multiple starts and stops. These operating conditions have the potential to increase CO_2 emissions, regardless of the deign efficiency of the turbine. Therefore, a unit could have an emission rate in excess of the proposed standard.

Regarding the relationship between the percentage electric sales criterion and system emergencies, multiple commenters supported exclusion of electricity generated as a result of a system emergency from counting towards net sales. These commenters stated that the exclusion was appropriate because the benefits of operating these units to generate electrical power during emergency conditions would outweigh any adverse impacts from short-term increases in CO_2 emissions. One commenter stated that, in addition to declared grid emergencies, other circumstances might warrant emergency exemption under the rule, including extreme market conditions, limitations on fuel supply, and reliability responses.

Multiple commenters opposed the exclusion of system emergencies when calculating a source's percentage electric sales for applicability purposes because NSPS must apply continuously, even during system emergencies. These commenters stated that the EPA does not have the authority under the CAA to suspend the applicability of a standard during periods of system emergency. Some commenters stated that an exclusion would be unnecessary because the EPA Assistant Administrator for Enforcement has the authority to advise a source that the government will not sue the source for taking certain actions during an emergency. Commenters said that this enforcement discretion approach has provided prompt, flexible relief that is tailored to the needs of the particular emergency and the communities being served and is only utilized where the relief will address the particular emergency at hand.

Commenters added that this enforcement discretion approach is consistent with the CAA's mandate that emission limits apply continuously and provide safeguards against abuse. One commenter stated that emergencies happen rarely and typically last for short periods, that the proposed percentage electric sales threshold would allow a source to operate at its full rated capacity for up to 2,920 hours per year without triggering applicability, and that the potential occurrence of grid emergencies would represent a tiny fraction of this time. Another commenter stated that no emergency short of large scale destruction of power generating capacity by terrorism, war, accident, or natural disaster could justify operating a peaking unit above a 10-percent capacity factor on a 3-year rolling average.

d. Broad applicability approach

In response to the EPA's request for comments on whether the proposed applicability requirements that retrospectively look back at actual events (*i.e.,* the electric sales and fuel use criteria) would create implementation issues, several permitting authorities opposed the provisions because units could be subject to coverage one year but not the next, resulting in compliance issues and difficulties in determining proper pre-construction and operating permit conditions. These permitting authorities suggested that in order for a source to avoid applicability, the source should be subject to a federally enforceable permit condition with associated monitoring, recordkeeping, and reporting conditions for assessing applicability on an ongoing basis. Other commenters stated that an applicability test that concludes after construction and operation have commenced is inconsistent with the general purpose of an applicability test—to provide clear and predictable standards of performance for new sources that would apply when they begin operations.

Some commenters opposed the proposed retrospective applicability criteria related to actual output supplied during a preceding compliance period because EGUs must know what performance standards will apply to them during the licensing process, and such criteria do not allow the permitting authority and the public to know in advance whether an emission standard applies to a proposed new unit. Other commenters said that EGUs undergoing permitting should be allowed to request limits in their operating permit conditions in order to remain below the applicability thresholds, as this methodology is consistent with the pre-construction permitting requirements in many federally approved SIPs and the current approach under the Title V permitting program.

Many commenters stated a preference for the ''proposed applicability approach'' over the ''broad applicability approach.'' These commenters did not think it was necessary to require non-base load or multi-fuel-fired combustion turbines to be subject to emission standards. They stated that there is no justification for imposing burdensome monitoring, reporting, and recordkeeping requirements that would have no environmental benefit (*i.e.,* would not reduce CO_2 emissions) because these units would be subject to ''no emissions standards.'' Other commenters supported the broad applicability approach and stated that all new, modified, and reconstructed units that sell electricity to the grid, including small EGUs, oil-fired combustion turbines, and simple cycle combustion turbines should be affected EGUs because they would otherwise have a competitive advantage in energy markets as they would not be required to internalize the costs of compliance.

In contrast, to preserve the discretion of state planners under section 111(d), many other commenters supported the broad applicability approach and the inclusion of new simple cycle units within the scope of the section 111(b) emission standards so that similar, existing simple cycle units could be subject to the 111(d) standards. Numerous other commenters stated that all units that sell electricity to the grid should be subject to a standard, including simple cycle units, because they view the utility grid as a single integrated system and that doing so may simplify development of future frameworks for cost-effective carbon reductions from existing units, such as frameworks based on system-wide approaches.

3. Final Applicability Criteria and Rationale

Based on our consideration of the comments received related to the proposed applicability criteria and practical implementation issues, we are revising how those criteria will be implemented. The final applicability criteria for combustion turbines are generally consistent with the broad applicability approach on which we solicited comment. Section VIII of this preamble presents each proposed applicability criterion together with the form of the criterion in the final rule. The final general applicability framework includes the proposed criteria based on the combustion turbine's base load rating and the combustion turbine's total electric sales capacity. The final general applicability framework also includes multiple exemptions that are relevant to combustion turbines: combustion turbines that are not connected to natural gas pipelines; CHP facilities with federally enforceable limits on total electric sales; dedicated non-fossil units with federally enforceable limits on the use of fossil fuels; and municipal waste combustors and incineration units.

The final applicability framework reflects multiple variations from the proposal that are responsive to public comments. First, consistent with the broad applicability approach, we are finalizing the percentage electric sales and natural gas-use thresholds as subcategorization criteria instead of as applicability criteria. In addition, for non-CHP combustion turbines, we are eliminating the proposed 219,000 MWh total electric sales criterion. Finally, we are eliminating the proposed ''constructed for the purpose of'' qualifier for the total and percentage electric sales criteria. We are also not finalizing CO_2 standards for dedicated non-fossil fuel-fired or industrial CHP combustion turbines. The rationale for not finalizing CO_2 standards for dedicated non-fossil and industrial CHP units is discussed in more detail in Section III.

The EPA agrees with commenters that the NSPS applicability framework should be structured so that permitting authorities, the regulated community, and the public can determine what standards apply prior to a unit having commenced construction. With this in mind, the EPA has concluded that the proposed fossil fuel-use, natural gas-use, percentage electric sales, and total electric sales applicability criteria for combustion turbines are not ideal approaches. Because applicability determinations based on these criteria could change from year to year (*i.e.,* units could move in and out of coverage each year depending on actual operating parameters), some operators would not know the extent of their compliance obligations until after the compliance period.

Further, from a practical implementation standpoint, existing permitting rules generally require pre-construction permitting authorities to include enforceable conditions limiting operations such that unaffected units will not trigger applicability thresholds. Such conditions are often called ''avoidance'' or ''synthetic minor'' conditions, and these conditions typically include ongoing monitoring, recordkeeping, and reporting requirements to ensure that operations remain below a particular regulatory threshold.

The following sections provide further discussion of the final general applicability criteria and the rationale for changing certain proposed applicability criteria to subcategorization criteria.

a. Base load rating criterion

We are retaining the applicability criterion that a combustion turbine must be capable of combusting more than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel. We revised the proposed 73 MW form of the base load rating criterion to 260 GJ/h because some commenters misinterpreted the 73 MW form (which is mathematically equivalent to 250 MMBtu/h) as the electrical output rating of the generator. This change is a non-substantive unit conversion intended to limit misinterpretation. While some commenters suggested that we expand this applicability criterion to cover smaller EGUs as well, we did not propose to cover smaller units. Because smaller units emit relatively few CO_2 emissions compared to larger units and because we currently do not have enough information to identify an appropriate BSER for these units, we are not finalizing CO_2 standards for smaller units.

b. Total electric sales criterion

The proposed 219,000 MWh total sales criterion was based on a 25 MW unit operating at base load the entire year (*i.e.,* 25 MW * 8,760 h/y = 219,000 MWh/y). This criterion was included in the original subpart Da coal-fired EGU criteria pollutant NSPS. Coal-fired EGUs tend to be much larger than 25 MW, and the criterion's primary purpose was to exempt industrial CHP facilities from the criteria pollutant NSPS. In the context of combustion turbines, however, commenters expressed concerns that the 219,000 MWh electric sales threshold would actually encourage owners and operators to install multiple, smaller, less-efficient simple cycle combustion turbines instead of a single, larger, more-efficient simple cycle turbine. The reason for this is that the 219,000 MWh threshold would allow smaller simple cycle combustion turbines of less than 80 MW to sell significantly more electricity relative to their potential electric output than larger turbines. Many commenters also indicated that having the flexibility to operate a simple cycle turbine at a higher capacity factor is important because it allows for capacity payments from the transmission authority. In light of these comments, we are not finalizing the 219,000 MWh total electric sales criterion for non-CHP combustion turbines. Instead, we are finalizing a criterion that will exempt combustion turbines that do not have the ability to sell at least 25 MW to the grid. This approach will maintain our goal of exempting smaller EGUs, while avoiding the perverse environmental incentives mentioned by the commenters. As explained in Section III, however, industrial CHP units are sized based on demand for useful thermal output, so there is less of an incentive for owners and operators to install multiple smaller units. Therefore, we are maintaining the 219,000 MWh total electric sales criterion for CHP units.

c. Percentage electric sales criterion

Commenters generally opposed the proposed percentage electric sales criterion approach because it was based in part on actual electric sales, meaning applicability could change periodically (*i.e.,* a unit's electric sales may change over time, rising above and falling below the electric sales threshold). The EPA agrees this situation is not ideal. To avoid situations in which applicability changes from year to year, we first considered two approaches using permit restrictions. Under the first approach, a standard would apply to all sources with permit restrictions mandating electric sales above a threshold (*i.e.,* an approach that closely mirrors the proposed percentage electric sales criterion). Under the second approach, a standard would apply to all sources without permit restrictions limiting electric sales to a level below that threshold (*i.e.,* effectively identifying non-base load units and excluding them from applicability). As stated in the proposal, we did not think it was critical to include peaking and cycling units because peaking turbines operate less and because it would be much more expensive to lower their emission profile to that of a combined cycle power plant or a coal-fired plant with CCS.

The first approach is not practical, however, because new combustion turbines could avoid applicability by simply not having a permit restriction at all. Moreover, even if a combustion turbine were subject to the restriction, it could violate its permit if it did not operate enough to sell the requisite amount of electricity. This would be nonsensical, especially because system demand would not always be sufficient to allow all permitted units to operate above the threshold. Therefore, we rejected the first permitting approach.

In contrast, the second approach would be a viable method for identifying and exempting peaking units from applicability. However, there are multiple drawbacks to such an applicability approach. First, this approach would subject those turbines without a permit restricting electric sales to the final emission standards, which raises concerns as to whether turbines with lower actual sales could achieve the standards. For example, new NGCC units tend to dispatch prior to older existing units and will generally operate for extended periods of time near full load and sell electricity above the percentage electric sales threshold. However, as NGCC units age, they tend to start and stop more frequently and operate at part load. Yet, even if these units sell below the percentage electric sales threshold, they would still be affected units if they did not take a permit restriction. As commenters noted, part-load operation and frequent starts and stops can reduce the efficiency of a combustion turbine. While we are confident that our final standards for base load natural gas-fired combustion turbines can be achieved by units serving either base or intermediate load, we are not as confident that affected NGCC units that might someday be operated as non-base load units (*e.g.,* as NSPS units age, their incremental generating costs will tend to be higher than newer units and they will dispatch less) could achieve the standards.

More importantly, however, we are concerned that using a permitting approach for the percentage electric sales criterion would create problems due to the interaction between 111(b) and 111(d). Under the second permitting approach we considered, units with low electric sales would be excluded from applicability, while units with high electric sales would be included. While these low-electric sales units would generally be simple cycle combustion turbines and the high-electric sales units would generally be NGCC combustion turbines, this would not always be the case. In contrast, we are finalizing an applicability approach in the 111(d) emission guidelines that is based on a combustion turbine's design characteristics rather than electric sales. Simple cycle combustion turbines are excluded from applicability, while NGCC units are included. As a result, the universe of sources covered by the 111(b) standards would not necessarily be the same universe of sources covered by the 111(d) standards.

To resolve this issue, we considered whether we could change the 111(d) applicability criteria to be based on historical operation rather than design characteristics. For example, if an existing combustion turbine had historically sold less than one-third of its potential output to the grid, then it would be exempt from the emission guidelines. However, many existing NGCC units have historically sold less than this amount of electricity, meaning that they would not be subject to the rule. We ran into similar issues when considering other thresholds. For example, a percentage electric sales threshold of 10 percent would still exempt roughly 5 percent of existing NGCC units from 111(d), while simultaneously raising achievability concerns with the 111(b) standard. Moreover, even if we had finalized 111(d) applicability criteria based on historical operations, existing NGCC units could have decided to take a permit restriction limiting their electric sales going forward to avoid applicability. Under any of these scenarios, our goals with respect to 111(d) would not be accomplished.

To avoid this result, the EPA has concluded that it is appropriate to finalize the broad applicability approach and set standards for combustion turbines regardless of what percentage of their potential electric output they sell to the grid. To accommodate the continued use of simple cycle and fast-start NGCC combustion turbines for peaking and cycling applications, however, the EPA has subcategorized natural gas-fired combustion turbines based on a variation of the proposed percentage electric sales criterion. Specifically, and as explained in more detail in Section IX.B.2, we are finalizing the sliding-scale approach on which we solicited comment.

d. Natural gas-use criterion

Similar to the proposed electric sales criteria, commenters generally opposed the proposed natural gas-use criterion being based on actual operating parameters. As with the electric sales criteria, the EPA agrees that applicability that can switch periodically due to operating parameters is not ideal. The EPA evaluated two approaches for implementing the intent of the proposed natural gas-use criterion (*i.e.,* to exclude non-natural gas-fired combustion turbines) through operating permit restrictions. Under the first approach, an emission standard would apply to all combustion turbines with a permit restriction mandating that natural gas contribute over 90 percent of total heat input.[530] Under the second approach, an emission standard would apply to all combustion turbines without a permit restriction limiting natural gas use to 90 percent or less of total heat input.[531] As with the percentage electric sales criterion, the first approach is not practical because combustion turbines could avoid

[530] This approach could also be written as ''an emission standard would apply to all combustion turbines with a permit restriction limiting the use of non-natural gas fuels to 10 percent or less of the total heat input.'' Applicability could then be avoided by simply being permitted to burn non-natural gas fuels for more than 876 hours per year even if they actually intended to seldom, if ever, combust the alternate fuels.

[531] This approach could also be written as ''an emission standard would apply to all combustion turbines without permit restrictions mandating that non-natural gas use contribute over 10 percent or more of total heat input.''

applicability by simply not having a permit that requires the use of more than 90 percent natural gas, even if they intend to only burn natural gas. We disregarded this approach because it would essentially provide a pathway for all NGCC units to avoid applicability under both 111(b) and 111(d). The second approach is problematic because operating permit restrictions to improve air quality are typically written to limit high emission activities (*e.g.,* limiting the use of distillate oil to 500 hours annually), not to limit lower emitting activities. This approach could lead to perverse environmental impacts by incentivizing the use of non-natural gas fuels, which would typically result in higher CO_2 emissions. Furthermore, the second approach would not limit the fuels that can be burned by affected units (*i.e.,* combustion turbines not required to use non-natural gas fuels) and would continue to cover combustion turbines even when they burn over 10 percent non–natural gas fuels. Because all non-natural gas fuels except H_2 have CO_2 emission rates higher than natural gas, this approach would exacerbate the concerns raised by commenters about the achievability of the 111(b) requirements when burning back up fuels.

In light of these issues, the EPA has concluded that permit restrictions are not an ideal approach to distinguishing between natural gas-fired and multi-fuel-fired combustion turbines and are finalizing a variation of the broad applicability approach. The EPA has concluded that the only practical approach to implement the natural gas-use criterion is to look at the turbine's physical ability to burn natural gas. Therefore, we are not finalizing CO_2 standards for combustion turbines that are not capable of firing any natural gas (*i.e.,* not connected to a natural gas pipeline). From a practical standpoint, the burners of most combustion turbines can be modified to burn natural gas, so this exemption is essentially limited to combustion turbines that are built in remote or offshore locations without access to natural gas. Consistent with the broad applicability approach, we are finalizing standards for all other combustion turbines, but are subcategorizing between natural gas-fired turbines and multi-fuel-fired turbines. Specifically, and as explained in more detail in Section IX.B.3, we are distinguishing between these classes of turbines based on whether they burn greater than 90 percent natural gas or not.

B. Subcategories

We are finalizing a variation of the broad applicability approach for combustion turbines where the percentage electric sales and natural gas-use criteria serve as thresholds that distinguish between three subcategories. These subcategories are base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units. Under the final subcategorization approach, multi-fuel-fired combustion turbines are distinguished from natural gas-fired turbines if fuels other than natural gas (*e.g.,* distillate oil) supply 10 percent or more of heat input. Natural gas-fired turbines are further subcategorized as base load or non-base load units based on the percentage electric sales criterion. The percentage electric sales threshold that distinguishes base load and non-base load units is based on the specific turbine's design efficiency (*i.e.,* the sliding-scale approach). The percentage electric sales threshold is capped at 50 percent.

This section describes comments we received regarding the proposed size-based subcategories and our rationale for not finalizing them. In addition, it describes comments we received regarding sales-based subcategories and our rationale for adopting the sliding scale to distinguish between subcategories. Finally, it describes comments we received regarding fuel-based subcategories and our rationale for adopting fuel-based subcategories.

1. Size-Based Subcategories

At proposal, the EPA identified two size-based subcategories: (1) large natural gas-fired stationary combustion turbines with a base load rating greater than 850 MMBtu/h and (2) small natural gas-fired stationary combustion turbines with a base load rating of 850 MMBtu/h or less. The EPA received numerous comments regarding our proposal to subcategorize combustion turbines by size. Some commenters agreed with the 850 MMBtu/h cut-point between large and small units, some suggested increasing it to 1,500 MMBtu/h, and others suggested eliminating size-based subcategorization altogether. For example, some commenters stated that the 850 MMBtu/h cut-point was inappropriate because it was originally calculated based on NO_X performance, not CO_2 performance. These commenters stated that 850 MMBtu/h was not a logical demarcation between more efficient and less efficient combustion turbines, but rather would divide the units into arbitrary size classifications. These commenters suggested that 1,500 MMBtu/h would be a better cut-point because data reported to *Gas Turbine World* (GTW) showed that new combustion turbines are not currently offered with a heat input rating between 1,300 MMBtu/h and 1,800 MMBtu/h, so the higher cut-point would more accurately reflect when more efficient technologies are available.

In contrast, other commenters said that differentiation between small and large combustion turbines was not justified at all because many of the same efficiency technologies that reduce the emission rates of larger units could be incorporated into smaller units (*e.g.,* upgrades that increase the turbine engine operating temperature, increase the turbine engine pressure ratio, or add multi-pressure steam and a steam reheat cycle). These commenters also said that separate standards for small and large turbines would undermine the incentive for technology innovation, which they described as a key purpose of the NSPS program, and that relaxing standards for smaller units would discourage investment in more efficient technologies, resulting in increased CO_2 emissions. These commenters recommended that the limit for both large and small units be no higher than 1,000 lb CO_2/MWh-g.

After evaluating these comments, the EPA has decided not to subcategorize combustion turbines based on size for several reasons. First, the heat input values listed in *Gas Turbine World* do not include potential heat input from duct burners.[532] Because the heat input from duct burners is necessary to accurately determine potential electric output, our definition of ''base load rating'' includes the heat input from any installed duct burners. The EPA reviewed the heat input data for existing NGCC units that has been submitted to CAMD. These data include the heat input from duct burners and show that multiple NGCC power blocks have been built in the past with heat input capacities that fall within the range that commenters suggested new turbines are not offered. Therefore, the EPA has concluded that the regulated community uses various sizes of NGCC turbines and when the heat input from duct burners is included, there is no clear break between the NGCC unit sizes that could distinguish between small and large units. In fact, subcategorizing

[532] Duct burners are optional supplemental burners located in the HRSG that are used to generate additional steam. Heat input to duct burners could in theory be twice that of the combustion turbine engine, but are more commonly sized at 10 to 30 percent of the heat input to the combustion turbine engine.

by size could unduly influence the development of future NGCC offerings because manufacturers could be incentivized to design new products at the top end of the small subcategory to take advantage of the less stringent emission standard.

Second, commenters suggested that a cut-point of 1,500 MMBtu/h reflects when more efficient technologies become available. However, when we reviewed actual operating data and design data, we only found a relatively weak correlation between turbine size and CO_2 emission rates and did not see a dramatic drop in CO_2 emission rates at 1,500 MMBtu/h. The variability of emission rates among similar size units far exceeds any difference that could be attributed to a difference in size. In addition, the most efficient one-to-one configuration NGCC power block with a base load rating of 1,500 MMBtu/h or less has a design emission rate of the 767 lb CO_2/MWh-n (984 MMBtu/h). The most efficient one-to-one configuration NGCC power block with a base load rating just greater than 1,500 MMBtu/h has a design emission rate of 772 lb CO_2/MWh-n (1,825 MMBtu/h). Because the smaller unit has a lower design emission rate than the larger unit, increasing the cut-point does not make sense.

Finally, the EPA has concluded that, while certain smaller NGCC designs may be less efficient than larger NGCC designs, most existing small units have demonstrated emission rates below the range of emission rates on which we solicited comment. We have concluded that the lower design efficiencies of some small NGCC units are primarily related to model-specific design choices in both the turbine engine and HRSG, not an inherent limitation in the ability of small NGCC units to have comparable efficiencies to large NGCC units. Specifically, manufacturers could improve the efficiency of the turbine engine by using turbine engines with higher firing temperatures and high compression ratios and could improve the efficiency of the steam cycle by switching from single or double-pressure steam to triple-pressure steam and adding a reheat cycle. For all of these reasons, we have decided against subcategorizing combustion turbines based on size. Our rationale for setting a single standard for small and large combustion turbines is explained in more detail in Section IX.D.3.a below.

2. Sales-Based Subcategories

As described above in Section IX.A.3.c, the final applicability criteria do not include an exemption for non-CHP units based on actual electric sales or permit restrictions limiting the amount of electricity that can be sold. Instead, we are finalizing the percentage electric sales criterion as a threshold to distinguish between two natural gas-fired combustion turbine subcategories. The industry uses a number of terms to describe combustion turbines with different operating characteristics based on electric sales (*e.g.,* capacity factors). Combustion turbines that operate at near-steady, high loads are generally referred to as ''base load'' or ''intermediate load'' units, depending on how many hours the units operate annually. Combustion turbines that operate continuously with variable loads that correspond to variable demand are referred to as ''load following'' or ''cycling'' units. Combustion turbines that only operate during periods with the highest electricity demand are referred to as ''peaking'' units. However, it is difficult to characterize a particular unit using just one of these terms. For example, a particular unit may serve as a load following unit during winter, but serve as a base load unit during summer. In addition, none of these terms has a precise universal definition. In this preamble, we refer to the subcategory of combustion turbines that sell a significant portion of their potential electric output as ''base load units.'' This subcategory includes units that would colloquially be referred to as base load units, as well as some intermediate load and load following units. We refer to all other units as ''non-base load units.'' This subcategory includes peaking units, as well as some load following and intermediate load units. The threshold that distinguishes between these two subcategories is determined by a unit's design efficiency and varies from 33 to 50 percent, hence the term ''slide scale'' approach.

Numerous commenters supported three sales-based subcategories for peaking, intermediate load, and base load units. These commenters said that each subcategory should be distinguished by annual hours of operation and that each should have a different BSER and emission standard. Other commenters opposed the tiered approach. These commenters said that separate standards for different operating conditions would be complicated to implement and enforce, while providing few benefits. These commenters said that a tiered approach could also have the unintended consequence of encouraging less efficient technologies because it would create a regulatory incentive to install lower-capital-cost, less-efficient units that would operate under the percentage electric sales threshold instead of higher-capital-cost, more-efficient units that would operate above the threshold.

After evaluating these comments, the EPA has concluded that it is appropriate to adopt a two-tiered subcategorization approach based on a percentage electric sales threshold to distinguish between non-base load and base load units. While we agree with commenters that separate standards for peaking, intermediate, and base load units is attractive on the surface, we ultimately concluded that a three-tiered approach is not appropriate for several reasons. First, the increased generation from renewable sources that is anticipated in the coming years makes it very difficult to determine appropriate thresholds to distinguish among peaking, intermediate, and base load subcategories. Indeed, the boundaries between these demand-serving functions may blur or shift in the years to come. The task is further complicated because each transmission region has a different mix of generation technologies and load profiles with different peaking, intermediate, and base load requirements.

Second, there are only two distinct combustion turbine technologies—simple cycle units and NGCC units. In theory, the BSER for the intermediate load subcategory could be based on high-efficiency simple cycle units or fast-start NGCC units, but these are variations on traditional technologies and not necessarily distinct. Moreover, we do not have specific cost information on either high-efficiency simple cycle turbines or fast-start NGCC units, so our ability to make cost comparisons to conventional designs is limited.

Finally, even if we could identify appropriate sales thresholds to distinguish between peaking, intermediate load, and base load subcategories, we do not have sufficient information to establish a meaningful output-based standard for an intermediate load subcategory at this time. In the transition zone from peaking to base load operation (*i.e.,* cycling and intermediate load), combustion turbines may have similar electric sales, but very different operating characteristics. For example, despite having similar sales, one unit might have relatively steady operation for a short period of time, while another could have variable operation throughout the entire year. The latter unit would likely have a higher CO_2 emission rate. For all of these reasons, the EPA has concluded that we do not have sufficient information at this time to establish three sales-based subcategories.

Instead, as we explained above, we are finalizing two sales-based subcategories. To determine an appropriate threshold to distinguish between base load and non-base load units, the EPA considered the important characteristics of the combustion turbines that serve each type of demand. For non-base load units, low capital costs and the ability to start, stop, and change load quickly are key. Simple cycle combustion turbines meet these criteria and thus serve the bulk of peak demand. In contrast, for base load units, efficiency is the key consideration, while capital costs and the ability to start and stop quickly are less important. While NGCC units have relatively high capital costs and are less flexible operationally, they are more efficient than simple cycle units. NGCC units recover the exhaust heat from the combustion turbine with a HRSG to power a steam turbine, which reduces fuel use and CO_2 emissions by approximately one-third compared to a simple cycle design. Consequently, base load units use NGCC technology. Because simple cycle turbines have historically been non-base load units, we have concluded that it is appropriate to distinguish between the non-base load and base load subcategories in a way that recognizes the distinct roles of the different turbine designs on the market.

The challenge, however, is setting a threshold that will not distort the market. The future distinction between non-base load and base load units is unclear. For example, some commenters indicated that increased generation from intermittent renewable sources has created a perceived need for additional cycling and load following generation that will operate between the traditional roles of peaking and base load units. To fulfill this perceived need, some manufacturers have developed high-efficiency simple cycle turbines. These high-efficiency turbines have higher capital costs than traditional simple cycle turbine designs, but maintain similar flexibilities, such as the ability to start, stop, and change load rapidly. Other manufacturers have developed fast-start NGCC turbines to fill the same role. These newer NGCC designs have lower design efficiencies than NGCC designs intended to only operate as base load units, but are able to startup more quickly to respond to rapid changes in electricity demand. As a result of these new technological developments, both high-efficiency simple cycle and fast-start NGCC units can be used for traditional peaking applications, as well as for higher capacity applications, such as supporting the growth of intermittent renewable generation.

With the changing electric sector in mind, we set out to identify an appropriate percentage electric sales threshold to distinguish between non-base load and base load natural gas-fired units. Two factors were of primary importance to our decision. First, the threshold needed to be high enough to address commenters' concerns about the need to maintain flexibility for simple cycle units to support the growth of intermittent renewable generation. Second, the threshold needed to be low enough to avoid creating a perverse incentive for owners and operators to avoid the base load subcategory by installing multiple, less efficient turbines instead of fewer, more efficient turbines.

To determine the potential impact of intermittent renewable generation on the operation of simple cycle units, we examined the average electric sales of simple cycle turbines in the lower 48 states between 2005 and 2014 using information submitted to CAMD. We combined this data with information reported to the EIA on total in-state electricity generation, including wind and solar, from 2008 through 2014. We focused on data from the Southwest Power Pool (data approximated by EGUs in Nebraska, Kansas, and Oklahoma), Texas, and California. All of these regions have relatively large amounts of generation from wind and solar and experienced increases in the portion of total electric generation provided by wind and solar during the 2008–2014 period.

a. Southwest Power Pool

The portion of in-state generation from wind and solar in the Southwest Power Pool increased from 3 to 16 percent between 2008 and 2014. The average growth rate of wind and solar was 28 percent, while overall electricity demand grew 1 percent annually on average. Based on statements in some of the comments, we expected to see a large change in the operation of simple cycle turbines in this region. However, the average electric sales from simple cycle turbines only increased at an annual rate of 1.7 percent, and remained essentially unchanged at 3 percent of potential electric output between 2008 and 2014. Total generation from simple cycle turbines in the Southwest Power Pool increased slightly more, at an annual rate of 2.5 percent, which was the result of additional simple cycle capacity being added to address increased electricity demand.

This lack of a significant change in the operation of simple cycle turbines could be explained by the Southwest Power Pool's relatively large amount of exported power. If most of the region's renewable generation was being exported, the intermittent nature of this power would primarily impact other transmission regions. An alternate explanation, however, is that other generating assets are flexible enough to respond to the intermittent nature of wind and solar generation and that simple cycle turbines are not necessary to back up these assets to the degree some commenters suggested. If this is the case, then new simple cycle turbines may primarily continue to fill their historical role as peaking units going forward, while other technologies, such as fast-start NGCC units, may provide the primary back up capacity for new wind and solar.

b. Texas

The portion of in-state generation from wind and solar in Texas increased from 4 to 9 percent between 2008 and 2014. The average growth rate of wind and solar was 13 percent, while overall demand grew at an average rate of 2 percent annually. Similar to the Southwest Power Pool, the average electric sales of simple cycle turbines has remained relatively unchanged. In fact, the average electric sales of these turbines decreased at an annual rate of 1.1 percent. Total generation from simple cycle turbines increased at an annual rate of 6.6 percent, however, due to simple cycle capacity additions that occurred at approximately four times the rate one would expect from the growth in overall demand.

The most likely technologies to back up intermittent renewable generation have low incremental generating costs and can start up and stop quickly. Highly efficient simple cycle units meet these criteria. As such, the EPA has concluded that the most efficient simple cycle turbines in a given region are the most likely to support intermittent renewable generation. Focusing on these simple cycle turbines will address concerns raised by commenters about the future percentage electric sales of highly efficient simple cycle turbines and give an indication of the impact of increased renewable generation on non-base load units intended to back up wind and solar. There are two highly efficient intercooled simple cycle turbines installed in Texas. These two combustion turbines sell an average of 10 percent of their potential electric output annually, compared to an average of 3 percent for the remaining simple cycle turbines. No simple cycle turbine in Texas sold more than 25 percent of its potential electric output annually. The rapid growth in simple cycle capacity, but not overall capacity factors, could indicate that the additional generation assets are providing firm capacity for intermittent generation sources such as wind and solar, but that capacity is infrequently required. Based on the data, even highly efficient simple cycle turbines are expected to continue to sell less than one-third of their potential electric output.

c. California

The portion of in-state generation from wind and solar in California increased from 3 to 11 percent between 2008 and 2014. The average growth rate of wind and solar was 25 percent, while overall demand has remained stable. The operation of simple cycle turbines in California has changed more significantly than in the other evaluated regions. The average electric sales from simple cycle turbines increased from 5.1 to 5.9 percent, an annual rate increase of 4.5 percent. As in Texas, considerable additional simple cycle capacity has been added in recent years. The total capacity of simple cycle turbines is increasing at 15 percent annually even though overall demand has remained relatively steady. In addition, the newest simple cycle turbines are operating at higher capacity factors than the existing fleet of simple cycle turbines, resulting in an average increase in generation from simple cycle turbines of 21 percent. Many of the new additions are intercooled simple cycle turbines that may have been installed with the specific intent to back up wind and solar generation.

The average electric sales for the intercooled turbines ranged from 3 to 25 percent, with a 7 percent average. No simple cycle turbines in California have sold more than one-third of their potential electric output on an annual basis. The operation of simple cycle turbines that existed prior to 2008 has not changed significantly. Average electric sales for these turbines increased at an annual rate of 0.1 percent. This indicates that support for new renewable generation is being provided by new units and not by the installed base of simple cycle units. These units are still serving their historical role of providing power during peak periods of demand.

Based on our data analysis, the proposed one-third electric sales threshold would appear to offer sufficient operational flexibility for new simple cycle turbines. Existing NGCC units, other generation assets, and demand-response programs are currently providing adequate back up to intermittent renewable generation. In the future, however, existing NGCC units will likely operate at higher capacity factors. They will therefore be less available to provide back up power for intermittent generation. In addition, the amount of power generated by intermittent sources is expected to increase in the future. Both of these factors could require additional flexibility from the remaining generation sources to maintain grid reliability.

Even though fast-start NGCC units, reciprocating internal combustion engines, energy storage technologies, and demand-response programs are promising technologies for providing back up power for renewable generation, none of them historically have been deployed in sufficient capacity to provide the potential capacity needed in the future to facilitate the continued growth of renewable generation. While we anticipate that state and federally issued permits for new electric generating sources will consider the CO_2 benefits of these technologies compared to simple cycle turbines, the EPA has concluded at this time that it is appropriate to finalize a percentage electric sales threshold that provides additional flexibility for simple cycle turbines.

Specifically, we have concluded that a percentage electric sales threshold based on a unit's design net efficiency at standard conditions is appropriate. This is the sliding-scale approach on which we solicited comment. Several commenters supported this approach because it provides sufficient operational flexibility for new simple cycle and fast-start NGCC combustion turbines and simultaneously promotes the installation of the most efficient generating technologies. By allowing more efficient turbines to sell more electricity before becoming subject to the standard for the base load subcategory, the sliding scale should reduce the perverse incentive for owners and operators to install more lower-capital-cost, less-efficient units instead of fewer higher-capital-cost, more-efficient units. At the same time, the sliding scale should incentivize turbine manufacturers to design higher efficiency simple cycle turbines that owners and operators can run more frequently.

The net design efficiencies for aeroderivative simple cycle combustion turbines range from approximately 32 percent for smaller designs to 39 percent for the largest intercooled designs. The net design efficiencies of industrial frame units range from 30 percent for smaller designs to 36 percent for the largest designs. These efficiency values follow the methodology the EPA has historically used and are based on the higher heating value (HHV) of the fuel. In contrast, combustion turbine vendors in the U.S. often quote efficiencies based on the lower heating value (LHV) of the fuel. The LHV of a fuel is determined by subtracting the heat of vaporization of water vapor generated during combustion of fuel from the HHV. For natural gas, the LHV is approximately 10 percent lower than the HHV. Therefore, the corresponding LHV efficiency ranges would be 35 to 44 percent for aeroderivative designs and 33 to 40 percent for frame designs. We considered basing the percentage electric sales threshold on both the HHV and LHV. The EPA typically uses the HHV, but in light of commenters' concerns regarding uncertainty in the operation of non-base load units in the future, we opted to be conservative and use the LHV efficiency.

We anticipate that high-efficiency simple cycle and fast-start NGCC turbines will make up the majority of new capacity intended for non-base load applications. Based on the sliding-scale approach, owners and operators of new simple cycle combustion turbines will be able to sell between 33 to 44 percent of the turbine's potential electric output. Our analysis showed that 99.5 percent of existing simple cycle turbines have not sold more than one-third of their potential electric output on an annual basis. In addition, 99.9 percent of existing simple cycle turbines have not sold more than 36 percent of their potential electric output on an annual basis. The two simple cycle turbines that exceeded the 36 percent threshold had annual electric sales of 39 and 45 percent and are located in Montana and New York, respectively. As noted earlier, the most efficient simple cycle turbine currently available is 44 percent efficient and would accommodate the operations at the Montana facility. The only existing simple cycle turbine that exceeded the maximum allowable percentage electric sales threshold of 44 percent, which is based on current simple cycle designs, sold an abnormally high amount of electricity in 2014. It is possible that this unit was operating under emergency conditions. As explained below, the incremental generation due to the emergency would not have counted against the percentage electric sales threshold.

We are capping the percentage electric sales threshold at 50 percent of potential electric output for multiple reasons. First, NGCC emission rates are relatively steady above 50 percent electric sales, so there is no reason that a NGCC unit with sales greater than this amount should not have to comply with the output-based standard for the base load subcategory. Second, the net design efficiency of the fast-start NGCC units intended for peaking and intermediate load applications is 49 percent. As described earlier, this technology can serve the same purpose as high-efficiency simple cycle turbines. If we were to set a cap any lower than 50 percent, it could create a disincentive for owners and operators to choose this promising new technology.

Finally, the EPA solicited comment on excluding electricity sold during system emergencies from counting towards the percentage electric sales threshold. After considering the comments, we have concluded that this exclusion is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector. We disagree with commenters that suggested that the EPA's existing enforcement discretion would be a viable alternative. An enforcement discretion-based approach would not provide certainty to the regulated community, public, and regulatory authorities on the applicability of the emission standards, which is a primary reason why we are finalizing the broad applicability approach. Moreover, system emergencies are defined events, so commenters' fears that the exclusion will be subject to abuse are overstated. Therefore, electricity sold during hours of operation when a unit is called upon to operate due to a system emergency will not be counted toward the percentage electric sales threshold. However, electricity sold by units that are not called upon to operate due to a system emergency (*e.g.,* units already operating when the system emergency is declared) will be counted toward the percentage electric sales threshold.

In summary, the EPA is finalizing the percentage electric sales criterion as a threshold to distinguish between two natural gas-fired combustion turbine subcategories. Specifically, all units that have electric sales greater than their net LHV design efficiencies (as a percentage of potential electric output) are base load units. All units that have electric sales less than or equal to their net LHV design efficiencies are non-base load units. We are capping the percentage electric sales threshold at 50 percent of potential electric output. This sliding-scale approach will limit the operation of the least efficient units, provide flexibility for renewable energy growth, and incentivize the development of more efficient simple cycle units.

3. Fuel-Based Subcategories

As described in Section IX.A.3.d, we are finalizing a version of the broad applicability approach. Under the broad applicability approach, the EPA solicited comment on a subcategorization approach based in part on natural gas-use. We received few comments on this issue. One of the comments we did receive was that combustion turbines that burn fuels other than natural gas have higher CO_2 emissions due to the higher relative carbon content of alternate fuels. Besides hydrogen,[533] natural gas has the lowest CO_2 emission rate on a lb/MMBtu basis of any fossil fuel. Therefore, burning fuels other than natural gas will result in a higher CO_2 emission rate. We interpret this comment to mean that, if we were to subcategorize based on fuel use, turbines that burn non-natural gas fuels should receive a less stringent emission standard.

For the reasons described in the applicability section, we have decided to set emission standards for all combustion turbines capable of burning natural gas, regardless of the actual fuel burned, to avoid the practical problems that would have arisen under the proposed approach. However, as commenters explained, multi-fuel-fired combustion turbines cannot achieve the emission standards achieved by natural-gas fired turbines. For this reason, it would not be reasonable to require affected EGUs to comply with a standard based on the use of natural gas during periods when significant quantities of non-natural gas fuels are being burned. If we did not subcategorize, owners and operators would not be able to combust other fuels in their turbines, including process gas, blast furnace gas, and petroleum-based liquid wastes, which might otherwise be wasted. In addition, without the ability to burn back up fuels during natural gas curtailments, grid reliability could be jeopardized. Therefore, we are finalizing a separate fuel-based subcategory for multi-fuel-fired combustion turbines. To distinguish between this subcategory and the natural gas-fired subcategories, we are using the same threshold as proposed. Specifically, combustion turbines that burn ninety percent or less natural gas on a 12-operating-month rolling average basis will be included in this subcategory and subject to a separate emission standard, which is discussed in Section IX.D.3.d.

[533] Hydrogen would only be considered a fossil fuel if it were derived for the purpose of creating useful heat from coal, oil, or natural gas.

C. Identification of the Best System of Emission Reduction

This section summarizes the EPA's proposed BSER determinations for stationary combustion turbines, provides a summary of the comments we received, and explains our final BSER determinations for each of the three subcategories we are now finalizing. For natural gas-fired stationary combustion turbines operating as base load units, we proposed and are finalizing the use of NGCC technology as the BSER. For the other two subcategories of affected combustion turbines—non-base load natural gas-fired combustion turbines and multi-fuel-fired combustion turbines—we are finalizing the use of clean fuels as the BSER.

1. Proposed BSER

We considered three alternatives in evaluating the BSER for base load natural gas-fired combustion turbines: (1) Partial CCS, (2) high-efficiency simple cycle aeroderivative turbines, and (3) modern, efficient NGCC turbines. We rejected partial CCS as the BSER because we concluded that we did not have sufficient information to determine whether implementing CCS for combustion turbines was technically feasible. We rejected high-efficiency simple cycle aeroderivative turbines as the BSER because this standalone technology does not provide emission reductions and generally is more expensive than NGCC technology for base load applications. In contrast, NGCC is the most common type of new fossil fuel-fired EGU currently being planned and built for generating base load power. NGCC is technically feasible, and NGCC units are currently the lowest-cost, most efficient option for new base load fossil fuel-fired power generation. After considering the options, the EPA proposed to find that modern, efficient NGCC technology is the BSER for base load natural gas-fired combustion turbines.

For non-base load natural gas-fired units and multi-fuel-fired units, we did not propose a specific BSER or associated numeric emission standards, but instead solicited comment on these issues.

2. Comments on the Proposed BSER for Base Load Natural Gas-Fired Combustion Turbines

This section summarizes the differing comments submitted on the proposed BSER for base load natural gas-fired combustion turbines. Some commenters supported partial CCS as the BSER, others supported advanced NGCC designs as the BSER, and others supported the proposed BSER.

a. Partial CCS

Some commenters stated that our proposed BSER analysis for stationary combustion turbines was inconsistent with our proposed BSER analysis for coal-fired units. They stated that the EPA had determined that the use of CCS was feasible for coal-fired generation based on current CCS projects under development at coal-fired generating stations, but did not come to the same conclusion for combustion turbines. These commenters stated that CO_2 removal is just as technologically feasible and economically reasonable for a natural gas-fired EGU as for a coal-fired EGU. While some of these commenters wanted the EPA to reconsider CCS as the BSER for NGCC, many of these commenters were attempting to prove that if the agency did not choose CCS as the BSER for NGCC units, then the agency should not for coal-fired units either.

Some commenters referenced the Northeast Energy Association NGCC plant in Bellingham, MA, which operated from 1991–2005 with 85–95 percent carbon capture on a 320 MW unit for use in the food and beverage industry, that was referred to in the proposal. This plant captured 330 tons of CO_2 per day from a 40 MW slip stream and was decommissioned as a result of financial difficulties, including rising gas prices and discontinuation of tax credits. According to these commenters, this plant provided sufficient proof that CCS technology is adequately demonstrated for NGCC units. Additionally, these commenters referred to other NGCC plants that are planned or in development that will incorporate CCS. The plants mentioned were the Sumitomo Chemical Plant in Japan, the Peterhead CCS project in Scotland, and the GE-Sargas Plant in Texas. The Sumitomo Chemical Plant has a base load NGCC unit with CCS operating on an 8 MW slip-stream that captures about 150 tons of CO_2 per day for commercial use in the food and beverage industry. This carbon capture system has been operating since 1994. The Peterhead CCS project in Scotland is in the planning stages. It is a collaboration between Shell and SSE to provide 320 MW of electricity to its customers from a base load NGCC unit with 90 percent carbon capture. The CO_2 will be transported to the depleted Goldeneye reservoir in the ocean where it will be stored and continuously monitored. The GE-Sargas Plant in Texas is a planned joint venture that does not currently have a location selected, but is intended to be a base load NGCC unit with CCS used for EOR.

These commenters also referenced reports authored by DOE, NETL, the Clean Air Task Force (CATF), CCS Task Force, ICF Inc., and Global CCS Institute, suggesting that, because CCS technology for NGCC is included in these reports, it is adequately demonstrated. Some commenters referred to a DOE/NETL study that suggested that the cost of CCS for NGCC units would be more cost-effective than for coal-fired EGUs. One non-industry commenter emphasized that a technology does not have to be in use to be considered adequately demonstrated.

In addition, some commenters disagreed with the EPA's decision to treat combustion turbines differently than coal-fired units with respect to CCS on the basis that combustion turbines startup, shutdown, and cycle load more frequently than coal-fired units. According to these commenters, the operating characteristics of combustion turbines do fluctuate, but so do those of coal-fired units. Another commenter said that even if NGCC operations vary more than they do for coal-fired units, it is not an impediment to using CCS because combustion turbine operators could bypass the carbon capture system during startup and shutdown modes (which are typically shorter and less intensive efforts compared to the startup or shutdown of a coal facility) and then employ the carbon capture system when operating normally. One commenter stated that most future base load fossil fuel-fired generation will be NGCC and that not making CCS the BSER for NGCC would result in significant CO_2 emissions.

Other commenters supported the EPA's determination that CCS is not the BSER for combustion turbines. These commenters said that CCS is not adequately demonstrated for combustion turbines because none are currently operating, under construction, or in the advanced stages of development. They also noted that CCS would have to be demonstrated for the range of facilities included in the regulated source category, which they alleged includes both simple cycle and NGCC units. They specifically noted that the Bellingham, MA demonstration facility was not a full-scale commercial NGCC power plant operating with CCS.

These commenters agreed with the EPA that CCS does not match well with the operating flexibilities of NGCC and simple cycle units. They agreed with the EPA that frequent cycling restricts the efficacy of CCS on these units, a problem which would only get worse as more renewable energy sources are integrated into the grid. These commenters added that NGCC units operate differently than coal-fired units because the former start, stop, and cycle frequently, whereas the latter tend to operate at relatively steady loads and do not start and stop frequently. They stated that even if technical barriers could be overcome, the application of CCS to combustion turbines would be more costly (compared to the application of CCS to coal-fired units) on a dollars-per-ton basis. In addition, these commenters said that other industries' experience with CCS could not be transferred to NGCC units due to differences in flue gas CO_2 concentration.

Some commenters stated that CAA section 111(a) requires the EPA to account not only for the cost of achieving emission reductions, but also for impacts on energy requirements and the environment. The commenters cited to *Sierra Club* v. Costle, where the D.C. Circuit observed that the EPA ''must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations.'' [534] The commenters stated that requiring CCS on combustion turbines would adversely affect the nation's energy needs and the environment because imposing CCS on combustion turbines would invariably delay the emission reductions that can be obtained from new NGCC projects that displace load from older, less efficient generating technologies. In addition, the commenters stated that, because combustion turbines are projected to provide a significant share of new power generation, the EPA should recognize that requiring CCS on these units would have a disproportionally higher impact on electricity prices when compared to the projected number of new coal-fired projects. These commenters concluded that the EPA could not determine that CCS is the BSER for combustion turbines without producing severe and unacceptable consequences for the availability of affordable electricity in the U.S.

b. NGCC Turbines

Some commenters stated that the proposed BSER analysis should have reflected the emission rates achieved by the latest designs deployed at advanced, state-of-the-art NGCC installations. These commenters stated that advanced NGCC technologies are the best system

[534] *Sierra Club* v. *Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

for reducing CO_2 emissions with no negative environmental impacts and no negative economic impacts on rate payers. They stated that advanced NGCC technologies are capable of achieving emission rates that are 8 percent lower than conventional NGCC facilities. They also said that the majority of existing sources that do not deploy these advanced technologies are currently able to meet the standard and that the proposal failed to explain why these lower-emitting advanced technologies that are more than adequately demonstrated were not selected as the BSER.

c. Simple Cycle Turbines

Many commenters opposed the EPA's proposal to set emission standards for combustion turbines based on their function rather than based on their design. These commenters stated that the EPA's determination that NGCC technology is the BSER for base load natural gas-fired combustion turbines would apply equally to simple cycle turbines if they sell electricity in excess of the percentage electric sales threshold. They pointed to the word ''achievable'' in CAA section 111(a)(1) and stated that applying an emission standard based on NGCC technology to simple cycle units was legally indefensible because simple cycle units cannot achieve emission rates as low as NGCC units. In contrast, many other commenters agreed with the EPA's basic approach and stated that NGCC technology should be the BSER for base-load functions, while simple cycle technology should be the BSER for peak-load functions.

3. Comments on Non-Base Load and Multi-Fuel-Fired Combustion Turbines

Multiple commenters suggested that high efficiency simple cycle or fast-start NGCC technologies should be the BSER for non-base natural gas-fired load units. They explained that high efficiency simple cycle units and fast-start NGCC units are actually more efficient when serving non-base load demand than NGCC units that are designed strictly for base load operation. Some commenters also suggested that we should subcategorize multi-fuel-fired combustion turbines, but did not provide any specific technologies that should be considered in the BSER analysis.

4. Identification of the BSER

After our evaluation of the comments and additional analysis, we identified the BSER for each subcategory of combustion turbine that we are finalizing: base load natural gas-fired units, non-base load natural gas-fired units, and multi-fuel-fired units.

a. Base Load Natural Gas-Fired Units

As described in the proposal, we evaluated CCS, NGCC, and high-efficiency simple cycle combustion turbines as the potential BSER for this subcategory. We selected NGCC as the BSER because it met all the BSER criteria. This section describes our response to issues raised by commenters and our rationale for maintaining that NGCC is the BSER for base load natural gas-fried combustion turbines.

(1) Partial CCS

Some commenters stated that CCS could be applied equally to both coal-fired and natural gas-fired EGUs. To support this conclusion, the commenters pointed to a retired NGCC-with-CCS demonstration project, as well as a few overseas projects and projects in the early stages of development. While we have concluded that these commenters made strong arguments that the technical issues we raised at proposal could in many instances be overcome, we have concluded that there is not sufficient information at this time for us to determine that CCS is adequately demonstrated for all base load natural-gas fired combustion turbines.

While the commenters make a strong case that the existing and planned NGCC-with-CCS projects demonstrate the feasibility of CCS for NGCC units operating at steady state conditions, many NGCC units do not operate this way. For example, the Bellingham, MA and Sumitomo NGCC units cited by the commenters operated at steady load conditions with a limited number of starts and stops, similar to the operation of coal-fired boilers.[535] In contrast, our base load natural gas-fired combustion turbine subcategory includes not only true base load units, but also some intermediate units that cycle more frequently, including fast-start NGCC units that sell more than 50 percent of their potential output to the grid. Fast-start NGCC units are designed to be able to start and stop multiple times in a single day and can ramp to full load in less than an hour. In contrast, coal-fired EGUs take multiple hours to start and ramp relatively slowly. These differences are important because we are not aware of any pilot-scale CCS projects that have demonstrated how fast and frequent starts, stops, and cycling will impact the efficiency and reliability of CCS. Furthermore, for those periods in which a NGCC unit is operating infrequently, the CCS system might not have sufficient time to startup. During these periods, no CO_2 control would occur. Thus, if the NGCC unit is intended to operate for relatively short intervals for at least a portion of the year, the owner or operator could have to oversize the CCS to increase control during periods of steady-state operation to make up for those periods when no control is achieved by the CCS, leading to increased costs and energy penalties. While we are optimistic that these hurdles are surmountable, it is simply premature at this point to make a finding that CCS is technically feasible for the universe of combustion turbines that are covered by this rule.

Notably, the Department of Energy has not yet funded a CCS demonstration project for a NGCC unit, and no NGCC-with-CCS demonstration projects are currently operational or being constructed in the U.S. In contrast, multiple CCS demonstration projects for coal-fired units are in various stages of development throughout the U.S., and a full-capture system is in operation at the Boundary Dam facility in Canada. See Sections V.E and D above.

One commenter suggested that not having CCS as the BSER for combustion turbines would ultimately halt the development of CCS in the U.S. We disagree. A number of coal-fired power plants are currently being built with CSS, while some existing plants are considering CCS retrofits. Moreover, the NSPS sets the minimum level of control for new sources. We expect that state air agencies and other air permitting authorities will evaluate CCS when permitting new NGCC power plants, taking into consideration case-specific parameters, like operating characteristics, to determine whether CCS could be BACT or LAER in specific instances. While the NGCC-with-CCS units that currently are in the planning stages do not provide us with enough assurance to determine that CCS is adequately demonstrated for combustion turbines, it is our expectation that these units and others to come will provide additional information for both permitting reviews and the next NSPS review in eight years.

(2) NGCC Turbines

Regarding the advanced NGCC technologies advocated by several commenters, the EPA has concluded

[535] As explained in Section V.J above, a new fossil fuel-fired steam generating EGU would, most likely, be built to serve base load power demand exclusively and would not be expected to routinely startup, shut down, or ramp its capacity factor in order to follow load demand. Thus, planned start-up and shutdown events would only be expected to occur a few times during the course of a 12-operating-month compliance period.

that the term ''advanced'' simply refers to incremental improvements to traditional NGCC designs, not a new and unique technology. These incremental improvements include higher firing temperatures in the turbine engine, increasing the number of steam pressures, and adding a reheat cycle to the steam cycle. The emission rates achieved by these so-called ''advanced'' technologies were included within the data set of newer NGCC designs that we used to establish the final emission standards. In addition, our review of the operating data for NGCC power blocks installed since 2000 indicates that a unit's mode of operation in response to system demand (*e.g.,* capacity factor) affects efficiencies achieved to the extent that we cannot evaluate the impact of particular subcomponents used within the power block. As a result, a conventional NGCC power block located in a region of the country where system demand requires the power block to run continuously at a steady high load can achieve higher efficiencies than an ''advanced'' NGCC power block located in a region where system demand requires the power block to cycle on and off to match system demand. For this reason, our data set included a large population of technologies and load conditions to ensure that new NGCC power blocks can achieve the final emission standards in all regions of the country.

As we explained in the proposal, NGCC technology meets all of the BSER criteria. For base load functions, NGCC units are technically feasible, cost-effective (indeed, less expensive than simple cycle combustion turbines), and have no adverse energy or environmental impacts. Moreover, NGCC units reduce emissions because they have a lower CO_2 emission rate than simple cycle units. Finally, selecting NGCC as the BSER will promote the development of new technology, such as the incremental improvements advocated by the commenters, which will further reduce emissions in the future.

Some commenters suggested that the costs and efficiency impacts of startup and shutdown events are higher for NGCC units than for simple cycle units. Consequently, we refined the LCOE costing approach used at proposal by adding these additional costs and efficiency impacts to our cost comparison. Even accounting for these new costs and impacts, we found that NGCC technology results in a lower cost of electricity than simple cycle technology when a unit's electric sales exceed approximately one-third of its potential electric output. The final percentage electric sales criterion for the base load natural gas-fired combustion turbine subcategory is based on the sliding scale. This means that the dividing line between the base load subcategory and the non-base load subcategory will change depending on a unit's nameplate design efficiency. For a conventional simple cycle turbine, the base load subcategory will begin at around 33 percent electric sales, while for a newer fast-start NGCC turbine, the base load subcategory will begin at approximately 50 percent electric sales. Anywhere within this range, our cost calculations have shown that NGCC technology is more cost-effective than simple cycle technology. Therefore, we are finalizing our determination that modern, efficient NGCC technology is the BSER for base load natural-gas fired combustion turbines.

(3) Simple Cycle Turbines

Many commenters mistakenly thought that the EPA proposed to require some simple cycle combustion turbines to meet an emission standard of 1,000 lb CO_2/MWh-g, a level that they assert is unachievable. On the contrary, the EPA is not finding that NGCC technology and a corresponding emission standard of 1,000 lb CO_2/MWh-g is the BSER for simple cycle turbines. Instead, the EPA is finding that NGCC technology is the BSER for base load turbine applications. This means that if an owner or operator wants to sell more electricity to the grid than the amount derived from a unit's nameplate design efficiency calculated as a percentage of potential electric output, then the owner or operator should install a NGCC unit. If the owner or operator elects to install a simple cycle turbine instead, then the practical effect of our final standards will be to limit the electric sales of that unit so that it serves primarily peak demand, not to subject it to an unachievable emission standard.

b. Non-base Load Natural Gas-Fired Load Units

To identify the BSER for non-base load natural gas-fired units, we evaluated a range of technologies, including partial CCS, high-efficiency NGCC technology designed for base load applications, fast-start NGCC, high-efficiency simple cycle units (*i.e.,* aeroderivative turbines), and clean fuels. For each of these technologies, we considered technical feasibility, costs, energy and non-air quality impacts, potential for emission reductions, and ability to promote technology.

While CCS would result in emission reductions and promote the development of new technology, we concluded that CCS does not meet the BSER criteria because the low capacity factors and irregular operating patterns (*e.g.,* frequent starting and stopping and operating at part load) of non-base load units make the technical challenges associated with CCS even greater than those associated with base load units. In addition, because the CCS system would remain idle for much of the time while these units are not running, CCS would be less cost-effective for these units than for base load units.

We have also concluded that the high-efficiency NGCC units designed for base load applications do not meet any of the BSER criteria for non-base load units. First, non-base load units need to be able to start and stop quickly, and NGCC units designed for base load applications require relatively long startup and shutdown periods. Therefore, conventional NGCC designs are not technically feasible for the non-base load subcategory. Also, non-base load units operate less than 10 percent of the time on average. As a result, conventional NGCC units designed for base load applications, which have relatively high capital costs, will not be cost-effective if operated as non-base load units. In addition, it is not clear that a conventional NGCC unit will lead to emission reductions if used for non-base load applications. As some commenters noted, conventional NGCC units have relatively high startup and shutdown emissions and poor part-load efficiency, so emissions may actually be higher compared with simple cycle technologies that have lower overall design efficiencies but better cycling efficiencies. Finally, requiring conventional NGCC units as the BSER for non-base load combustion turbines would not promote technology because these units would not be fulfilling their intended role. In fact, it could hamper the development of technologies with lower design efficiencies that are specifically designed to operate efficiently as non-base load units (*i.e.,* high-efficiency simple cycle and fast-start NGCC units). For all these reasons, we have concluded that conventional NGCC units designed for base load applications are not the BSER for non-base load natural gas-fired units.

Compared to conventional NGCC technology, fast-start NGCC units have lower design efficiencies, but are able to start and ramp to full load more quickly. Therefore, it is possible that requiring fast-start NGCC as the BSER for non-base load units would result in emission reductions and further promote the development of fast-start NGCC technology, which is relatively new and advanced. However, because the majority of non-base load combustion turbines operate less than 10 percent of the time, it would be cost-prohibitive to require fast-start NGCC, which have relatively high capital costs compared to simple cycle turbines, as the BSER for all non-base load applications. Also, as we explained above in Section IX.B.2, we do not have sufficient emissions data for fast-start NGCC units operating over the full range of non-base load conditions (*e.g.,* peaking, cycling, etc.), so we would not be able to establish a reasonable emission standard.

High-efficiency simple cycle turbines are primarily used for peaking applications. High-efficiency simple cycle turbines often employ aeroderivative designs because they are more efficient at a given size and are able to startup and ramp to full load more quickly than industrial frame designs. Requiring high-efficiency simple cycle turbines as the BSER could result in some emission reductions compared with conventional simple cycle turbines. It would also promote technology development by incentivizing manufacturers to increase the efficiency of their simple cycle turbine models. However, aeroderivative designs have higher initial costs that must be weighed against the specific peak-load profiles anticipated for a particular new non-base load unit. Many utility companies have elected to install the heavier industrial frame turbines because the ramping capabilities of aeroderivative turbines are not required for their system demand profiles (*i.e.,* the speed and durations of daily changes in electricity demand), and the fuel savings do not justify the higher initial costs. We currently do not have precise enough costing information to compare the cost-effectiveness of aeroderivative turbines and industrial frame turbines for all non-base load applications. Determining cost-effectiveness is further complicated because the efficiencies of the available aeroderivative and industrial frame technologies significantly overlap. For example, the efficiencies of aeroderivative turbines range from 32 to 39 percent, while the efficiencies of industrial frame turbines range from 30 to 36 percent. Based on these cost uncertainties, we cannot conclude that high-efficiency simple cycle turbines are the BSER for natural gas-fired non-base load applications at this time.

The final option that we considered for the BSER was clean fuels, specifically natural gas with a small allowance for distillate oil. The use of clean fuels is technically feasible for non-base load units. Based on available EIA data,[536] natural gas comprises more than 96 percent of total heat input for simple cycle combustion turbines. In addition, natural gas is frequently the lowest cost fossil fuel used in combustion turbines, so it is cost-effective. Clean fuels will also result in some emission reductions by limiting the use of fuels with higher carbon content, such as residual oil. Finally, the use of clean fuels will not have any significant energy or non-air quality impacts. Based on these factors, the EPA has determined that the BSER for non-base load natural gas-fired units is the use of clean fuels, specifically natural gas with a small allowance for distillate oil. Natural gas has approximately thirty percent lower CO_2 emissions per million Btu than other fossil fuels commonly used by utility sector non-base load units.

c. Multi-Fuel-Fired Units

To identify the BSER for multi-fuel-fired units, we again evaluated CCS, NGCC technology, high-efficiency simple cycle units (*i.e.,* aeroderivative turbines), and clean fuels. For each of these technologies we considered technical feasibility, costs, energy and non-air quality impacts, emission reductions, and technology promotion. For many of the same reasons we provided above in our discussion of the BSER for non-base load natural gas-fired combustion turbines, only clean fuels meets the BSER criteria for multi-fuel-fired units.

While CCS would result in emission reductions and the promotion of technology, we concluded that CCS does not meet the BSER criteria because multi-fuel-fired units tend to start, stop, and operate at part load frequently. Also, there are impurities and contaminants in some alternate fuels which make the technical challenges of applying CCS to multi-fuel-fired units greater than for natural gas-fired units.

In regards to NGCC technology, we have concluded that it is technically feasible, would result in emission reductions, is cost-effective, and would promote the development of technology. However, a BSER determination based on the use of NGCC technology could pose challenges for facilities operating in remote locations and certain industrial facilities. In remote locations, the construction of a NGCC facility is often not practical because it requires larger capital investments and significant staffing for construction and operation. In contrast, simple cycle turbines are cheaper and can be operated with minimal staffing. Also, many industrial facilities do not have the space available to build a HRSG and the associated cooling tower. Therefore, requiring NGCC as the BSER could have unforeseen energy impacts at these types of facilities. Moreover, these same kinds of facilities also burn by-product fuels. Faced with a decision to install an NGCC unit, these facilities might seek alternative energy options, which could lead to increased flaring or venting of by-product fuels because they are no longer being burned onsite for energy recovery. Therefore, in light of these potential energy and non-air quality impacts, we have concluded that NGCC technology is not the BSER for multi-fuel-fired combustion turbines.

Similarly, while high-efficiency simple cycle turbines would result in emission reductions and promote the advancement of this technology, we are not confident that high-efficiency simple cycle units are technically feasible or cost-effective for this subcategory. Aeroderivative turbines are not as flexible with regards to what fuels that can be burned. Because by-product fuels vary in composition, it is not clear that all by-products fuels could be burned in a high-efficiency simple cycle turbine. In addition, even if a by-product fuel could be burned in an aeroderivative turbine, we do not have information on the potential for increased maintenance costs, so we cannot determine whether using high-efficiency simple cycle turbines would be cost-effective.

The final option that we considered for the BSER was clean fuels. The use of clean fuels is technically feasible and cost-effective. The use of clean fuels also provides an environmentally beneficial alternative to the flaring or venting of by-product fuels and limits the use of dirtier fuels with higher CO_2 emission rates, such as residual oils. Clean fuels also promote technology development by allowing manufacturers to develop new combustion turbine designs that are capable of burning by-product fuels that currently cannot be burned in combustion turbines. Finally, the use of clean fuels does not have any significant energy or non-air quality impacts. Based on these factors, the EPA has determined that the BSER for multi-fuel-fired combustion turbines is the use of clean fuels.

D. Achievability of the Final Standards

We are finalizing emission standards for three subcategories of combustion turbines. Specifically, units that sell electricity in excess of a threshold based on their design efficiency and that burn more than 90 percent natural gas (*i.e.,* base load natural gas-fired units) will be

[536] *http://www.eia.gov/electricity/data/eia923/.*

subject to an output- based standard. The output-based standard is based on the performance of existing NGCC units and takes into account a range of operating conditions, future degradation, etc. Units not meeting either the percentage electric sales or natural gas-use criteria (*i.e.,* non-base load natural gas-fired and multi-fuel units, respectively) will be subject to an input-based standard based on the use of clean fuels. This section summarizes what emission standards we proposed and related issues we solicited comment on, describes the comments we received regarding the proposed emission standards and our responses to those comments, and provides our rationale for the final emission standards.

1. Proposed Standards

For large newly constructed, modified, and reconstructed stationary combustion turbines (base load rating greater than 850 MMBtu/h), we proposed an emission standard of 1,000 lb CO_2/MWh-g. For small stationary combustion turbines (base load rating of 850 MMBtu/h or less), we proposed an emission standard of 1,100 lb CO_2/MWh-g. We also solicited comment on a range of 950–1,100 lb CO_2/MWh-g for large stationary combustion turbines and a range of 1,000–1,200 lb CO_2/MWh-g for small stationary combustion turbines.

In addition, we solicited comment on increasing the size distinction between large and small stationary combustion turbines to 900 MMBtu/h to account for larger aeroderivative designs; increasing the size distinction to 1,000 MMBtu/h to account for future incremental increases in base load ratings; increasing the size distinction to between 1,300 to 1,800 MMBtu/h; and eliminating the size subcategories altogether. To account for potential reduced efficiencies when units are not operating at base load, we also solicited comment on whether a separate, less stringent standard should be established for non-base load combustion turbines.

2. Comments

As described previously, we are not finalizing the size-based subcategories that we proposed and instead are finalizing emission standards for sales- and fuel-based subcategories. Specifically, we are finalizing emission standards for three subcategories of stationary combustion turbines: base load natural-gas fired units, non-base load natural gas-fired units and multi-fuel-fired units. The relevant comments concerning the emission standards for the first two subcategories are discussed below. Any comments we received supporting tiered emission standards are included in the discussion of non-base load natural gas-fired units. We did not receive comments on an appropriate emission standard for multi-fuel-fired units.

a. Emission standards for Base Load Natural Gas-Fired Units

Many commenters stated that the proposed emission standards did not properly take into account the losses in efficiency that occur due to long-term degradation over multiple decades, operation at non-base load conditions (load cycling, frequent startups and shutdowns, and part-load operations), site-specific factors such as ambient conditions and cooling technology, and secondary fuel use (*e.g.,* distillate oil). These commenters stated that the EPA should conduct a more comprehensive analysis that addresses worst-case conditions for each of these factors. They also stated that all of the units included in the analysis supporting the proposal were relatively new and therefore have experienced limited degradation. The commenters stated that, while some degradation in efficiency can be recovered during periodic maintenance outages, it is not always possible or feasible to repair a degraded component immediately because repairs often involve extended outages that must be scheduled well in advance. They stated that a new unit that initially could meet the standard at base load conditions can experience increasing heat rates with age even when adhering to the manufacturer's recommended maintenance program.

Some commenters stated that the proposed standards were derived by looking at emissions data from years with historically low natural gas prices. They surmised that the NGCC units were taking advantage of these prices by running at historically high capacity factors and concluded that the efficiencies and CO_2 emission rates underlying the proposed standards were not representative of periods with higher natural gas prices. Other commenters said that many NGCC units are increasingly required to cycle and operate at lower capacities (compared to the proposal's baseline) to accommodate hourly variations in intermittent renewable generation. They anticipated that this type of generation will increase, requiring NGCC units to start, stop, and operate at part load more frequently than in the past, increasing CO_2 emissions.

Some commenters indicated that, during startup, combustion turbines must be operated at low load for extended periods to gradually warm up the HRSG to minimize thermal stresses on pressure vessels and boiler tubes. During these startup periods, significant CO_2 emissions occur, but steam production is not sufficient for the steam turbine generator to produce electricity. They also stated that a similar situation occurs during shutdown when the steam cycle does not generate electricity, but the combustion turbine is still combusting fuel as it proceeds through the shutdown process. These commenters recommended that the EPA could address these issues by creating a subcategory for NGCC units that cycle and operate at intermediate load.

Many commenters said that site-specific factors can often preclude operators from achieving design efficiencies based on ISO conditions. These factors include high elevations, high ambient temperatures, and cooling system constraints. They stated that local water temperatures can impact condenser operating pressure and heat rates. They also said that areas with limited water resources could require systems that rely on air-cooled condensers, which cannot achieve thermal efficiencies comparable to water-cooled plants. These commenters stated that the final rule should include provisions for addressing site-specific constraints that preclude individual affected EGUs from achieving the emissions rates achieved on average by other sources.

Some commenters stated that the proposed standards for modified and reconstructed combustion turbines would foreclose future opportunities for operators to undertake projects to restore the performance of both degraded units subject to the NSPS and existing, pre-NSPS units. They said that it is not possible to bring older combustion turbines (built prior to the year 2000) up to the efficiency levels of modern units because many newer technological options that deploy higher temperatures are not available for pre-2000 combustion turbines.

Commenters from the power sector generally supported increasing the standards to 1,100 lb CO_2/MWh-g and 1,200 lb CO_2/MWh-g for the newly constructed large and small turbines, respectively. They also advocated finalizing standards for modified and reconstructed standards that are 10 percent higher than the final standards for new sources because combustion turbines constructed prior to 2000 were not included in the EPA's analysis.

Conversely, some commenters stated that the proposed standards for combustion turbines do not reflect the emission rates that are achievable by modern, efficient NGCC power blocks. These commenters stated that the appropriate standard, consistent with Congressional objectives under CAA section 111, should be 800 lb CO_2/MWh-g based on the performance of the lowest emitters in the CAMD database. Some commenters stated that a standard of 850 lb CO_2/MWh-g reflects BSER for high-capacity factor units because half of the NGCC units in the CAMD database are achieving this level of emissions. One commenter from the power sector who operates NGCC power plants stated that the final standard for new large combustion turbines should be 925 lb CO_2/MWh-g. Another commenter also supported an emission standard of 925 lb CO_2/MWh-g, which is consistent with recent BACT determinations in the state of New York. Several other commenters stated that a reasonable standard for new large combustion turbines should be 950 lb CO_2/MWh-g and that the final standard for new small combustion turbines should be 1,000 lb CO_2/MWh-g. Numerous commenters stated that the final standards for new sources should not exceed 1,000 lb CO_2/MWh-g for either large or small combustion turbines. Other commenters stated that, because the standards were developed based on emission rates that are being achieved by the majority of existing units, the final standards should be the same for new, modified, and reconstructed units.

b. Emission Standards for Non-Base Load Natural Gas-Fired Units and Multi-Fuel-Fired Units

Many commenters stated that the EPA cannot finalize ''no emission standard'' for non-base load units, which the EPA solicited comment on in the broad applicability approach. They argued that this approach was not consistent with the definition of ''standard of performance'' in CAA section 111(a)(1), which requires there to be an ''emission limitation'' that reflects a ''system of emission reduction.'' Some commenters recommended that non-base load units should be subject to work practice standards, such as operating safely with good air pollution control practices, including CO_2 monitoring and reporting requirements. Other commenters pointed to recent PSD permits that include tiered emission limits for the different roles served by combustion turbines. They cited BACT limits from 1,328 to 1,450 lb CO_2/MWh-g for peaking units. One commenter supported tiered limits consistent with recent BACT determinations in the state of New York, which include limits for simple cycle combustion turbines of 1,450 lb CO_2/MWh-g. An air quality regulator from a state with rapidly increasing renewable generation supported a limit of 825 lb CO_2/MWh-g for all base load NGCC units; 1,000 lb CO_2/MWh-g for large intermediate load NGCC units; 1,100 lb CO_2/MWh-g for small intermediate load NGCC units. This commenter also recommended that the EPA set a numerical limit specifically for peaking units after the completion of a peaking unit-specific BSER analysis. Several commenters supported tiered standards based on capacity factor. They proposed 825 lb CO_2/MWh-g for base load units (those operating over 4,000 hours annually), 875 lb CO_2/MWh-g for intermediate and load-following units (those operating between 1,200 and 4,000 hours annually), and 1,100 lb CO_2/MWh-g for peaking units (those operating less than 1,200 hours per year).

3. Final Standards

a. Newly Constructed Base Load Natural Gas-Fired Units

In evaluating the achievability of the base load natural gas-fired emission standard, we focused on three types of data. Specifically, we looked at existing NGCC emission rates, recent PSD permit limits for CO_2 emissions, and NGCC design efficiency data and specifications. Based on this analysis, we have concluded that an emission rate of 1,000 lb CO_2/MWh-g is appropriate for all base load natural gas-fired combustion turbines, regardless of size.

Since the standards were proposed, the EPA has expanded the NGCC emission rate analysis that supported the proposed emission standards to include emissions information for NGCC units that commenced operation in 2011, 2012, and 2013, and updated the emissions data to include emissions through 2014. In our analysis, we evaluated 345 NGCC units with online dates ranging from 2000 to 2013. The analysis included emissions data from 2007 to 2014 as submitted to the EPA's CAMD. The average maximum 12-operating-month CO_2 emission rate for all NGCC units was 897 lb CO_2/MWh-g, with individual unit maximums ranging from 751 to 1,334 lb CO_2/MWh-g.

Consistent with our proposed size-based subcategories, we also reviewed the emissions data for small and large NGCC units separately. For small units, we evaluated emissions data from 17 NGCC units with heat input ratings of 850 MMBtu/h or less. These units had an average maximum 12-operating-month CO_2 emission rate of 953 lb/MWh-g. Individual unit maximum emission rates ranged from 898 to 1,175 lb CO_2/MWh-g. Two of the units had a maximum emissions rate equal to or greater than 1,000 lb CO_2/MWh-g.[537] However, one of the units with a maximum emission rate above 1,000 lb CO_2/MWh-g was only selling approximately 20 percent of its potential electric output (significantly below the design-specific percentage electric sales threshold) when the emission rate occurred. If this unit were a new unit, the applicable emission standard would be the heat input-based clean fuels standard, and the unit would not be out of compliance. Therefore, 16 of the 17 existing small NGCC units have demonstrated that an emission rate of 1,000 lb CO_2/MWh-g is achievable. In addition, the six newest units, which commenced construction between 2007 and 2012, all have maximum 12-operating-month emission rates of less than 950 lb CO_2/MWh-g. While these units might not be old enough to have experienced degradation, their maximum emission rates demonstrate that the final standard of 1,000 lb CO_2/MWh-g includes a significant compliance margin for any future degradation.

For large units, the average maximum 12-operating-month emission rate was 895 lb CO_2/MWh-g, with individual unit maximum emission rates ranging from 751 to 1,334 lb CO_2/MWh-g. Twenty-three of the 328 large NGCC units had maximum 12-operating-month emission rates greater than 1,000 lb CO_2/MWh-g. While we do not have precise design efficiency information for each of these units, and thus cannot calculate the precise percentage electric sales threshold to which each unit would be subject, it appears that all of the emission rates in excess of 1,000 lb CO_2/MWh-g occurred during periods when electric sales were low and would be below the threshold. Thus, if these units were new units, they would only have to comply with the heat input-based clean fuels standard. Therefore, essentially all existing NGCC units would have been in compliance with the final emission standard. We note also that there are 51 new NGCC units that have started operation since 2010, and the average maximum 12-operating-month emission rate for these units is 833 lb CO_2/MWh-g. Therefore, the final emission standard includes a very significant compliance margin to account for any potential future degradation of large units.

[537] For emission standards of 1,000 lb CO_2/MWh-g and above, the emission standard uses three significant figures. See Section X.D.

To evaluate degradation further, the EPA reviewed the emission rate information for the 55 oldest NGCC units in our data set (*i.e.,* units that came online in 2000 and 2001). According to the commenters, we should expect to see degradation when reviewing the annual emissions data for these turbines because they are 14 to 15 years old. However, we did not see any sign of degradation. The CO_2 rates for these turbines have little standard deviation between 2007 and 2014. In addition, there were many instances where the CO_2 emission rate of a unit actually decreased with age. This indicates that the efficiency of the unit is increasing, possibly as a result of good operating and maintenance procedures or upgrades to equipment that improved efficiency beyond the original design. Based on these findings, we have concluded that our analysis adequately accounts for potential degradation.

We also evaluated the impact of elevation, ambient temperature, cooling type, and operating conditions (startups, shutdowns, and average run time per start) because commenters indicated that these could affect a unit's ability to achieve the standard. We saw little correlation between elevation or ambient temperature and emission rate. In addition, any correlation was relatively small and would have an insignificant impact on the ability of a unit to achieve the final standard. We identified 32 large NGCC units with dry cooling towers. The average maximum 12-operating-month emission rate for this group of units was 875 lb CO_2/MWh. This rate was actually lower than the average rate for the large NGCC group as a whole. Based on these findings, we have concluded that the final emission standard will not limit the use of dry cooling technologies. Finally, the EPA evaluated the impact of run time per start, average duty cycle, and number of starts on emission rates. While these factors do influence emission rates, the non-base load natural gas-fired subcategory inherently addresses efficiency issues related to operating conditions.

In addition to evaluating existing NGCC emissions data, the EPA reviewed the CO_2 emission limits included in PSD preconstruction permits issued since January 1, 2011. We evaluated all permit limits over an annual period. In total, we identified 31 major source PSD permits with 39 discrete limits on CO_2 emissions. Eight of the limits were expressed in terms of lb/h or tons per year, so we did not include them in the analysis. In addition, one CHP unit that generates electricity and supplies steam to a chemical plant was in the data set. This facility had a permit limit of 1,362 lb CO_2/MWh based only on gross electrical output and does not account for useful thermal output. Therefore, we did not include it in the analysis either. Finally, we excluded two permits that did not clearly specify if the output-based standard was on a gross or net basis.

The remaining 28 permit limits were expressed in lb CO_2/MWh or a heat rate basis that could be converted to lb CO_2/MWh. Eight permit limits were based on net output, ranging from 774–936 lb CO_2/MWh-n. The lowest emission limit was for a hybrid power plant with a solar component that could contribute up to 50 MW. Twenty permit limits were based on gross output, ranging from 833–1,100 lb CO_2/MWh-g. Of these 28 permit limits, the only limit in excess of our final emission standard of 1,000 lb CO_2/MWh-g is for a relatively small NGCC unit (base load rating of 366 MMBtu/h) that commenced construction prior to the proposal and thus will not be subject to the requirements of this final rule.

Each of the permit limits discussed above that is 1,000 lb CO_2/MWh or less includes all periods of operation, including startup, shutdown, and malfunction events. In addition, each permit limit was set after back up and additional fuel use were taken into consideration. While some permits restrict fuel use to only natural gas, others allow limited usage (duration and type) of back up and other fuels. For example, the Pioneer Valley Energy Center has unrestricted use of natural gas, but can burn ultra-low sulfur diesel (ULSD) for up to 1,440 hours per 12-month period. This permit requires the unit to comply with a limit of 895 lb CO_2/MWh-n even when burning up to 16 percent distillate oil. Each permit limit takes into account the mode of operation for the combustion turbine. For example, the permit for the Lower Colorado River Authority's Ferguson plant evaluated emission limits for the plant at 50, 75, and 100 percent gross load. The emission limit of 918 lb CO_2/MWh-n accounts for the unit's expected operation at 50 percent gross load. For NGCC units with duct burners on their HRSGs, the permit limits account for the hours of operation with duct burners firing. Finally, most of these permits include compliance margins to account for efficiency losses due to degradation and other factors (*e.g.,* actual operating parameters, site-specific design considerations, and the use of back up fuel). In total, these compliance margins result in a 10 to 13 percent increase in the permitted CO_2 emission limits, yet all of the limits except one were still below 1,000 lb CO_2/MWh-g.

Finally, we also reviewed NGCC design efficiency data and specifications submitted to *Gas Turbine World.* Specifically, we reviewed the reported efficiency data for 88 different 60 Hz NGCC units manufactured by Alstom, GE Energy Aeroderivative and Heavy Duty, Mitsubishi Heavy Industries, Pratt & Whitney, Rolls-Royce, and Siemens Energy. The designs ranged in model year from 1977 to 2011, capacities ranged from 31 to 1,026 MW, and base load ratings ranged from 236 to 3,551 MMBtu/h. The average reported design emission rate for these units was 834 lb CO_2/MWh-n and ranged from 725 to 941 lb CO_2/MWh-n. Therefore, our optional standard of 1,030 lb CO_2/MWh-n would allow for an average compliance margin of 24 percent, with a range from 10 to 42 percent, over the design rate. Ninety-five percent of designs would have a compliance margin of 13 percent or more, the top end of the range of compliance margins determined to be appropriate in the PSD permits we reviewed.

Because some commenters were concerned that smaller NGCC units will not be able to achieve the emission standard, we specifically considered the design rates for smaller units. For the 52 small units (base load rating of 850 MMBtu/h or less), the average design emission rate was 865 lb CO_2/MWh and ranged from 796 to 941 lb CO_2/MWh-n. Therefore, our optional standard of 1,030 lb CO_2/MWh-n would allow for an average compliance margin of 19 percent, with a range of 10 to 29 percent, over the design rate. Ninety-five percent of small NGCC designs would have a compliance margin of 13 percent or more.

We further refined our analysis by only considering the most efficient design for a given combustion turbine engine. For example, GE Energy Aeroderivative offers four design options for its LM2500 model-type, all with a rating of approximately 45 MW. The design emission rates for these various options range from 827 to 914 lb CO_2/MWh-n. When only the most efficient models for a particular combustion turbine engine design are considered, all NGCC models have over a 13 percent compliance margin. In other words, developers of new base load natural gas-fired combustion turbines concerned about the achievability of the final standard have multiple more efficient options offered by the same manufacturer. Therefore, we have concluded that the final emission standard allows sufficient flexibility for end users to select an

NGCC design appropriate for their specific requirements.

After considering these three sources of information—actual NGCC emission rate data, PSD permit limits for NGCC facilities, and NGCC design information—we have concluded that a standard of 1,000 lb CO_2/MWh is both achievable and appropriate for newly constructed base load natural gas-fired combustion turbines. While we anticipate that the large majority of new NGCC units will operate well below this emission rate, this standard provides flexibility for developers to take into account site-specific conditions (*e.g.,* ambient conditions and cooling system), operating characteristics (*e.g.,* part-load operation and frequent starting and stopping), and reduced efficiency due to degradation. The standard also accommodates the full size range of turbines.

We also expect multiple technology developments to further increase the performance of new base load natural gas-fired stationary combustion turbines. Vendors continue to improve the single cycle efficiency of combustion turbines. The use of more efficient combustion turbine engines improves the overall efficiency of NGCC facilities. In addition, existing smaller NGCC facilities were likely designed using single or dual pressure HRSGs without a reheat cycle. New designs can incorporate three pressure steam generators with a reheat cycle to improve the overall efficiency of the NGCC facility. Finally, additional technologies to reduce emission rates for new combustion turbines include CHP and integrated non-emitting technologies. For example, an NGCC unit that is designed as a CHP unit where ten percent of the overall output is useful thermal output would have an emission rate approximately five percent less than an electric-only NGCC. In sum, we believe that our final emission standards of 1,000 lb CO_2/MWh-g and 1,030 lb CO_2/MW-n are not only readily achievable, but likely conservative.

b. Reconstructed Base Load Natural Gas-Fired Units

We disagree with commenters that stated that reconstructed combustion turbines will not be able to achieve the proposed emission standards. For the reasons listed below, we have concluded that an existing base load natural-gas fired unit that reconstructs can achieve an emission rate of 1,000 lb CO_2/MWh-g, regardless of its size.

Highly efficient NGCC units include (1) an efficient combustion turbine engine, (2) an efficient steam cycle, and (3) a combustion turbine exhaust system that is ''matched'' to the steam cycle for maximum efficiency. In order for an existing NGCC unit to trigger the reconstruction provisions, the unit would have to essentially be entirely rebuilt. This would involve extensive upgrades to both the combustion turbine engine and the HRSG. Therefore, a reconstructed NGCC unit will be able to maximize the efficiency of the turbine engine and the steam cycle and match the two for maximum efficiency.

According to comments submitted in response to the proposal for existing sources under CAA section 111(d), there are various options available to improve the efficiency of existing combustion turbines. One combustion turbine manufacturer provided comments describing specific technology upgrades for the compressor, combustor, and gas turbine components. This manufacturer stated that operators of existing turbines can replace older internal components along the gas path with state-of-the-art components that have higher aerodynamic efficiencies and improved seal designs. These gas-path enhancements enable existing sources to both improve the efficiency of the turbine engine and improve the systems used for cooling the metal parts along the hot-gas path to allow existing systems to achieve higher operating temperatures. In total, the manufacturer stated that utilities deploying these gas-path improvements on reconstructed industrial frame combustion turbines with nominal output ratings of 170 to 180 MW can increase their output by 10 MW while reducing CO_2 emissions by more than 2.6 percent compared to baseline. In addition to gas-path and software improvements, the manufacturer stated that the newest low-NO_X combustor designs can be retrofitted on modified and reconstructed turbines to achieve lower NO_X emissions, which improves turndown (*i.e.,* to enable stable operations at lower loads compared to the lowest stable load achievable at baseline conditions) and efficiencies across all load conditions. The manufacturer indicated that operators of existing combustion turbines deploying both state-of-the-art gas-path and software upgrades and combustor upgrades can increase output on frame-style turbines with nominal output ratings of 170 to 180 MW by 14 MW, while reducing CO_2 emissions by 2.8 percent. In addition to the preceding upgrades, the manufacturer stated that existing combustion turbines can achieve the largest efficiency improvements by upgrading existing compressors with more advanced compressor technologies, potentially improving the combustion turbine's efficiency by an additional 3.8 percent. Thus, the total potential CO_2 emissions reductions for just the combustion turbine portion of a combined cycle unit is 6.6 percent.

In addition to upgrades to the combustion turbine engine, an operator reconstructing a NGCC unit will have the opportunity to improve the efficiency of the HRSG and steam cycle. For example, a steam turbine manufacturer identified three retrofit technologies available for reducing the CO_2 emissions rate of existing steam turbines by 1.5 to 3 percent: (1) Steam-path upgrades can minimize aerodynamic and steam leakage losses; (2) replacement of the existing high pressure turbine stages with state-of-the-art stages capable of extracting more energy from the same steam supply; and (3) replacement of low-pressure turbine stages with larger diameter components that extract additional energy and that reduce velocities, wear, and corrosion.

In addition, an operator reconstructing a NGCC unit could upgrade the entire steam cycle. For example, combined cycle units originally constructed with only a single pressure level can be upgraded to also include second and third pressure levels. Studies [538] [539] [540] show that converting a single pressure HRSG with steam reheat to a double pressure configuration with steam reheat can reduce the CO_2 emission rate of a NGCC unit by 1.5 to 1.7 percent. These same studies show that converting from a single pressure configuration with reheat to a triple pressure configuration with reheat can yield a 1.8 to 2 percent reduction in the CO_2 emission rate. Similarly, units constructed with only a double pressure configuration without reheat can obtain a 0.4 percent reduction by adding a reheat cycle or a 0.9 percent reduction by converting to a triple pressure configuration and adding a reheat cycle. Existing NGCC turbines that convert to these advanced HRSG configurations and that deploy the previously discussed combustion turbine and steam turbine upgrades can

[538] ''Exergetic and Economic Evaluation of the Effects of HRSG Configurations on the Performance of Combined Cycle Power Plants.'' M. Mansouri, *et al. Energy Conversion and Management* 58:47–58, 2012.

[539] ''Combined Cycle Power Plant Performance Analyses Based on Single-Pressure and Multipressure Heat Recovery Steam Generator.'' M. Rahim, *Journal of Energy Engineering,* 138:136–145, 2012.

[540] ''Thermodynamic Evaluation of Combined Cycle Plants.'' N. Woudstras *et al. Energy Conversion and Management* 51:1099–1110, 2010.

realize CO_2 emission rate reductions ranging from 6 to 10 percent, depending on their baseline design and condition. Based on the available options to improve the efficiency of existing NGCC units and the fact that the vast majority of existing NGCC units are already achieving emission rates of 1,000 lb CO_2/MWh-g or less, we have concluded that all reconstructed NGCC units can achieve this emission rate.

Finally, we note that an owner or operator that is considering reconstructing an existing simple cycle turbine should decide how they wish to operate that turbine in the future. If they anticipate operating above the percentage electric sales threshold, then they should install a HRSG and steam turbine and convert to a NGCC power block in accordance with our determination that NGCC is the BSER for base load applications. If they intend to operate the turbine below the percentage electric sales threshold, however, then the clean fuels standard, described below, will apply.

c. Newly Constructed and Reconstructed Non-Base Load Natural Gas-Fired Units

The EPA agrees with the commenters who stated that ''no emission limit'' would be inconsistent with the requirements of CAA 111(a)(1). We therefore are finalizing an input-based standard based on the use of clean fuels for non-base load natural gas-fired combustion turbines in recognition that efficiency can be reduced due to operation at low loads, cycling, and frequent startups. The EPA has concluded that, at this time, we do not have sufficient information to set a meaningful output-based standard for non-base load natural gas-fired combustion turbines. The input-based standard requires non-base load units to burn fuels with an average emission rate of 120 lb CO_2/MMBtu or less. This standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb CO_2/MMBtu. The most common back up fuel is distillate oil, which has a CO_2 emission rate of 163 lb CO_2/MMBtu. A non-base load natural gas-fired combustion turbine burning 9 percent distillate oil and 91 percent natural gas has an emission rate of 121 lb CO_2/MMBtu, which rounds to 120 lb CO_2/MMBtu using two significant digits. Therefore, the vast majority of owners and operators of non-base load natural gas-fired combustion turbines will be able to achieve the standard using business-as-usual fuels.

While the emission reductions that will result from restricting the use of fuels with higher CO_2 emission rates is minor, the compliance burden is also minimal. Owners and operators of non-base load natural gas-fired combustion turbines burning fuels with consistent chemical compositions that meet the clean fuels requirement (*e.g.,* natural gas, ethane, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, and biodiesel) will only need to maintain records that they burned these fuels in the combustion turbine. No additional recordkeeping or reporting will be required. Owners and operators burning fuels with higher CO_2 emission rates and/or chemical compositions that vary (*e.g.,* residual oil, non-jet fuel kerosene, landfill gas) will have to follow the procedures in part 98 of this part to determine the average CO_2 emission rate of the fuels burned during the applicable 12-operating-month compliance period and submit quarterly reports to verify that they are in compliance with the required emission standard.

d. Newly Constructed and Reconstructed Multi-Fuel-Fired Units

We also are finalizing an input-based standard based on the use of clean fuels, as opposed to an output-based standard, for multi-fuel units for several reasons. Specifically, we do not currently have continuous CO_2 emissions data for multi-fuel-fired units, we have not evaluated the potential efficiency impacts of different fuels, and the range of carbon content of non-natural gas fuels complicates establishing an appropriate output-based standard. Based on this lack of data, we have concluded that we cannot establish an output-based emission standard for multi-fuel-fired combustion turbines at this time.

The input-based emissions standard for this subcategory is based on the use of clean fuels. The use of clean fuels will ensure that newly constructed and reconstructed combustion turbines minimize CO_2 emissions during all periods of operation by limiting the use of fuels with higher CO_2 emission rates. To accurately represent the BSER and limit the ability of units to co-fire higher CO_2 emitting fuels with natural gas, we have concluded that it is necessary to use an equation based on the heat input from natural gas to determine the applicable emission standard. The 12-operating-month standard will vary from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending on the fraction of heat input from natural gas. The standard will be calculated by adding the product of the percent of heat input from natural gas and 120 with the product of the heat input from non-natural gas fuels and 160. For example, a combustion turbine that burns 80 percent natural gas and 20 percent distillate oil would be subject to an emission standard of 130 lb CO_2/MMBtu (rounded to two significant figures), which is equivalent to the actual emission rate of a unit burning this combination of fuels. On the other hand, a combustion turbine that burns 100 percent residual oil would be subject to an emission standard of 160 lb CO_2/MMBtu, but would have a higher actual emission rate, and would thus be out of compliance. In this way, the standard will restrict higher carbon fuels from being burned in multi-fuel-fired units, but will be readily achievable by units burning clean fuels.

According to information submitted to the EIA, the primary, non-natural gas fuels used by combustion turbines today for the production of electricity should all meet our definition of a clean fuel. Thus, while the emission reductions that will result from restricting the use of fuels with higher CO_2 emission rates is minor, the compliance burden is also minimal. Owners and operators of multi-fuel-fired combustion turbines burning fuels with consistent chemical compositions that meet the clean fuels requirement (*e.g.,* natural gas, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, and biodiesel) will only need to maintain records that they burned these fuels in the combustion turbine. No additional recordkeeping or reporting will be required. Owners and operators burning fuels with higher CO_2 emission rates and/or chemical compositions that vary (*e.g.,* residual oil, non-jet fuel kerosene, landfill gas) will have to follow the procedures in part 98 of this part to determine the average CO_2 emission rate of the fuels burned during the applicable 12-operating-month compliance period and submit quarterly reports to verify that they are in compliance with the required emission standard.

e. Modified Units

The EPA is not finalizing the proposed emission standards for stationary combustion turbines that conduct modifications. As explained in Section XV below, we are withdrawing the June 2014 proposal with respect to these sources. We received a significant number of comments asserting that modified combustion turbines could not meet the proposed emission standards of 1,000 lb/MWh-g for large turbines and 1,100 lb/MWh-g for small turbines. For the reasons explained in Section IX.B.1 above, we have decided not to subcategorize combustion turbines based on size for a number of reasons and are setting a single standard of

1,000 lb/MWh-g for all base load natural gas-fired turbines instead. While we are confident that all new and reconstructed units will be able to achieve this standard, we are less confident that all smaller combustion turbines that undertake a modification, specifically those that were constructed prior to 2000, will be able to do so. Until we have the opportunity to further investigate the full range of modifications that turbine owners and operators might undertake, we consider it premature to finalize emission standards for these sources.

Combustion turbines have unique characteristics that make determining an appropriate emission standard for modified sources a more challenging task than for coal-fired boilers. For example, each combustion turbine engine has a specific corresponding combustor. The development of more efficient combustor upgrades for existing turbine designs typically requires manufacturers to expend considerable resources. Consequently, not all manufacturers offer combustor upgrades for smaller or older designs because it would be difficult to recoup their investment. In contrast, efficiency upgrades for boilers can generally be installed regardless of the specific boiler's characteristics.

In addition, natural gas has the lowest CO_2 emission rate (in terms of lb CO_2/MMBtu) of any fossil fuel. As a result, an owner or operator that adds the ability to burn a back up fuel, such as distillate oil, to an existing turbine would likely trigger an NSPS modification. This is a relatively low-capital-cost upgrade that would significantly increase a unit's potential hourly emission rate, even though the annual emissions increase would be relatively minor because operating permits generally limit the amount of distillate oil that a unit can burn. We need to conduct additional analysis to determine an appropriate emission standard for units that undertake this type of modification, which does not involve any of the combustion turbine components that impact efficiency.

To be clear, the EPA is not reaching a final decision that modifications should be subject to different requirements than we are finalizing in this rule for new and reconstructed sources. We have made no decisions, and this matter is not concluded. We plan to continue to gather information, consider the options for modifications, and develop a new proposal for modifications in the future. Therefore, the EPA is withdrawing the proposed standards for all combustion turbines that conduct modifications and is not issuing final standards for those sources at this time. See Section XV below. We note that the effect of this withdrawal is that modified combustion turbines will continue to be existing sources subject to section 111(d).[541]

X. Summary of Other Final Requirements for Newly Constructed, Modified, and Reconstructed Fossil Fuel-Fired Electric Utility Steam Generating Units and Stationary Combustion Turbines

This section describes the final action's requirements regarding startup, shutdown, and malfunction; continuous monitoring; emissions performance testing; continuous compliance; and notification, recordkeeping, and reporting for newly constructed, modified, and reconstructed affected steam generating units and combustion turbines. We also explain final decisions regarding several of these requirements.

A. Startup, Shutdown, and Malfunction Requirements

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the D.C. Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of hazardous air pollutants (HAP) during periods of startup, shutdown, and malfunction (SSM). Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some CAA section 112 standards apply continuously.

Consistent with *Sierra Club* v. *EPA,* the EPA has established standards in this rule that apply at all times. In establishing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below as well as in Section V.J.1 above, has not established alternate standards for those periods. Specifically, startup and shutdown periods are included in the compliance calculation as periods of partial load. The final 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 affected CHP EGUs), over a rolling 12-operating-month period. In their compliance determinations, sources must incorporate emissions from all periods, including startup or shutdown, during which fuel is combusted and emissions are being monitored, in addition to all power produced over the periods of emissions measurements. As explained in Section V.J.1, given that the duration of startup or shutdown periods is 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 over a 12-operating-month period is expected to be minimal.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead they are, by definition sudden, infrequent and not reasonably preventable failures of emissions control, process or monitoring equipment. (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting emissions standards, nothing in CAA section 111 requires the agency to consider malfunctions as part of that analysis. A malfunction should not be treated in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance.

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

[541] As discussed above in Section VI.A of this preamble, a modified source that is not covered by a final or pending proposed standard continues to be an ''existing source'' and so will be covered by requirements under section 111(d). Under the definition of ''existing source'' in section 111(a)(6), an existing source is any source that is not a new source. Under the definition of ''new source'' in section 111(a)(2), a modified source is a new source only if the modification occurs after the publication of regulations (or proposed regulations, if earlier) that will be applicable to that source. Because we are not finalizing regulations with respect to modified steam turbines, and are withdrawing the proposal with respect to such sources, there are neither final regulations nor pending proposed regulations which will be applicable to such modifications.

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. For example, if an air pollution control device with 99 percent removal goes off-line as a result of a malfunction (as might happen if, for example, the bags in a baghouse catch fire) and the emission unit is a steady state type unit that would take days to shut down, the source would go from 99 percent control to zero control until the control device was repaired. The source's emissions during the malfunction would be 100 times higher than during normal operations. As such, the emissions over a 4-day malfunction period would exceed the annual emissions of the source during normal operations. As this example illustrates, accounting for malfunctions could lead to standards that are not reflective of (and 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.

Given that compliance with the emission standard is determined on a 12-operating-month rolling average basis, the impact of periods of malfunctions on the total average over a 12-operating-month period is expected to be minimal. Thus, malfunctions over that period are not likely to result in a violation of the standard.

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

If the EPA determines in a particular case that an enforcement action against a source for violation of an emission standard is warranted, the source can raise any and all defenses in that enforcement action and the 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 summary, the EPA interpretation of the CAA and, in particular, CAA section 111 is reasonable and encourages practices that will avoid malfunctions. Administrative and judicial procedures for addressing exceedances of the standards fully recognize that violations may occur despite good faith efforts to comply and can accommodate those situations.

In the January 2014 proposal for newly constructed EGUs, the EPA had proposed to include 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, to ensure 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 an affirmative defense in one of the EPA's CAA section 112 regulations. *NRDC* v. *EPA,* 749 F.3d 1055 (D.C. Cir., 2014) (vacating affirmative defense provisions in CAA section 112 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 in such cases 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 NRDC* at 1063 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.'').[542] In light of *NRDC,* the EPA is not including a regulatory affirmative defense provision in this final rule. 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 D.C. 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. NRDC,* at 1064 (arguments that violations were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.[543]

[542] 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.*

[543] Although the *NRDC* case does not address the EPA's authority to establish an affirmative defense to penalties that is available in administrative enforcement actions, the EPA is not including such an affirmative defense in the final rule. As explained above, such an affirmative defense is not necessary. Moreover, assessment of penalties for violations caused by malfunctions in administrative

Continued

B. Continuous Monitoring Requirements

The majority of comments received on the proposal supported the EPA's use of existing monitoring requirements under the Acid Rain Program, which are contained in 40 CFR part 75 requirements. In response to this, the EPA is finalizing monitoring requirements that incorporate and reference the part 75 monitoring requirements for the majority of the CO_2 and energy output monitoring requirements while ensuring accuracy and stringency required under the program.

This final rule requires owners or operators of EGUs that combust solid fossil fuel to install, certify, maintain, and operate continuous emission monitoring systems (CEMS) to 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/hr).

The rule allows owners or operators of affected 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 of part 75. To implement this option, hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of the fuel are also required, in accordance with appendix D of part 75.

In addition to requiring monitoring of the CO_2 mass emission rate, the rule requires 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 rule requires 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). The electronic portion of the monitoring plan should be submitted to the EPA's CAMD using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. The hard copy portion of the plan should be sent to the applicable state and EPA Regional office. Further, all monitoring systems used to determine the CO_2 mass emission rates have to be certified according to 40 CFR 75.20 and section 6 of part 75, appendix A within the 180-day window of time allotted under 40 CFR 75.4(b), and are required to meet the applicable on-going quality assurance procedures in appendices B and D of part 75.

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

The rule requires 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 calculating compliance with applicable emission limits. Additionally for EGUs using CO_2 CEMS, only unadjusted stack gas flow rate values should be used in the emissions calculations. In this rule, part 75 bias adjustment factors (BAFs) should 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. Additionally if an affected EGU combusts natural gas and/or fuel oil and the CO_2 mass emissions rate are measured using Equation G–4 in appendix G of part 75, then determination of site-specific carbon-based F-factors using Equation F–7b in section 3.3.6 of appendix F of part 75 is allowed, and use of these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature is also allowed.

This final rule includes the following special compliance provisions for units with common stack or multiple stack configurations; these provisions are consistent with 40 CFR 60.13(g):

- If two or more EGUs share a common exhaust stack, are subject to the same emission limit, and the operator is required to (or elects to) determine compliance using CEMS, then monitoring the hourly CO_2 mass emission rate at the common stack instead of monitoring each EGU separately is allowed. If this option is chosen, the hourly gross electrical load (or steam load) is the sum of the hourly loads for the individual EGUs and the operating time is expressed as ''stack operating hours'' (as defined in 40 CFR 72.2). Then, if compliance with the applicable emission limit is attained at the common stack, each EGU sharing the stack will be in compliance with the CO_2 emissions limit.
- If the operator is required to (or elects to) determine compliance using CEMS and the effluent from the EGU discharges to the atmosphere through multiple stacks (or, if the effluent is fed to a stack through multiple ducts and is monitored in the ducts), then monitoring the hourly CO_2 mass emission rate and the ''stack operating time'' at each stack or duct separately is required. In this case, compliance with the applicable emission limit is determined by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the unit.

The rule requires 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 have the option to use back up monitoring systems, as provided in 40 CFR 75.10(e) and 75.20(d), to help meet this data capture requirement. This requirement is separate from the requirement for a source to demonstrate compliance with an applicable emission standard. When demonstrating compliance with an emission standard the calculation must use all valid data to calculate a compliance average even if the percent of valid hours recorded in the period is less than the 95 percent requirement.

C. Emissions Performance Testing Requirements

Similarly to the comments received on monitoring for the proposal, commenters in general supported the use of current testing requirements required under the Acid Rain Program 40 CFR part 75 requirements. Thus the EPA is finalizing requirements for performance testing as consistent with part 75 requirements where appropriate to ensure the quality and accuracy of data and measurements as required by the final rule.

In accordance with 40 CFR 75.64(a), the final rule requires an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in 40 CFR 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). For EGUs subject to the

proceedings and judicial proceedings should be consistent. *Cf.* CAA section 113(e) (requiring both the Administrator and the court to take specified criteria into account when assessing penalties).

1,400 lb CO_2/MWh-g) emission standard, the initial performance test consists 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 begins 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 40 CFR 60.8 are not required for this rule. Following the initial compliance determination, the emission standard is met on a 12-operating-month rolling average basis.

D. Continuous Compliance Requirements

Commenters supported the use of a 12-operating-month rolling average for the compliance period for the final standards. In response, this final rule specifies that compliance with the 1,400 lb CO_2/MWh-g emission limit is 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 is used together with the gross output over that period of time to calculate the average CO_2 mass emissions rate.

The rule specifies that the first operating month included in the initial 12-operating-month compliance period is the month in which reporting of emissions data is required to begin under 40 CFR 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).

Initial compliance with the applicable emissions limit in kg/MWh is 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 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.

Several commenters stated that the final rule should require operators to round their calculated emissions rates to three significant figures when comparing their actual rates to the standard. These commenters said that allowing use of only two significant digits when calculating the 12-operating-month rolling average emission rate would constitute relaxation of the standard by 5 percent because an actual emission rate of 1,049.9 lb CO_2/MWh rounds to 1,000 lb of CO_2 per MWh when only two significant figures are required in the final step of compliance calculations. Commenters also suggested that the emission limits be written in scientific notation (*e.g.,* 1.10 x 10 − 3 lb CO_2/MWh) to clarify the number of significant digits that should be used when evaluating compliance. Other commenters suggested that the final step in compliance calculations should reflect rounding the emission rate to the nearest whole number using the ASTM rounding convention (ASTM E29).

The General Provisions of Part 60 specify the rounding conventions for compliance calculations at 40 CFR 60.13(h)(3) including the provision that ''after conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.''

The final rule requires that the 12-operating-month rolling average emission rate must be rounded to three significant figures if the applicable emissions standard is greater than or equal to 1,000 (*e.g.,* an actual emission rate of 1,004.9 lb CO_2/MWh is rounded to 1,000 lb CO_2/MWh); for standards of 1000 or less, the final rule requires rounding the actual emission rate to two significant figures (*e.g.,* an actual emission rate of 454.9 kg CO_2/MWh is rounded to 450 kg CO_2/MWh). Historically, many of the emissions limits under part 60 have been expressed to two significant digits (*e.g.,* the original SO_2 emission standard for coal-fired units under Subpart D was 1.2 lb SO_2/MMBtu). The rounding conventions under the General Provisions allow the reporting of all emission rates in the range from 1.15 to 1.249 as 1.2 lb SO_2/MMBtu. During compliance periods with emissions at the lower end of this range, the operator is required to report higher emissions than actually occurred; during compliance periods at the upper end of this range the operator is allowed to report lower emissions than actually occurred. In either case the absolute error remains small because the emission rate in this example is a relatively small numerical value. In addition, the required emission reductions typically are large enough that rounding does not impact the emission control strategy of affected units. However, the final standards for CO_2 emissions include numerical values that are larger than many historical emissions standards and require a relatively small percent reduction in emissions. Accordingly, it is appropriate to require the use of three significant digits when completing compliance calculations resulting in numerical values larger than 1,000. This is particularly important when considering the relatively small emission rate changes that may be required for compliance with the unit-specific emission standards being finalized for modified steam generating and IGCC units because a rounding error of 5 percent may be larger than the percent difference between the affected unit's historically best emission rate and the emission rate immediately preceding the modification.

The final rule requires rounding of emission rates with numerical values greater than or equal to 1,000 to three significant figures and rounding of rates with numerical values less than 1,000 to two significant figures.

E. Notification, Recordkeeping, and Reporting Requirements

Commenters supported the coordination of notification, recordkeeping, and reporting required under this rule in conjunction with the requirements already in place under part 75, so the EPA has made the requirements as efficient and streamlined as possible with the current requirements under part 75. The final rule requires an EGU owner or operator to comply with the applicable notification requirements in 40 CFR 75.61, 40 CFR 60.7(a)(1) and (a)(3), and 40 CFR 60.19. The rule also requires the applicable recordkeeping requirements in subpart F of part 75 to be met. For EGUs using CEMS, the data elements that are 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 are recorded include hourly fuel flow rates, fuel usage times, fuel GCV, gross electric generation.

The rule requires EGU owners or operators to keep records of the calculations they perform to determine the total CO_2 mass emissions and gross output for each operating month. Records 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 are required to be kept. The rule also requires sources to keep records of calculations performed to determine site-specific carbon-based F-factors for use in Equation G–4 of part 75, appendix G (if applicable).

Sources are required to keep all records for a period of 3 years. All required records must be kept on-site for a minimum of two years, after which the records can be maintained off-site.

The rule requires all affected EGU owners/operators to submit quarterly electronic emissions reports in accordance with subpart G of part 75. The reports in appendix G that do not include data required to calculate compliance with the applicable CO_2 emission standard are not required to be reported under this rule. The rule requires the reports in 40 CFR 60.5555 to be submitted using the ECMPS Client Tool. Except for a few EGUs that may be exempt from the Acid Rain Program (*e.g.,* oil-fired units), this is not a new reporting requirement. Sources subject to the Acid Rain Program are already required to report the hourly CO_2 mass emission rates that are needed to assess compliance with this rule.

Additionally, in the final rule and as part of an agency-wide effort to streamline and facilitate the reporting of environmental data, the rule requires selected data elements that pertain to compliance under this rule, and that serve the purpose of identifying violations of an emission standard, to be reported periodically using ECMPS.

Specifically, EGU owners/operators must submit quarterly electronic reports within 30 days after the end of each quarter consistent with current part 75 reporting requirements. The first report is for the quarter that includes the final (12th) operating month of the initial 12-operating-month compliance period. For that initial report and any subsequent report in which the 12th operating month of a compliance period (or periods) occurs during the calendar quarter, the average CO_2 mass emissions rate (kg/MWh) is reported for each compliance period, along with the dates (year and month) of the first and twelfth operating months in the compliance period and the percentage of valid CO_2 mass emission rates obtained in the compliance period. The dates of the first and last operating months in the compliance period clearly bracket the period used in the determination, which facilitates auditing of the data. 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 violations that occur during the quarter are identified. If there are no compliance periods that end in the quarter, a definitive statement to that effect must be included in the report. If one or more compliance periods end in the quarter but there are no violations, a statement to that effect must be included in the report.

Currently, ECMPS is not programmed to receive the additional information included in the report required under 40 CFR 60.5555(a)(2) for affected EGUs. However, we will make the necessary modifications to the system in order to fully implement the reporting requirements of this rule upon promulgation.

XI. Consistency Between BSER Determinations for This Rule and the Rule for Existing EGUs

In the CAA section 111(d) rule for existing steam units and combustion turbines that the EPA is promulgating at the same time as this CAA section 111(b) rule, the EPA is identifying as part of the BSER for those sources, building block 1 (for steam units, efficient operation), building block 2 (for steam units, dispatch shift to existing NGCC units), and building block 3 (for steam units and combustion turbines, substitution of generation with new renewable energy). In this section, we explain why the EPA is not identifying building blocks 1, 2, or 3 as part of the BSER for new, modified, or reconstructed steam generators or combustion turbines.

A. Newly Constructed Steam Generating Units

1. Preference for Technological Controls as the BSER for New EGUs

As discussed in this preamble and in more detail in the preamble to the CAA section 111(d) rule for existing sources, the phrase ''system of emission reduction'' is undefined and provides the EPA with discretion in setting a standard of performance under CAA section 111(b) or emission guidelines under CAA section 111(d). Because the phrase by its plain language does not limit our review of potential systems in either context, the same systems could be considered for application in new and existing sources. That said, many other factors and considerations direct us to focus on different systems when establishing a standard of performance under CAA section 111(b) and an emission guideline under CAA section 111(d). Thus, it is useful to describe part of the underlying basis for the BSER—partial CCS—that the EPA has determined for new steam units before discussing the building blocks that form the BSER for existing units.

For new steam generating units, the EPA is identifying, as the BSER, systems of emission reduction that assure that these sources are inherently low-emitting at the time of construction. The following reasons support this approach to the BSER.

New sources are expected to have long operating lives over which initial capital costs can be amortized. Thus, new construction is the preferred time to drive capital investment in emission controls. In this case, the BSER for new steam generators, partial CCS, requires substantial capital expenditures, which new sources are best able to accommodate.

While CAA section 111(b)(1)(B) and (a)(1) by their terms do not mandate that the BSER assure that new sources are inherently low emitting, that approach to the BSER is consistent with the legislative history.[544] See Section III.H.3.b.4 above. For instance, the 1970 Senate Committee Report explains that ''[t]he overriding purpose of this section [concerning new source performance standards] would be to prevent new air pollution problems, and toward that end, *maximum feasible control of new sources at the time of their construction* is seen by the committee as the most effective and, in the long run, the least expensive approach.'' [545] Existing sources, on the other hand, would be regulated through emission standards, which were broadly understood at the time to reflect available technology, alternative methods of prevention and control, alternative fuels, processes, and operating methods.[546] [547]

[544] Although Congress expressed a clear preference that new sources would be ''designed, built, equipped, operated, and maintained so as to reduce emissions to a minimum,'' the Senate Committee Report also makes clear that the term standard of performance ''refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, *or other methods.''* Sen. Rep. No. 91–1196 at 15–17, 1970 CAA Legis. Hist. at 415–17 (emphasis added).

[545] Sen. Rep. No. 91–1196 at 15–16, 1970 CAA Legis. Hist. at 416 (emphasis added).

[546] *See* 1970 CAA Amendments, Pub. L. 91–604, section 4, 84 Stat. 1676, 1679 (Dec. 31, 1970) (describing information that the EPA must issue to the states and appropriate air pollution control agencies along with the issuance of ambient air quality criteria under Section 4 of the 1970 CAA titled ''Ambient Air Quality and Emission Standards'').

[547] In the 1977 CAA Amendments, Congress revised section 111(a)(1) to mandate that the EPA base standards for new sources on technological controls, but, at the same time, made clear that the EPA was not required to base the emission guidelines for existing sources on technological controls. In the 1990 CAA Amendments, Congress repealed the section 111(a)(1) requirements that distinguished between new and existing sources and largely restored the 1970 CAA Amendments version of section 111(a)(1).

2. Practical Implications of Including the Building Blocks

Several practical considerations make the building blocks inappropriate for new sources. Thus, for the following reasons, the EPA does not consider it appropriate to include the building blocks as part of the BSER for new sources:

a. Additional Cost

Partial CCS will impose substantial (albeit reasonable) costs on new steam-generating EGUs, and, as a result, the EPA does not believe that including additional measures as part of the BSER would be appropriate. One disadvantage in adding additional costs is that doing so would make it more difficult for new steam-generating EGUs to compete with new nuclear units. Because the BSER is selected after considering cost (among other factors), the EPA is not required to,[548] and in this case believes it would not be appropriate to, select the most stringent adequately demonstrated system of emission reduction (through the combination of partial CCS and the building blocks) for purposes of setting a standard of performance under CAA section 111(b).

Building block 1 measures are not appropriate (or would be redundant) because the BSER for new steam generating units is based on highly efficient supercritical technology, *i.e.,* state-of-the-art, efficient equipment. See Section V.K above. Accordingly, there is little improvement in efficiency that can be justified as part of the BSER.

Building block 2 and 3 measures are not appropriate for the BSER because new steam units would have a significantly limited range of options to implement building blocks 2 and 3. The new source performance standard was proposed and is being finalized as a rate-based standard. Thus, if building blocks 2 and 3 were included in the BSER, a more stringent rate-based standard would be applicable to all new sources. However, it is conceivable that the EPA could propose a hybrid standard that would include both an emission-rate limit that reflects partial CCS and a requirement for allowances that reflects building blocks 2 and 3. Accordingly, the following discussion assumes either a rate-based or mass-based standard, or part of a hybrid standard.

In both a rate-based program and a mass-based program, building blocks 2 and 3 measures can be implemented through a range of methods, including trading with other EGUs. While it is not necessarily the case that every existing source will be able to implement each of the methods, in general, existing sources will have a range of measures to choose from. However, at least some of those methods may not be available to new sources, which would render compliance with their emission limits more challenging and potentially more costly.

One example is emission trading with other affected EGUs. For existing sources, emission trading is an important option for implementing the building blocks. There are large numbers of existing sources, and they will become subject to the section 111(d) standards of performance at the same time. It may be more cost-effective for some to implement the building blocks than others, and, as a result, some may over-comply and some may under-comply, and the two groups may trade with each other. Because of the large numbers of existing sources, the trading market can be expected to be robust. Trading optimizes efficiency. As a result, existing sources have more flexibility in the overall amount of their investment in building blocks 2 and 3 and can adjust investment obligations among themselves through emissions trading.

In contrast, new sources construct one at a time, and it is unknown how many new sources there will be. Without a sizeable number of new sources, there will not be a robust trading market. Thus, a new source cannot count on being able to find a new source trading partner. In addition, it is not possible to count on new sources being able to trade with existing sources, for several reasons. First, as noted, there are indications in the legislative history that new sources should be well-controlled at the source, which casts doubt on whether new sources should be allowed to meet their standards through the purchase of emission credits. Second, new sources must meet their standards of performance as soon as they begin operations. If they do so before the year 2022, when existing sources become subject to section 111(d) state plan standards of performance, no existing sources will be available as trading partners.

In addition, for section 111(d) sources, we are granting a 7-year period of lead-time for the implementation of the building blocks. This is due, in part, to the benefits of allowing the ERC and allowance markets to develop. However, the new source standards take effect immediately, so new sources would not have the advantage of this lead time were they subject to more stringent standards that also reflected the building blocks.[549]

In addition, if there are an unexpectedly large number of new sources, then they would be obliged to invest in greater amounts of building blocks 2 and 3, and that could reduce the amounts of building blocks 2 and 3 available for existing sources, and thereby raise the costs of building blocks 2 and 3 for existing sources. This could compromise the BSER under section 111(d) and undermine the ability of existing sources to comply with their section 111(d) obligations.[550]

B. New Combustion Turbines

For new combustion turbines, the building blocks are not appropriate as part of the BSER either. Building block 1 is limited to steam generating units, and therefore has no applicability to new combustion turbines. Measures comparable to those in building block 1 would not be appropriate because new highly efficient NGCC construction already entails high efficiency equipment and operation. Building block 2 is also limited to steam generating units and is not appropriate as part of the BSER for new NGCC units because it would not result in any emission reductions.

The reasons why building block 3 are not appropriate are the same as discussed above for why building blocks 2 and 3 are not appropriate for new steam generating units (limited range of options for implementation (including lack of availability of trading), lack of

[548] For example, as early as a 1979 NSPS rulemaking for affected EGUs, the EPA recognized that it was not required to establish as the BSER the most stringent adequately demonstrated system of emission reduction available, and instead could weigh the amount of additional emission reductions against the costs. *See* 44 FR 52792, 52798 (Sept. 10, 1979) (''Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.'').

[549] At least in theory, we could consider promulgating a standard of performance for new affected EGUs that becomes more stringent beginning in 7 years, based on a more stringent BSER. We are not inclined to adopt that approach because section 111(b)(1)(B) requires that we review and, if necessary, revise the section 111(b) standards of performance no later than every 8 years anyway.

[550] The EPA is authorized to consider the BSER for new and existing sources in conjunction with each other. In the 1977 CAA Amendments, Congress revised section 111(a)(1) to require technological controls for new combustion sources at least in part because this requirement would preclude new sources from relying on low-sulfur coal to achieve their emission limits, which, in turn, would free up low-sulfur coal for existing sources.

lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

C. Modified and Reconstructed Steam and NGCC Units

For modified and reconstructed steam generators, the EPA identified the BSER as maintenance of high efficiency or implementation of a highly efficient unit. The resulting emission limit must be met over the specified time period and cannot be deviated from or averaged. As a result, a modified or reconstructed steam generator generally will require ongoing maintenance and may find it prudent to operate below its limit as a safety margin. This represents a substantial commitment of resources. For these units, the additional costs of implementing the building blocks would not be appropriate.

In addition, building block 1 is not appropriate for modified or reconstructed steam generating units because the BSER for these units is already based on highly efficient performance. For the same reasons, it does not make sense to attempt to develop the analogue to building block 1 for reconstructed NGCC units—the BSER for them, too, is already based on highly efficient performance.

Building block 2 is not appropriate for reconstructed NGCC units because it would not yield any reductions.

Building blocks 2 and 3 are not appropriate for modified or reconstructed steam generators, and building block 3 is not appropriate for reconstructed NGCC units, for the same reasons that they are not appropriate for new EGUs, as described above (limited range of options for implementation (including lack of availability of trading), lack of lead-time for implementation, and the possibility of reducing the availability of renewable energy for existing sources).

XII. Interactions With Other EPA Programs and Rules

A. Overview

This final rule will, for the first time, regulate GHGs under CAA section 111. In Section IX of the preamble to the proposed rule, the EPA addressed how regulation of GHGs under CAA section 111 could have implications for other EPA rules and for permits written under the CAA Prevention of Significant Deterioration (PSD) preconstruction permit program and the CAA Title V operating permit program. The EPA proposed to adopt provisions in the regulations that explicitly addressed some of these implications.

For purpose of the PSD program, the EPA is finalizing provisions in part 60 of its regulations that make clear that the threshold for determining whether a PSD source must satisfy the BACT requirement for GHGs continues to apply after promulgation of this rule. This rule does not require any additional revisions to State Implementation Plans. As discussed further below, this final rule may have bearing on the determination of BACT for new, modified, and reconstructed EGUs that require PSD permits. With respect to the Title V operating permits program, this rule does not affect whether sources are subject to the requirement to obtain a Title V operating permit based solely on emitting or having the potential to emit GHGs above major source thresholds. However, this rule does have some implications for Title V fees, which the EPA is addressing in this final rule.

Finally, the fossil fuel-fired EGUs covered in this rule are or will be potentially impacted by several other recently finalized or proposed EPA rules, and such potential interactions with other EPA rules are discussed below.

B. Applicability of Tailoring Rule Thresholds Under the PSD Program

In our January 8, 2014 proposal, the EPA proposed to adopt regulatory language in 40 CFR part 60 that would ensure the promulgation of this NSPS would not undercut the application of rules that limit the application of the PSD permitting program requirements to only the largest sources of GHGs. An intervening decision of the United States Supreme Court has, to a large extent, resolved the legal issue that led the EPA to propose these part 60 provisions. The Supreme Court has since clarified that the PSD program does not apply to smaller sources based on the amount of GHGs they emit. However, because the largest sources emitting GHGs remain subject to the PSD permitting requirements, the EPA has concluded that it remains appropriate to adopt the proposed regulatory provisions in 40 CFR part 60 in this rule. We discuss our reasons for this action in detail below.

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds is required to obtain a preconstruction permit. This permit assures that the source meets specific requirements, including application of BACT to each pollutant subject to regulation under the CAA. Many states (and local districts) are authorized by the EPA to administer the PSD program and to issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits for facilities in that state.

To identify the pollutants subject to the PSD permitting program, EPA regulations contain a definition of the term ''regulated NSR pollutant.'' 40 CFR 52.21(b)(50); 40 CFR 51.166(b)(49). This definition contains four subparts, which cover pollutants regulated under various parts of the CAA. The second subpart covers pollutants regulated under section 111 of the CAA. The fourth subpart is a catch-all provision that applies to ''[a]ny pollutant that is otherwise subjection to regulation under the Act.''

This definition and the associated PSD permitting requirements applied to GHGs for the first time on January 2, 2011, by virtue of the EPA's regulation of GHG emissions from motor vehicles, which first took effect on that same date. 75 FR 17004 (Apr. 2, 2010). As such, GHGs became subject to regulation under the CAA and the fourth subpart of the ''regulated NSR pollutant'' definition became applicable to GHGs.

On June 3, 2010, the EPA issued a final rule, known as the Tailoring Rule, which phased in permitting requirements for GHG emissions from stationary sources under the CAA PSD and Title V permitting programs (75 FR 31514). Under its understanding of the CAA at the time, the EPA believed the Tailoring Rule was necessary to avoid a sudden and unmanageable increase in the number of sources that would be required to obtain PSD and Title V permits under the CAA because the sources emitted GHGs emissions over applicable major source and major modification thresholds. In Step 1 of the Tailoring Rule, which began on January 2, 2011, the EPA limited application of PSD or Title V requirements to sources of GHG emissions only if the sources were subject to PSD or Title V ''anyway'' due to their emissions of non-GHG pollutants. These sources are referred to as ''anyway sources.'' In Step 2 of the Tailoring Rule, which began on July 1, 2011, the EPA applied the PSD and Title V permitting requirements under the CAA to sources that were classified as major, and, thus, required to obtain a permit, based solely on their potential GHG emissions and to modifications of otherwise major sources that required a PSD permit because they increased only GHG emissions above applicable levels in the EPA regulations.

In the PSD program, the EPA implemented the steps of the Tailoring Rule by adopting a definition of the term ''subject to regulation.'' The limitations in Step 1 of the Tailoring Rule are reflected in 40 CFR 52.21(b)(49)(iv) and 40 CFR 51.166(b)(48)(iv). With respect to ''anyway sources'' covered by PSD during Step 1, this provision established that GHGs would not be subject to PSD requirements unless the source emitted GHGs in the amount of 75,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e) or more. The primary practical effect of this paragraph is that the PSD BACT requirement does not apply to GHG emissions from an ''anyway source'' unless the source emits GHGs at or above this threshold. The Tailoring Rule Step 2 limitations are reflected in 40 CFR 52.21(b)(49)(v) and 51.166(b)(48)(v). These provisions contain thresholds that, when applied through the definition of ''regulated NSR pollutant,'' function to limit the scope of the terms ''major stationary source'' and ''major modification'' that determine whether a source is required to obtain a PSD permit. See *e.g.* 40 CFR 51.166(a)(7)(i) and (iii); 40 CFR 51.166(b)(1); 40 CFR 51.166(b)(2).

This structure of the EPA's PSD regulations created questions regarding the extent to which the limitations in the Tailoring Rule would continue to apply to GHGs once they became regulated, through this final rule, under section 111 of the CAA. 79 FR 1487–1488. As discussed above, the definition of ''regulated NSR pollutant'' in the PSD regulations contains a separate PSD trigger for air pollutants regulated under the NSPS, 40 CFR 51.166(b)(49)(ii) (the ''NSPS trigger provision''). Thus, when GHGs become subject to a standard promulgated under CAA section 111 for the first time under this rule, PSD requirements would presumably apply for GHGs on an additional basis besides through the regulation of GHGs from motor vehicles. However, the Tailoring Rule, on the face of its regulatory provisions, incorporated the revised thresholds it promulgated into only the fourth subpart of the PSD definition of regulated NSR pollutant (''[a]ny pollutant that otherwise is subject to regulation under the Act''). The regulatory text does not clearly incorporate the thresholds into the NSPS trigger provision in the second subpart (''[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act''). For this reason, a question arose as to whether the Tailoring Rule limitations would continue to apply to the PSD requirements after they are independently triggered for GHGs by the NSPS that the EPA is now promulgating. Stakeholders questioned whether the EPA must revise its PSD regulations —and, by the same token, whether states must revise their SIPs—to assure that the Tailoring Rule thresholds will continue to apply to sources potentially subject to PSD under the CAA based on GHG emissions.

In the January 8, 2014 proposed rule, the EPA explained that the agency had included an interpretation in the Tailoring Rule preamble, which means that the Tailoring Rule thresholds continue to apply if and when the EPA promulgates requirements under CAA section 111. 79 FR 1488 (citing 75 FR 31582). Nevertheless, to ensure there would be no uncertainty as to this issue, the EPA proposed to adopt explicit language in 40 CFR 60.46Da(j), 40 CFR 60.4315(b), and 40 CFR 60.5515 of the agency's regulations. The proposed language makes clear that the thresholds for GHGs in the EPA's PSD definition of ''subject to regulation'' apply through the second subpart of the definition of ''regulated NSR pollutant'' to GHGs regulated under this rule.

The EPA received comments supporting the adoption of this proposed language, but several commenters also expressed concern that adding this language to part 60 alone would not be sufficient. Several commenters urged the EPA to instead revise the PSD regulations in parts 51 and 52. In addition, commenters expressed concern that further steps were needed to amend the SIPs before there would be certainty that the Tailoring Rule limitations continued to apply after the adoption of CO_2 standards under CAA section 111 in this final rule.

On June 23, 2014, the United States Supreme Court, in *Utility Air Regulatory Group* v. *Environmental Protection Agency,* issued a decision addressing the application of PSD permitting requirements to GHG emissions. The Supreme Court held that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source (or modification thereof) for the purpose of PSD applicability. The Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of pollutants other than GHGs, contain limitations on GHG emissions based on the application of BACT. The Supreme Court decision effectively upheld PSD permitting requirements for GHG emissions under Step 1 of the Tailoring Rule for ''anyway sources'' and invalidated application of PSD permitting requirements to Step 2 sources based on GHG emissions. The Court also recognized that, although the EPA had not yet done so, it could ''establish an appropriate *de minimis* threshold below which BACT is not required for a source's greenhouse gas emissions.'' 134 S. Ct. at 2449.

In accordance with the Supreme Court decision, on April 10, 2015, the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) issued an amended judgment vacating the regulations that implemented Step 2 of the Tailoring Rule, but not the regulations that implement Step 1 of the Tailoring Rule. The court specifically vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v) of the EPA's regulations, but did not vacate 40 CFR 51.166(b)(48)(iv) or 40 CFR 52.21(b)(48)(iv). The court also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake such revisions.

The practical effect of the Supreme Court's clarification of the reach of the CAA is that it eliminates the need for Step 2 of the Tailoring Rule and subsequent steps of the GHG permitting phase in that the EPA had planned to consider under the Tailoring Rule. This also eliminates the possibility that the promulgation of GHG standards under section 111 could result in additional sources becoming subject to PSD based solely on GHGs, notwithstanding the limitations the EPA adopted in the Tailoring Rule. However, for an interim period, the EPA and the states will need to continue applying parts of the PSD definition of ''subject to regulation'' to ensure that sources obtain PSD permits meeting the requirements of the CAA.

The CAA continues to require that PSD permits issued to ''anyway sources'' satisfy the BACT requirement for GHGs. Based on the language that remains applicable under 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv), the EPA and states may continue to limit the application of BACT to GHG emissions in those circumstances where a source emits GHGs in the amount of at least 75,000 tpy on a CO_2e basis. The EPA's intention is for this to serve as an interim approach while the EPA moves forward to propose a GHG Significant Emission Rate (SER) that would establish a *de minimis* threshold level for permitting GHG emissions under PSD. Under this forthcoming rule, the EPA intends to propose restructuring the GHG provisions in its PSD regulations so that the *de minimis* threshold for GHGs will not reside within the definition of ''subject to regulation.'' This restructuring will be designed to make the PSD regulatory provisions on GHGs universally applicable, without regard to the particular subparts of the definition of ''regulated NSR pollutant'' that may cover GHGs. Upon promulgation of this PSD rule, it will then provide a framework that states may use when updating their SIPs consistent with the Supreme Court decision.

While the PSD rulemaking described above is pending, the EPA and approved state, local, and tribal permitting authorities will still need to implement the BACT requirement for GHGs. In order to enable permitting authorities to continue applying the 75,000 tpy CO_2e threshold to determine whether BACT applies to GHG emissions from an ''anyway source'' after GHGs are subject to regulation under CAA section 111, the EPA has concluded that it continues to be appropriate to adopt the proposed language in 40 CFR 60.5515 (subpart TTTT). Because the EPA is not finalizing the proposed regulations in subparts Da and KKKK, it is not necessary to adopt the comparable provisions that the EPA proposed in 40 CFR 60.46Da(j) and 40 CFR 60.4315(b).

The EPA has evaluated 40 CFR 60.5515 in light of the Supreme Court decision and the comments received on the question of whether this CAA section 111 standard will undermine the application of the Tailoring Rule limitations. While most of the Tailoring Rule limitations are no longer needed to avoid triggering the requirement to obtain a PSD permit based on GHGs alone, the limitation in 40 CFR 51.166(b)(48)(iv) and 40 CFR 52.21(b)(49)(iv) will remain important to provide an interim applicability level for the GHG BACT requirement in ''anyway source'' PSD permits. Thus, there continues to be a need to ensure that the regulation of GHGs under CAA section 111 does not make this BACT applicability level for anyway sources effectively inoperable. The language in 40 CFR 60.5515 will continue to be effective at avoiding this result after the judicial actions described above and the adoption of this final rule. The provisions in part 60 reference 40 CFR 51.166(b)(48) and 40 CFR 52.21(b)(49) of the EPA's regulations. However, the courts have now vacated 40 CFR 51.166(b)(48)(v) and 40 CFR 52.21(b)(49)(v), and the EPA will take steps soon to eliminate these subparts from the CFR. As a result of these steps, the language of final 40 CFR 60.5515 will not incorporate the vacated parts of 40 CFR 51.166(b)(48) and 40 CFR 52.21(b)(49), but these provisions in part 60 will continue to apply to those subparts of the PSD rules that are needed on an interim basis to limit application of BACT to GHGs only when emitted by an anyway source in amounts of 75,000 tpy CO_2e or more. Thus, in this final rule, the EPA is adopting the proposed text of 40 CFR 60.5515 for this purpose without substantial change.

As to the concern expressed by some commenters that revisions to part 60 alone are not sufficient, the GHG SER rulemaking described above will include proposed revisions to the PSD regulations in parts 51 and 52 that should ultimately address this concern. The EPA acknowledges that the commenters concern will not be fully addressed for an interim period of time, but (for the reasons discussed above) the part 60 provisions adopted in this rule are sufficient to make explicit that the 75,000 tpy CO_2e BACT applicability level for GHGs will apply to GHGs that are subject to regulation under the CAA section 111 standards adopted in this rule.

Rather than adopting a temporary patch in its PSD regulations in this rule to address the implications for PSD of regulating GHGs under CAA section 111, the EPA believes it will be most efficient for the EPA and the states if the EPA completes a comprehensive PSD rule that will address all the implications of the Supreme Court decision. The revisions the EPA will consider based on the Supreme Court decision will inherently address the commenters concerns about the definition of the ''subject to regulation'' and the proposed part 60 provisions. To the extent this PSD rule is not complete before the EPA proposes additional CAA section 111 standards for GHGs, the EPA will need to consider adding provisions like 40 CFR 60.5515 to other subparts of part 60. In a separate rulemaking finalized concurrently with this rule, the EPA is also finalizing corresponding edits to 40 CFR 60.5705 in subpart UUUU to clarify that the regulated pollutant is the same for both the CAA section 111(b) and section 111(d) rules. As of this time, the EPA has not proposed GHG standards for other source categories under CAA section 111. To the extent needed, this approach of adding provisions to a few subparts in part 60 would be less burdensome to states and more efficient than revising 40 CFR 51.166 at this time solely to address the implications of regulating GHGs under CAA section 111.

The EPA understands that many commenters expressed concern that PSD SIPs would also have to be amended to address the implications of regulating GHGs under CAA section 111. However, the language in 40 CFR 60.5515 is designed to avoid the need for states to make revisions to the PSD regulations in their SIPs at this time. The EPA has previously observed that the form of each pollutant regulated under the PSD program is derived from the form of the pollutant described in regulations, such as an NSPS, that make the pollutant regulated under the CAA. 56 FR 24468, 24470 (May 30, 1991); 61 FR 9905, 9912–18 (Mar. 12, 1996); 75 FR 31522.

Moreover, it is more likely that states would need to consider a SIP revision if the EPA were to revise 40 CFR 51.166 in this rule. Revisions to 51.166 can trigger requirements for states to revise their PSD program provisions under 40 CFR 51.166(a)(6).

Given the process required in states to review their SIPs and submit them to the EPA for approval, it is most efficient for all concerned when the EPA is able to consolidate its revisions to 40 CFR 51.166. The EPA, thus, believes it will be less work for states if we issue a comprehensive set of rules addressing regulation of GHGs under the PSD program after the Supreme Court decision.

In comments on the proposed rules, states generally did not express concern that the proposed revisions to part 60 were insufficient to avoid the need for SIP revisions. In our proposal, we addressed any state with an approved PSD SIP program that applies to GHGs which believed that this final rule would require the state to revise its SIP so that the Tailoring Rule thresholds continue to apply. First, the EPA encouraged any state that considered such revisions necessary to make them as soon as possible. Second, if the state could do so promptly, the EPA said it would assess whether to proceed with a separate rulemaking action to narrow its approval of that state's SIP so as to assure that, for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of the final NSPS rule. 79 FR 1487. The EPA did not receive any comments or other feedback from states requesting that the EPA narrow their program to ensure the Tailoring Rule thresholds continue to apply after promulgating this rule. We do not believe such action will be necessary in any state after the Supreme Court decision and our action in this rule is to adopt the proposed part 60 provisions for purposes of ensuring the Step 1 BACT applicability level for GHGs continues to apply on an interim basis.

C. Implications for BACT Determinations Under PSD

New major stationary sources and major modifications at existing major stationary sources are required by the

CAA to, among other things, obtain a permit under the PSD program before commencing construction. The emission thresholds that define PSD applicability can be found in 40 CFR parts 51 and 52, and the PSD thresholds specific to GHGs are explained in the preceding section of this preamble.

Sources that are subject to PSD must obtain a preconstruction permit that contains emission limitations based on application of BACT for each regulated NSR pollutant. The BACT requirement is set forth in section 165(a)(4) of the CAA, and in EPA regulations under 40 CFR parts 51 and 52. These provisions require that BACT determinations be made on a case-by-case basis. CAA section 169(3) defines BACT, in general, as:

> ''an emissions limitation . . . based on the maximum degree of reduction for each pollutant . . . emitted from any proposed major stationary source or major modification which the Administrator . . . [considering energy, environmental, and economic impacts] . . . determines is achievable for such facility . . .''

Furthermore, this definition in the CAA specifies that

> ''[i]n no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of the Act.''

This condition of CAA section 169(3) has historically been interpreted to mean that BACT cannot be less stringent than any applicable standard of performance under the NSPS. *See, e.g.,* U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA–457/B–11–001 (March 2011) (''GHG Permitting Guidance'' or ''Guidance'') at 20–21. Thus, upon completion of an NSPS, the NSPS establishes a ''BACT Floor'' for PSD permits that are issued to affected facilities covered by the NSPS.

BACT is a case-by-case review that considers a number of factors. These factors include the availability, technical feasibility, control effectiveness, and the economic, environmental and energy impacts of the control option. See GHG Permitting Guidance at 17–46. The fact that a minimum control requirement (*i.e.,* the BACT Floor) is established by the EPA through an applicable NSPS does not bar a permitting agency from justifying a more stringent control level as BACT for a specific PSD permit.

It is important to understand how this NSPS may relate to determining BACT for new and existing EGUs that require PSD permits. PSD generally applies to major sources, while this NSPS applies to units that may be within a source. Under this NSPS, an affected facility is a new EGU or a modified or reconstructed EGU. The new source NSPS requirements apply, in general, to any stationary source that adds a new EGU that is an affected facility under this NSPS. This could, for example, include a proposed brand new (''greenfield'') power plant or an existing power plant that proposes to add a new EGU (*e.g.,* to increase its generating capacity). While this latter scenario is considered a ''new affected facility'' under the NSPS, it is generally viewed under PSD as a ''modification'' of an existing stationary source. Thus, the new source NSPS requirements could apply to a modification, as that term is defined under PSD.

In addition, this NSPS will apply to some modified and reconstructed units, as those terms are defined under part 60. Consequently, this NSPS could establish a BACT floor for existing stationary sources that are modifying an existing EGU and experience an emissions increase that makes the source subject to PSD review. However, a physical change that triggers the NSPS modification or reconstruction requirements does not necessarily subject the source to PSD requirements, and vice versa. In general, in order to trigger the NSPS modification or reconstruction requirements, a physical change must increase the maximum hourly emission rate of the pollutant (to be an NSPS modification) or the fixed capital cost of the change must exceed 50 percent of the fixed capital cost of a comparable entirely new facility (to be an NSPS reconstruction). *See* 40 CFR 60.2, 60.14, 60.15. Under the PSD program, however, a physical change (or change in the method of operation) must result in an increase in annual emissions of the pollutant by a specified emission threshold in order to be subject to PSD requirements. This emission calculation considers the unit's past annual emissions and its projected annual emissions. See, *e.g.,* 40 CFR 52.21(a)(2)(iv)(C). In addition, the PSD emissions test for a modification allows the existing source to consider qualifying emission reductions and increases at the source within a contemporaneous period to ''net out'' of, or avoid, triggering PSD review. Thus, it is important to understand the differences in how the term ''modification'' is used in the NSPS and PSD programs, and that a physical change that is a modification under one program may not necessarily be a modification under the other program.

In the preamble to the proposed NSPS for new sources, the EPA discussed whether a standard of performance for the new source NSPS, specifically the BSER for solid fuel-fired EGUs that is based on partial CCS, could become the BACT floor when permitting a modified or reconstructed EGU or non-EGU source. As noted above, BACT is a case-specific review by a permitting agency. In evaluating BACT, the permitting authority should consider all available control technologies that have the potential for practical application to the facility or emission unit under evaluation. See GHG Permitting Guidance at 24. This BACT review must include any technologies that are part of an applicable NSPS for the specific type of source and would therefore establish the minimum level of stringency for the BACT. Thus, it is possible that partial CCS could be considered in a BACT review as an available control option for a modified or reconstructed EGU facility, or for another type of source (*e.g.,* natural gas processing plant), but this NSPS is not an applicable standard to such sources so it would not establish a requirement that partial CCS is a minimum level of stringency for the BACT for those sources.

Some commenters expressed concern that, if the EPA finalizes a BSER for utility boilers and IGCC units that is based on partial CCS, it would establish a BACT Floor for new EGUs that would be inconsistent with prior BACT determinations for EGUs in both permits issued by EPA Regions and permits issued by state agencies on which the EPA has commented. Many of these comments were more directed at the development and deployment of CCS (*i.e.,* the commenter did not believe CCS should be the basis for BSER) rather than examining whether an NSPS should establish the BACT floor for applicable sources, which is the legal consequence of setting an NSPS under the terms of the CAA. Consequently, we respond to these comments in other sections of this preamble that support the selection of partial CCS as the basis for the BSER for fossil fuel-fired electric utility steam generating units.

With regard to the commenters who stated that a BSER for EGUs that is based on partial CCS would be inconsistent with BACT determinations in previous GHG PSD permits, it is important to recognize that a BACT determination is a case-by-case analysis and that technological capabilities and costs evolve over time.[551] In addition, to

[551] In this regard, the 2011 GHG Permitting Guidance states that ''although CCS is not in widespread use at this time, EPA generally considers CCS to be an 'available' add-on pollution control technology for facilities emitting CO_2 in

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date the EPA has not issued a PSD permit with GHG BACT for a source that would be an affected facility requiring partial CCS under this NSPS (*i.e.,* a fossil fuel-fired steam generating unit), so one cannot determine whether the EPA—as a PSD permitting authority—has been either consistent or inconsistent by setting a BSER of partial CCS in this NSPS. Although, in the course of a BACT review, some permitting authorities may have determined that CCS is not technologically feasible or economically achievable for a gas-fired EGU, because of the case-by-case nature of the BACT analysis it does not automatically follow that the same conclusion is appropriate for a solid fuel-fired EGU. Furthermore, PSD permitting requirements first applied to GHGs in January 2011 and more information about GHG control technology has been gained in this four-and-a-half year period. Thus, we would expect BACT decisions to evolve as well, such that a GHG BACT review for a coal-fired EGU in 2015 may look very different from a review that was done in 2011.

Additionally, if a state agency is processing a permit application for a solid fuel-fired EGU and does not propose CCS as BACT (or does not even consider CCS as an available control for BACT), the EPA is not necessarily required to comment negatively on the draft permit, or to otherwise request or require that the state agency amend the BACT to include CCS. For state agencies that have their own EPA-approved state implementation plan, the state has primacy over their permitting actions and discretion to interpret their approved rules and to apply the applicable federal and state regulatory requirements that are in place at the time for the facility in question. The EPA's role is to provide oversight to ensure that the state operates their PSD program in accordance with the CAA and applicable rules. If the EPA does not adversely comment on a certain draft permit or BACT determination, it does not necessarily imply EPA endorsement of the proposed permit or determination.

Some commenters also felt that the determination of partial CCS as BSER is inconsistent with the agency's position on CCS in the EPA's GHG Permitting Guidance, which they say supports the notion that additional work is required before CCS can be integrated at full-scale electric utility applications. It is important to recognize that the EPA's Permitting Guidance is guidance, so it does not contain any final determination of BACT for any source. Furthermore, we disagree with the commenters' characterization of the GHG Permitting Guidance. The Guidance specifically states ''[f]or the purposes of a BACT analysis for GHGs, the EPA classifies CCS as an add-on pollution control technology that is ''available'' for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (*e.g.,* hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs.'' GHG Permitting Guidance at 32. As discussed elsewhere in the Guidance, technologies that should be listed in Step 1 are those that ''have the potential for practical application to the emissions unit and regulated pollutant under evaluation.'' GHG Permitting Guidance at 24. The EPA continues to stand by its position on the availability of CCS in this context, as expressed in the GHG Permitting Guidance.

The GHG Permitting Guidance continues on to discuss case-specific factors and potential limitations with applying CCS, and it acknowledges that CCS may not be ultimately selected as BACT in ''certain cases'' based on technology feasibility and cost. GHG Permitting Guidance at 36, 43. While acknowledging these potential challenges when it was issued in March 2011, the Guidance clearly does not rule out the selection of CCS as BACT for any source category and it is forward looking. GHG Permitting Guidance at 43 (''. . . as a result of ongoing research and development, . . . CCS may become less costly and warrant greater consideration . . . in the future'') Nothing in the Guidance is inconsistent with EPA's present position that CCS is adequately demonstrated for the types of sources covered by this NSPS, as articulated elsewhere in this preamble.

A commenter asserted that the GHG Permitting Guidance should be amended because it calls for consideration of CCS in BACT determinations even though the proposed NSPS identified ''partial CCS'' as BSER for new boiler and IGCC EGUs. The Guidance explains that ''the purpose of Step 1 of the process is to cast a wide net and identify all control options with potential application to the emissions unit under review.'' GHG Permitting Guidance at 26. The EPA agrees that the GHG Permitting Guidance only uses the term ''CCS'' and does not distinguish ''partial CCS'' from ''full CCS.'' But considering the purpose of Step 1 of the process, we believe that the term ''CCS'', as it is used in the GHG Permitting Guidance, adequately describes the varying levels of CO_2 capture. A BACT review should analyze all available technologies in order to adequately support the BACT determination, and may require evaluation of partial CCS, full CCS, and/or no CO_2 capture. The specific facility type and CO_2 capture conditions will dictate the level(s) of CO_2 capture that are most appropriate to consider as ''available'' in a BACT review.

D. Implications for Title V Program

Under the Title V program, certain stationary sources, including ''major sources'' are required to obtain an operating permit. This permit includes all of the CAA requirements applicable to the source, including adequate monitoring, recordkeeping, and reporting requirements to assure sources' compliance. These permits are generally issued through EPA-approved state Title V programs.

In the January 8, 2014 proposal, the EPA discussed whether this rulemaking would impact the applicability of Title V requirements to major sources of GHGs. 79 FR 1489–90. The relevant issue for Title V purposes was, in essence, whether promulgation of CAA section 111 requirements for GHGs

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large amounts and industrial facilities with high-purity CO_2 streams.'' GHG Permitting Guidance at 35. The Guidance goes on to note that CCS may not be technically feasible at modified sources (citing possible issues with ''space for CO_2 capture equipment at an existing facility''), or in other specific circumstances. Id. at 36 (''Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition . . ., the need for funding . . ., timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard''). Id. at 42–3 EPA also noted that CCS may be expensive in individual instances and thus eliminated as a control option for that reason under step 4 of the BACT analysis, noting further that revenues from EOR may offset other costs. Id. at 42–3. See also *UARG* v. *EPA,* 134 S.Ct. 2427, 2448 (2014) (noting that EPA's GHG Permitting Guidance states that carbon capture is reasonably comparable to more traditional, end-of-stack BACT technologies, and that petitioners do not dispute that).

As explained at Section V.I.5 above, in determining that partial CCS is BSER for new fossil fuel steam electric plants, the EPA has carefully considered the issue of logistics (including cost estimates for land acquisition, transportation, and sequestration) and costs generally. Nor would new plants face the same types of constraints as modified or reconstructed sources in a BACT determination, since a new source has more leeway in choosing where to site. See text at V.G.3. above. Moreover, the GHG Permitting Guidance considered BACT determinations for all types of sources, not just those for which the EPA has determined in this rule that partial CCS is the BSER, and the concerns expressed in the Guidance thus must be considered in that broader context.

would undermine the Tailoring Rule, which, as explained above, phased in permitting requirements for GHG emissions for stationary sources under the CAA PSD and Title V permitting programs. Based on the EPA's understanding of the CAA at that time, the proposal discussed this issue in the context of the regulatory and statutory definitions of ''major source,'' focusing on revisions that had been made in the Tailoring Rule to the definitions in the Title V regulations of ''major source'' and ''subject to regulation.'' 79 FR 1489–90 (quoting 75 FR 31583). Under the Title V regulations, as revised by the Tailoring Rule, ''major source'' is defined to include, in relevant part, ''a major stationary source . . . that directly emits, or has the potential to emit, 100 tpy or more of any air pollutant subject to regulation.'' The proposal further explained that the GHG threshold that had been established in the Tailoring Rule had been incorporated into the definition of ''subject to regulation'' under 40 CFR 70.2 and 71.2, such that those definitions specify '' 'that GHGs are not subject to regulation for purposes of defining a major source, unless as of July 1, 2011, the emissions of GHGs are from a source emitting or having the potential to emit 100,000 tpy of GHGs on a CO_2e basis.' '' *Id.* (quoting 75 FR 31583). The proposal thus concluded that the Title V definition of ''major source,'' as revised by the Tailoring Rule, did not on its face distinguish among types of regulatory triggers for Title V. It further noted that the Title V program had already been triggered for GHGs, and thus concluded that the promulgation of CAA section 111 requirements would not further impact Title V applicability requirements for major sources of GHGs. 79 FR 1489–90.

As noted elsewhere in this section, after the proposal for this rulemaking was published, the United States Supreme Court issued its opinion in *UARG* v. *EPA,* 134 S.Ct. 2427 (June 23, 2014), and in accordance with that decision, the D.C. Circuit subsequently issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir., April 10, 2015). Those decisions support the same overall conclusion as the EPA discussed in the proposal, though for different reasons.

With respect to Title V, the Supreme Court said in *UARG* v. *EPA* that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a Title V operating permit. In accordance with that decision, the D.C. Circuit's amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* vacated the Title V regulations under review in that case to the extent that they require a stationary source to obtain a Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions. These court decisions make clear that promulgation of CAA section 111 requirements for GHGs will not result in the EPA imposing a requirement that stationary sources obtain a Title V permit solely because such sources emit or have the potential to emit GHGs above the applicable major source thresholds.[552]

To be clear, however, unless exempted by the Administrator through regulation under CAA section 502(a), any source, including an area source (a ''non-major source''), subject to an NSPS is required to apply for, and operate pursuant to, a Title V permit that assures compliance with all applicable CAA requirements for the source, including any GHG-related applicable requirements. This aspect of the Title V program is not affected by *UARG* v. *EPA,* as the EPA does not read that decision to affect either the grounds other than those described above on which a Title V permit may be required or the applicable requirements that must be addressed in Title V permits.[553] Consistent with the proposal, the EPA has concluded that this rule will not affect non-major sources and there is no need to consider whether to exempt non-major sources. Thus, sources that are subject to the CAA section 111 standards promulgated in this rule are required to apply for, and operate pursuant to, a Title V permit that assures compliance with all applicable CAA requirements, including any GHG-related applicable requirements.

E. Implications for Title V Fee Requirements for GHGs

1. Why is the EPA revising Title V fee rules as part of this action?

The January 8, 2014 notice of proposed rulemaking (79 FR 1430) (the ''EGU GHG NSPS proposal'' or ''NSPS proposal'') proposed the first section 111 standards to regulate GHGs at EGUs. That notice also included proposed revisions to the fee requirements of the 40 CFR part 70 and part 71 operating permit rules under Title V of the CAA to avoid inadvertent consequences for fees that would be triggered by the promulgation of the first CAA section 111 standard to regulate GHGs. If we do not revise the fee rules by the time of the promulgation of the NSPS standards for GHGs, then approved part 70 programs implemented by state, local and tribal permitting authorities[554] that rely on the ''presumptive minimum'' approach and the part 71 program implemented by the EPA would be required to account for GHGs in emissions-based fee calculations at the same dollar per ton ($/ton) rate as other air pollutants. The EPA believes this would result in the collection of fees in excess of what is required to cover the reasonable costs of an operating permit program. See NSPS proposal 79 FR 1490.

In response to these concerns, the EPA proposed regulatory changes to limit the fees collected based on GHG emissions and proposed two fee adjustment options to increase the fees collected based on the costs for permitting authorities to conduct certain review activities related to GHG emissions, while still providing sufficient funding for an operating permit program. Also, we proposed an option that would have provided for no fee adjustments to recover the costs of conducting review activities related to GHG emissions. *Id.* 79 FR 1490. The EPA did not propose any action related to state and local permitting authorities that do not use the presumptive minimum approach.

Most commenters on the proposal, including state and local permitting authorities, were supportive of exempting GHGs from the emissions-based fee calculations of the permit

[552] As explained elsewhere in this notice, the EPA intends to conduct future rulemaking action to make the appropriate revisions to the operating permit rules to respond to the Supreme Court decision and the D.C. Circuit's amended judgment. To the extent there are any issues related to the potential interaction between the promulgation of CAA section 111 requirements for GHGs and Title V applicability based on emissions above major source thresholds, the EPA expects there would be an opportunity to consider those during that rulemaking.

[553] See Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

[554] Hereafter, for the sake of simplicity, we will generally refer to part 70 permitting authorities as ''state'' permitting authorities and refer to part 70 programs as ''state'' programs.

rules, but support for the fee adjustment options was mixed, with state and local permitting authorities generally supporting either of the two fee adjustments, and other commenters generally supporting the option that provides for no fee adjustment.

2. Background on the Fee Requirements of Title V

In the NSPS proposal, the EPA explained the statutory and regulatory background related to the requirement that permitting authorities collect fees from the owner or operator of Title V sources that are sufficient to cover the costs of the operating permit program. CAA section 502(b)(3)(A) requires an operating permit program to include a requirement that sources ''pay an annual fee, or the equivalent over some other period, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program.'' See also 40 CFR 70.9(a). CAA section 502(b)(3)(B)(i) requires that, in order to have an approvable operating permit program, the permitting authority must show that ''the program will result in the collection, in the aggregate, from all sources [required to get an operating permit]'' of either ''an amount not less than $25 per ton of each regulated pollutant [adjusted annually for changes in the consumer price index], or such other amount as the Administrator may determine adequately reflects the reasonable costs of the permit program.'' See also 40 CFR 70.9(b)(2). This has been generally referred to as the ''presumptive minimum'' approach. If a permitting authority does not wish to use the presumptive minimum approach, it may demonstrate ''that collecting an amount less than the [presumptive minimum amount] will'' result in the collection of funds sufficient to cover the costs of the program. CAA section 503(b)(3)(B)(iv); see also 40 CFR 70.9(b)(5). This has been generally referred to as the ''detailed accounting'' approach. CAA section 502(b)(3)(B)(ii) sets forth a definition of ''regulated pollutant'' for purposes of calculating the presumptive minimum that includes each pollutant regulated under section 111 of the CAA. See also 40 CFR 70.2.

3. What fee rules did we propose to revise?

In the NSPS proposal, to exempt GHGs from emissions-based fee calculations, we proposed to exempt GHGs from the definition of ''regulated pollutant'' for purposes of operating permit fee calculations (''the GHG exemption''). The EPA then proposed two alternative ways to account for the costs of addressing GHGs in operating permits through a cost adjustment. First, we proposed a modest additional cost for each GHG-related activity of certain types that a permitting authority would process (''the GHG adjustment option 1''). Alternatively, we proposed a modest additional increase in the per ton rate used in the presumptive minimum calculation for all non-GHG fee pollutants (''the GHG adjustment option 2''). The EPA also solicited comment on an option that would provide no additional cost adjustment to account for GHGs (''the GHG adjustment option 3''). All of the GHG adjustment options are based on the assumption that the GHG exemption is finalized. See NSPS Proposal 79 FR 1493–1495.

The EPA additionally proposed two clarifications. The first was regulatory text in 40 CFR part 60, subparts Da, KKKK, and TTTT, to clarify that GHGs, as opposed to CO_2, is the regulated pollutant for fee purposes (''the fee pollutant clarification''). *Id.* at 1505, 1506 and 1511. The second was a proposal to move the existing definition of ''Greenhouse gases (GHGs)'' within 40 CFR 70.2 and 71.2 to promote clarity in the regulations (''the GHG clarification''). *Id.* 79 FR 1490, 1517, 1518.

For background purposes, below is a brief summary of each of the proposals.

a. The GHG Exemption

To address the fee issues discussed in the NSPS proposal, the EPA proposed to exempt GHG emissions from the definition of ''regulated pollutant (for presumptive fee calculation)'' in 40 CFR 70.2 and the definition of ''regulated pollutant (for fee calculation)'' in 40 CFR 71.2.[555] See NSPS preamble 79 FR 1493, 1495.

b. The GHG Adjustment Option 1

The first proposed ''GHG adjustment'' option (option 1) was to include an additional cost for each GHG-related activity of certain types that a permitting authority would process (an activity-based adjustment). The three activities identified for this option were ''GHG completeness determination (for initial permit or for updated application)'' at 43 hours of burden,[556] ''GHG evaluation for a modification or related permit action'' at 7 hours of burden, and ''GHG evaluation at permit renewal'' at 10 hours of burden. See also 79 FR 1494, fn. 280 (providing a description of each of these activities).

For part 70, the burden hours per activity would be multiplied by the cost of staff time (in $/hour) specific to the state, including wages, benefits, and overhead, to determine the cost of each activity. All the activities for a given period would be totaled to determine the total GHG adjustment for the state. See 79 FR 1494.

For part 71, we proposed a labor rate assumption of $52 per hour in 2011 dollars. Using that labor rate, we proposed to determine the GHG fee adjustment for each GHG permitting program activity to be a specific dollar amount for each activity (''set fees'') that the source would pay for each activity performed. See 79 FR 1495. The EPA proposed to revise 40 CFR 70.9(b)(2)(v) and 40 CFR 71.9(c)(8) to implement this option.

c. The GHG Adjustment Option 2

The second proposed GHG adjustment option (option 2) was to increase the dollar per ton ($/ton) rates used in the fee calculations for each non-GHG fee pollutant. The revised $/ton rates would be multiplied by the total tons of non-GHG fee pollutants actually emitted by any source to determine the applicable total fees. The EPA proposed to increase the $/ton rates by 7 percent.[557] See NSPS proposal 79 FR 1494, 1495.

d. The GHG Adjustment Option 3

The EPA also solicited comment on not charging any fees related to GHGs (option 3). The basis for this proposed option was the observation that most sources that need to address GHGs in a permit would also emit non-GHG fee pollutants, and thus, the cost of permitting for any particular source may be accounted for adequately without charging any additional fees related to GHGs. *Id.* 79 FR 1494–1495.

e. The Fee Pollutant Clarification

Another fee-related proposal was to add regulatory text to 40 CFR part 60, subparts Da, KKKK, and TTTT, to clarify that the fee pollutant for operating permit purposes would be considered to be ''GHGs,'' (as defined in

[555] Hereafter we will refer to these definitions as the ''fee pollutant'' definitions. Also, note that both fee pollutant definitions cross-reference the definitions of ''regulated air pollutant'' which includes air pollutants ''subject to any standard promulgated under section 111 of the Act.''

[556] Burden is the hours of staff time necessary to perform a task.

[557] The EPA estimated that both options 1 and 2 would result in about a 7 percent increase in the fees collected by operating permit programs affected by the proposed rule. For example, the presumptive minimum fee rate in effect for September 1, 2014 through August 31, 2015 is $48.27/ton. A 7 percent increase under option 2 would result in a revised fee of $51.65/ton.

40 CFR 70.2 and 71.2),[558] rather than solely CO_2, which would be regulated under the section 111 standards and implemented through the EGU GHG NSPS. *Id.* 79 FR 1505, 1506, and 1511.

f. The GHG Clarification

The EPA proposed to move the existing definition of ''Greenhouse gases (GHGs)'' within the definition of ''Subject to regulation'' in 40 CFR 70.2 and 71.2 to a separate definition within those sections to promote clarity in the regulations. *Id.* 79 FR 1490, 1517, 1518.

4. What action is the EPA finalizing?

In this action, the EPA is finalizing the following elements as proposed: (1) The GHG exemption, (2) the GHG adjustment option 1, and (3) the fee pollutant clarification.

Public commenters on the proposal stated both support and opposition to using the NSPS rulemaking action to revise the Title V fee rules. Two commenters stated that proposing the Title V fee revisions within the NSPS rulemaking would result in fewer commenters, particularly state and local permitting authorities, having knowledge of the changes to the fee rules and sufficient opportunity to comment on the changes because the NSPS proposal is limited to a single source category, and one stated that a separate proposal for the fee rules would provide a sufficient opportunity for public comment. The EPA believes it is appropriate to move forward with final action amending the Title V fee regulations as part of this NSPS. As we explained in the preamble for the proposal and elsewhere in this final rule, the fee rules and the section 111 standards are interrelated because, if we do not revise the fee rules, promulgation of the final NSPS will trigger certain requirements related to Title V fees for GHG emissions that the EPA believes will result in the collection of excessive fees in states that implement the presumptive minimum approach and in the part 71 program. Thus, it is important to finalize the revisions to the fee rules at the same time or prior to this NSPS, and it is within the EPA's discretion to address the NSPS and the fee rules at the same time as part of the same rulemaking action. In response to the commenters who were concerned that including the fee rule proposal as part of the NSPS proposal would result in the public not having sufficient public comment opportunities, the EPA believes sufficient public comment opportunities were provided on the fee rule changes because the proposal met all public participation requirements and we provided additional public outreach, including to state and local permitting authorities, which discussed the fee rule proposal. In addition to the publication of the proposed rulemaking in the **Federal Register**, the EPA held numerous hearings, reached out to state partners and the public, and developed numerous fact sheets and other information to support public comment on this rule. The EPA has complied with the applicable public participation requirements and executive orders. The proposal met all the requirements for public notice—it contained a clear and detailed explanation of how the part 70 and 71 rules would be affected by the promulgation of the CAA section 111 standard for EGUs and how the EPA proposed to revise the related regulatory provisions. We received many comments on the proposal to revise the fee rule for operating permits programs, and we are taking those comments into consideration in the finalization of the rulemaking action.

a. The GHG Exemption

The EPA is taking final action to revise the definition of regulated pollutant (for presumptive fee calculation) in 40 CFR 70.2 and regulated pollutant (for fee calculation) in 40 CFR 71.2 to exempt GHG emissions. This regulatory amendment will have the effect of excluding GHG emissions from being subject to the statutory ($/ton) fee rate set for the presumptive minimum calculation requirement of part 70 and the fee calculation requirements of part 71. We received supportive comments from the majority of public commenters, including state and local permitting authorities and others, on revising the operating permit rules to exempt GHGs from the emission-based calculations that use the statutory fee rates. We are finalizing this portion of the proposal for the same reasons we explained in the proposal notice, including that leaving these regulations unchanged would have resulted in the collection of fee revenue far beyond the reasonable costs of an operating permit program. The EPA believes that these revisions (in conjunction with the GHG adjustment, see below) are consistent with the CAA requirements for fees pursuant to the authority of section 502(b)(3)(B)(i).

Some members of the public opposed the proposed GHG exemption for reasons including that it may limit permitting authorities' ability to charge sufficient fees to cover the cost of GHG permitting[559] if the state is barred from exceeding minimum requirements set by the EPA. Despite this adverse comment, the EPA believes it is appropriate to finalize the GHG exemption because we are not finalizing any requirements that would require states to charge any particular fees to any particular sources. The changes we are finalizing to part 70 concern the presumptive minimum approach, which sets a minimum fee target for states that have decided to follow the presumptive minimum approach. Neither the statute nor the final rule require any state following the presumptive minimum approach (or any other approach) to charge fees to sources using any particular method. Thus, the GHG exemption will not limit states' ability to structure their individual fee programs however they see fit in order to meet the requirement that they collect revenue sufficient to cover all reasonable costs of their permitting program. See CAA section 502(b)(3); 40 CFR 70.9(b)(3).

b. The GHG Adjustment Option 1

The EPA is finalizing GHG adjustment option 1 because we believe it will result in a system for the calculation of costs for part 70 and fees for part 71 that is most directly related to the costs of GHG permitting. The EPA has determined that some adjustment to cost and fee accounting is important because the recent addition of GHG emissions to the operating permitting program does add new burdens for permitting authorities. Although GHG adjustment option 3 (no GHG permitting fee adjustments) was supported by many industrial commenters, the EPA rejected it because it is in tension with the statutory requirement that permitting authorities collect sufficient fees to cover all the reasonable costs of permitting. See CAA section 502(b)(3)(A). Some state and local permitting authorities provided comments supporting option 1, while others supported option 2, and some supported either option, stating no preference. Also, a few state and local permitting authorities supported finalizing no adjustment and a few others asked for flexibility to set fee adjustments not proposed by the EPA, but that they believed would be appropriate for their program.

[558] Note that in 40 CFR 70.2 and 71.2, the term ''Greenhouse gases (GHGs)'' is defined as the ''aggregate group of six greenhouse gases: Carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.''

[559] We use the term ''GHG permitting'' in this section of the notice to refer to measures undertaken by permitting authorities to ensure that GHGs and any applicable requirements related to GHGs are appropriately addressed in Title V permitting.

The EPA is finalizing option 1 instead of option 2 because the option 1 adjustments are based on the actual costs for permitting authorities to process specific actions that require GHG reviews. The option 2 approach, which would have added a 7 percent surcharge to the \$/ton rate used in the fee-related calculations, may have been administratively easier to implement, but is tied to the emissions of non-GHG air pollutants, which are not directly related to the costs of GHG permitting.

Consistent with CAA section 502(b)(3)(B)(i), the Administrator has determined that the final rule's approach of exempting GHG emissions from fee-related calculations and accounting for the GHG permitting costs through option 1 will result in fees that will cover the reasonable costs of the permitting programs.

The EPA is revising the part 70 regulations through this final action, specifically 40 CFR 70.9(b)(2), to modify the presumptive minimum approach to add the activity-based cost of GHG permitting activities, outlined in the revised 40 CFR 70.9(b)(2)(v), to the emissions-based calculation of 40 CFR 70.9(b)(2)(i), which is being revised to now exclude GHG emissions. To determine the activity-based GHG adjustment under 40 CFR 70.9(b)(2)(v), the permitting authority will multiply the burden hours for each activity (set forth in the regulation) by the cost of staff time (in \$ per hour), including wages, benefits, and overhead, as determined by the state, for the particular activities undertaken during the particular time period.

States that implement the presumptive minimum approach will need to follow the final rule's option 1 approach.[560] States that use the detailed accounting approach are not directly affected by this rulemaking, but they must ensure that their fee collection programs are sufficient to fully fund all reasonable costs of the operating permit program, including costs attributable to GHG-related permitting. The EPA suggests states that use the detailed accounting approach consider the 7 percent assumption for the costs of GHG permitting in any such analysis, consistent with the EPA analysis of options 1 and 2 in the proposal.

Consistent with 40 CFR 70.4(i), a state that wishes to change its operating permit program as a result of this final rule must apprise the EPA. The EPA will review the materials submitted concerning the change and decide if a formal program revision process is needed and will inform the state of next steps. The communication apprising the EPA of any such changes should include at least a narrative description of the change and any other information that will assist the EPA in its assessment of the significance of the changes. Certain changes, such as switching from the presumptive minimum method to a detailed accounting method, will be considered substantial program revisions and be subject to the requirements of 40 CFR 70.4(i)(2).

With respect to the part 71 program, in this final action the EPA is revising 40 CFR 71.9(c) to require each part 71 source to pay an annual fee which is the sum of the activity-based fee of 40 CFR 71.9(c)(8) and the emissions-based fee of 40 CFR 71.9(c)(1)–(4),[561] which excludes GHG emissions. To determine the activity-based fee, the revised 40 CFR 71.9(c)(8) requires the source to pay a ''set fee'' for each listed activity that has been initiated since the fee was last paid. Under part 71, fees are typically paid at the time of initial application submittal, and thereafter, annually on the anniversary of the initial fee payment, or on any other dates that may be established in the permit. These set fees would not change until such time as we may revise our part 71 rule to change the set fees.

The final rule implements the option 1 approach by listing three activities performed by permitting authorities that involve GHG reviews. The following describes the activities as described in our proposal and certain clarifications we are making in the final rule to ensure consistent implementation.

The EPA is finalizing that the first listed activity under option 1 is ''GHG completeness determination (for initial permit or updated application).'' This activity must be counted for each new initial permit application, even for applications that do not include GHGs emissions or applicable requirements, since an important part of any completeness determination will be to determine that GHG emissions and applicable requirements have been properly addressed, as needed, in the application. The fee for this activity is a one-time charge that covers the initial application and any supplements or updates. The EPA believes that a single charge for a GHG completeness determination will be adequate to cover the reasonable costs for a permitting authority to review an initial application and any subsequent application updates related to initial permit issuance; thus, any updates to an initial application are included in a single ''GHG completeness determination,'' rather than as a separate activity for which the source would be charged in addition to the completeness determination for the initial application. This is an important distinction because many sources submit multiple permit application updates, either voluntarily or as required by the permitting authority, during application review, many of which do not require a separate or comprehensive completeness determination.

The EPA is finalizing regulatory text that would describe the second listed activity as ''GHG evaluation for a permit modification or related permit action.''[562] The EPA had proposed that the second listed activity under option 1 would be ''GHG evaluation for a modification or related permit action.'' For the final rule, we are clarifying that we are adding a cost for a ''permit modification'' rather than for a ''modification.'' The term ''modification'' may be interpreted to refer to any change at a source, even a change that would not be required to be processed as a ''permit modification,'' while ''permit modification'' refers to any revision to an operating permit that cannot be processed as an administrative permit amendment and thus requires a review by a permitting authority as either a significant or minor permit modification.

The EPA is finalizing the third activity as ''GHG evaluation at permit renewal.'' This activity covers the processing of all permit renewal applications and will involve evaluations of whether any GHG applicable requirements are properly included.

Some members of the public commented that finalizing a GHG adjustment would inappropriately

[560] A presumptive minimum state may require various changes to its approved operating permit program before it may begin to implement the option 1 approach. For example, its regulations, and/or program procedures and practices, may need to be revised, depending on the structure of the fee provisions in the state's program; thus, the exact response necessary to address this final action may vary from state to state.

[561] Note that the emissions-based fee calculation differs somewhat depending on whether the part 71 program is being implemented by the EPA (see 40 CFR 71.9(c)(1)); a state, local or tribal agency with delegated authority from the EPA (see § 71.9(c)(2)); the EPA with contractor assistance (see § 71.9(c)(3)); or an agency with partial delegation authority (see § 71.9(c)(4)).

[562] The EPA notes that the term ''permit modification'' in this context refers to all significant permit modifications and minor permit modifications under operating permit rules, but not to ''administrative permit amendments,'' as such amendments are not defined as ''permit modifications'' in the permit rules. See, *e.g.,* 40 CFR 70.7(d), (e), and (f).

increase sources' financial burdens. The EPA has explained, both in the proposal notice and elsewhere in this preamble, the importance of the fee-related revisions to account for the costs associated with GHG-related permitting. The EPA believes that the revisions being finalized will result in modest and reasonable fee increases necessary to cover states' increased costs.[563] To the extent that commenters intended to argue that the adjustments we proposed would exceed the actual costs of GHG permitting, no commenters provided any information or analysis to support that position. Some commenters did state that the costs associated with GHG-related permitting should be minimal because few applicable requirements will apply to GHGs. As stated earlier in this notice, the EPA's cost estimate for the proposal concerned the incremental costs of GHG permitting for any source, not just those that would have, at the time of the analysis, triggered the requirement to get a permit based on GHG emissions or applicable requirements.

Despite some comments received to the contrary, the EPA does not believe it is appropriate to delay the finalization of the GHG adjustment. The EPA does not believe such delays would be consistent with CAA section 502(b)(3)(A) because states have been incurring costs attributable to GHG permitting for several years now and increased fees must be collected to cover the increased costs. The regulatory changes being finalized in this action provide the states with optimal flexibility and sufficient funding to implement their GHG permitting programs. Some commenters had specifically stated that the EPA should delay finalization of this rule until the completion of the next ICR renewal process. While we do not believe delaying this rule is appropriate, as explained above, the EPA notes that we remain committed to collecting and analyzing additional data on costs attributable to GHG permitting for operating permit programs. We may adjust the GHG cost adjustments in future rulemakings if necessary to comply with the requirements of the Act.

As an alternative to the options proposed by the EPA, some commenters asserted that the EPA should make a GHG cost adjustment using a separate, but reduced fee rate ($/ton) for GHGs. We, however, believe that the option 1 approach of the final rule will be more equitable for sources and more representative of actual costs because option 1 considers the costs of the actual permitting activities performed by a particular permitting authority, while any emissions-based approach would not be as directly related to actual costs incurred by permitting authorities.

Some commenters alleged that the EPA's proposal on adjustments to the operating permit programs was vague. The EPA provided a thorough discussion of our rationale in the proposal, including the basis for the GHG adjustments, and we proposed regulatory text to implement our proposal. We explained in the proposal that support for the cost adjustment for GHGs under option 1 is contained in several analyses performed by the EPA and approved by the OMB related to the effect of the addressing GHG requirements in operating permits. These analyses have been placed in the docket for this rulemaking. The analyses include: The Regulatory Impact Assessment (RIA) for the Tailoring Rule (see Regulatory Impact Analysis for the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Final Report, May 2010); the part 70 ICR change request for the Tailoring Rule (which was based on the RIA for the Tailoring Rule); and the current ICR for part 70 (EPA ICR number 1587.12; OMB control number 2060–0243).

Several commenters asked that we make changes to the option 1 approach that we proposed, such as adding new activities or decreasing the costs we assumed for the proposal. In response to these comments, we note that we received no quantitative data or other information from commenters that we believe demonstrates the need to revise the list of activities we included under option 1 or the burden hour assumptions under option 1 for the activities. Note that to promote consistent implementation of the final option 1 approach, the preamble describes elsewhere a few clarifications concerning the activities under option 1 and one minor revision to the regulatory text of one of the activities.

Since the EPA's proposed rulemaking, the Supreme Court decided in *UARG* v. *EPA* that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a Title V operating permit.[564] The EPA's review of the effect of the Supreme Court decision on the burden hour assumptions for the GHG review activities under proposed option 1 is that the effects are not significant enough to warrant revision of the burden hour assumptions in the final rule. Proposed option 1 was based on the assumption that permitting authorities would need to evaluate all permit applications for initial permit issuance, significant and minor permit modifications, and permit renewals for GHG issues (even if there are no applicable GHG requirements). Even after the *UARG* v. *EPA* decision, permitting authorities will continue to need to evaluate GHG issues for sources applying for a title V permit and for permit modifications and renewals for existing permits, and we do not anticipate that the decision will significantly affect the total number of such evaluations that will occur in any given year compared to the assumptions in our analysis, which as explained above, were based on the incremental costs of GHG permitting for any source. Thus, we are finalizing the burden hour assumptions as they were proposed. See NSPS proposal at 1494 and the supporting statement for the 2012 part 70 ICR renewal. Also, as discussed previously, we remain committed to collecting and analyzing additional data on costs and we may adjust the burden hour assumptions or other aspects of option 1 in a future rulemaking, if needed.

c. The Fee Pollutant Clarification

We are also finalizing the proposed addition of text within 40 CFR part 60, subpart TTTT, to clarify that the fee pollutant for operating permit purposes is GHG (as defined in 40 CFR 70.2 and 71.2). We are finalizing these provisions to add clarity to our regulations and to avoid the potential need for possible future rulemakings to adjust the title V fee regulations if any constituent of GHG, other than CO_2, becomes subject to regulation under section 111 for the first time. The proposal was to add this clarifying text to 40 CFR part 60, subparts Da, KKKK, and TTTT. The final rule adds the clarification text only to subpart TTTT because the EPA is

[563] The EPA estimated in the proposal that option 1 would result in about a 7 percent overall increase in the annual part 70 fees that are collected by all permitting authorities nationally. See 79 FR 1494.

[564] The EPA does not, however, read the *UARG* decision to affect other grounds on which a Title V permit may be required or the applicable requirements that must be addressed in Title V permits. *See* Memorandum from Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, and Cynthia Giles, Assistant Administrator, Office of Enforcement and Compliance Assurance, to Regional Administrators, Regions 1–10, *Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Regulatory Group* v. *Environmental Protection Agency* (July 24, 2014) at 5.

codifying all of the requirements for the affected EGUs in a new subpart TTTT and including all CO_2 emission standards for the affected EGUs (electric utility steam generating units, as well as natural gas-fired stationary combustion turbines) in that newly created subpart. See Section III.B of this preamble for more on this subject.

d. The GHG Clarification

The EPA is taking no action at this time on the proposal to move the definitions of ''Greenhouse gases (GHG)'' within the definition of ''Subject to regulation'' in 40 CFR parts 70 and 71. No public comments were received on this proposed clarification; however, subsequent to the proposal, on June 23, 2014, the Supreme Court in *UARG* v. *EPA* decided that GHG emissions could not be used in making certain applicability determinations under the operating permit rules. More specifically with respect to title V, as described above, the Supreme Court said that the EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a title V operating permit. In accordance with the Supreme Court decision, on April 10, 2015, the D.C. Circuit issued an amended judgment in *Coalition for Responsible Regulation, Inc.* v. *Environmental Protection Agency,* Nos. 09–1322, 10–073, 10–1092 and 10–1167 (D.C. Cir. April 10, 2015), which, among other things, vacated the title V regulations under review in that case to the extent that they require a stationary source to obtain a title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed the EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG* v. *EPA,* and, if so, to undertake to make such revisions.

In response to the Supreme Court decision and the D.C. Circuit's amended judgment, the EPA intends to conduct future rulemaking action to make the appropriate revisions to the operating permit rules. As part of any such future rulemaking action, the EPA may consider finalizing the proposal to move the definitions of GHGs within the operating permit rules.

F. Interactions With Other EPA Rules

Fossil fuel-fired EGUs are, or potentially will be, impacted by several other recently finalized or proposed EPA rules.[565] Many of the rules that impact fossil fuel-fired EGUs apply to existing facilities as well as newly constructed, modified, or reconstructed facilities. In fact, the rules described below are more applicable to existing EGUs than to newly constructed, modified, or reconstructed EGUs. Although those rules will affect EGUs as existing sources, because we expect that there will be few NSPS modifications or reconstructions, we don't anticipate those rules affecting EGUs as modified or reconstructed sources. In constructing new EGUs, sources can take all applicable requirements of the various rules into consideration.

1. Mercury and Air Toxics Standards (MATS)

On February 16, 2012, the EPA issued the MATS rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known to cause, or suspected of causing, damage nervous system damage, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

New or reconstructed EGUs (*i.e.,* sources that commence construction or reconstruction after May 3, 2011) subject to the MATS rule are required to comply by April 16, 2012 or upon startup, whichever is later.

Existing sources subject to the MATS rule were required to begin meeting the rule's requirements on April 16, 2015. Controls that will achieve the MATS performance standards are being installed on many units. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and are closing. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.[566]

2. Cross-State Air Pollution Rule (CSAPR)

The CSAPR requires states to take action to improve air quality by reducing SO_2 and NO_X emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to attain and maintain the NAAQS. The first phase of CSAPR became effective on January 1, 2015, for SO_2 and annual NO_X, and May 1, 2015, for ozone season NO_X. The second phase will become effective on January 1, 2017, for SO_2 and annual NO_X, and May 1, 2017, for ozone season NO_X. Many of the power plants participating in CSAPR have taken actions to reduce hazardous air pollutants for MATS compliance that will also reduce SO_2 and/or NO_X. In this way these two rules are complementary. Compliance with one helps facilities comply with the other.

3. Requirements for Cooling Water Intake Structures at Power Plants (316(b) Rule)

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S. Code section 1326(b)) (referred to hereinafter as the 316(b) rule.) The rule was published on August 15, 2014 (79 FR 48300; August 15, 2014), and became effective October 14, 2014. The 316(b) rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[567] The 316(b)

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

[566] Following promulgation of the MATS rule, industry, states and environmental organizations challenged many aspects of the EPA's threshold determination that regulation of EGUs is ''appropriate and necessary'' and the final standards regulating hazardous air pollutants from EGUs. The U.S. Court of Appeals for the D.C. Circuit upheld all aspects of the MATS rule. *White Stallion Energy Center* v. *EPA,* 748 F.3d 1222 (D.C. Cir. 2014). The decision was unanimous on all issues except a dissent was filed because the EPA did not consider cost when determining regulation of EGUs is appropriate. In *Michigan* v. *EPA,* case no. 14–46, the Supreme Court reversed the D.C. Circuit decision upholding the MATS rule finding that EPA erred by not considering cost when determining that regulation of EGUs was ''appropriate'' pursuant to section 112(n)(1). The Supreme Court considered only the narrow question of cost and did not review the other holdings of the D.C. Circuit, nor did the Supreme Court vacate the MATS rule.

[567] CWA section 316(b) provides that standards applicable to point sources under sections 301 and

rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2 million gallons per day (MGD) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and entrainment. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority. Additional information regarding the 316(b) rule for existing sources is included in Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule. Although the recently issued 316(b) rule discussed here applies to existing sources, there are also 316(b) technology-based standards for new sources with cooling water intake structures.

4. Disposal of Coal Combustion Residuals From Electric Utilities (CCR Rule)

On December 19, 2014, the EPA issued the final rule for the disposal of coal combustion residuals from electric utilities. The rule provides a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The CCR rule establishes technical requirements for existing and new CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA), the nation's primary law for regulating solid waste. New CCR landfills and surface impoundments are required to meet the technical criteria before any CCR is placed into the unit. Existing CCR surface impoundments and landfills are subject to implementation timeframes established in the rule for the individual technical criteria. For additional information regarding the CCR rule, see Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing along with this rule.

306 of the Act must require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

5. Steam Electric Effluent Limitation Guidelines and Standards (SE ELG Rule)

The EPA is reviewing public comments and working to finalize the proposed SE ELG rule which will impact fossil fuel-fired EGUs. In 2013, the EPA proposed the SE ELG rule (78 FR 34432; June 7, 2013) to strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. The proposed regulation, which includes new requirements for both existing and new generating units, would reduce impacts to human health and the environment by reducing the amount of toxic metals and other pollutants currently discharged to surface waters from power plants. The EPA intends to take final action on the proposed rule by September 30, 2015. Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule includes additional information regarding the SE ELG rule.

The EPA recognizes the importance of assuring that each of the rules described above can achieve its intended environmental objectives in a commonsense, cost-effective manner, consistent with underlying statutory requirements, and while assuring a reliable power system. Executive Order (E.O.) 13563, ''Improving Regulation and Regulatory Review,'' issued on January 18, 2011, states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote . . . coordination, simplification, and harmonization.'' E.O. 13563 further states that ''[e]ach agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

As discussed in earlier sections of this preamble, the EPA has identified potential alternative compliance pathways for affected newly constructed, modified, and reconstructed fossil fuel-fired steam generating units. We are finalizing an emission standard for newly constructed highly efficient fossil fuel-fired steam generating units that can be met by capturing and storing approximately 16 to 23 percent of the CO_2 produced from the facility or by utilizing other technologies such as natural gas co-firing. For a subcategory of steam generating units that conduct ''large'' modifications according to definitions in this final rule, we are finalizing an emission standard that is based on a unit-specific emission limitation consistent with each modified unit's best one-year historical performance and can be met through a combination of best operating practices and equipment upgrades. For reconstructed steam generating units, the EPA is finalizing standards of performance based on the performance of the most efficient generation technology available, which we concluded is the use of the best available subcritical steam conditions for small units and the use of supercritical steam conditions for large units. The standards can also be met through other technology options such as natural gas co-firing. In light of these potential alternative compliance pathways, we believe that sources will have ample opportunity to coordinate their response to this rule with any obligations that may be applicable to affected EGUs as a result of the MATS, CSAPR, 316(b), SE ELG and CCR rules, all of which are or soon will be final rules—and to do so in a manner that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[568]

The EPA is also endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (*e.g.,* by facilitating their ability to coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. Section IX.C of the preamble to the CAA section 111(d) emission guidelines for existing EGUs that the EPA is finalizing simultaneously with this rule describes such an example with respect to the SE ELG and CCR rules.

In light of the compliance flexibilities we are offering in this action, we believe that sources will have ample opportunity to use cost-effective regulatory strategies and build on their longstanding, successful records of complying with multiple CAA, CWA, and other environmental requirements, while assuring an adequate, affordable, and reliable supply of electricity.

[568] It should be noted that regulatory obligations imposed upon states and sources operate independently under different statutes and sections of statutes; the EPA expects that states and sources will take advantage of available flexibilities as appropriate, but will comply with all relevant legal requirements.

XIII. Impacts of This Action

As explained in the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) (RIA), available data indicate that, even in the absence of the standards of performance for newly constructed EGUs, existing and anticipated economic conditions will lead electricity generators to choose new generation technologies that will meet the standards without installation of additional controls. Therefore, based on the analysis presented in Chapter 4 of the RIA, the EPA projects that this final rule will result in negligible CO_2 emission changes, quantified benefits, and costs on owners and operators of newly constructed EGUs by 2022.[569] This conclusion is based on the EPA's own modeling as well as projections by EIA. While the primary conclusion of the analysis presented in the RIA is that the standards for newly constructed EGUs will result in negligible costs and benefits, the EPA has also performed several illustrative analyses that show the potential impacts of the rule if certain key assumptions were to change. This includes an analysis of the impacts under a range of natural gas prices and the costs and benefits associated with building an illustrative coal-fired EGU with CCS. These are presented in Chapter 5 of the RIA.

As also explained in the RIA for this final rule, the EPA also expects that few sources will trigger either the NSPS modification or reconstruction provisions that we are finalizing in this rule. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

A. What are the air impacts?

As explained immediately above, the EPA does not anticipate that this final rule will result in notable CO_2 emission changes by 2022 as a result of the standards of performance for newly constructed EGUs. The owners of newly constructed EGUs will likely choose technologies, primarily NGCC, which meet the standards even in the absence of this rule due to existing economic conditions as normal business practice.

As also explained immediately above, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

New steam generating EGUs that choose to comply with the final standard of performance by implementing partial post-combustion CCS are likely to use commercially-available amine-based capture systems. Some concern has been raised regarding emissions of amines and amine degradation by-products (*e.g.,* NH_3) from the capture process. To reduce the amine emissions, MHI introduced the first optimized washing system within an absorber column in 1994, and developed a proprietary washing system in 2003. In that system, a proprietary reagent is added to the water washing section to capture amine impurities such as amine, degraded amine, ammonia, formaldehyde, acetaldehyde, carbonic acids and nitrosamines.[570] MHI has continued to improve this technology for further reduction of amine emissions and established an ''advanced amine emission reduction system''.

Research performed by MHI at Alabama Power's Plant Barry indicated that an increasing SO_3 content in the flue gas caused a significant increase of amine emissions. During testing, at Plant Barry, MHI applied its proprietary washing system and confirmed that the amine emission were drastically reduced.[571] Others have also studied emissions and control strategies and have determined that a conventional multi-stage water wash and mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products emissions.[572] [573] Additional research continues in this area.

B. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has also considered the effects of this rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or the designated critical habitat of such species and whether consultation with the U.S. Fish and Wildlife Service (FWS) and/or National Marine Fisheries Service (together, the Services) is required by the ESA. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the Service(s), to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, ESA section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Direct effects are the direct or immediate effects of an action on a listed species or its habitat.[574] Indirect effects are those that are ''caused by the proposed action and are later in time, but still are reasonably certain to occur.'' *Id.* To trigger the consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and if the effect is indirect, it must be reasonably certain to occur.

The EPA notes that the projected environmental effects of this final action are positive: Reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_X and NO_X). The EPA recognizes that beneficial effects to listed species can, as a general matter, result in a ''may affect'' determination under the ESA. However, the EPA's assessment that the rule will have an overall net positive environmental effect by virtue of reducing emissions of certain air pollutants does not address whether the rule may affect any listed species or designated critical habitat for ESA section 7(a)(2) purposes and does not constitute any finding of effects for that purpose. The fact that the rule will have overall positive effects on the national

[569] Conditions in the analysis year of 2022 are represented by a model year of 2020.

[570] Sharma, S.; Azzi, M.; ''A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies'', *Fuel,* 121, 178 (2014).

[571] Kamijo, T.; et al., ''SO_3 Impact on Amine Emission and Emission Reduction Technology'', *Energy Procedia,* Volume 37, 1793 (2013).

[572] Sharma, S. (2014).

[573] Mertens, J.; et al., ''Understanding ethanolamine (MEA) and ammonia emissions from amine based post combustion carbon capture: Lessons learned from field tests'', *Int'l J. of GHG Control,* 13, 72 (2013).

[574] *See* Endangered Species Consultation Handbook, U.S. Fish & Wildlife Service and National Marine Fisheries Service at 4–25(March 1998) (providing examples of direct effects: *e.g.,* driving an off road vehicle through the nesting habitat of a listed species of bird and destroying a ground nest; building a housing unit and destroying the habitat of a listed species).

and global environment does not mean that the rule may affect any listed species in its habitat or the designated critical habitat of such species within the meaning of ESA section 7(a)(2) or the implementing regulations or require ESA consultation.

The EPA notes that the emission reductions achieved by the rule are projected to be minor. See Section XIII.F and G. below, and RIA chapter 4. Although the final rule imposes substantial controls on CO_2 emissions, we project few if any new fossil fuel-fired steam generating units to be built. Emissions reductions from turbines are likewise projected to be minimal. Moreover, we reasonably project that capacity additions during the analysis period out to 2022 would already be compliant with the rule's requirements (*e.g.,* natural gas combined cycle units, low capacity factor natural gas combustion turbines, and small amounts of coal-fired units with CCS supported by federal and state funding). See RIA chapter 4.

With respect to the projected GHG emission reductions, the EPA does not believe that such minor reductions trigger ESA consultation requirements under section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior (DOI) in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[575] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the section 7 regulations and thus are not subject to ESA consultation.

The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2) and has supplemented DOI's analysis with additional consideration of GHG modeling tools and data regarding listed species. The EPA evaluated this same issue in the context of the light duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected GHG emission reductions many orders of magnitude greater over the lifetimes of the model years in question[576] and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards,* Response to Comment Document for Joint Rulemaking at 4–102 (Docket EPA–OAR–HQ–2009–4782). The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7(a)(2).''*Id.* The EPA believes that the same conclusions apply to the present action, given that the projected CO_2 emission reductions are *far* less than those projected for either of the light duty vehicle rules. *See, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation). The EPA's conclusion is entirely consistent with DOI's analysis regarding ESA requirements in the context of federal actions involving GHG emissions.[577]

The EPA received a comment on the proposal referencing a prior letter sent to the EPA by three U.S. Senators,[578] which asserted that the rule will cause a shift to alternative sources of energy such as wind and solar and that such facilities may have impacts on listed species. The comment inquired regarding ESA consultation in connection with the rule. We reiterate that no consultation is required for a rule without potential for a specific impact on listed species in their habitats.

C. What are the energy impacts?

This final rule is not anticipated to have a notable effect on the supply, distribution, or use of energy. As previously stated, the EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions. As also previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

D. What are the water and solid waste impacts?

This final rule is not anticipated to have notable impacts on water or solid waste. As we have noted, the EPA believes that utilities and project developers will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily through the construction of new NGCC units. As also previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Still there are expected to be a small number of coal plants with CCS and the use of CCS systems (especially post-combustion system) will increase the amount of water used at the facility. If those plants utilize partial CCS to meet the final standard of performance (*i.e.,* approximately 16 to 23 percent capture), the increased water use will not be significant. See Section V.O.2. The EPA is unaware of any solid waste impact resulting from this rule.[579]

E. What are the compliance costs?

For steam generating EGUs, the EPA has carefully analyzed the costs of meeting the promulgated standard of performance for a highly efficient SCPC

[575] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (Oct. 3, 2008).

[576] *See* 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (Oct. 15, 2012).

[577] The EPA has received correspondence from Members of Congress asserting that the Services have identified several listed species affected by global climate change. The EPA's assessment of ESA requirements in connection with the present rule does not address whether global climate change may, as a general matter, be a relevant consideration in the status of certain listed species. Rather, the requirements of ESA section 7(a)(2) must be considered and applied to the specific action at issue. As explained above, the EPA's conclusion that ESA section 7(a)(2) consultation is not required here is premised on the specific facts and circumstances of the present rule and is fully consistent with prior relevant analyses conducted by DOI, FWS, and the EPA.

[578] *See* Letter from David Vitter, James M. Inhofe, and Mike Crapo, United States Senate Committee on Environment and Public Works, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, and Dan Ashe, Director, U.S. Fish and Wildlife Service, dated March 6, 2014.

[579] Estimated costs for the rule include costs for fly ash and bottom ash disposal and for spent solvent recovery and handling. See ''Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3'', DOE/NETL–2015/1723 (July 2015) at pp. 43, 130.

using partial CCS and found these costs to be reasonable. See Sections V.H and I above. This analysis assumes new capacity not otherwise compliant with the standards would be constructed. Based on the analysis in chapter 4 of the RIA, the EPA believes the standards of performance for newly constructed EGUs will have no notable compliance costs, because electric power companies are expected to build new EGUs that comply with the regulatory requirements of this final rule even in the absence of the rule, primarily NGCC units, due to existing and expected market conditions. While the EPA's analysis and projections from EIA continue to show that the rule is likely to result in negligible costs and benefits due to existing generation choices, the EPA recognizes that some companies may choose to construct coal or other fossil fuel-fired units and has set standards for these units accordingly. For this reason, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS.

In addition, the EPA believes the standards of performance for modified and reconstructed EGUs will have minimal associated compliance costs, because, as previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis.

F. What are the economic and employment impacts?

The EPA does not anticipate that this final rule will result in notable CO_2 emission changes, energy impacts, monetized benefits, costs, or economic impacts by 2022 as a result of the standards of performance for newly constructed EGUs. The owners of newly constructed EGUs will likely choose technologies that meet the standards even in the absence of this rule, due to existing economic conditions as normal business practice. Likewise, the EPA believes this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy. See RIA chapter 4.6.[580]

As previously stated, the EPA anticipates few units will trigger the NSPS modification or reconstruction provisions. As with the new source standards, the EPA does not expect macroeconomic or employment impacts as a result of the standards.

G. What are the benefits of the final standards?

We are not projecting direct monetized climate benefits in terms of CO_2 emission reductions associated with these standards of performance. This is because, as stated above, the EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this rule even in its absence, primarily NGCC units, because of existing and expected market conditions. See RIA chapter 4. Moreover, a cost-reasonable standard is, in fact, what will drive new technology deployment and provide a path forward for new coal-fired capacity. See Section V.L above.

As also previously stated, the EPA anticipates few units will trigger the NSPS modification or reconstruction provisions. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

XIV. Statutory and Executive Order Reviews

Additional information about these Statutory and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

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

This final action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. It is a significant regulatory action because it raises novel legal or policy issues arising out of legal mandates. Any changes made in response to OMB recommendations have been documented in the established dockets for this action under Docket ID No. EPA–HQ–OAR–2013–0495 (Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units) and Docket ID No. EPA–HQ–OAR–2013–0603 (Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units). The EPA prepared an economic analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015), is available in both dockets.

The EPA does not anticipate that this final action will result in any notable compliance costs. Specifically, we believe that the standards for newly constructed fossil fuel-fired EGUs (electric utility steam generating units and natural gas-fired stationary combustion turbines) will have negligible costs associated with it over a range of likely sensitivity conditions because electric power companies will choose to build new EGUs that comply with the regulatory requirements of this action even in the absence of the action, because of existing and expected market conditions. (See the RIA for further discussion of sensitivities). The EPA does not project any new coal-fired steam generating units without CCS to be built in the absence of this action. However, because some companies may choose to construct coal or other fossil fuel-fired EGUs, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired EGU with CCS.

The EPA also believes that the standards for modified and reconstructed fossil fuel-fired EGUs will result in minimal compliance costs, because, as previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis (through 2022). In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources.

B. Paperwork Reduction Act (PRA)

The information collection activities in this final action have been submitted for approval to OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2465.03. Separate ICR documents were prepared and submitted to OMB for the proposed standards for newly constructed EGUs (EPA ICR number 2465.02) and the proposed standards for modified and reconstructed EGUs (EPA ICR number 2506.01). Because the CO_2 standards for newly constructed, modified, and reconstructed EGUs will be included in the same new subpart (40 CFR part 60, subpart TTTT) and are being finalized in the same action, the ICR document for this action includes estimates of the information collection burden on owners and operators of newly constructed, modified, and reconstructed EGUs. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data.

[580] The employment analysis in the RIA is part of the EPA's ongoing effort to ''conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]'' pursuant to CAA section 321(a).

Thus, all burden estimates are in 2013 dollars. Burden is defined at 5 CFR 1320.3(b). You can find a copy of the ICR in the dockets for this action (Docket ID Numbers EPA–HQ–OAR–2013–0495 and EPA–HQ–OAR–2013–0603), and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The recordkeeping and reporting requirements in this final action 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.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final action.

1. Newly Constructed EGUs

This final action will impose minimal new information collection burden on owners and operators of affected newly constructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines) beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs to comply with the emission standards under the rule, there are no new information collection costs, as the information required by the standards for newly constructed EGUs is already collected and reported by other regulatory programs.

The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any newly constructed coal-fired steam generating units that commenced construction after proposal (January 8, 2014) to commence operation over the 3-year period covered by this ICR. We estimate that 12 affected newly constructed NGCC units and 25 affected newly constructed natural gas-fired simple cycle combustion turbines will commence operation during that time period. As a result of this final action, owners or operators of those newly constructed units will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months.

2. Modified and Reconstructed EGUs

This final action is not expected to impose an information collection burden under the provisions of the PRA on owners and operators of affected modified and reconstructed fossil fuel-fired EGUs (steam generating units and stationary combustion turbines). As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units or stationary combustion turbines will take actions that would constitute modifications or reconstructions as defined under the EPA's NSPS regulations. Accordingly, the standards for modified and reconstructed EGUs are not anticipated to impose any information collection burden over the 3-year period covered by this ICR. We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed.

Although not anticipated, if an EGU were to modify or reconstruct, this final action would impose minimal information collection burden on those affected EGUs beyond what they would already be subject to under the authorities of CAA 40 CFR parts 75 and 98. As described above, the OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations. Apart from certain reporting costs to comply with the emission standards under the rule, there would be no new information collection costs, as the information required by the final rule is already collected and reported by other regulatory programs.

As stated above, although the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions, if an EGU were to modify or reconstruct during the 3-year period covered by this ICR, the owner or operator of the EGU will be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months. The annual reporting burden for such a unit is estimated to be $1,333 and 16 labor hours. There are no annualized capital costs or O&M costs associated with burden for modified or reconstructed EGUs.

3. Information Collection Burden

The annual information collection burden for newly constructed, modified, and reconstructed EGUs consists only of reporting burden as explained above. The annual reporting burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $60,977 and 651 labor hours. There are no annualized capital costs or O&M costs associated with burden for newly constructed, modified, or reconstructed EGUs. Average burden hours per response are estimated to be 7 hours. The total number of respondents over the 3-year ICR period is estimated to be 62.

C. Regulatory Flexibility Act (RFA)

I certify that this final action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule.

1. Newly Constructed EGUs

The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. RIA Chapter 4. The EPA does not project any new coal-fired steam generating units without CCS to be built. We expect that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. We do not include an analysis of the illustrative impacts on small entities that may result from implementation of the final rule because we anticipate negligible compliance costs over a range of likely sensitivity conditions as a result of the standards for newly constructed EGUs. Thus the cost-to-sales ratios for any affected small entity would be zero costs as compared to annual sales revenue for the entity. Accordingly, there are no anticipated economic impacts as a result of the standards for newly constructed EGUs. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) for further discussion of sensitivities.) We have therefore concluded that this final action will have no net regulatory burden for all directly regulated small entities.

2. Modified and Reconstructed EGUs

The EPA expects few fossil fuel-fired electric utility steam generating units to trigger the NSPS modification provisions 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.

In addition, the EPA expects few reconstructed fossil fuel-fired electric utility steam generating units or natural gas-fired 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.

In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources, including any that are owned by small entities. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015).

D. Unfunded Mandates Reform Act (UMRA)

This final action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

The EPA believes the final rule will have negligible compliance costs on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015) for further discussion of sensitivities.)

As previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. In Chapter 6 of the RIA, we discuss factors that limit our ability to quantify the costs and benefits of the standards for modified and reconstructed sources. However, we do not anticipate that the rule would impose significant costs on those sources. (See the ''Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units'' (EPA–452/R–15–005, August 2015).)

We have therefore concluded that the standards for newly constructed, modified, and reconstructed EGUs do not impose enforceable duties on any state, local or tribal governments, or the private sector, that may result in expenditures by state, local and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. We have also concluded that this action does not have regulatory requirements that might significantly or uniquely affect small governments. The threshold amount established for determining whether regulatory requirements could significantly affect small governments is $100 million annually and, as stated above, we have concluded that the final action will not result in expenditures of $100 million or more in any one year. Specifically, the EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly constructed natural gas-fired stationary combustion turbines will meet the standards. Further, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis.

E. Executive Order 13132: Federalism

This final action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. We, therefore, anticipate that the final rule will impose minimal compliance costs.

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

This final action does not have tribal implications as specified in Executive Order 13175. The final rule will impose requirements on owners and operators of newly constructed, modified, and reconstructed EGUs. The EPA is aware of three facilities with coal-fired steam generating units, as well as one facility with natural gas-fired stationary combustion turbines, located in Indian Country, but is not aware of any EGUs owned or operated by tribal entities. We note that because the rule addresses CO_2 emissions from newly constructed, modified, and reconstructed EGUs, it will affect existing EGUs such as those located at the four facilities in Indian Country only if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. As previously stated, the EPA expects few EGUs to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, the rule will neither impose substantial direct compliance costs on tribal governments nor preempt Tribal law. Accordingly, Executive Order 13175 does not apply to this action.

Nevertheless, because the EPA is aware of Tribal interest in carbon pollution standards for the power sector and, consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered consultation with tribal officials during development of this rule. Prior to the April 13, 2012 proposal (77 FR 22392), the EPA sent consultation letters to the leaders of all federally recognized tribes. Although only newly constructed, modified, and reconstructed EGUs will be affected by this action, the EPA's consultation regarded planned actions for new and existing sources. The letters provided information regarding the EPA's development of NSPS and emission guidelines for EGUs and offered consultation. A consultation/outreach meeting was held on May 23, 2011, with the Forest County Potawatomi Community, the Fond du Lac Band of Lake Superior Chippewa Reservation, and the Leech Lake Band of Ojibwe. A description of that consultation is included in the preamble to the proposed standards for new EGUs (79 FR 1501, January 8, 2014).

The EPA also offered consultation to the leaders of all federally recognized tribes after the proposed action for newly constructed EGUs was signed on September, 20, 2013. On November 1, 2013, the EPA sent letters to tribal leaders that provided information regarding the EPA's development of carbon pollution standards for new, modified, reconstructed and existing EGUs and offered consultation. No tribes requested consultation regarding the standards for newly constructed EGUs.

In addition to offering consultation, the EPA also conducted outreach to tribes during development of this rule. The EPA held a series of listening sessions prior to proposal of GHG standards for newly constructed EGUs. 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 also held a series of listening sessions prior to proposal of GHG standards for modified and reconstructed EGUs and GHG emission guidelines for existing EGUs. Tribes participated in a session on September 9, 2013, together with the state agencies, as well as in a separate tribe-only session on September 26, 2013. In addition, an outreach meeting was held on September 9, 2013, with tribal representatives from some of the federally recognized 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. Additional detail regarding this stakeholder outreach is included in the preamble to the proposed emission guidelines for existing EGUs (79 FR 34830, June 18, 2014).

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

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866. While the action is not subject to Executive Order 13045, the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

CO_2 is a potent GHG that contributes to climate change and is emitted in significant quantities by fossil fuel-fired power plants. As stated above, the EPA believes the final rule will have negligible effects on owners and operators of newly constructed EGUs over a range of likely sensitivity conditions because electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the rule because of existing and expected market conditions. However, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS. RIA chapter 5. Under these scenarios, the rule would result in substantial reductions of both CO_2, and also fine particulate matter (sulfate PM 2.5) such that net quantifiable benefits exceed regulatory costs under a range of assumptions. Under these same scenarios, this rule would have a positive effect for children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and lifestages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in Section II.A of this preamble.

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

This final action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. See Section V.O.3 above. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. Thus, this action is not anticipated to have notable impacts on emissions, costs or energy supply decisions for the affected electric utility industry.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This final action involves technical standards. The EPA has decided to use 10 voluntary consensus standards (VCS) in the final rule.

One VCS, American National Standards Institute (ANSI) Standard C12.20, ''American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes,'' is cited in the final rule to assure consistent monitoring of electric output. This standard establishes the physical aspects and acceptable performance criteria for 0.2 and 0.5 accuracy class electricity meters. This standard is available at *http://www.ansi.org* or by mail at American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036.

Six VCS, ASTM Methods D388–99, ''Standard Classification of Coals by Rank''; D396–98, ''Standard Specification for Fuel Oils''; D975–08a, ''Standard Specification for Diesel Fuel Oils''; D3699–08, ''Standard Specification for Kerosine''; D6751–11b, ''Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels''; and D7467–10, ''Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)'' are cited in the final rule to identify the different fuel types. ASTM D388 covers the classification of coals by rank, that is, according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite. ASTM D396 covers grades of fuel oil intended for use in various types of fuel-oil-burning equipment under various climatic and operating conditions. These include Grades 1 and 2 (for use in domestic and small industrial burners), Grade 4 (heavy distillate fuels or distillate/residual fuel blends used in commercial/industrial burners equipped for this viscosity range), and Grades 5 and 6 (residual fuels of increasing viscosity and boiling range, used in industrial burners). ASTM D975 covers seven grades of diesel fuel oils based on grade, sulfur content, and volatility. These grades range from *Grade No. 1–D S15* (a special-purpose, light middle distillate fuel for use in diesel engine applications requiring a fuel with 15 ppm sulfur (maximum) and higher volatility than that provided by Grade No. 2–D S15 fuel) to *Grade No. 4–D* (a heavy distillate fuel, or a blend of distillate and residual oil, for use in low- and medium-speed diesel engines in applications involving predominantly constant speed and load). ASTM D3699 covers two grades of kerosene suitable for use in critical kerosene burner applications: No. 1–K (a special low-sulfur grade kerosene suitable for use in non-flue-connected kerosene burner appliances and for use in wick-fed illuminating lamps) and No. 2–K (a regular grade kerosene suitable for use in flue-connected burner appliances and for use in wick-fed illuminating lamps). ASTM D6751 covers biodiesel (B100) Grades S15 and S500 for use as a blend component with middle distillate fuels. ASTM D7467 covers fuel blend grades of 6 to 20 volume percent biodiesel with the remainder being a light middle or middle distillate diesel fuel, collectively designated as B6 to B20. These standards are available at *http://www.astm.org* or by mail at ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, PA 19428–2959.

Two VCS, American Society of Mechanical Engineers (ASME) Performance Test Codes PTC 22–2014, ''Performance Test Codes on Gas Turbines'' and PTC 46–1996, ''Performance Test Codes on Overall Plant Performance'' are cited in the final rule for their guidance on measuring the performance of stationary combustion turbines. PTC–22 provides directions and rules for conduct and report of results of thermal performance tests for open cycle simple cycle combustion turbines. The object is to determine the thermal performance of the combustion turbine when operating at test conditions, and correcting these test results to specified reference conditions. PTC 22 provides explicit procedures for the determination of the following performance results: corrected power, corrected heat rate (efficiency), corrected exhaust flow, corrected exhaust energy, and corrected exhaust temperature. Tests may be designed to satisfy different goals, including absolute performance and comparative performance. The objective of PTC 46 is to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and combined heat and power units (PTC 46 is not applicable to simple cycle combustion turbines). Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions. PTC 46 provides explicit procedures for the determination of the following performance results: corrected net power, corrected heat rate, and corrected heat input. These standards are available at *http://www.asme.org* or by mail at American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990.

One VCS, International Organization for Standardization method ISO 2314:2009, ''Gas Turbines—Acceptance Tests'' is cited in the final rule for its guidance on determining performance characteristics of stationary combustion turbines. ISO 2314 specifies guidelines and procedures for preparing, conducting and reporting thermal-acceptance tests in order to determine and/or verify electrical power output, mechanical power, thermal efficiency (heat rate), turbine exhaust gas energy and/or other performance characteristics of open-cycle simple cycle combustion turbines using combustion systems supplied with gaseous and/or liquid fuels as well as closed-cycle and semi-closed-cycle simple cycle combustion turbines. It can also be applied to simple cycle combustion turbines in combined cycle power plants or in connection with other heat recovery systems. ISO 2314 includes procedures for the determination of the following performance parameters, corrected to the reference operating parameters: electrical or mechanical power output (gas power, if only gas is supplied), thermal efficiency or heat rate; and combustion turbine engine exhaust energy (optionally exhaust temperature and flow). This standard is available at *http://www.iso.org/iso/home.htm* or by mail at International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland.

Since no EPA Methods were used, there was no need for a NTTAA search. The rule also requires use of appendices A, B, D, F and G to 40 CFR part 75 and the procedures under 40 CFR 98.33; these appendices contain standards that have already been reviewed under the NTTAA.

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

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S. The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work.

Leading up to this rulemaking the EPA summarized the public health and welfare effects of GHG emissions in its 2009 Endangerment Finding. As part of the Endangerment Finding, the Administrator considered climate change risks to minority or low-income populations, finding that certain parts of the population may be especially vulnerable based on their circumstances. Populations that were found to be particularly vulnerable to climate change risks include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. See Sections XIV.F and G, above, where the EPA discusses Consultation and Coordination with Tribal Governments and Protection of Children. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

The record for the 2009 Endangerment Finding summarizes the strong scientific evidence in the major assessment reports 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 that the potential impacts of climate change raise environmental justice issues. These reports concluded that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The 2009 Endangerment Finding record also specifically noted that Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are already experiencing disruptive impacts, including coastal erosion and shifts in the range or abundance of wild species crucial to their livelihoods and well-being.

The most recent assessments continue to strengthen scientific understanding of climate change risks to minority and low-income populations in the United States.[581] The new assessment literature provides more detailed findings regarding these populations' vulnerabilities and projected impacts they may experience. In addition, the most recent assessment reports provides new information on how some communities of color may be uniquely vulnerable to climate change health impacts in the United States. These reports find that certain climate change related impacts—including heat waves, degraded air quality, and extreme weather events—have disproportionate effects on low-income and some communities of color, raising environmental justice concerns. Existing health disparities and other inequities in these communities increase their vulnerability to the health effects of climate change. In addition, assessment reports also find that climate change poses particular threats to health, wellbeing, and ways of life of indigenous peoples in the United States.

As the scientific literature presented above and in the Endangerment Finding illustrates, low income communities and some communities of color are especially vulnerable to the health and other adverse impacts of climate change.

The EPA believes the human health or environmental risk addressed by this final action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The final rule limits GHG emissions from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units and newly constructed and modified stationary combustion turbines by establishing national emission standards for CO_2.

The EPA has determined that the final rule will not result in disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because the rule is not anticipated to notably affect the level of protection provided to human health or the environment. The EPA believes that electric power companies will choose to build new fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines that comply with the regulatory requirements of the final rule because of existing and expected market conditions. The EPA does not project any new coal-fired steam generating units without CCS to be built and expects that any newly built natural gas-fired stationary combustion turbines will meet the standards. In addition, as previously stated, the EPA expects few fossil fuel-fired electric utility steam generating units or natural gas-fired stationary combustion turbines to trigger the NSPS modification or reconstruction provisions in the period of analysis. This final rule will ensure that, to whatever extent there are newly constructed, modified, and reconstructed EGUs, they will use the best performing technologies to limit emissions of CO_2.

K. Congressional Review Act (CRA)

This final action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

XV. Withdrawal of Proposed Standards for Certain Modified Sources

In this action, as discussed above in Sections IV and VI, the EPA is issuing final standards of performance for affected fossil fuel-fired steam generating EGUs that implement modifications resulting in an increase of CO_2 emissions (in lb/hr) of more than 10 percent. In addition, the EPA is withdrawing the proposed standards of performance for emissions of carbon dioxide (CO_2) from modified fossil fuel-fired EGUs not covered by those final standards. Specifically, the EPA is withdrawing the proposed standards for fossil fuel-fired steam generating EGUs that implement modifications resulting in an increase of CO_2 emissions (in lb/hr) of less than or equal to 10 percent. A detailed rationale for the withdrawal of these proposed standards is provided in Section VI above.

The EPA is also, in this action, withdrawing proposed standards for modified stationary combustion turbines. A detailed rationale for the withdrawal of these proposed standards is provided in Section IX above.

The proposed standards for modified fossil fuel-fired EGUs that the EPA is withdrawing in this action were published in the **Federal Register** on June 18, 2014 (79 FR 34960).

[581] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, 841 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 1132 pp.

IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, 688 pp.

XVI. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects

40 CFR Part 60

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

40 CFR Part 70

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

40 CFR Part 71

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

40 CFR Part 98

Environmental protection, Greenhouse gases and monitoring, Reporting and recordkeeping requirements.

Dated: August 3, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, parts 60, 70, 71, and 98 of the Code of the Federal Regulations are amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

■ 2. Section 60.17 is amended by:

■ a. Redesignating paragraphs (d) through (t) as paragraphs (e) through (u) and adding paragraph (d);

■ b. In newly redesignated paragraph (g), further redesignating paragraph (g)(15) as paragraph (g)(17) and adding paragraphs (g)(15) and (16);

■ c. In newly redesignated paragraph (h), revising paragraphs (h)(37), (42), (46), (138), (187), and (190); and

■ c. In newly redesignated paragraph (m), further redesignating paragraph (m)(1) as paragraph (m)(2) and adding paragraph (m)(1).

The revisions and additions read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) The following material is available for purchase from the American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036, Telephone (212) 642–4980, and is also available at the following Web site: *http://www.ansi.org.*

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010), IBR approved for § 60.5535(d).

(2) [Reserved]

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(g) * * *

(15) ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), IBR approved for § 60.5580.

(16) ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), IBR approved for § 60.5580.

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(h) * * *

(37) ASTM D388–99 (Reapproved 2004) $^{\varepsilon 1}$ Standard Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, 60.251, and 60.5580.

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(42) ASTM D396–98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), 60.111a(b), and 60.5580.

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(46) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b 60.41c, and 60.5580.

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(138) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

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(187) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

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(190) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

* * * * *

(m) * * *

(1) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for § 60.5580.

* * * * *

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

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

Applicability

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU.

§ 60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any steam generating unit or IGCC that commenced modification after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC that is currently and always has been subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of combusting 50 percent or more non-fossil fuel and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline).

(9) The proposed Washington County EGU project described in Air Quality Permit No. 4911–303–0051–P–01–0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

(10) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of January 8, 2014.

Emission Standards

§ 60.5515 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5520 What CO_2 emission standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in Table 1 or 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Stationary combustion turbines subject to a heat input-based standard in Table 2 of this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). All other stationary combustion turbines subject to a heat input based standard in Table 2 are subject to the requirements in paragraph (d)(2) of this section.

(1) Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 160 lb CO_2/MMBtu or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

General Compliance Requirements

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

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See Table 1 or 2 of this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in million Btus (MMBtu) from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

$$CO_2 \text{ emission standard} = \frac{(120 \text{ x HTIP}_{ng})+(160 \text{ x HTIP}_{o})}{\text{HTIP}_{ng}+\text{HTIP}_{o}} \quad \text{(Eq. 1)}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of lb/MMBtu.
$HTIP_{ng}$ = the heat input in MMBtu from natural gas.
$HTIP_o$ = the heat input in MMBtu from all fuels other than natural gas.
120 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from natural gas.
160 = allowable emission rate in lb of CO_2/MMBtu for heat input derived from all fuels other than natural gas.

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in Table 1 or 2 of this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in § 72.2 of this chapter) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 63.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 63.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced COMMERCIAL operation (as defined in § 72.2 of this chapter) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015, emissions reporting shall begin according to § 63.5555(c)(3)(i) (for Acid Rain program units), or according to § 63.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under § 75.64(a) of this chapter occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 63.5555(c)(3)(iii).

Monitoring and Compliance Determination Procedures

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

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter. The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(c)).

(b) You must determine the hourly CO_2 mass emissions in kilograms (kg) from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected coal-fired EGU or for an IGCC unit you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to § 75.10(a)(3)(i) of this chapter. As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with § 75.10(a)(3)(iii) of this chapter. If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter. Alternatively, you may either use an appropriate fuel-specific default moisture value from § 75.11(b) or submit a petition to the Administrator under § 75.66 of this chapter for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and appendices A and B to part 75 of this chapter.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with part 75 of this chapter. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ‘‘valid operating hours’’, as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in Appendix F to part 75 of this chapter (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 of this chapter (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 909.1 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to part 75 of this chapter to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(3) For each ‘‘valid operating hour’’ (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in § 72.2 of this chapter), to convert it to tons of CO_2. Then, multiply the result by 909.1 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under § 75.57(e) of this chapter and must be reported electronically under § 75.64(a)(6) of this chapter. You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to part 75 of this chapter.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under § 98.33(a)(3) of this chapter.

(d) Consistent with § 60.5520, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to part 75 of this chapter;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under § 98.33(a)(3) of this chapter, you may convert your CO_2 emissions to heat input using the appropriate emission factor in Table C–1 of part 98 of this chapter. If your fuel is not listed in Table C–1, you must determine a fuel-specific carbon-based F-factor (F_c) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to part 75 of this chapter.

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard in Table 1 or 2 of this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(g) In accordance with §§ 60.13(g) and 60.5520 if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in Table 1 or 2 of this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in Table 1 or 2 of this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (7) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*i.e.,* either kg/MWh or lb/MMBtu). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input; or

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) *Sources subject to output based standards.* For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the

procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of megawatt-hours (MWh). To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_A}{\text{TDF}} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_A$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) *Calculation of annual basis for standard.* Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (7) of this section and must be less than or equal to the applicable CO_2 emissions standard in Table 1 or 2 of this part, or the emissions standard calculated in accordance with § 60.5525(a)(2).

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see Table 3 of this subpart).

(b) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable, to your affected EGUs.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525 to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1)(i) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in Table 1 or 2 of this part) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with § 75.64(a) of this chapter, *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in § 75.20(a)(3) of this chapter; or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in § 72.2 of this chapter).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after:

(A) The date on which reporting is required to begin under § 75.64(a) of this chapter, if that date occurs on or after October 23, 2015; or

(B) October 23, 2015, if the date on which reporting would ordinarily be required to begin under § 75.64(a) of this chapter has passed prior to October 23, 2015.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with § 75.4(j) of this chapter, § 75.37(b) of this chapter, or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under § 72.20 of this chapter; or

(2) The person appointed as the Alternate Designated Representative (ADR) under § 72.22 of this chapter; or

(3) A person (or persons) authorized by the DR or ADR under § 72.26 of this chapter to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs on-site, or

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, if injection occurs off-site.

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system itself, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560 What records must I maintain?

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

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under § 75.53(g) and (h) of this chapter;

(ii) Operating parameter records under § 75.57(b)(1) through (4) of this chapter;

(iii) The records under § 75.57(c)(2) of this chapter, for stack gas volumetric flow rate;

(iv) The records under § 75.57(c)(3) of this chapter for continuous moisture monitoring systems;

(v) The records under § 75.57(e)(1) of this chapter, except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O_2 monitors used to calculate CO_2 concentration;

(vi) The records under § 75.58(c)(1) of this chapter, specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under § 75.58(c)(4) of this chapter, specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under § 75.59(a) of this chapter, specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under § 75.59(e) of this chapter.

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in Table 1 or 2 of this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

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

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 3 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570 What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in Table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions of this part).

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99 (Reapproved 2004) ε^1 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that that use a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see § 60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see § 60.17) or ISO 2314 Gas turbines—acceptance tests (incorporated by reference, see § 60.17).

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined by ASTM International in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined by ASTM International in ASTM D3699 (incorporated by reference, see § 60.17); biodiesel as defined by ASTM International in ASTM D6751 (incorporated by reference, see § 60.17); or biodiesel blends as defined by ASTM International in ASTM D7467 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria)

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

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

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on an annual basis, the gross electric sales to the utility power

distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales that that result from a system emergency are not included when calculating net-electric sales.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss of load.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in § 75.20 of this chapter and appendix A to part 75 of this chapter must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to part 75 of this chapter must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to part 75 of this chapter apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to part 75 of this chapter must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 or 2 of this subpart.

TABLE 1 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS AND INTEGRATED GASIFICATION COMBINED CYCLE FACILITIES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION OR MODIFICATION AFTER JUNE 18, 2014

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg of CO_2 per MWh of gross energy output (2,000 lb CO_2/MWh).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg of CO_2 per MWh of gross energy output (1,800 lb CO_2/MWh).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: 1. 1,800 lb CO_2/MWh-gross for units with a base load rating greater than 2,000 MMBtu/h; or 2. 2,000 lb CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or less.

TABLE 2 OF SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION AFTER JANUARY 8, 2014 AND RECONSTRUCTION AFTER JUNE 18, 2014 (NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh).
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in § 60.5525.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8	Performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	No	All monitoring is done according to part 75.

TABLE 3 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTT—Continued

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

PART 70—STATE OPERATING PERMIT PROGRAMS

■ 4. The authority citation for part 70 continues to read as follows:

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

■ 5. In § 70.2, the definition of ''Regulated pollutant (for presumptive fee calculation)'' is amended by:
■ a. Revising the introductory text;
■ b. Removing ''or'' from the end of paragraph (2);
■ c. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ d. Adding paragraph (4).

The revision and additions read as follows:

§ 70.2 Definitions.

* * * * *

Regulated pollutant (for presumptive fee calculation), which is used only for purposes of § 70.9(b)(2), means any regulated air pollutant except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 6. Section 70.9 is amended by revising paragraph (b)(2)(i), and adding paragraph (b)(2)(v) to read as follows:

§ 70.9 Fee determination and certification.

* * * * *

(b) * * *

(2)(i) The Administrator will presume that the fee schedule meets the requirements of paragraph (b)(1) of this section if it would result in the collection and retention of an amount not less than $25 per year [as adjusted pursuant to the criteria set forth in paragraph (b)(2)(iv) of this section] times the total tons of the actual emissions of each regulated pollutant (for presumptive fee calculation) emitted from part 70 sources and any GHG cost adjustment required under paragraph (b)(2)(v) of this section.

* * * * *

(v) *GHG cost adjustment.* The amount calculated in paragraph (b)(2)(i) of this section shall be increased by the GHG cost adjustment determined as follows: For each activity identified in the following table, multiply the number of activities performed by the permitting authority by the burden hours per activity, and then calculate a total number of burden hours for all activities. Next, multiply the burden hours by the average cost of staff time, including wages, employee benefits and overhead.

Activity	Burden hours per activity
GHG completeness determination (for initial permit or updated application)	43
GHG evaluation for a permit modification or related permit action	7
GHG evaluation at permit renewal	10

* * * * *

PART 71—FEDERAL OPERATING PERMIT PROGRAMS

■ 7. The authority citation for part 71 continues to read as follows:

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

■ 8. In § 71.2, the definition of ''Regulated pollutant (for fee calculation)'' is amended by:
■ a. Removing ''or'' from the end of paragraph (2);
■ b. Removing the period at the end of paragraph (3) and adding ''; or'' in its place; and
■ b. Adding paragraph (4).

The revisions and additions read as follows:

§ 71.2 Definitions.

* * * * *

Regulated pollutant (for fee calculation), which is used only for purposes of § 71.9(c), means any ''*regulated air pollutant''* except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

■ 9. Section 71.9 is amended by:
■ a. Revising paragraphs (c)(1), (c)(2)(i), (c)(3), and (c)(4); and
■ b. Adding paragraph (c)(8).

The revisions and addition read as follows:

§ 71.9 Permit fees.

* * * * *

(c) * * *

(1) For part 71 programs that are administered by EPA, each part 71 source shall pay an annual fee which is the sum of:

(i) $32 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(ii) Any GHG fee adjustment required under paragraph (c)(8) of this section.

(2) * * *

(i) Where the EPA has not suspended its part 71 fee collection pursuant to paragraph (c)(2)(ii) of this section, the annual fee for each part 71 source shall be the sum of:

(A) $24 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(B) Any GHG fee adjustment required under paragraph (c)(8) of this section.

* * * * *

(3) For part 71 programs that are administered by EPA with contractor assistance, the per ton fee shall vary depending on the extent of contractor involvement and the cost to EPA of contractor assistance. The EPA shall establish a per ton fee that is based on the contractor costs for the specific part 71 program that is being administered, using the following formula:

Cost per ton = $(E \times 32) + [(1 - E) \times \$C]$

Where E represents EPA's proportion of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed by using the following formula:

$C = [B + T + N]$ divided by 12,300,000

Where B represents the base cost (contractor costs), where T represents travel costs, and where N represents nonpersonnel data management and tracking costs. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

(4) For programs that are delegated in part, the fee shall be computed using the following formula:

Cost per ton = $(E \times 32) + (D \times 24) + [(1 - E - D) \times \$C]$

Where E and D represent, respectively, the EPA and delegate agency proportions of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E - D$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed using the formula for contractor assistance cost found in paragraph (c)(3) of this section and shall be zero if contractor assistance is not utilized. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

* * * * *

(8) *GHG fee adjustment.* The annual fee shall be increased by a GHG fee adjustment for any source that has initiated an activity listed in the following table since the fee was last paid. The GHG fee adjustment shall be equal to the set fee provided in the table for each activity that has been initiated since the fee was last paid:

Activity	Set fee
GHG completeness determination (for initial permit or updated application)	$2,236
GHG evaluation for a permit modification or related permit action	364
GHG evaluation at permit renewal	520

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PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 10. The authority citation for part 98 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 11. Section 98.426 is amended by adding paragraph (h) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(h) If you capture a CO_2 stream from an electricity generating unit that is subject to subpart D of this part and transfer CO_2 to any facilities that are subject to subpart RR of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the subpart D facility;

(2) Report each facility identification number associated with the annual GHG reports for each subpart RR facility to which CO_2 is transferred; and

(3) Report the annual quantity of CO_2 in metric tons that is transferred to each subpart RR facility.

■ 12. Section 98.427 is amended by adding paragraph (d) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(d) Facilities subject to § 98.426(h) must retain records of CO_2 in metric tons that is transferred to each subpart RR facility.

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